EXHIBIT NO. ___(JCW-2C)
DOCKET NO. UG-151663
WITNESS: JEFF C. WRIGHT

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

In the Matter of the Petition of **PUGET SOUND ENERGY** **for (i) Approval of a Special Contract for Liquefied Natural Gas Fuel Service with Totem Ocean Trailer Express, Inc. and (ii) a Declaratory Order Approving the Methodology for Allocating Costs Between Regulated and Non-regulated Liquefied Natural Gas Services**	**DOCKET NO. UG-151663**

FIRST EXHIBIT (CONFIDENTIAL) TO THE
PREFILED TESTIMONY OF JEFF C. WRIGHT
IN SUPPORT OF SETTLEMENT

REDACTED VERSION

OCTOBER 7, 2016

BWMQ FINAL REPORT

ON

PSE TACOMA LNG PROJECT

FOR

MEDIATION PARTIES

September 29, 2016

Brown, Williams, Moorhead & Quinn, Inc.
Energy Consultants

Redacted Version

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BWMQ ISSUES AND ANALYSIS FOR MEDIATION PARTIES IN:

***The Petition of Puget Sound Energy for Approval of a Special Contract for Liquefied Natural Gas Fuel Service with Totem Ocean Trailer Express, Inc. and a Declaratory Order Approving the Methodology for Allocating Costs Between Regulated and Non-regulated Liquefied Natural Gas Services*, Docket UG-151663 ("Docket UG-151663").**

INTRODUCTION

Brown Williams Moorhead & Quinn (BWMQ) is an energy consulting firm that specializes in Federal Energy Regulatory Commission (FERC) rate and certificate proceedings and State proceedings. BWMQ's consultants have participated in hundreds of Section 4 and Section 5 rate case proceedings before FERC. BWMQ offers specialized knowledge regarding cost of service and rate design issues in interstate pipeline rate proceedings and State rate proceedings. BWMQ provides detailed testimony and exhibits on rate case/cost of service issues that include operation and maintenance costs, return on equity, cost of debt, proxy group companies, federal, state, local and other tax issues, depreciation and negative salvage, accumulated deferred tax issues, cost classification, cost functionalization, cost allocation and rate design.

EXECUTIVE SUMMARY

The Mediation Parties in the current proceeding have asked BWMQ to provide assistance in analyzing the evidence presented by Puget Sound Energy in Docket No. UG-151633 concerning (1) approval of a special contract for LNG service to Totem Ocean Trailer Express, Inc. (TOTE) and (2) a declaratory order approving the methodology for allocating costs between regulated and non-regulated LNG services.

In particular, BWMQ was asked to review the following six specific issues.

(1) Analysis of pipeline transportation costs to the Puget Sound geographic market compared to PSE's estimated Tacoma LNG Project. Provide BWMQ's estimate as to the availability and cost of pipeline capacity to meet PSE's stated peaking needs.

(2) Evaluation of cost estimates, including the distribution integration costs, for an alternative and comparable stand-alone LNG peaker plant sited to minimize distribution

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integration costs. "Stand-alone" means the plant provides only peaking services to PSE regulated operations.

(3) Provide an opinion of the just and reasonable range of development cost estimates for this type of project and whether PSE's development cost estimates for this project are within a just and reasonable range.

(4) Cost of Service, Capital Cost Allocations, and Operating Cost Allocations - check and validate the proposed cost allocations for the major capital cost components for the LNG Project to PSE's regulated customers and the cost allocation to the non-regulated Puget LNG customers of PSE's proposed project, consistent with traditional regulatory definitions of fair, just, and reasonable.

(5) LNG Fuel Market - Provide a competitive market analysis for LNG fuel use in the Pacific Northwest geographic market.

(6) An analysis of the costs/benefits and risk/rewards for the Tacoma LNG Project and provide a study that separates the costs/benefits and risk/rewards for the regulated gas ratepayers and the non-regulated LNG fuel market. In addition, provide an analysis of the costs and benefits of the 1.4 million gallons of LNG tank capacity that will, on peak days, serve the LNG fuel customers allowing up to 19,273 Dth/day of flowing gas to be diverted to PSE's Core Gas Customers.

This report addresses each issue in detail below. In summary:

Issue 1

BWMQ finds that there is a difference in the cost of incremental pipeline capacity on Northwest Pipeline (Northwest) and Westcoast Energy (Westcoast) as presented by PSE. Specifically, PSE's Tacoma LNG cost model utilizes pipeline cost assumptions of 56 cents per dekatherm per day (Dth/d) for incremental capacity on Northwest and 52 cents per Dth/d for incremental capacity on Westcoast. Northwest presented information that shows several potential capacity increases on several paths on its system resulting in incremental rates of between [redacted] cents to [redacted] cents per Dth/d when utilizing a 25-year levelized negotiated rate or a cost based recourse rate with incremental rates between [redacted] cents and [redacted] cents per Dth/d. In addition, Westcoast presented information showing that an expansion of 85,000 Dth/d would result in rates in a range from [redacted] cents to [redacted] cents per Dth/d. BWMQ reviewed PSE's Tacoma LNG Project (LNG Project) cost model and utilized the model to analyse ten different pipeline rate. Under each scenario tested, the Tacoma LNG cost model demonstrates that the LNG Project has a cost advantage over a pipeline expansion alternative for the PSE Core Gas Customers. Two additional scenarios demonstrate that the LNG Project has a cost advantage for PSE's Core Gas Customers over a pipeline expansion alternative even if the capacity for third party LNG fuel sales is unsubscribed.

Issue 2

BWMQ contracted with Mott MacDonald and Northstar Industries (Northstar) to provide estimates for the LNG Project as proposed by PSE. Mott MacDonald and Northstar provided independent cost estimates for two different alternatives.

> Alternative 1: an 8 million gallon storage tank, 250,000 gallon per day liquefaction capacity, regasification capacity of 66,000 Dth per day, truck loading system (2 racks), 800 feet of 10" cryogenic line (pipe in casing with nitrogen jacket) to deliver up to 10,000 gallons per day.
>
> Alternative 2: a 6.3 million gallon storage tank, liquefaction scaled down from Alternative 1, regasification capacity of 66,000 Dth per day, truck loading facility (1 rack), no cryogenic line or associated facilities to serve marine fuel market.

The Alternative 1 estimates by Mott MacDonald and Northstar resulted in a lower cost than PSE's filed estimate of $310.7 million. However, the estimators were required to complete their estimates in a short timeframe and lacked project-specific information due to confidentiality concerns. PSE has included a cost estimate of $53.5 million for the upgrades to its distribution facilities. BWMQ independently estimated the cost of the distribution system upgrade at $26.3 million. Like the LNG Project, BWMQ lacked detailed site-specific information about the route of the distribution system upgrades and its estimate reflected a more generic type of construction.

Issue 3

BWMQ was asked to provide an opinion of the just and reasonable range of development cost estimates for this type of project and whether PSE's development cost estimates for this project are within a just and reasonable range. Logic dictates that the LNG Project should be pursued when the Incremental Cost to Core Gas Customers is lower than the costs of Incremental Pipeline Capacity and a pipeline expansion should be followed if the converse is true. As stated above, the LNG Project cost estimate results in lower costs to PSE Core Gas Customers than the cost of Incremental Pipeline Capacity as estimated by BWMQ. Further, while the cost estimates performed by Mott MacDonald and Northstar for the LNG Project were lower than PSE's filed estimate, they do not cause BWMQ to believe that such estimates should supplant PSE's estimate due to the reasons cited under Issue 2. In theory, the cost of the LNG Project would be just and reasonable if the LNG Project results in similar or lower costs to PSE Core Gas Customers than the costs of Incremental Pipeline Capacity.

Issue 4

BWMQ has reviewed the filed Cost of Service, Capital Cost Allocations, and Operating Cost Allocations. BWMQ has made several adjustments to some of the inputs to these calculations that are explained in detail in this report under Issue 4. PSE has followed its Commission approved cost allocation methodology from Docket Nos. UE-960195 and U-072375 and BWMQ finds this cost allocation methodology to be consistent with traditional regulatory definitions of just and reasonable. However, BWMQ believes that Puget LNG should bear the risk for the capacity related to the TOTE contract and capacity for other LNG fuel sales. That is, PSE's filing should be revised and the Washington Commission's accepted cost allocation methodology employed after the PSE LNG Project costs are assigned to jurisdictional service (PSE LDC Costs) and non-jurisdictional service (TOTE LNG fuel sales and third party LNG fuel sales).

Issue 5

BWMQ has provided an updated study of the LNG market in the Pacific Northwest and in particular has reviewed the earlier work of Concentric Energy and Wood Mackenzie. This study is included in Appendix A.

Issue 6

BWMQ has reviewed PSE's Tacoma LNG cost model and has offered various changes in input assumptions. This model allows the Mediation Parties to see the results of different assumptions regarding the cost estimates for the LNG Project and whether or not there is a benefit/reward to PSE's LDC customers. BWMQ explains in Issue 6 that the risk/ rewards vary depending upon the cost of incremental pipeline capacity and adjustments to discrete cost of service items. BWMQ finds that the LNG Project provides a benefit/reward to PSE's LDC customers in all scenarios.

BWMQ has also analyzed the cost of diverting up to 19,273 Dth/day of flowing gas from LNG fuel sales customers and compared this cost to the incremental price of pipeline. The analysis demonstrates that the benefits (in terms of avoided cost) outweigh the costs for the additional LNG storage capacity that allows for the diversion of the gas.

1. Analysis of Pipeline Transportation Costs to the Puget Sound Geographic Market Compared to PSE's Estimated Tacoma LNG Project. Provide BWMQ's estimate as to the availability and cost of pipeline capacity to meet PSE's stated peaking needs.

PSE Filed Position:

PSE believes that it will need additional peaking resources to meet demand beginning in 2017. The Tacoma LNG Project (85,000 Dth/d) will satisfy a portion of the expected demand growth that is outlined in its 2015 Integrated Resource Plan (IRP).[1] PSE chose the Tacoma LNG Project as the least cost resource as opposed to either (1) long-haul interstate pipeline capacity, or (2) regional storage service with pipeline storage redelivery service. Regarding long-haul pipeline capacity, PSE states that Northwest and Westcoast are both fully contracted. Therefore, new pipeline capacity to PSE would have to be based on expansions of these pipeline systems. PSE's Tacoma LNG cost model utilizes pipeline cost assumptions of 56 cents per Dth/d for incremental capacity on Northwest and 52 cents per Dth/d for incremental capacity on Westcoast. PSE's estimated cost assumptions of 56 cents on Northwest and 52 cents on Westcoast are based on the cost of expansions on each pipeline, as will be explained below. PSE's testimony states that it does not generally rely on spot market availability for firm natural gas supply requirements.

PSE provides an in-depth analysis of its natural gas market in its 2015 IRP. PSE's 2015 IRP indicates that the Tacoma LNG Project is cost effective in all ten scenarios that PSE modeled.

BWMQ Analysis:

BWMQ conducted confidential interviews with personnel at Northwest, Westcoast, Kinder Morgan, TransCanada and Gas Transmission Northwest LLC (GTN) concerning the availability and cost of pipeline capacity and the availability and cost of additional storage capacity in the Pacific Northwest geographic market. In addition, both Northwest and Westcoast made presentations to the Mediation Parties on the rate impact of building additional transmission capacity on their pipeline systems to accommodate additional capacity for PSE. The presentations on September 15, 2016, provided updated information on pipeline capacity and costs that supplemented the information BWMQ had ascertained in its earlier interviews with Northwest and Westcoast. Considerable uncertainty exists regarding the cost of incremental natural gas pipeline capacity because there are no recently authorized FERC natural gas pipeline projects nor pending greenfield or expansion projects in the Pacific Northwest market that are relevant to this examination. Further, the need for additional capacity is subject to a myriad of factors.

[1] Note: MMBtu and Dth are equivalent thermal measures of the content of natural gas and are used interchangeably throughout this document.

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Existing Pipeline Capacity on Northwest and Westcoast

PSE states that Westcoast's Huntingdon export point to the U.S. is currently fully contracted as is Northwest's import point at Sumas. BWMQ reviewed the informational postings provided on each pipeline's website to review the contractual commitments, by shipper, and to review the type of shipper. The assumption is that marketer/producer shippers will make their transportation capacity (or bundled commodity) available to other market participants, such as PSE, when market conditions support sales to the LDC load.

Westcoast has 73 percent (888,930 million Btu or MMBtu) of its Huntingdon capacity contracted by marketing/producer shippers while 27 percent (331,985 MMBtu) of Huntingdon capacity was contracted by the LDC shippers as of August 4, 2016. Some short term capacity was also available at the Huntingdon delivery point but this was not year-round capacity. The percentage of marketer/producers on Westcoast likely changes at peak periods.

Northwest has 88 percent (1,147,986 MMBtu) of its Sumas capacity contracted by LDC shippers and the remaining 12 percent contracted by marketer/producers. Northwest is fully contracted at Sumas on a year-round basis.

Cost of Existing and Incremental Pipeline Capacity on Northwest and Westcoast

Northwest

Existing pipeline capacity on Northwest under its postage stamp rate design at Sumas is 44 cents per MMBtu (firm demand rate of 40.88 cents and a 3 cent commodity rate). PSE states that there is uncertainty regarding the cost of new pipeline projects on Northwest and Westcoast. BWMQ agrees that there is uncertainty associated with a major expansion on the Northwest system. PSE assumes new incremental pipeline capacity on Northwest would be 56 cents per MMBtu based on incremental pipeline capacity for a much larger project, the Washington Expansion Project, which proposed a capacity of 750,000 MMBtu/d with significant new pipeline facilities (extensive looping of Northwest's existing pipeline) founded, in part, on serving significant new incremental load from a proposed LNG export facility in Washington. (FERC Docket No. CP13-507, withdrawn May 9, 2016, effective May 24, 2016). BWMQ discussed the cost of incremental pipeline capacity with an official at Northwest. The Northwest official indicated that facilities with a capacity of 200,000 MMBtu/d could be added to the Northwest system to make deliveries along the I-5 Corridor at [redacted] cent rate (the so called Washington Expansion Light Project).

In addition, Northwest and GTN (a TransCanada subsidiary) are working on a larger pipeline project, the Trail West Pipeline Project, (which evolved from the now-withdrawn Palomar Gas Transmission Project, FERC Docket No. CP09-35) that could expand pipeline capacity in the Northwest by up to 1,000,000 MMBtu/d. This project would also allow shippers to access additional pipeline capacity and competitively priced Western Canadian Sedimentary Basin (WCSB) gas supplies via GTN. Although shippers would have to contract for capacity on GTN and on WCSB pipelines (e.g., NOVA) in Canada, significant expansions of pipeline

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capacity will be needed in Northern Alberta to move shale gas (Montney, Horn River and Duvernay) to the Alberta Pool (AECO), as will be explained below.

Northwest more recently presented information which portrays a detailed study of expansion on its system to accommodate PSE through what it terms as its Sumas Express Project (formerly, the Washington Expansion Light Project). Northwest indicated that its mainline south of Sumas is a 60-year old 30-inch diameter pipeline with periodic loops of 36-inch diameter pipe. This non-continuous looping has created 161 miles of gaps between Sumas and Washougal (near Portland, Oregon). Northwest is currently in discussion with parties – utilities and others – on the interest in an expansion along such a corridor. Such an expansion would consist of looping (i.e., filling in some of the looping gaps) and compression. Several scenarios have been looked at, all of which involve the receipt of gas at Sumas. The first scenario would consist of building capacity to transport 80,000 MMBtu/d to Tacoma. This example would result in a cost that would translate to a recourse rate of [redacted] cents per MMBtu or a negotiated rate with levelized depreciation over 25 years of [redacted] cents per MMBtu. The second scenario would transport 250,000 MMBtu/day to Tacoma and would have a recourse rate of [redacted] cents per MMBtu and a negotiated rate (as described above) of [redacted] cents per MMBtu. A third scenario would transport 100,000 MMBtu/day to Chehalis with a recourse rate of [redacted] cents per MMBtu and a negotiated rate of [redacted] cents. A final scenario would transport 394,000 MMBtu/day and make deliveries at Chehalis, Grays Harbor, and near Portland at a recourse rate level of [redacted] cents per MMBtu and a negotiated rate of [redacted] cents per MMBtu.

These scenarios would not be economic according to PSE. PSE acknowledges that while its IRP states that it will need additional sources of supply in the future, a pipeline expansion solution of 250,000 MMBtu/d in lieu of the LNG Project will require it to contract for some capacity that it does not need through at least the year 2030. PSE does not believe that it can receive full value compensation in the capacity release market if it released the excess pipeline capacity it would need to contract for. Information from Northwest on capacity releases over the last two years show that for releases of firm capacity (TF-1) between Sumas and Jackson Prairie Storage (south of Chehalis), the capacity release rate ranged between 5 cents per MMBtu and 15 cents per MMBtu. Releases of firm capacity between Sumas and points south of Chehalis, but north of Washougal only received the maximum rate in 4 of 18 incidences with the remaining releases at rates between 4 cents and 27.27 cents per MMBtu. Maximum rate releases have only occurred for capacity releases between Sumas and points south of Washougal.

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Westcoast

Westcoast is a National Energy Board of Canada (NEB) regulated pipeline and is allowed to roll in the cost of expansion facilities into its existing rate structure even if it raises the transportation rates to existing customers. This is in contrast to FERC policy which requires incremental rates to be charged for expansion capacity if the cost of rolling-in the expansion capacity would result in higher transportation rates for existing customers. In effect, the NEB's policy is beneficial to new projects and results in more economic expansions of transmission systems because all of the transportation customers help pay for the facilities not just the incremental customers.

Westcoast's existing fixed toll/tariff rates in U.S. dollars (as of September 29, 2016) are:

Service Term	US$/MMBtu
1 year	0.2718
2 years	0.2639
3 years	0.2560
4 years	0.2533
5 years	0.2506

A favorable exchange rate has decreased the Westcoast toll (rate) in U.S. dollars in recent years and a similar discount to the U.S. dollar is expected to continue into the future. Westcoast is now fully contracted which has helped to lower transportation tolls over the past few years. Current one-year capacity is 27.18 cents per MMBtu exclusive of taxes on Westcoast.

PSE assumes new pipeline capacity on Westcoast would be priced at 52 cents per Dth/d. PSE states that there is uncertainty regarding the cost of new pipeline capacity on Westcoast. Westcoast told BWMQ that [redacted] cent estimate was for a large "T South" expansion project that would have significantly increased Westcoast's pipeline capacity. Westcoast directly accesses the Montney and Horn River shales in northern British Columbia.

BWMQ discussed the cost of Westcoast pipeline capacity with an official at Westcoast. Westcoast has one "sweet spot" expansion left for capacity to Huntingdon and can increase its transportation capacity by 100,000 to 200,000 MMBtu/d at a rolled-in cost increase of approximately 4 cents. This relatively cheap expansibility would result from the installation of more compression versus pipeline looping. Expansions beyond 200,000 MMBtu/d would be priced much higher because a greater amount of pipeline looping would need to be installed.

On September 15, 2016, Westcoast updated some of the cost estimates for capacity expansions. Westcoast now believes that an expansion of 85,000 MMBtu/d to 160,000 MMBtu/d will add an additional 4 to 7 cents to its unit transportation rate. In addition, the Westcoast shippers are requiring improvements and system upgrades approved by the NEB that will add more to the unit transportation rate in 2017 and 2018. Westcoast believes that an

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expansion on the Westcoast pipeline system with the upgrades will result in a transportation cost of between [redacted] cents and [redacted] cents US per MMBtu/d, or an average rate of [redacted] cents.[2]

Storage

PSE currently holds 480,000 Dth/d of delivery capacity from the Jackson Prairie Storage Facility located off of Northwest's system, south of Chehalis. This deliverability allows PSE to meet about 40 percent of its customers peak winter demand. When withdrawn, this stored gas is transported by Northwest to PSE's system. Two questions arise: can the storage capacity of Jackson Prairie can be expanded and, if so, can Northwest transport more gas out of Jackson Prairie storage to PSE? PSE has confirmed that the Jackson Prairie storage reservoirs cannot be expanded. More importantly, even if the deliverability out of storage could be increased, there is no capacity on the Northwest system to ship additional volumes to PSE on peak days. This also eliminates any idea of attempting to acquire additional storage capacity from other storage customers. With the limitation on pipeline capacity, the acquisition of additional capacity from other storage customers, if possible, would only allow PSE to have more days of storage, but not the ability to meet "needle-peak" demand.

U.S. Pacific Northwest Infrastructure

The U.S. Pacific Northwest will need additional pipeline capacity within the next several years. A growing population, higher emission standards, and potential growth of natural gas as a generation fuel and as a transportation fuel are all factors that indicate the need for additional pipeline capacity. Pipeline capacity needs could grow significantly if a large LNG export facility is constructed in the Northwest and/or methanol plants are constructed in the Northwest. In the latter case, a new greenfield pipeline would be required with the ability to move up to 2 to 3 billion cubic feet per day (Bcf/d) and possibly greater quantities.[3]

Currently, the Trail West Pipeline Project is looking for support before proceeding further. Trail West Pipeline capacity could be up to 1 Bcf/d. However, Trail West Pipeline would not deliver gas directly to PSE; Northwest would also need to expand its existing pipeline facilities across the Columbia River and along the I-5 Corridor. These expansion projects would be challenged by environmentalists and may be delayed based on the history of recent pipeline projects in the Northeast U.S.

Natural Gas Supply Considerations

PSE currently supplies its customers with natural gas supplies from the Rockies, San Juan Basin, Northern British Columbia and the WCSB. PSE can receive gas supplies from the Rockies and San Juan Basin through its existing interconnect with Northwest. It could receive Rockies gas supplies from Ruby Pipeline via displacement/backhaul service on GTN to Northwest or to a new Trail West Pipeline to Northwest. PSE can receive Northern British

[2] An NEB forecasting model projects a conversion range of 81 cents to 85 cents US per $1CAD through 2035. BWMQ used a mid-point of 83 cents.
[3] 1 Bcf/d is roughly equivalent to 1,000,000 MMBtu/d or 1,000,000 Dth/d.

Columbia (Montney and Horn River) shale gas delivered by Westcoast to Northwest at Sumas, Washington. PSE can receive WCSB gas supplies from Alberta via GTN and Northwest (and potentially through GTN and Trail West), and/or the prospective expansion of Fortis BC pipeline capacity to Northwest at Sumas.

PSE's access to natural gas supplies from a diverse geographic area benefits rate payers by reducing the cost of natural gas supplies as producers/marketers compete for markets in the Northwest. Multiple supply basins also reduce price volatility and risk. At the current time and based on market intelligence gathered by BWMQ, Canadian natural gas supplies are seen as the preferred gas supplies for the Pacific Northwest based on delivered cost and future availability. The discovery of significant new shale and tight gas reserves in the Montney, Horn River, and Duvernay with low development/production costs combined with a significantly weaker Canadian currency has led to WCSB natural gas prices that are the lowest in North America. Cash market prices for gas on Westcoast at Station 2 was the lowest cost gas in North America on August 16, 2016 according to Natural Gas Intelligence $1.08 Cdn$/GJ or $0.88 US$/MMBtu. Exploration and production companies claim very low development and production costs for these developing supply basins in Northern British Columbia and Northern Alberta. Potential reserves are in the category of the Marcellus/Utica resource base, or well in excess of 1,000 trillion cubic feet.

The primary issue with Montney, Horn River and Duvernay gas reserves are the distance those reserves have to be transported to markets. It is approximately 800 miles to the AECO hub in Southern Alberta from the Montney and even further from Horn River. TransCanada's NOVA Gas Transmission (NGTL) pipeline system has received initial approval from the NEB to construct significant new pipeline facilities to increase its transportation capacity to flow additional gas supplies from Northern Alberta to Alberta markets and the TransCanada mainline. Access to Montney, Horn River and Duvernay gas reserves for PSE customers via TransCanada will likely be more expensive due to pancaked transportation rates (NGTL, NIT A/BC, A/BC-Kingsgate, GTN at Kingsgate to Stanfield, and Northwest to PSE. See, TransCanada Toll Calculator).

Transportation of Montney and Horn River gas supplies to PSE utilizing the pipeline facilities of Westcoast would not incur pancaked rates similar to supply via NGTL, TransCanada and GTN. Montney and Horn River gas supplies are expected to continue to increase significantly and displace the continuing decline in WCSB conventional production. The ongoing displacement of WCSB gas supplies by Marcellus/Utica gas supplies in the U.S. Northeast, Upper Midwest, and even Ontario and Quebec markets, means that WCSB gas supplies will compete for markets in Western Canada and the Western U.S.

Numerous LNG export facilities have been proposed near Prince Rupert and Kitimat, British Columbia. Most of these projects are producer-driven projects that are dependent upon proposed pipeline projects that would transport gas from the Montney and Horn River shale deposits to the potential LNG terminals on the British Columbia coast. Significant uncertainty exists as to how many LNG export facilities will be constructed in Western Canada, as well as the pipeline projects that would supply them. Further uncertainty exists regarding whether the construction of LNG export facilities will impact available pipeline capacity on Westcoast (marketers and producers may take their gas to British Columbia LNG export markets instead of Huntingdon) or the availability of gas supplies from the Montney and Horn River shales. No LNG export facilities (or supplying pipelines) are under construction in British Columbia. These projects are experiencing environmental and economic issues.

California gas demand has been declining and is expected to be flat or decline slightly in the future (see, e.g., 2016 California Gas Report, prepared by the California Gas and Electric Utilities which predicts a decline from demand of 6.1 Bcf/d in 2016 to 4.9 Bcf/d in 2035). The California natural gas market has significant excess interstate pipeline capacity. The Pacific Northwest market and LNG exports are potential growth areas for Canadian natural gas exports, especially with this expected decline in California demand. British Columbia and WCSB gas supplies should be readily available at very competitive prices (likely below Henry Hub index prices for a significant period of time).

Rocky Mountain gas supplies have been declining in recent years and this trend is expected to continue due to higher marginal costs of Rocky Mountain gas production. The recently-built Rocky Mountain supply pipelines (Ruby and Bison) are experiencing significant underutilization. The Rockies Express Pipeline has been reversed to flow Marcellus/Utica gas supplies as far west as Chicago.

BWMQ Conclusion

PSE witness Riding’s testimony explains that PSE has made the decision to directly purchase capacity on Westcoast for up to 100 percent of its peak-day Sumas/Huntingdon supply requirements, given the projected increase in demand in the Vancouver, British Columbia area and considering that Westcoast is now fully contracted. PSE previously balanced 50 percent of its supply needs through Sumas with a combination of Westcoast capacity and purchases from marketers and third parties at the border. Witness Riding’s testimony states that approximately 25 percent of Westcoast’s year-round capacity is held by marketers and third party shippers (producers) that make sales at Sumas. Based on the evidence reviewed by BWMQ, we believe that PSE’s decision to source gas supplies from Westcoast will result in lower delivered costs for PSE LDC customers than sourcing gas supplies from the Rockies or WCSB gas delivered through Northwest and GTN.

PSE utilized transportation rates for incremental pipeline capacity on Westcoast and Northwest that are higher than incremental pipeline capacity should cost on those two systems. As discussed above, improved estimates of the cost of incremental pipeline capacity by Northwest and Westcoast show a unit transportation cost less than what was utilized by PSE in its analysis. However, reflecting updated transportation rates in the Tacoma LNG cost model does not reverse the findings that the PSE Tacoma LNG Project is the least cost alternative for the PSE Core Gas Customers. As can be seen in Appendix D, under each scenario tested, a comparison of the 25-year and 40-year net present value (NPV) of the PSE Core Gas Customers

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allocated costs of Tacoma LNG are less than the projected cost of incremental pipeline capacity.[4] Appendix D also shows that this finding remains true regardless of the quantity of the initially unsubscribed capacity that later becomes subscribed.

2. <u>Evaluation of cost estimates, including the distribution integration costs, for an alternative and comparable stand-alone LNG peaker plant sited to minimize distribution integration costs. "Stand-alone" means the plant provides only peaking services to PSE regulated operations.</u>

<u>PSE LNG Estimate and Independent Engineering Estimates from Mott MacDonald and Northstar Industries:</u>

BWMQ received and examined three estimates for the construction of the Tacoma LNG Facility. There was the estimate performed by Chicago Bridge & Iron for PSE (CB&I/PSE) which was contained in the materials that BWMQ received. In addition, BWMQ sought and received estimates from the engineering firms Mott MacDonald and Northstar Industries.

The estimates are organized by the major cost elements displayed in the CB&I/PSE estimate. The Mott MacDonald and Northstar Industries estimates fit into this major cost element outline for the sake of comparability. The estimates from Mott MacDonald and Northstar Industries contain pricing estimates for two alternatives as requested by the Parties. The Alternative 1 estimates are comparable in scope to the CB&I/PSE in that they are based on the following design criteria: an 8 million gallon LNG storage tank, 250,000 gallon per day liquefaction capacity, regasification capacity of 66,000 Dth per day, truck loading system (2 racks), 800 foot 10" cryogenic line (pipe in casing with nitrogen jacket) to deliver up to 10,000 gallons per day. The Alternative 2 estimates prepared by Mott MacDonald and Northstar Industries are based on the following criteria: a 6.3 million gallon LNG storage tank, liquefaction scaled down from Alternative 1, regasification capacity of 66,000 Dth per day, truck loading facility (1 rack), and no cryogenic line or associated facilities to serve the marine fuel market.

Mott MacDonald's Alternative 1 estimate is $173.3 million and Northstar Industries Alternative 1 estimate is $233.8 million, which should be compared to the CB&I/PSE's estimate of $310.7 million. Mott MacDonald's Alternative 2 estimate is $138.8 million and Northstar Industries alternative two estimate is $154.1 million. Again, these alternative two estimates are for a scaled-down storage tank and liquefaction facilities and do not include a cryogenic line or the associated facilities to serve the marine market.

[4] Since the cost advantage of Tacoma LNG over incremental pipeline capacity occurred even in a scenario where Northwest Pipeline capacity is assumed to be $[redacted] Dth/day and PSE is assumed to be able to remarket (or equivalent) any remaining excess capacity associated with the pipeline expansion, BWMQ determined that the outcome for any scenario where PSE is unable to remarket (or equivalent) any excess Northwest capacity would similarly result in an outcome where Tacoma LNG offers a cost advantage to incremental pipeline capacity.

Distribution Upgrade Costs

PSE has included a cost estimate of $56.3 million ($53.5 million in capital costs, $2.8 million in AFUDC) for the upgrades to its distribution facilities. The costs associated with the distribution facilities is separately estimated by BWMQ to be $27.3 million. This estimated cost was calculated by taking the estimated cost per mile of construction for applications filed with the FERC between July 1, 2014 and June 30, 2015 compiled by the *Oil & Gas Journal*. BWMQ examined the cost per mile for 12-inch and 16-inch pipelines, as well as the overall cost per mile for diameter pipelines. Then, BWMQ adopted the average of the highest per mile cost (all diameter, $5.3 million per mile) and the lowest cost per mile (12-inch diameter, $3.95 million per mile) and then multiplied by the number of miles of pipeline needed to construct – five miles – to arrive at a pipeline cost of $23.9 million. With regard to the Limit Station and the Gate Station, BWMQ examined the cost of building similar facilities as reported to the FERC by interstate pipelines for 2015. This yielded results ranging from $1.3 million to $2.1 million. The average of this range is $1.7 million and applying this average cost to the two facilities yields an estimated cost of $3.4 million.

BWMQ Analysis:

The Mott MacDonald and Northstar estimates show great variance from the CB&I/PSE estimate, especially regarding major cost items. BWMQ believes that the estimates it received from Mott MacDonald and Northstar Industries are not reasonable comparisons to the CB&I/PSE estimate of the Tacoma LNG facility, given the short timeframe and the paucity of data that BWMQ was able to furnish to the two parties due to confidentiality concerns. In essence, the lack of available site-specific information for both estimators resulted in estimates that are fairly generic in nature. PSE has included a cost estimate of $53.5 million for the upgrades to its distribution facilities. BWMQ independently estimated the cost of the distribution system upgrade at $26.3 million. Like the LNG Project, BWMQ lacked detailed site-specific information about the route of the distribution system upgrades and its estimate reflected a more generic type of construction.

BWMQ is not a cost engineering firm and, therefore, has no reason to doubt the veracity of any of the three estimates. However, it is evident that the CB&I estimate benefited from several advantages that Mott MacDonald and Northstar did not have. First, CB&I had the advantage of 3 to 4 years of preparation. CB&I was also able to have access to site-specific information concerning the project. In conjunction with this, CB&I had constant access to the PSE staff assigned to the LNG Project for consultation and clarification. In addition, CB&I has great experience in the field of LNG estimation and construction and is a leader in the industry. Finally, CB&I has an "open book" policy that allowed PSE personnel to examine and question all items in the estimate. These factors lead BWMQ to believe that the CB&I estimate is a reasonable estimate of the cost of constructing the Tacoma LNG Facility.

The amount claimed by PSE for the distribution system upgrade appears to be high in comparison to the BWMQ estimate. Again, BWMQ is not a construction cost estimation firm and used a composite of estimates for seemingly similar facilities (as explained above) that yielded an estimated cost much lower that the PSE estimate. Much like the estimates for the LNG facility, the difference in estimates here reflects the short time frame in which to perform the estimate, the generic nature of the estimate, and, most importantly, the lack of site-specific information to inform a more detailed and accurate estimate.

3. <u>Provide an opinion of the just and reasonable range of development cost estimates for this type of project and whether PSE's development cost estimates for this project are within a just and reasonable range.</u>

<u>BWMQ Comments Regarding the LNG Project Engineering Cost Estimates:</u>

As noted in the previous section, the Mott MacDonald and Northstar Industries estimates for the Tacoma LNG Facility in Alternative 1 in comparison to the CB&I estimate and the BWMQ estimate of the distribution system upgrade versus the PSE estimate were divergent. The differences primarily are due to: (1) the amount of time that was allowed to perform the estimate, and (2) access to PSE. CB&I was hired by PSE to do the front end engineering design and was therefore given time and access to PSE to ascertain all of the unique qualities of the facility to be designed as well as the unique qualities of the site and surrounding area. Mott MacDonald and Northstar Industries were operating on limited time. Their estimates were performed within a 2 to 3 week span based on imperfect information due to the different confidential classifications in the PSE materials supplied to BWMQ. Given this, BWMQ believes that for the reasons stated here and in the previous section, the estimate performed by CB&I represents the best and most practical representation of the expected cost of the LNG Facility. In theory, the cost of the LNG Project would be just and reasonable if the benefits of the LNG Project results in lower costs to PSE's Core Gas Customers than Incremental Pipeline Capacity.

4. <u>Cost of Service, Capital Cost Allocations, and Operating Cost Allocations - check and validate the proposed cost allocations for the major capital cost components for the LNG Project to PSE's regulated customers and the cost allocation to the non-regulated Puget LNG customers of PSE's proposed project, consistent with traditional regulatory definitions of fair, just, and reasonable.</u>

<u>BWMQ Analysis</u>:

BWMQ believes that PSE's filed case generally reflects traditional regulatory rate making concepts. BWMQ further believes that the cost classification, cost allocation and rate making principles used by PSE are within the normal definitions of just and reasonable rate making standards and in accord with the Washington Utilities and Transportation Commission's (Washington Commission) approved rate making methodology for PSE. PSE's witnesses Free and Piliaris follow the cost and rate making principles that have been previously accepted by the Washington Commission.

One of the major issues in this proceeding is the issue of PSE seeking jurisdictional service for the TOTE service, including the proper allocation of costs to TOTE service as a jurisdictional service subject to the Washington Commission. BWMQ is not offering a legal opinion as to whether or not the TOTE service is a jurisdictional service under the Washington Commission. We propose a simple solution and one that the FERC has used numerous times to protect ratepayers and put the risk of projects squarely on the back of project sponsors. BWMQ believes that all of the costs for TOTE LNG service and future third party service should be borne by Puget LNG. PSE jurisdictional distribution customers should not bear any of the costs for TOTE service or third party services. The FERC has a long history of making the sponsors of pipeline and storage projects responsible for the costs of unsubscribed capacity or capacity sold under negotiated rates. Although PSE has designed a cost-based rate for the TOTE services, BWMQ believes that the TOTE contract is more in the nature of a competitive/negotiated rate due to the unique structure of the contract. That is, the TOTE contract was based on a competitive bidding process, TOTE is paying a levelized premium, the TOTE contract is subject to a maximum fixed-price component, and the TOTE contract is subject to reduced pricing if extended in the future. All of these pricing features are representative of the negotiations that take place in a competitive market and reflect the way that Puget LNG will have to market LNG as a fuel for the shipping and trucking industries. Said another way, the competitive market and the good alternatives to LNG as a fuel source (diesel and other fuels) will limit the price that Puget LNG can receive for LNG as a vehicular fuel. In the experience of BWMQ, competitive market pricing does not reflect cost of service ratemaking except in the long run. And over time, Puget LNG will be better served by having the flexibility to price the LNG service to meet the market, providing a discounted price when competitive fuel prices and demand are lower and a higher price when competitive fuel prices and demand are higher.

BWMQ believes that the principle of cost causation and cost incurrence requires Puget LNG to be responsible for the TOTE capacity and third party capacity. This is particularly true for the proposed LNG facility that is designed, in part, to serve these incremental loads. While BWMQ believes that the proposed PSE LNG Project is a creative and worthwhile project it carries a level of risk to PSE's jurisdictional ratepayers that is substantially higher than a pipeline capacity expansion investment. The higher risk of unsubscribed capacity for the LNG facility and the risk of the TOTE contract should be borne solely by Puget LNG. If the LNG Project is approved as filed, with TOTE service deemed a jurisdictional service, PSE could potentially seek to recover costs allocated to TOTE service from the remaining jurisdictional customers if TOTE went bankrupt or failed to pay. However, if the TOTE service is deemed non-jurisdictional and the TOTE contract is prematurely terminated or TOTE went into bankruptcy Puget LNG would be at risk for cost recovery assigned to TOTE. BWMQ believes that in the best interest of the PSE ratepayers, the cost assignment issue should be settled before approval of the LNG facilities.

What LNG Project Costs Should Be Directly Assigned to TOTE and Third Parties (PSE at Risk Condition) and Which Project Costs Should Be Assigned to PSE?

PSE's testimony provides an explanation of the allocation of cost elements to PSE peak shaving LDC customers, TOTE and Third Parties. BWMQ believes that these cost allocators are reasonable allocators with the exception of the assignment of Truck Loading and Common Capital costs. See explanation below. PSE's filed cost allocators are:

Liquefaction Allocator – 90% to TOTE and Third Parties and 10% to LDC Peak Shaving

Storage Allocator – 21% to TOTE and Third Parties and 79% to LDC Peak Shaving

Bunkering (LNG Transport) Allocator – 100% to TOTE (Third Party credit to TOTE) and 0% to LDC Peak Shaving

Vaporization Allocator - 0% to TOTE and Third Parties and 100% to LDC Peak Shaving

Wharfage Allocator – 100% to TOTE and Third Parties and 0% to LDC Peak Shaving

Trucking Allocator – 0% to TOTE, 75% to Third Parties and 25% to LDC Peak Shaving (Updated as of 09/21/16 Parties Support 95% to Third Parties and 5% to LDC Peak Shaving)

Common Capital Cost Allocator – 24% to TOTE, 30% to Third Parties and 46% to LDC Peak Shaving

PSE supports an allocation of 25 percent of trucking capital costs to the LDC Peak Shaving customers, explaining that LNG trucking will be used to support the Gig Harbor LNG facility and mobile LNG operations that support PSE gas system operations. Subsequent to PSE's allocation proposal, discussions between the Mediation Parties have found agreement that a 5 percent allocation of the trucking costs to LDC Peak Shaving customers is appropriate. Seeing that there an understanding between the parties on this particular allocation, BWMQ will not make a recommendation.

BWMQ believes that PSE should allocate the common capital costs based on the weighted costs of liquefaction, storage, bunkering, truck loading and vaporization. PSE only used the weighted costs of liquefaction and storage to allocate common costs. BWMQ's allocation of common costs reduces the LDC Peak Shaving percentage from the filed 46 percent to 43 percent.

BWMQ believes that the trucking allocator favored by the Mediation Parties along with the other major cost allocators (liquefaction, storage, bunkering, vaporization and wharfage) are correctly allocated between PSE Core Customers and TOTE and Third Parties. BWMQ recommends that these allocators be used to determine the costs that are deemed jurisdictional costs that can be recovered from PSE Core Customers and non-jurisdictional costs that are borne by Puget LNG and at risk in the LNG fuel market. Similarly, PSE should make an assignment of other incremental costs (maintenance, labor, lease, insurance, electric, etc.) based on their Washington Commission approved cost allocation methodology between jurisdictional costs (PSE Core Customers) and the non-jurisdictional (LNG fuel market).

BWMQ made additional changes to the PSE model to reflect updates or changes for the cost of debt, inflation rate, the cost of working capital, and the calculation of AFUDC. See BWMQ's Inputs Tab Explanation for an explanation of these adjustments and how to change these cost items in the Excel spreadsheet model.

5. <u>LNG Fuel Market - Provide a competitive market analysis for LNG fuel use in the Pacific Northwest geographic market.</u>

<u>BWMQ Analysis:</u>

Please see the LNG Fuel Market Study included in Appendix A.

6. <u>An analysis of the costs/benefits and risk/rewards for the Tacoma LNG Project and provide a study that separates the costs/benefits and risk/rewards for the regulated gas ratepayers and the non-regulated LNG fuel market.</u>

<u>BWMQ Analysis:</u>

BWMQ has provided alternative cost scenarios using the CB&I cost estimate for the LNG Project utilizing PSE's Tacoma LNG cost model with various changes in input assumptions regarding pipeline expansion rate levels as well as additional cost model changes that are outlined in Appendix B. The Tacoma LNG cost model modifications allow the Mediation Parties to see the results of different assumptions and whether or not there is a benefit/reward to PSE's LDC customers from the costs/risks assumed by the LNG project vis-à-vis pipeline capacity solutions. The risk/rewards vary depending upon the cost of incremental pipeline capacity and the CB&I estimate for the LNG facilities and BWMQ adjustments to discrete cost of service items. As can be seen in Appendix D, the 25-year and 40-year NPV calculations of both the PSE Core Gas Customer's Allocated Costs for Tacoma LNG and the alternative incremental pipeline costs demonstrate that the PSE Core Gas Customers would benefit from the lower-cost Tacoma LNG project compared to incremental pipeline capacity in each scenario tested. This remains true regardless of the amount of unsubscribed capacity which becomes subscribed at a later date.

BWMQ also analyzed the cost to PSE's Core Gas Customers of having additional LNG tank capacity. The LNG Facility's LNG fuel customers will procure 19,273 Dth/day of year-round capacity for its LNG liquefaction needs. As the LNG Facility will not have the ability to liquefy gas at the same time it vaporizes gas, during peak days where PSE Core Gas Customers require up to 19,273 Dth/day of additional gas supplies, the LNG fuel sales customers will divert their 19,273 Dth/day of supplies to meet the needs of the Core Gas Customers in exchange for gas supplies already liquefied by the Core Gas Customers. To make this exchange possible, PSE will hold 1.4 million gallons of additional tank capacity. Since the additional 1.4 million gallons of tank capacity would be allocated to PSE, BWMQ analyzed the cost to the PSE Core Gas Customers for this additional tank capacity and compared this cost to the potential cost to the Core Gas Customers if PSE simply contracted for an additional 19,273 Dth/day of pipeline capacity.

Redacted Version

BWMQ's analysis shows that over 25 years, the total cost to the PSE Core Gas Customers for the additional tank capacity is approximately $24.7 million in 2015 dollars, while the potential cost to contract for an additional 19,273 Dth/day of pipeline capacity on both Northwest and Westcoast is $57.1 million, or higher[5], in 2015 dollars. Also, during peak days, PSE would avoid additional costs associated with purchasing more expensive gas in the spot market. This analysis demonstrates that the estimated benefits (in terms of avoided cost of incremental pipeline capacity) outweigh the costs for the additional LNG storage capacity that allows for the diversion of gas.

[5] This estimate utilized $[redacted] Dth/d for Northwest capacity and $[redacted] Dth/d for Westcoast capacity. As discussed earlier, the cost for Northwest capacity may be underestimated as it may require PSE to contract for capacity in excess of its current needs.

Appendix A

Competitive Market Analysis for LNG Fuel Use in the Pacific Northwest

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I. Introduction

At the request of Puget Sound Energy, Inc. ("PSE"), Washington Utilities and Transportation Commission Staff ("Commission Staff"), the Public Counsel Unit of the Office of Attorney General ("Public Counsel"), the Northwest Industrial Gas Users ("NWIGU"), and the Industrial Customers of Northwest Utilities ("ICNU"), Brown Williams Moorhead & Quinn, Inc. ("BWMQ") has independently prepared a competitive market analysis for liquefied natural gas ("LNG") for use as marine and ground transportation fuel in the Pacific Northwest geographic area.

Examining competition in LNG fuel use markets involves the comparison of a projected Tacoma LNG price to the projected prices of alternative fuels. Since PSE witness Riding has stated that PSE will source 100 percent of peak-day Sumas/Huntingdon supply requirements from Westcoast, Canada will be the most likely source of supply. BWMQ therefore utilized the projected price of natural gas imported from Canada by the U.S. Energy Information Administration ("EIA") as a base price onto which the transportation (upstream and on PSE), storage, and liquefaction costs are added to determine an estimated Tacoma LNG price. For these other costs, BWMQ utilized the (unedited, with the exception of utilizing the above commodity price projection) cost of service model for Tacoma LNG provided by PSE.[1] Other energy price projections from the EIA's Annual Energy Outlook are also utilized for alternative fuels, as discussed below. BWMQ utilized projections from the EIA since they can be publicly and independently audited.

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[1] The model can be found in the data response titled "151663-UG PSE Resp WUTC DR 005_Attach A (HC).xlsx".

II. LNG as a Marine Transportation Fuel

In order to evaluate the competitiveness of LNG fuel use as a replacement for oil as a marine transportation fuel, price projections for LNG and oil are identified and compared over time. The price projection for LNG is constructed by adding a commodity price for natural gas to the cost of transportation, storage, and liquefaction at the Tacoma LNG facility. Relevant oil price projections for the comparison are also identified.

As discussed earlier, price projections for natural gas imported from Canada are used as a base price on which the transportation (upstream and on PSE), storage, and liquefaction costs are added to determine an estimated Tacoma LNG price.

For marine oil-based fuel prices, both West Texas Intermediate ("WTI") and Brent crude oil price projections are examined. Both Brent and WTI have low sulfur contents which are cleaner burning than residual fuel oil, which contains a relatively high sulfur content when compared to Brent and WTI. New global and national regulations have been put into place with the goal of reducing sulfur emissions.[2] The International Maritime Organization put into effect new sulfur regulations for both the North American Energy Control Area ("ECA") and international waters at the start of 2015. The protocols limit emissions in the ECA to "a maximum of 0.1 percent sulfur."[3] Emissions from vessels outside of the ECA are limited to no greater than 0.5 percent sulfur.[4]

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[2] http://www.glmri.org/downloads/lngMisc/NEPIpercent20LNGpercent20aspercent20apercent20Marinepercent20Fuelpercent205-7-13.pdf
[3] EIA, "Marine Fuel Choice for Ocean-Going Vessels within Emissions Control Areas," (2015) at 36.
[4] *Ibid*. at 36.

Fleet owners are faced with three options to reduce sulfur emissions in order to comply with new sulfur standards. The three options include: (1) using high sulfur intermediate fuel oil ("IFO") and installing scrubbers to "clean" the fuel, (2) convert ships to use LNG fuel, or (3) use low sulfur marine gas oil ("MGO"). Although the EIA states that low-sulfur oil has been the preferred choice to accommodate the new ECA standards through 2015[5], it projects that most fleets will choose to go back to using low cost high-sulfur oil (following the installation of scrubbers) as oil prices rise.[6] While LNG as a marine fuel source is the cleanest burning option, resulting in the elimination of essentially all sulfur emissions,[7] conversion costs to utilize LNG are substantial and the price-competitiveness of LNG is critical for LNG to be commercially viable (this comparison is analyzed below).

Current scrubber technology allows for 95 percent of the sulfur found in IFO to be removed, which currently meets ECA emissions standards.[8] If there is an additional lowering of the sulfur emissions standards, however, the current scrubber technology would no longer be sufficient to comply. This suggests that although fleets opting to use LNG for marine transport may initially be paying higher prices for conversion, they will not be affected if the amount of sulfur allowed in emissions is lowered once again and, in fact, may save money in the long-run as an early converter.

As mentioned above, projections by the EIA state that MGO will be the most used substitute only until scrubbers are installed. This is because MGO will become more expensive

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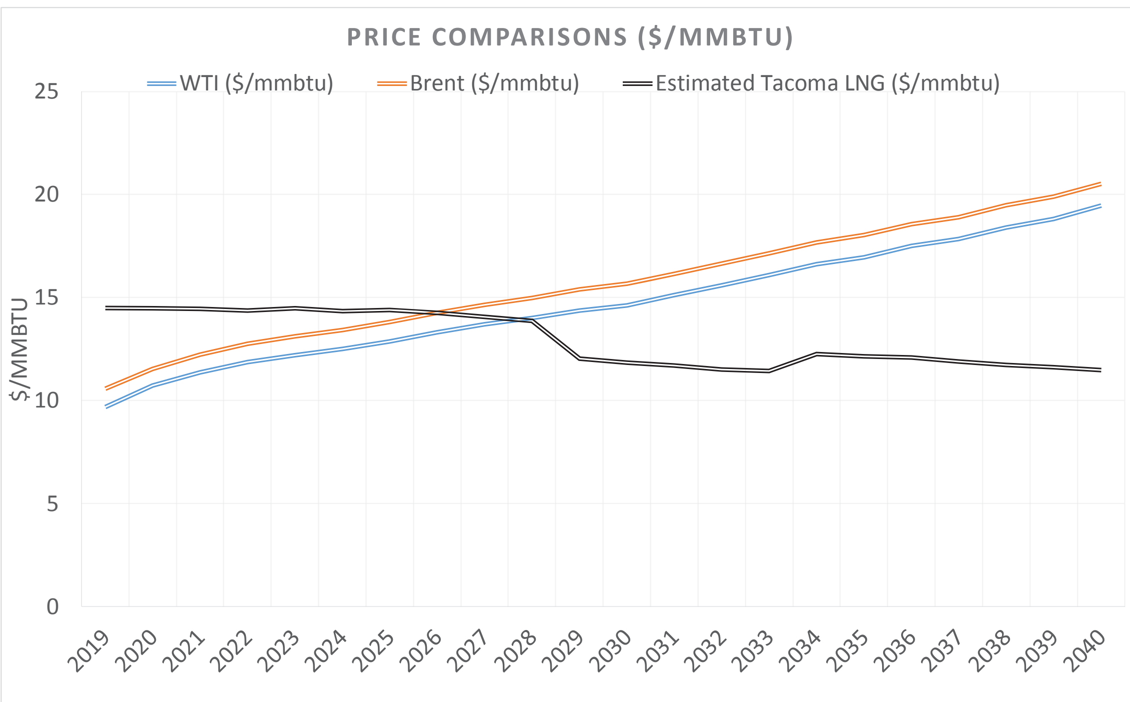
[5] *Ibid*. at 36-38
[6] *Ibid*. at 36-38
[7] API, Liquefied Natural Gas (LNG) Operations, Consistent Methodology for Estimating Greenhouse Gas Emissions. (2015) at 8. http://www.api.org/~/media/files/ehs/climate-change/api-lng-ghg-emissions-guidelines-05-2015.pdf?la=en
[8] EIA, "Marine Fuel Choice for Ocean-Going Vessels within Emissions Control Areas," (2015) at 23

as oil prices rise, causing the investment in scrubbers and fuel alternatives to become more attractive.[9]

The original Wood Mackenzie study utilized by PSE used only the price of Brent crude oil for comparison purposes. WTI is added in BWMQ's projection as it is a domestic product. While historically both Brent and WTI prices have been quite similar, beginning in 2011 domestic U.S. markets have pushed the price of WTI lower than Brent prices consistently, due to higher U.S. oil production.

The WTI, Brent and estimated Tacoma LNG price projections are shown below, converted into real 2015 U.S. dollars per million British Thermal Units (MMBTU).



[9] *Ibid.* at 37

The estimated Tacoma LNG price is projected to be higher than Brent until 2026 and higher than WTI until 2028. The noticeable drop in the estimated Tacoma LNG price from 2028 to 2029 occurs due to the expiration of TOTE's initial 10-year contract term for the Tacoma LNG facility which contained a contract premium, followed by two separate contract extension terms.

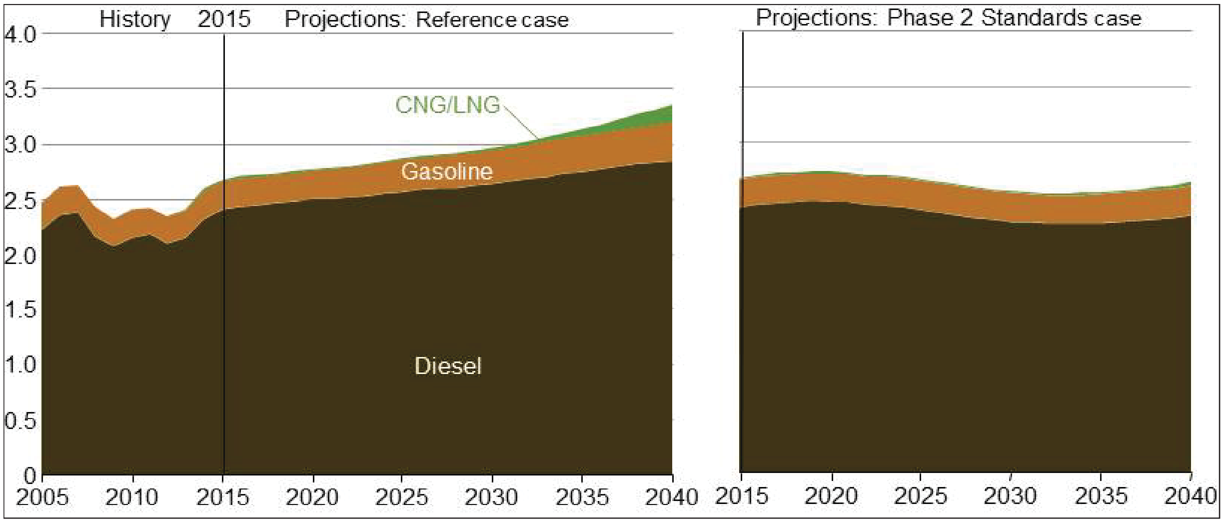
The result of this projection suggests that the estimated Tacoma LNG price in the earliest scenario will not drop below the price of oil before 2026. This is assuming that foreign oil price indicators (Brent) are being used as opposed to domestic oil indicators (WTI). The outcome of this projection also suggests the trend of oil prices will continue to climb in the future, with WTI prices being slightly lower than Brent prices. This analysis of LNG as a marine transportation fuel suggests that low oil prices may dampen the demand for LNG as a marine transportation fuel for the next decade.

III. LNG as Ground Transportation Fuel

Although compressed natural gas has a small market share within various classes of ground transportation within Washington State, LNG use is very limited as a ground transportation fuel. BWMQ analyzed the market for LNG as a fuel for ground transportation within Washington State.

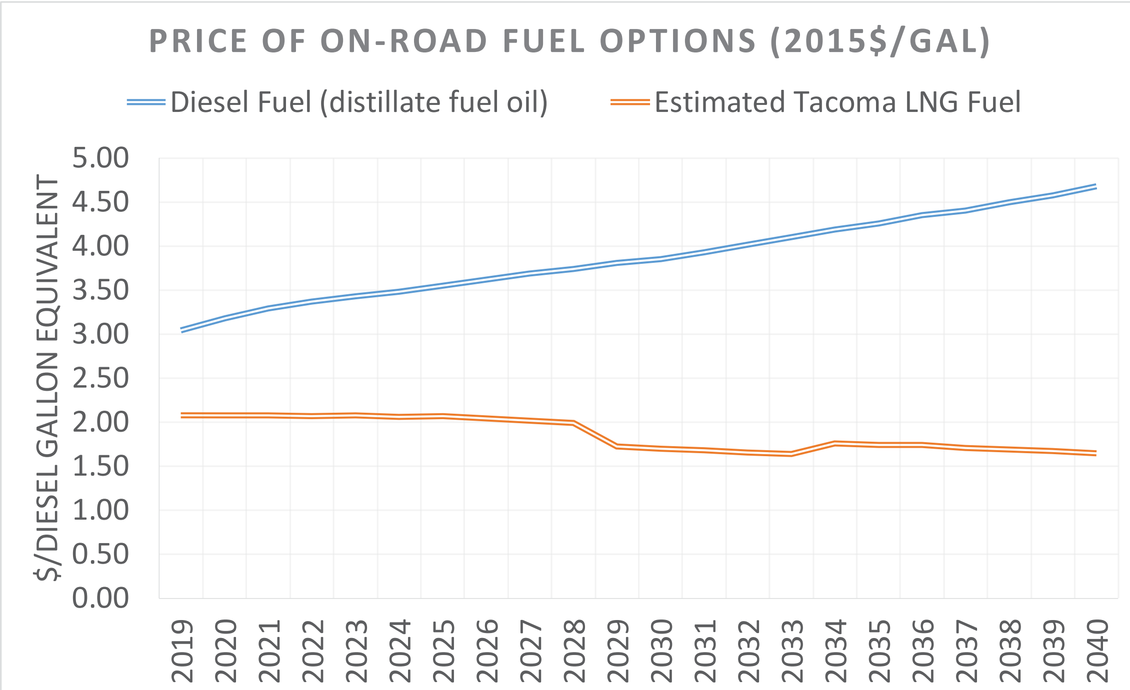
Trucking

Light and heavy trucking, which primarily rely on diesel fuel, have the ability to utilize LNG as a source of fuel. The EIA projects the fuel consumption for "large trucks" through 2040 under both a "reference case" that utilizes existing policies and laws, as well as a "Phase 2" projection that analyzes the impact of a proposed rulemaking jointly issued by the U.S. Environmental Protection Agency and the National Highway Traffic Safety Administration. The Phase 2 projections institute additional standards on greenhouse gas emissions and fuel consumption for medium- and heavy-duty trucks. The EIA's projection of the fuel mix for trucks through 2040 for its reference case and Phase 2 case are shown below.



The EIA combines compressed natural gas (CNG) and LNG in its projection. As can be seen above, the EIA projects (on a national basis) that very little natural gas will be used in either case through the entire time horizon. Projected use of CNG/LNG will increase from only 0.017 million barrels oil equivalent per day (BOE/day) in 2016 to 0.162 million BOE/day in 2040 in the reference case, and to 0.031 million BOE/day in the Phase 2 case.

BWMQ examined the projected price of Tacoma LNG converted into a diesel gallon equivalent (DGE) to compare it to a projected price for diesel. The methodology to calculate the Tacoma LNG price is identical to the method described earlier, except the price is converted into the MMBtu equivalent of a gallon of diesel. The price projections are shown below.



The price of diesel is projected to be above the MMBtu-equivalent price of Tacoma LNG throughout the entire study horizon. For LNG as a transportation fuel, in addition to the costs discussed above, there are additional LNG station costs that may add approximately $1/DGE to the final delivered cost to customers.[10] The addition of station costs would put Tacoma LNG and diesel approximately at price parity in 2019, with the price of Tacoma LNG falling compared to diesel through 2040. To utilize LNG as a fuel, new heavy trucks will also need to be purchased, which is estimated to be at a $38,200 to $67,800 price premium to diesel fuel trucks.[11]

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[10] Amy Jeffe, et al., "Exploring the Role of Natural Gas in U.S. Trucking," UC Davis and Rice University NextSTEPS White Paper, (February 18,2015) ("UC Davis Study") at 30.
[11] UC Davis Study at 27. The price range correspond to different engine technology that offer ranges between 570 and 700 miles.

Despite the projected price premium of diesel fuel compared to LNG in the future, the additional costs associated with LNG adoption for heavy trucking, including the additional capital cost of new fueling stations and trucks, significantly reduce the commercial incentives of LNG fuel adoption. The UC Davis Study concludes:

> In summary, the natural gas cost advantage at present is not sufficiently large enough to launch a national network based on commercial market forces. Rather, we find that it would take roughly 15 years for fuel demand to rise sufficiently and additional technological learning to take hold before lower station equipment costs and higher rates of trucking demand would support construction of a comprehensive American natural gas highway. Although a network of LNG stations is currently in place in several locations, our analysis would suggest that many of those stations will have difficulty sustaining profitable operations."[12]

Despite the findings of the UC Davis Study, construction of additional LNG fueling stations across the West Coast and the nation have increased, even since Concentric's original market analysis in 2012. In 2011, approximately 34 LNG fueling stations were open, which increased to approximately 100 in 2014.[13] The U.S. Department of Energy's Alternative Fuels Data Center ("AFDC") as of August, 2016, lists 141 operational LNG fueling stations (81 public and 60 private), and an additional 52 planned stations. The AFDC shows two LNG stations in Washington, both located near Tacoma, including facilities owned by Clean Energy and Blu LNG.

This analysis suggests that Tacoma LNG may find a market for LNG as a fuel for heavy trucking, though the level of demand is highly uncertain.

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[12] UC Davis Study at 35.
[13] Exhibit No. MFB-4C at 12.

IV. Conclusions

The major conclusions of BWMQ's LNG fuel use competition analysis are the following:

1. Current oil price projections have moderate increases for the price of oil in the future versus the oil price projections utilized earlier in Concentric's study (which utilized a study by Wood Mackenzie) for PSE. The differentials between the projected price for oil and natural gas have also declined but gas prices retain a distinct advantage over oil on a Btu equivalent basis in the projection horizon.

2. BWMQ agrees with Concentric's findings that there is a strong *potential* market for LNG fuel use in the Pacific Northwest maritime market primarily due to emission requirements. The Washington State Ferries have been studying the issue of LNG conversion for over five years without a final commitment. Other shipping lines and cruise ships have also been studying the issue without final commitments.

3. The future demand for LNG as a fuel source beyond the dedicated service for TOTE for the maritime industry in the Pacific Northwest is uncertain. Concentric's forecast seems to acknowledge this uncertainty because it only increased demand for marine LNG fuel by 75,000 gallons a day for the Washington State Ferries by 2030. (Exhibit No. MFB-4C at P. 10.) BWMQ believes this is a reasonable forecast based on TOTE's executed contract and the likely addition of the Washington State Ferries in the future.

4. BWMQ believes that the demand for LNG fuel use in the heavy duty truck market is more uncertain. The technology for converting heavy trucks to run on natural gas has been in existence for a number of years. And the Btu-equivalent pricing advantage of natural gas to oil has been in existence since at least 2009. As the EIA projections and UC Davis Study indicate, the growth of LNG fuel in the heavy duty truck market in the near term is unlikely. Lower long term price forecasts for oil based fuels also decrease incentives for trucking firms to incur the greater cost of trucks that are fueled by LNG.

5. However, BWMQ believes that non-pecuniary higher emission quality standards on the heavy trucking industry may provide the greatest incentive to convert heavy duty trucks to LNG fuel. The U.S. issued final rules on August 16, 2016, to cut greenhouse gas emissions from medium and heavy duty trucks over the next decade. Stringent emission rules could provide a strong incentive to convert heavy duty trucks to LNG fuel use.

6. Based on discussions that BWMQ has had with industry sources, the lack of existing LNG facilities has constrained demand growth opportunities and conversions. Market sentiment will likely shift significantly as more LNG facilities are constructed, particularly large LNG export facilities, and public perceptions regarding the availability of LNG as a fuel will improve. There are five large LNG export facilities under construction in the U.S (four in the Gulf Coast, one in Maryland). Market participants expect a critical mass to develop in the Gulf Coast LNG fuel use market as LNG operators realize they have significant opportunities to market LNG as a transportation fuel in the maritime, trucking and rail industries across the Gulf Coast. Third party sales

of LNG fuel could become an important revenue source for these LNG operators. BWMQ believes that the same opportunities will be available on the Pacific Coast if more LNG facilities are constructed.

Appendix B

Appendix B

Tacoma LNG Cost of Service Model -- BWMQ Inputs Tab Explanation

- The "BWMQ Inputs" tab is inserted into the PSE's Tacoma LNG model to make various changes to inputs and to easily allow sensitivity analyses to be conducted.
- On the left side of the tab, various cells are highlighted in yellow that allow the user to either change the input value to a specific number, or to enter either a "1" or "0" to toggle a specified formulaic change to the model.
    - "Pipeline cost inflation adjustment": The PSE model originally assumed a 1.25% pipeline cost inflation increase per year. This input value is utilized in the "DR Respons" tab in order to calculate the alternative cost of pipeline transportation.
    - "Cost of Incremental Northwest Pipeline Capacity": As discussed in BWMQ's report, BWMQ recommends that the incremental cost of Northwest pipeline capacity should be reduced.
    - "Cost of Incremental Westcoast Energy Capacity": As discussed in BWMQ's report, BWMQ recommends that the incremental cost of Westcoast Energy capacity should be reduced.
    - "Cost of Long Term Debt": BWMQ recommends that PSE's long term cost of debt should be reduced from 6.16 percent to 5.95 percent to reflect PSE's 2015 capital structure.
    - "Inflation": BWMQ recommends that PSE's inflation rate of 2.5 percent be reduced to 0 percent, as the Bureau of Labor Statistics inflation rate for "Natural Gas Distribution" has been negative from 2012 to 2015.
    - "Inflation Labor": BWMQ has no recommended changes to this input.
    - "Toggle Working Capital Change": Selecting "1" for this value changes the working capital formula for TOTE and Other Non-regulated. The PSE working capital assumptions "Assumption (HC)" is set at 72.29% of O&M expense. There is no relationship between O&M and working capital. Working capital should include parts inventory (the plant will be new and it is assumed that there will be spare parts that are provided by the venders and thus will be capitalized). Thus, the only working capital initially should be prepayments. Prepayments are generally common for Real Estate Taxes and Insurance as these expenses are

prepared and amortized monthly. An appropriate balance to use would be 50% of the combined annual cost for these two items. This input has no impact on PSE.

- "Working Capital (% of O&M if 0, % of Prepaids if 1): This allows a change based on the above toggle. BWMQ recommends 50 percent as described. This input has no impact on PSE.
- "Depreciation Schedule (years)": BWMQ recommends that Tacoma LNG's depreciation schedule should be changed from 25 years to 40 years to better represent the expected useful life of the facility.
- "Capital Input Selector": These boxes allow the user to change the capital input assumptions that are used in the model. Option "1. As Filed" makes no changes to PSE's filed position. If the Mott MacDonald and Northstar estimates are selected, the specific scenario capital inputs for those scenarios (shown in Excel rows 48 to 74 of the same tab) are used to populate the "Capital Inputs (HC)" tab and flow through PSE's model.
- "AFUDC Change": Choosing option "1" enables BWMQ's recommended change to the AFUDC calculation. In accordance with FERC Uniform System of Accounts Regulations AFUDC should be financed with the least cost of funds. The changed computation assumes funds are raised by short term debt (at 2.95 percent) to finance plant additions through 2014. Beginning in 2015 the funds used were based on the capital structure using debt costs of 5.95%. The toggle makes these changes to the "Capital Inputs (HC)" tab.
- "Common Cost Reallocation/Common Costs allocated by all 5 categories": By choosing option "1", the recommended change described in BWMQ's report, that common costs (shown in the "Capital Inputs (HC)" tab) are reallocated such that they are weighted by all five categories (liquefaction, storage, bunkering, truck loading, and vaporization) rather than just the two categories used by PSE (liquefaction and storage).
- "Truck Allocation": By choosing option "1", the trucking allocation of costs is changed from 75 percent non-regulated to 95 percent non-regulated, with the remaining 5 percent assigned to PSE.

- To easily ascertain the impact to PSE Core Customers of a change to an input on the left side of the tab, outputs for specific values are shown on the right side of the tab.
    - "PSE Core Customer's Allocated Cost of Service": this panel of data lists, by year, PSE Core Customer's allocated Cost of Service for Tacoma LNG (excluding natural gas cost), PSE's allocation of the new distribution costs associated with Tacoma LNG, and the summation of both of these costs. A net present value (in 2015 USD) of these costs are calculated below the panel for both a 25-year and 40-year period.
    - "PSE Pipeline Transportation Alternative": this panel of data lists, by year, the estimated cost to PSE Core Customers if they purchased additional pipeline capacity instead of contracting with Tacoma LNG. This panel assumes that the total Dth/day transported by PSE Core Customer's peaks at 66,000 Dth/day in 2021. A net present value (in 2015 USD) of these costs are calculated below the panel for both a 25-year and 40-year period.

Appendix C

EXPLORING the ROLE of NATURAL GAS in U.S. TRUCKING

A NextSTEPS white paper by: Amy Myers Jaffe,[1] Rosa Dominguez-Faus,[1] Allen Lee,[1] Kenneth Medlock,[2] Nathan Parker,[1] Daniel Scheitrum,[1] Andrew Burke,[1] Hengbing Zhao,[1] Yueyue Fan[1]

NextSTEPS
(Sustainable Transportation Energy Pathways) Program

UC Davis Institute of Transportation Studies

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Final Version

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NextSTEPS White Paper:

Exploring the Role of Natural Gas in U.S. Trucking

Amy Myers Jaffe,[1] Rosa Dominguez-Faus,[1] Allen Lee,[1] Kenneth Medlock,[2] Nathan Parker,[1] Daniel Scheitrum,[1] Andrew Burke,[1] Hengbing Zhao,[1] Yueyue Fan[1]

1 Institute of Transportation Studies, UC Davis
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Abstract

The recent emergence of natural gas as an abundant, inexpensive fuel in the United States could prompt a momentous shift in the level of natural gas utilized in the transportation sector. The cost advantage of natural gas vis-à-vis diesel fuel is particularly appealing for vehicles with a high intensity of travel and thus fuel use. Natural gas is already a popular fuel for municipal and fleet vehicles such as transit buses and taxis. In this paper, we investigate the possibility that natural gas could be utilized to provide fuel cost savings, geographic supply diversity and environmental benefits for the heavy-duty trucking sector and whether it can enable a transition to lower carbon transport fuels. We find that a small, cost-effective intervention in markets could support a transition to a commercially sustainable natural gas heavy-duty fueling system in the state of California and that this could also advance some of the state's air quality goals. Our research shows that an initial advanced natural gas fueling system in California could facilitate the expansion to other U.S. states. Such a network would enable a faster transition to renewable natural gas or biogas and waste-to-energy pathways. Stricter efficiency standards for natural gas Class 8 trucks and regulation of methane leakage along the natural gas supply chain would be necessary for natural gas to contribute substantially to California's climate goals as a trucking fuel. To date, industry has favored less expensive technologies that do not offer the highest level of environmental performance.

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Summary of Findings

- *If recent, wide oil and gas price differentials hold, greater use of natural gas in the heavy-duty sector could potentially lower the cost of U.S. freight supply chains, thereby enhancing global U.S. competitiveness by lowering domestic fuel costs for long-distance trucking routes in certain regions.*
- *The use of natural gas in the U.S. freight system improves energy security through geographic supply diversification.*
- *A concentrated regional focus in key markets for early investment is the least-cost strategy to initiate the development of natural gas transportation networks in the United States.*
- *In the case of LNG heavy-duty trucking networks, California is uniquely positioned to launch a profitable natural gas network. The costs to provide dedicated coverage for LNG across California are estimated to be less than $100 million. The Great Lakes and mid-Atlantic areas are also well-positioned to incubate a natural gas transportation network.*
- *Despite the fuel cost advantages that might result from some limited regional natural gas transportation network buildouts, the development of a U.S. national natural gas transportation network will be encumbered by high initial investment costs for new cross country infrastructure relative to the fully discounted, incumbent oil-based network.*
- *Lower levels of methane leakage will be required throughout the natural gas supply system in order to enable natural gas to provide a net greenhouse gas benefit relative to diesel. Technologies exist to facilitate this, but supportive policies may be required to encourage their adoption.*
- *The level of profitability of natural gas fueling infrastructure is more highly correlated with access to a high volume of traffic flows of freight movements than with the locus of surplus supplies of natural gas. Thus, initiatives to introduce natural gas freight fueling businesses in regions with stranded or inexpensive gas resources (natural gas supplies that lack sufficient demand to be commercialized) run a greater risk of failure than efforts to introduce natural gas fueling infrastructure along major freight routes in California, the Great Lakes region and the US Mid-Atlantic.*
- *The cost-benefit for natural gas as a direct fuel is most compelling for heavy truck fleets whose vehicles travel 120,000 miles a year or more.*
- *Current commercial economic drivers mean that conventional stations supported by mini-LNG facilities are likely to be the favored technology in the early stages of the market development. Additional options to supply CNG can be an enabling network feature.*

- *The lessons for natural gas apply more broadly to the question of the barriers to the development of national networks for alternative fuels. Generally speaking, the lower cost of alternative fuel is an important element of commerciality but is not the only driver to a successful transition to low carbon fuels. The level of costs of new infrastructure is also a significant variable to developing new networks, potentially creating region specific economics.*

Background

Increasingly abundant natural gas supplies are significantly transforming the U.S. energy landscape. Innovations in horizontal drilling and hydraulic fracturing are unlocking vast unconventional reserves of U.S. domestic natural gas and oil. The so-called "shale revolution" has unleashed a giant surge in U.S. natural gas production that is making natural gas a competitively priced fuel in many different applications, including power generation, manufacturing and petrochemical production. Although differences exist in estimates of recoverable unconventional U.S. natural gas resources, the preponderance of geological and commercial assessments project that U.S. natural gas supplies will remain ample, lending credence to the possibility that natural gas could penetrate new markets.

So far, the shale revolution is providing U.S. domestic natural gas at extraordinarily low prices. Liquefied natural gas (LNG) for trucks has seen a fuel price discount of $12-$16/mmBTU (energy basis equivalent) over the past year. More recently, as both U.S. diesel and spot natural gas prices have declined, the price discount has decreased. At present, even with recent oil price declines, the oil–natural gas differential available on futures markets is averaging around $9-$10/mmBTU (energy basis equivalent) over the next one to three years forward. The price of natural gas is about $9.18/mmBTU (energy basis equivalent) less than oil in the derivatives markets for longer range future purchases (over the next five- to ten-years).

The emergence of natural gas as an abundant, inexpensive fuel in the United States has raised the possibility of a larger shift in the level of natural gas utilized in the transportation sector. The cost advantages of natural gas and the diversity of its geographical sources in North America raises the possibility that natural gas can increase the global competitiveness of the U.S. transportation supply chains. Commercial forecasts for how much natural gas could replace oil in transportation vary widely, with high end estimates in the millions of barrels per day (mbd).[1] That's 5% to 10% of the total available market of about 13 mbd or more than 25% to 50% of the existing 3.9 mbd market for diesel. But questions remain about the commercial viability of natural gas in transportation given the broad investment required to create a national fueling

[1] In its June 2013 report, "Energy 2020:Trucks, Trains and Automobiles," Citi Group projects that a shift to liquefied natural gas (LNG) for heavy trucking could eliminate 1.2 to 1.8 mbd of U.S. diesel demand by 2030 and 3.4 mbd globally.

infrastructure network and about the environmental performance of natural gas as a fuel for trucks. We investigate whether a shift to natural gas vehicles (NGVs) in the U.S. freight system can be commercially profitable and study the environmental consequences of such a transformation.

The U.S. and Global Natural Gas Vehicle Fleet

Natural gas is already used as a transportation fuel in many applications in the United States and globally. There are currently 17.7 million natural gas vehicles operating worldwide, and 92% are light-duty vehicles.[2] Iran and Pakistan represent the largest markets for NGVs at 3 million and 2.9 million, respectively. Other large markets for light-duty NGVs are India, China, Argentina and Brazil.

Driven mostly by air quality concerns and an abundance of natural gas in some provinces, China has seen a rapid increase in the number of NGVs on the road, from 60,000 in 2000 to more than 1.5 million today. Compressed natural gas (CNG) vehicles are predominant in China's NGV market, including buses, taxis, private cars and commercial vehicles.[3] China's national oil company CNPC (China National Petroleum Corporation) is projecting that natural gas use in transportation in China could rise to 54 billion cubic meters (bcm) by 2020, an annual growth rate of 16% a year. China's 12th Five Year Plan encourages the development of liquefied natural gas (LNG) vehicles. The country currently has 70,000 LNG trucks on the road.[4]

By contrast, there are 250,000 NGVs on the road in the United States including 14,000 municipal buses and 4,000 medium and heavy duty trucks.[5] Roughly 3,600 LNG trucks are operating in the United States.[6] Nearly half of garbage trucks sold in the United States last year ran on natural gas. Only one automobile manufacturer, Honda Motor Co., offers a natural gas passenger vehicle for sale in the United States, but the car has so far failed to capture a large market base.

Across the United States, there is a mature, robust distribution network for diesel fuel and gasoline. There are 59,739 diesel fueling stations and 121,446 gasoline stations, and 2,542 truck stops where fuel is readily and conveniently available. This translates on average to about 20 truck stops for every 400 miles of interstate freeway. By contrast, there are just 800 CNG fueling sites, and just under half are public.[7]

To be successful, a new alternative fuel must offer the same convenience at a lower cost. Otherwise, governments must provide public incentives to investors to provide new

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[2] http://www.ngvaeurope.eu/worldwide-ngv-statistics
[3] UC Davis Institute of Transportation Studies China Workshop Beijing, China, October 2013
[4] UC Davis Institute of Transportation Studies China Workshop Beijing, China, October 2013
[5] http://www.ngvaeurope.eu/worldwide-ngv-statistics
[6] www.afdc.energy.gov/vehicles/natural_gas.html
[7] http://www.afdc.energy.gov/fuels/stations_counts.html

stations for an alternative fuel. The slow vehicle turnover and the prolific network of incumbent diesel fueling venues across the U.S. highway system limits the transition rate for alternative fuels.

U.S. consumers are unlikely to adopt NGVs in large numbers because other, more convenient alternative fuel options are becoming available and those alternative fuel vehicles are perceived as more environmentally friendly and modern. By contrast, natural gas has high potential to make inroads as a fuel for commercial use, particularly for long-distance freight movement.

In the light-duty sector, U.S. consumers have not gravitated widely to NGVs. In a 2006 U.S. National New Car Buyers survey, non-NGV drivers did not rate natural gas well, compared to alternatives, and ranked NGVs fifth after other options including "electric", "all biofuels", "hydrogen", and "I have no idea." Polling indicates that CNG is perceived as an older technology, in contrast to plug-in electric vehicles (PEVs) which are viewed to represent innovative, forward-looking technologies. The primary reason consumers buy NGVs is cheaper fuel and access to high occupancy vehicle lanes in urban centers. In contrast, fleet owners gravitate to NGVs to comply with clean air standards. Vehicle range and initial cost remain barriers. The Honda Civic NG, with improved fuel economy and acceleration, can go 248 miles without fueling, about 10% farther than the previous NG version, the Honda Civic GX, and has roughly a seven-year payback period.
The economic advantage of utilizing natural gas to save on fueling costs is highly correlated to both the relative efficiency of the vehicle and intensity of travel. In the United States, most individual drivers do not travel sufficient miles in daily driving to reap cost advantages from a switch to natural gas, given other attractive highly fuel-efficient light-duty vehicle alternatives such as hybrids and PEVs.[8] But for commercial fleet vehicles, which regularly undertake intensive travel, natural gas can potentially offer cost savings and some environmental benefits. Figure 1 shows the annual fuel savings as a function of annual vehicle miles traveled under three different scenarios of LNG fuel discount to diesel.

[8] For a more detailed analysis of the economics of CNG-fueled light duty vehicles, see Alan J. Krupnick, Will Natural Gas Vehicles Be in Our Future? Resources for the Future Issue Brief 11-06, May 2011

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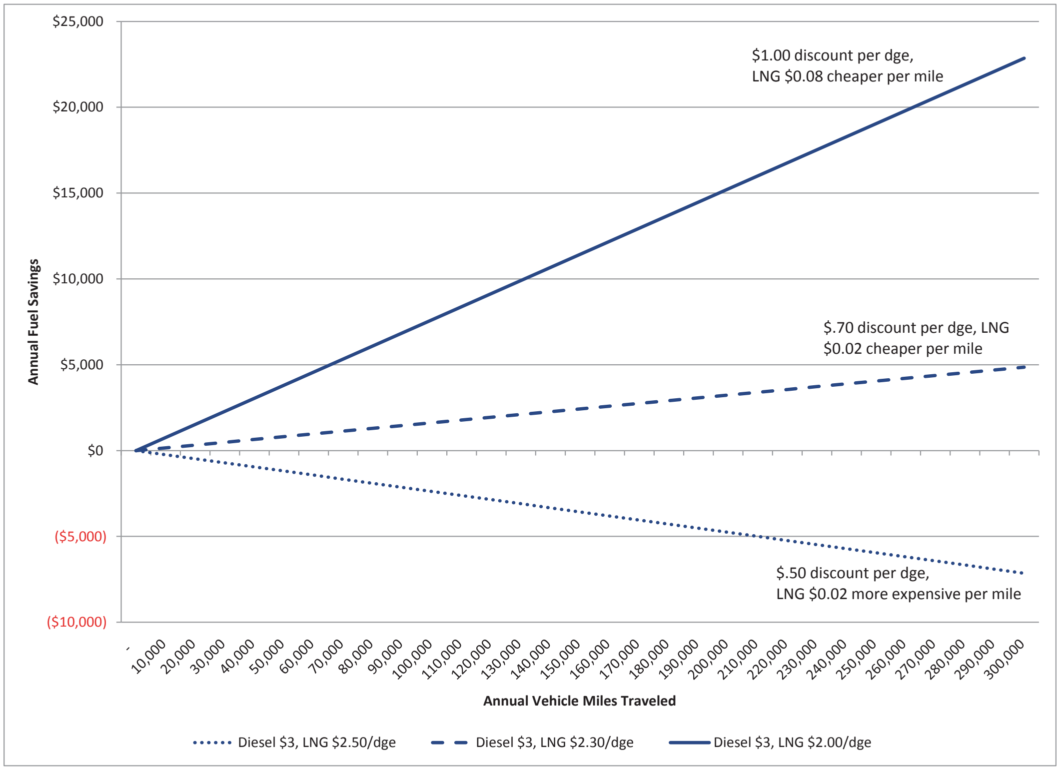
Figure 1. Annual Fuel Savings by Vehicle Miles Traveled



In this study we use a proprietary spatial modeling program to investigate the possible advantages and disadvantages of natural gas as a transportation fuel and its potential role in enabling other alternative fuels for the United States. In considering the future role of natural gas in U.S. transportation, we analyze vehicle applications where natural gas could potentially offer sustained fuel cost advantages in the commercial sector and investigate whether such fuel price savings would be sufficiently large to generate commercial drivers for construction of a national network of natural gas fueling infrastructure.

We also analyze the environmental impacts of a shift to natural gas compared to diesel in commercial applications. We consider what such a change in fuel type would mean both for air quality in terms of criteria pollutants (i.e., urban pollutants) and for cumulative greenhouse gas emissions. Finally, we use our results to consider whether a public role might be justified in the development of natural gas fueling infrastructure and, if so, where or how such an intervention might be most productive. Several U.S. states, including Oklahoma and Utah, have policies to promote natural gas vehicle use and investment. We investigate the optimum locations for such public policy measures and the specific benefits that might result from a shift to natural gas as a transport fuel in those locations.

We begin by summarizing our findings and then proceed to discuss cost, technical and environmental issues in more detail. We conclude with a policy analysis discussion based on our findings.

Freight Supply Chain Competitiveness

Natural gas station developer Clean Energy recently estimated that the cost benefit of natural gas as a fuel is most compelling for heavy truck fleets whose vehicles travel over 90,000 miles a year or more[9]. Our results support this analysis in part. Further, we find that greater use of natural gas in the heavy-duty sector could potentially lower the cost of U.S. freight supply chains and thereby enhance competitiveness and energy security. In particular, we find that while NGVs can be more expensive upfront than conventional diesel-powered medium- and heavy-duty vehicles, the fuel savings can produce attractive payback for natural gas fleet owners in less than three years.

Of course, this result is sensitive to changes in the price differential between diesel and natural gas. The cost advantage for LNG compared to diesel has been hovering around $8-$16/mmBTU in recent years but has narrowed recently with the crude oil price collapse in the second half of 2014. A significant differential remains since the spot price of U.S. natural gas has declined 30%, while U.S. diesel prices have also dropped 25% since the summer. Fuel switching will be based on long term price trends, where natural gas supplies at present appear to be more prolific and less risk prone than oil.

Energy Security through Geographic Diversification

A shift to natural gas in the freight sector provides key energy diversification benefits to the nation. It brings the transportation sector in line with America's power sector—where electricity providers can choose between a half a dozen fuels other than oil. The result is more flexibility, increased price competition and greater security of supplies. On the power sector side, supply and price competition from natural gas and other diverse fuels have benefited the U.S. economy and average Americans resulting in lower electricity prices and increased global competitiveness, according to studies by the Congressional Research Service and other think tanks.[10] The shift to natural gas from coal has also contributed to a 10% drop in U.S. greenhouse gas emissions between 2005 and 2012.[11] Similar benefits could come from a greater diversity of fuel choices in the transportation sector.

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[9] UC Davis Natural Gas Workshop February 2013
[10] http://fas.org/sgp/crs/misc/R42814.pdf
[11] http://www.scientificamerican.com/article/us-greenhouse-gas-emissions-fall-10-since-2005

In the case of natural gas as a transportation fuel, we find that the diverse geographic location of U.S. natural gas supplies offers a strategic and economic benefit. Greater geographical diversity of domestic energy supply sources is a key benefit coming from the shale oil and gas boom and thus could similarly be transferred into the transportation sector by adoption of natural gas as a heavy-duty vehicle fuel. Shale gas geologic formations are distributed across the country with natural gas production disseminating from onshore shale gas abundance not only in the U.S. Southwest, but also in the U.S. Northeast, Midwest and North Dakota. This broad geographic distribution across the country helps shore up supply resiliency. In contrast, imported oil and traditional U.S. domestic oil reservoirs and oil refining infrastructure are heavily concentrated in the Gulf of Mexico and interruptible by severe storms. Shale gas is, in fact, ushering in a changed paradigm where consuming countries like the United States will increasingly be able to source their supply at home, lowering geopolitical and weather and climate change-related risks and enhancing economic benefits.[12]

Least Cost Options

The geographic diversity of natural gas supply opens the question to the optimal locations to build natural gas fueling infrastructure. To answer this question we use a modeling framework that utilizes spatial mapping of existing major interstate highways, trucking routes, key fueling routes for fleets and heavy-duty trucks, and fueling infrastructure for CNG for fleet operation and LNG for long-haul trucks to make infrastructure planning decisions. Spatial network theory and network analysis are used to calculate the most profitable trucking corridors to establish LNG infrastructure.[13]

Our special optimization model is designed to determine the most profitable transportation networks and locations for natural gas flows into transportation markets in California and nationwide. Our model uses the spatial infrastructure data and compares costs for transportation of natural gas by source, distribution method, and other market development variables through mathematical optimization. In other words, we study where the most cost-effective and profitable locations to build natural gas fueling infrastructure would need to be located in order to minimize the costs of an overall national system of natural gas fueling along major inter-state highways. Our inquiry assumes that all commercial players would benefit most from a system that would allow the widest number of stations at the lowest possible cost per total capital deployed and cheapest available fuel. Our main study finding is that concentrated regional focus in key

[12] Medlock, Kenneth, Amy Myers Jaffe, Meghan O'Sullivan, "The Global Gas Market, LNG Exports and the Shifting US Geopolitical Presence," Energy Strategy Reviews, Special Issue, Current and Emerging Strategies for US Energy Independence, December 2014

[13] Allen Lee, Nathan Parker, Rosa Dominquez-Faus, Daniel Scheitrum, Yueyue Fan, Amy Myers Jaffe, "Sequential Buildup of an LNG Refueling Infrastructure System For Heavy Duty Trucks" Proceedings and Presentation to Transportation Research Board Annual Meeting, January 2015

markets for early investment is the least-cost strategy for developing a broader national network over time.

High Traffic Density Routes: California's Unique Characteristics

The cost benefit for natural gas as a direct fuel is most compelling for heavy truck fleets whose vehicles travel 120,000 miles a year or more. However, despite the cost advantages of natural gas fuel, the development of a national natural gas transportation network will be encumbered by high initial investment costs relative to the low operating costs for the incumbent oil-based network. Compared to the incumbent fuel, the lower cost of alternative fuel is an important element to commerciality, but is not the only driver to a successful transition. The costs of new infrastructure are also a significant variable to developing new networks.

To overcome the competitive hurdle posed by incumbent stations, our research finds that traffic volume is a more important success factor than the location of surplus natural gas supplies. The availability of cheap natural gas in locations such as Pennsylvania or Texas is less relevant than the overall density and volumetric flow of trucking. In other words, locations with stranded gas, that is gas that is located somewhere with insufficient access to possible buyers, are not necessarily the best locations for natural gas freight fueling businesses. Instead, we find that geographically dense and high volume freight corridors provide the most optimum locations for new investment in NGV fueling infrastructure, especially if coupled with higher than average retail diesel prices. Supportive state policies can also be influential if other conditions are prime. The best example of this is the state of California, which meets all of these criteria, including a robust freight corridor, high diesel prices compared to the rest of the country, and a carbon pollution credit market.

Our study shows that California's heavily trafficked Interstate 5 (I-5) corridor, which hosts almost all of the long-haul truck travel in the state, would provide investors with the most favorable commercial opportunity to initiate a concentrated profitable network of LNG fueling stations that might someday seed a possible expansion to a wider, national network. Because truckers have fewer options to travel outside route I-5, the initial costs for building a profitable NGV fueling network in the state are lower than in other parts of the country where multiple roads must provide dense station coverage. In addition, traffic flows on I-5 are robust compared to the national average, increasing the potential sales rate from any particular station location on the route. We calculate that an initial investment of under \$100 million (under assumptions for a 12% return on capital) could be sufficient to start the launch of a dedicated network along I-5. However, in order for this investment to be effective, the market for LNG trucks must first reach 6,000 vehicles nationwide, or about twice current levels. Further, California is a potentially attractive location for a prospective natural gas transportation network because California-based fleet operators currently enjoy a 20% credit benefit under the Low Carbon Fuel Standard

(LCFS). (Fossil natural gas currently has a 20% lower carbon score than diesel under the LCFS, although a regulatory proposal could shrink this percent reduction).

The other region that appears to have high enough demand to support early adoption of LNG as a trucking fuel is the Great Lakes area, which, like California, sees a high volume of traffic and experiences higher diesel prices. It is possible that a national network could evolve over time as more regionally profitable routes in California and the Great Lakes region proliferate outwards. Counter to popular thinking, the profitability of LNG stations is most tied to intensity of traffic flows and higher than average local petroleum prices than to ample availability of local natural gas, our modeling shows. These results paint a potentially positive picture for construction of infrastructure that might promote an easy transition from LNG to renewable natural gas in heavy trucking in the state of California as desired by state policy makers.[14]

California may have stronger interest in assisting the development of an LNG fueling network for heavy-duty trucking in the state – but only if vehicle efficiency and capture of production and distribution system leakage could be improved to add to environmental benefits. Still, the construction of an LNG refueling infrastructure system for heavy-duty vehicles would also enable the greater use of biogas, which might argue for state support if NGVs could be equal to or slightly better in their overall environmental performance than diesel. Consumption of biogas in transportation in California increased by an order of magnitude in one year jumping from 1.7 million gallons of diesel equivalent (dge) during the year beginning in Q3 2012 to 17.5 million dge the following year. During this time, biogas represented 4% of low carbon fuel credits generated for the state and has a substantial growth potential.

The construction of natural gas infrastructure would be enabling to biogas producers who would be assured that fueling networks would be available to commercialize their production. California and neighboring states have a biogas resource base that is large enough to support between 10,000 and 30,000 LNG trucks, but further study is needed to determine what distant resources could be developed and imported profitably from other states and nearby countries. The California Biomass Collaborative, a University of California Davis-led public-private partnership for the promotion of California biomass industries, estimates that 32.5 million billion dry tons (bdt) of in-state biomass feedstocks could be available for conversion to useful energy[15] In particular, estimates for methane production from landfill gas are 55 bcf/year, 4.8 bcf/year for waste water biogas, and 14.6 bcf/year for biogas from manure sources. Similar biomass resources are located in states

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14 Our independent academic research findings support the rationale for US Department of Energy efforts to create Interstate Clean Transportation Corridors and add new insights into the most economically optimum locations for such corridors. For example, see Stephanie Meyn (2012) Greener Alternatives for Transportation Corridors, Presentation to the US Department of Energy Clean Cities Program, West Coast Collaborative Partners Meeting. In 1996, similar ideas were presented by Bruce Resnik, on Alternative Fuels Trucking, NREL

15 Williams, R. B., Gildart, M., & Jenkins, B. M. (2008). An Assessment of Biomass Resources in California, 2007. CEC PIER Contract50001016: California Biomass Collaborative., (http://biomass.ucdavis.edu/files/reports/2008-cbc-resource-assessment.pdf)

that border California or along routes for the transmission of natural gas to the state from major producing states.

We estimate that the methane potential from landfill gas in the Western states outside of California is 105 bcf/year based on existing and candidate landfills identified by the EPA.[16] Parker estimates an additional 100 million bdt/year of lignocellulosic biomass in the Western states which are roughly equivalent on an energy-content basis to the gasoline used by 14.5 million passenger cars a year. However, some of these in-state and external biomass sources are already committed to or could be used for the production of liquid biofuels or for dedicated power generation services to the businesses where they are co-located[17].

Barriers to Entry: High Capital Costs for New Infrastructure

Despite the cost advantages of a regional natural gas transportation network build-out, the development of a national natural gas transportation network will be encumbered by high initial investment costs relative to the low cost operations of the existing incumbent oil-based network. Thus, we find that commercial factors will not be sufficient to overcome the infrastructure capital and operational costs that must be considered in any competition with the widely disseminated, fully discounted incumbent infrastructure for diesel fuel all over the United States in a matter of just a few years.

Our analysis concurs with other alternative fuels research that demonstrates how the capital intensity of fueling station investments makes it difficult for new fuels to compete with incumbent oil-based fuels that benefit from mature, financially amortized distribution networks. The case of natural gas is more glaring than other promising fuels such as hydrogen or liquid biofuels because natural gas has as its starting point a substantial fuel cost discount compared to diesel, its incumbent competitor. Even though major corporations have begun investing billions of dollars to build infrastructure to feed natural gas into the U.S. trucking industry and expand the use of natural gas in fleets, natural gas' success as a transport fuel is by no means guaranteed.

Thus, a focused, regional approach that would lay the groundwork for expansion over a longer period of time would be most productive to tap the benefits of rising U.S. natural gas supply for transportation uses. Our scenario analysis shows that even a return to lofty diesel prices such as those seen in July 2008 would not significantly alter this conclusion because even this wider cost incentive does not create a sufficient economic environment to finance the wide gap needed for infrastructure capitalization. And a 50% government

[16] "Landfill Methane Outreach Program: Energy Projects and Candidate Landfills." US EPA, (http://www.epa.gov/lmop/projects-candidates/index.html)

[17] Parker, Nathan, Peter Tittmann, Quinn Hart, Richard Nelson, Ken Skog, Anneliese Schmidt, Edward Gray, and Bryan Jenkins. "Development of a biorefinery optimized biofuel supply curve for the Western United States." *Biomass and Bioenergy* (2010) (34), pp 1597-1607.

subsidy for LNG fueling stations similarly would not be effective in solving the problem of station unprofitability in many locations across the United States, our research shows.

Carbon Intensity and Air Quality Considerations of Natural Gas in Transportation

The benefit of natural gas on a net carbon intensity basis in transportation is less clear. In terms of climate pollution, tailpipe carbon dioxide emissions from burning natural gas in heavy-duty trucking applications are roughly one fourth to one third as compared to burning gasoline or diesel. [18]. But for spark ignition LNG trucks to match high-efficiency diesel trucks in life-cycle carbon intensity, methane leakage from the natural gas production and distribution system must be negligible. If the more efficient (and expensive) HPDI engine is used in LNG trucking, analysis shows, system methane leakage must be under 2.8% for natural gas to break even in carbon intensity. In addition, a large improvement in natural gas vehicle efficiency would be necessary for natural gas to compete effectively against future best-in-class diesel engines in life-cycle greenhouse emissions.

Generally speaking, natural gas-based fuels emit less particulate matter and sulfur components than diesel. Vehicle modeling research shows that a shift to LNG fuel can contribute a significant reduction in SOx tailpipe emissions as well as almost a full scale elimination in fine particulate matter in heavy-duty trucks. Regions with heavy use of diesel and bunker fuel (marine ECAS, ports, industrial sites, and roads with dense heavy-truck traffic or other non-attainment areas where diesel is heavily used) could experience substantial air quality improvements by switching to natural gas-based fuel. The scientific literature also suggests that aftertreatment technology is more important than the type of fuel used and, thus, this must also be taken into account for California to garner the optimum air quality benefits from a shift to natural gas in heavy-duty trucking. For example, diesel engines with particulate filters could produce lower levels of particulates than natural gas engines not equipped with aftertreatment technologies, but when NGV engines are equipped with three-way catalyst technology they generally produce much lower particulate and SOx emissions than updated diesel engines. Similarly, NGV engines without aftertreatment have less ability to control formaldehydes and NOx pollution but with appropriate technology they could produce similar or lower levels than diesel[19].

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[18] Hengbing Zhao, Andrew Burke, Lin Zhu "Analysis of Class 8 Hybrid-Electric Truck Technologies Using Diesel, LNG, Electricity, and Hydrogen, as the Fuel for Various Applications" Proceedings of EVS27 Barcelona, Spain, November 17-20, 2013

[19] Yoon S, Collins J et al, Criteria pollutant and greenhouse gas emissions from CNG transit buses equipped with three way catalysts compared to lean-burn engines and oxidation catalyst technologies, Journal of Waste Management, 2013 August, (8) 926-33

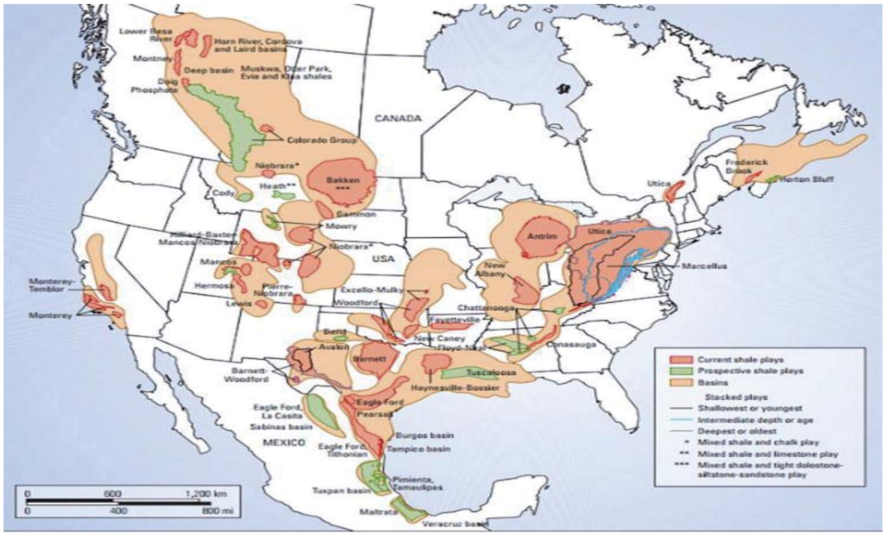
The Case for Natural Gas: An Abundant, Domestic Fuel

A primary consideration for the adoption of natural gas as a key transportation fuel in the U.S. heavy-duty trucking sector is whether natural gas will remain in abundant supply, holding prices relatively low compared to oil-based fuels. U.S. gross natural gas production has risen from an annual average rate of 64.3 billion cubic feet per day (bcfd) in 2005 to 82.7 bcfd in 2013, driven primarily by momentous growth in production from shale from less than 4 bcfd to more than 31 bcfd. Natural gas supplies from the Marcellus formation in the U.S. Northeast have gained tremendous ground in the past year, altering historical patterns for oil and gas flows inside the United States and creating new opportunities.

In 2011, Advanced Resources International (ARI) estimated 1,930 trillion cubic feet (tcf) of technically recoverable resource for North America and 6,622 tcf globally, with over 860 tcf in U.S. gas shales alone.[20] Most recently, the U.S. Energy Information Administration (EIA) commissioned assessments from Intek in 2011 and another assessment from ARI in 2013. The Intek study estimated 750 tcf of recoverable shale gas resources in the U.S. Lower 48. ARI increased its U.S. shale estimate to 1,161 tcf, as part of a global assessment of shale resources of a world total of 7,299 tcf.[21] As more drilling has taken place, information about the size and economics of recoverable U.S. unconventional resources has improved. While concerns about sharp initial production decline rates have emerged, enhanced understanding about long term performance at fields and the closer distribution of infill drilling has increased optimism about the potential for improved recovery rates.

[20] "World Gas Shale Resources: An Assessment of 14 Regions outside the United States, a report prepared by Advanced Resources International (ARI) for the United States Energy Information Administration (EIA) April 2011.
[21] "A Review of Emerging Resources U.S. Shale Gas and Shale Oil Plays" Prepared by INTEK Inc. for US Energy Information Administration. July 2011.

Figure 2. Shale Resources in North America[22]



Several organizations have studied the ARI, Intek and other assessments such as Rogner[23] and concluded that this large natural gas resource base will allow U.S. natural gas prices to remain relatively low for an extended period of decades, even if North American exports occur (barring a major unexpected disruption in global supplies). NERA Economic Consulting in a report prepared for the U.S. Department of Energy in 2012 analyzed multiple U.S. liquefied natural gas scenarios under EIA's high, low, and reference case for U.S. oil and gas resources. NERA's analysis found that average U.S. natural gas prices generally remain within the $4.00–$5.00 per thousand cubic feet (mcf) range, under most of the export scenarios studied and below $3.50/mcf under high resource scenarios for the study period to 2040.[24]

Another study by Rice University's Baker Institute, University of California, Davis, and Harvard University projects that U.S. Henry Hub spot prices will average $4.00–$6.00/mcf to 2030 under a status quo case where U.S. LNG exports average around 5 to 6 bcfd (Figure 2). Under a high export case of 12 bcfd, study researchers project that U.S. natural gas prices would be about $0.20 higher in the 2020s and $0.40 higher in the 2030s as compared to the status quo case.[25]

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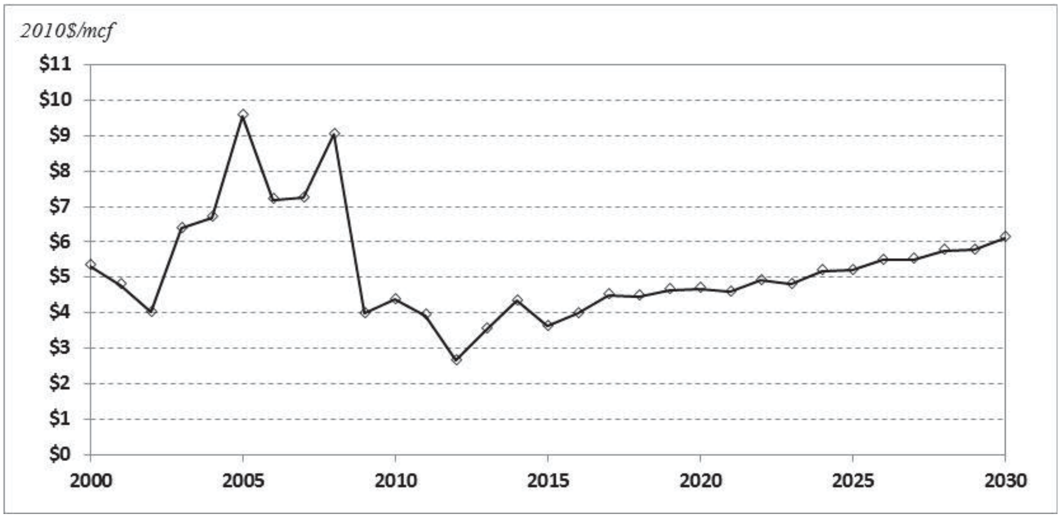
[22] Source: Gallery of World Hydrocarbon Endowment & Shale Gas Resources, Al Fin Energy blog at http://alfin2300.blogspot.com/2012/03/gallery-of-world-hydrocarbon-endowment.html
[23] H.H. Rogner, "An Assessment of World Hydrocarbon Resources" Annual Review of Energy and Environment, 1997
[24] NERA Economic Consulting http://www.nera.com/publications/archive/2014/updated-macroeconomic-impacts-of-lng-exports-from-the-united-sta.html
[25] Medlock, Kenneth, Amy Myers Jaffe, Meghan O'Sullivan, "The Global Gas Market, LNG Exports and the Shifting US Geopolitical Presence," Energy Strategy Reviews, Special Issue, Current and Emerging Strategies for US Energy Independence, December 2014

Figure 3. Henry Hub Price, 2000-2030, according to Rice Model Status Quo Scenario (Real 2010$)[26]



Medlock (2014) studies the average expected ultimate recovery (EUR), drilling costs and break even prices for key U.S. shales. He finds that there is an estimated 1060 tcf of shale gas resource recoverable across North America at prices below $6/mcf, and almost 1,450 tcf at prices below $10/mcf (Figure 3)

[26] Source: Baker Institute CES Rice World Gas Trade Model, vApr14 (Medlock). For much more detail on modeling approach and results see the CES working papers "U.S. LNG Exports: Truth and Consequence," 2012, available at http://bakerinstitute.org/research/us-lng-exports-truth-and-consequence; and "Natural Gas Price in Asia: What to Expect and What it Means," 2014, available at http://bakerinstitute.org/research/natural-gas-price-asia-what-expect-and-what-it-means. Both are authored by Ken Medlock.

Figure 4. Estimated Expected Ultimate Recovery by Shale Play per Average Well by Location[27]

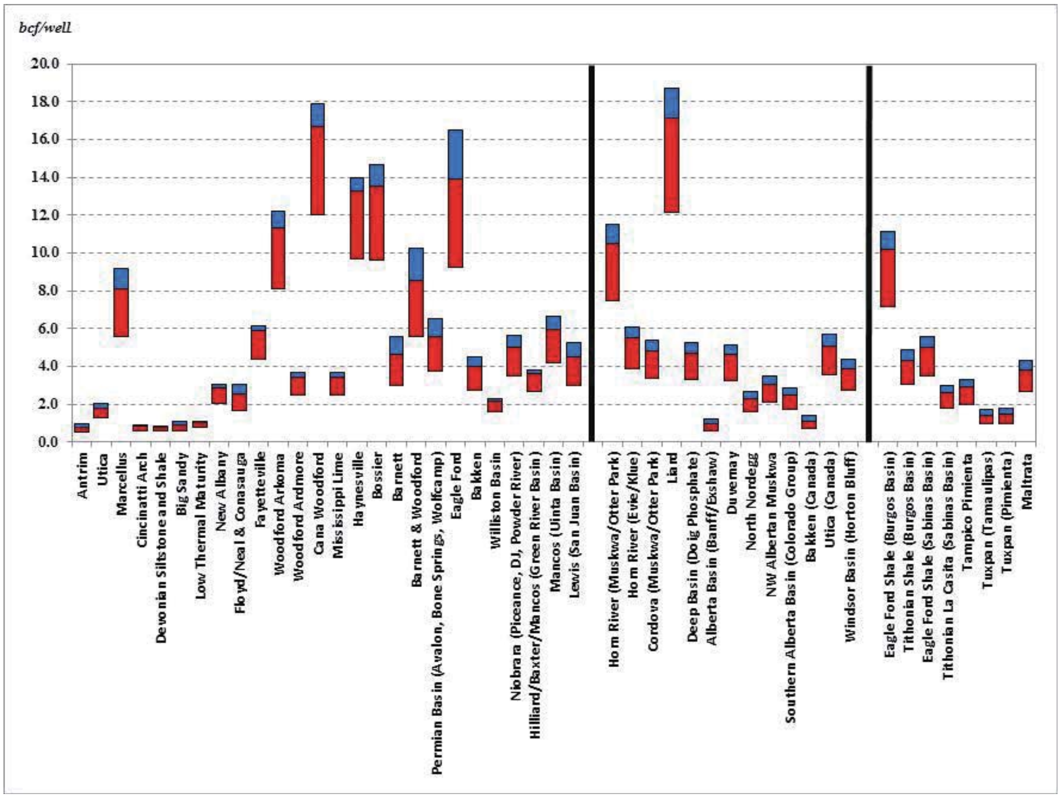


Figure 5 represents the average breakeven price by shale play in North America. Medlock (2014) concludes that about 246 tcf of the available resource at a breakeven price of under $6/mcf is in Canada, 111 tcf is in Mexico, and the remaining 656 tcf is in the United States. At prices under $10/mcf, 358 tcf is in Canada, 215 tcf is in Mexico, and 874 tcf is in the United States. Finally, Medlock notes that the total *technically* recoverable resource associated with Figure 5 is 1,844 tcf, where almost 400 tcf of the technically recoverable resource is commercially viable only if prices are at a minimum of $10/mcf.

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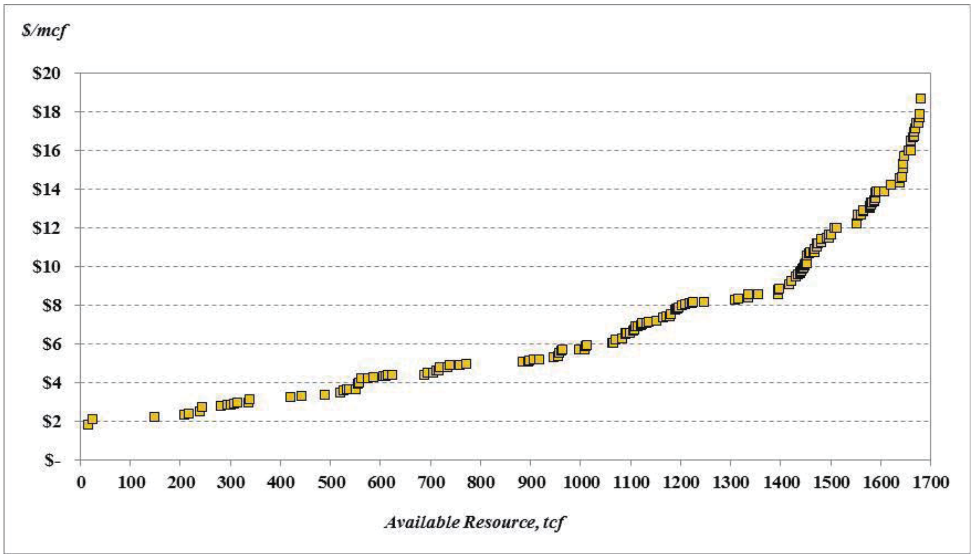
[27] Source: Baker Institute CES Rice World Gas Trade Model, Apr14 (Medlock)

Figure 5. North American Shale Gas Resource and Average Breakeven Price by Play.



The above analysis supports the notion that the North American natural gas resources have a relatively elastic supply curve at affordable prices. But natural gas' price attractiveness as a substitute for diesel fuel is also predicated on the durability of the sizable gap between relatively inexpensive natural price levels as compared to lofty oil price levels, and some uncertainty remains about long term trends for global oil prices. Rising tight oil resource development in North America combined with advances in automotive and other energy efficiency technologies are currently placing downward pressure on oil prices and could be part of a cyclical downturn,[28] but natural gas prices have also been declining of late. In recent months, spot prices of U.S. diesel have fallen roughly 25% while the price of U.S. natural gas has declined 30%. At present, the oil–natural gas differential available on futures markets is averaging around $9-$10/mmBTU equivalent from one year forward to three years forward. The long range derivatives differential is about $9.18/mmBTU equivalent cheaper. The possibility that natural gas prices could remain relatively affordable compared to diesel prices has increased interest in natural gas applications for transportation.

[28] El-Gamal, Mahmoud Amin and Amy Myers Jaffe (2013) Oil Demand, Supply and Medium Term Price Prospects: A Wavelets-Based Analysis. Institute of Transportation Studies, University of California, Davis, Research Report UCD-ITS-RR-13-10

The U.S. Freight Supply Chain and Potential for Natural Gas

Over 70% of all freight tonnage transported inside the United States moves by trucks. A high proportion of this movement of goods by trucks concentrates on the Interstate Highway system where some 2.5 million Class 8 heavy-duty vehicles carry 8.2 billion tons of goods a year. In addition, there are roughly 1.3 million medium-duty trucks in service in the United States[29]. Heavy-duty vehicles are defined as those in the highest weight class of 33,001 lbs. and over and include truck tractors, dump trucks, and cement trucks. Medium-duty vehicles are defined as service vehicles with weights of between 19,501 lbs. and 33,000 lbs., including a wider variety of trucks such as single-axle trucks, city transit buses and smaller truck tractors. Heavy-duty vehicle classes include classes 8B, (67%), 6 (14%), 8A (8%), 7 (5%), and Class 3 (1%).

The size of the U.S. diesel fuel market is approximately 41 billion gallons a year (excluding military). Heavy-duty vehicles represent about 62% of this market, with roughly 23-25 billion gallons per year demand coming from line-haul Class 8 trucks. Currently, there are only 9,500 truck stations in the United States that serve 1.5 million Class 8 trucks. Class 8 trucks use 30 billion gallons per year diesel consumption, the equivalent to 3.3 tcf/year natural gas or 10 to 15% of current U.S. natural gas consumption.

According to the EIA, annual demand for diesel fuel from freight trucks could rise to as much as 45 billion gallons under a business as usual forecast by 2025 or about double current use. Thus, the potential of natural gas to diversify the U.S. freight system away from oil is large.[30]

The heavy-duty trucking industry shifted from gasoline to diesel fuel after the 1970s oil crises in an effort to save money on fuel. The shift was slow in the 1950s but then ramped up quickly to 50% of the market after 10 years, and 100% of the market after the 1970s oil crises created competitive forces which gave firms switching to diesel fuel from gasoline a competitive advantage.[31] The rate of technology adoption is shown in Figure 6,[32] which represents the transition to diesel's share of new sales of Class 8 trucks in the United States starting in the 1960s.

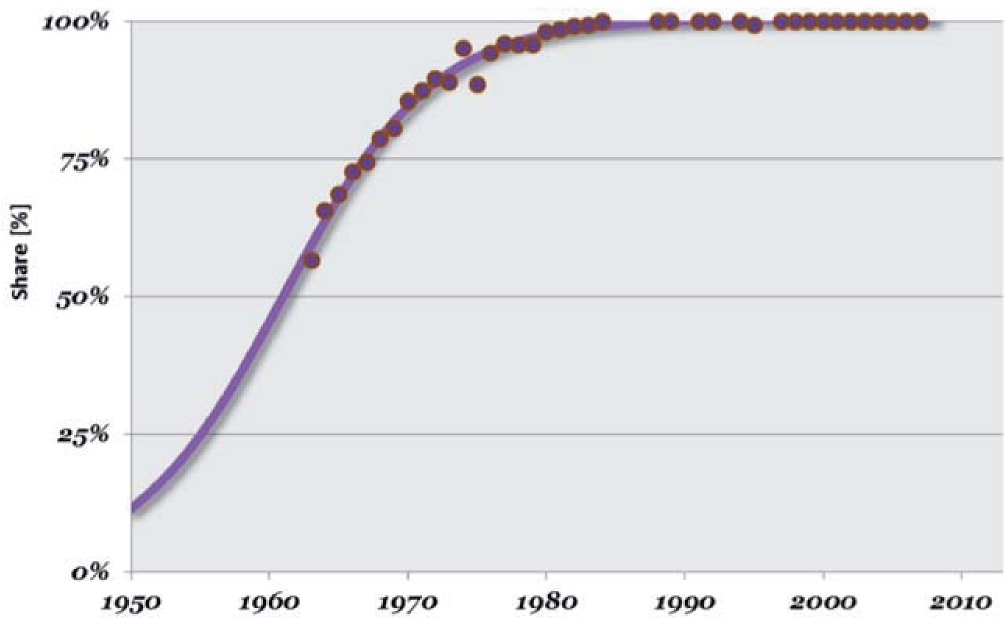
[29] http://www.afdc.energy.gov/vehicles/natural_gas.html

[30] In the U.S. the heaviest trucks consume an average of roughly 6.5 gallons per thousand ton-miles. However, fuel efficiency of the existing truck fleet varies by weight range, drive cycle and terrain. In 2014, the Cummins/Peterbilt team announced their fully-loaded class 8 truck achieved a fuel economy of 10.7 miles per gallon.

[31] LNG as a Fuel for Demanding High Horsepower Engine Applications: Technology and Approaches, Paul Blomerus 2012. Page 6.

[32] LNG as a Fuel for Demanding High Horsepower Engine Applications: Technology and Approaches, Paul Blomerus 2012. Page 6.

Figure 6. Percent of New Class 8 Truck Sales with Diesel Engines.



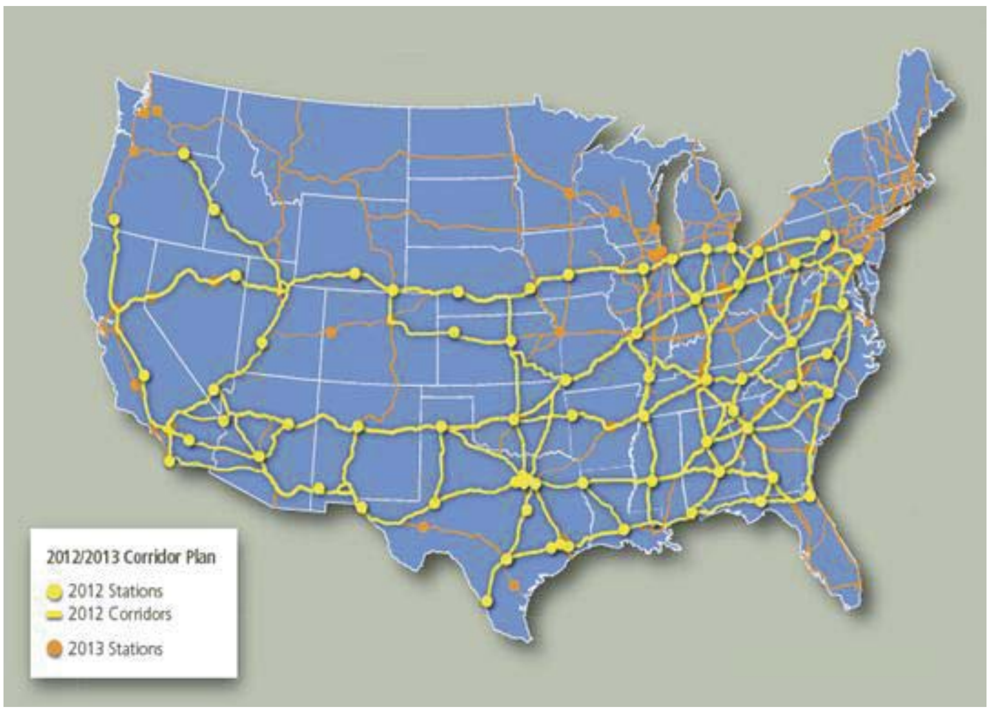
Because the turnover rate for new trucks for large fleets among first owners is relatively swift (i.e., three to four years) and natural gas is abundant and has seen a price advantage compared to diesel of between $1.50 and $2.00 a gallon over the last two years, there has been a growing interest in natural gas as a fuel for long distance trucking. In its report, "Energy 2020: Trucks, Trains and Automobiles," Citi projects that a shift to liquefied natural gas (LNG) for heavy trucking could eliminate 1.2 to 1.8 million barrels per day (mbd) of U.S. diesel demand by 2030 and 3.4 mbd globally.

At least two firms, Clean Energy Fuels, and ENN have begun building LNG fueling stations in the United States. There are currently 59 public LNG fueling stations and 42 private LNG fueling stations along routes from Los Angeles to Las Vegas, around Houston and around Chicago. The stations currently serve a fleet of 3,600 LNG trucks. California is the state with the largest number of LNG fueling stations, serving over 200,000 gallons a day, with local facilities in Tulare, Lodi, Fontana, Lost Hills, San Diego, Aurora and Ripon, among others. Zeuss Intelligence reports that there are 34 LNG supply plants with trailer loadout capable of producing about 3 million gallons of LNG a day[33]. The United States has over 800 CNG fueling sites of which a little under half are public.[34]

[33] Provided to authors by Zeuss Research consultants
[34] http://www.afdc.energy.gov/fuels/stations_counts.html

Clean Energy is the largest natural gas fuel provider in North America with over 330 natural gas fueling stations, serving 660 fleets and 25,000 vehicles. The company currently sells an average of 200 million gallons of CNG and LNG a year. The projected America's Natural Gas Highway (ANGH) by Clean Energy includes 150 natural gas stations spread out every 200–300 miles. Clean Energy says it is able to achieve a return on capital for fueling station investment and still pass on between $1.00–$1.50 a gallon in fuel savings to customers. Figure 7 shows Clean Energy's American Natural Gas Highway.

Figure 7. America's Natural Gas Highway envisioned by Clean Energy.



The company's business model is to line up with return-to-base segment shipping that is enabling a shift to LNG fuel. Increasingly, long distance trucking is changing from patterns where a single vehicle with a single driver transverses the entire country to a hub and spoke operation where more localized fleets handle part of a longer journey for modular containers.[35] This new transport paradigm means more trucks return to a local home base in the evening, not only improving the lifestyles of drivers but also creating more opportunities to fuel and maintain fleets from a home base. This emerging "relay

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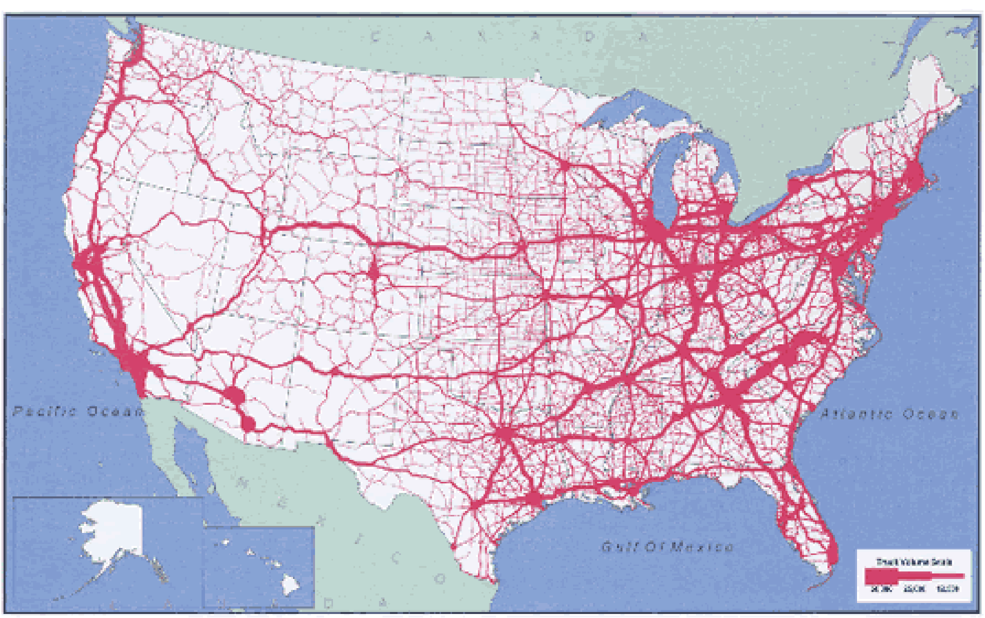
[35] For more details on this phenomenon and its potential to enable LNG as a trucking fuel, see Alan J. Krupnick, Will Natural Gas Vehicles Be in Our Future? Resources for the Future Issue Brief 11-06

race" supply chain model to daily regional operations with a home base is conducive to a shift to natural gas for fleets.

Some U.S. trucking corridors have heavier traffic than others and may therefore be better suited for a shift to natural gas than less traveled routes. Among the highest traveled trucking corridors I-5 in California; Milwaukee to Chicago; upstate New York, New York City and New Jersey; Dayton, Ohio to Cincinnati; routes around the Kansas City region; Chicago to Indiana; Dallas to Houston and Orlando to Tampa. Routes such as I-5 in California where truckers have fewer alternative routes to choose from offer the best potential for alternative fuels because they can support a dedicated network with the highest chances that the majority of trucks will pass a particular station. As might be expected, several of these highly trafficked routes also tend to have the highest diesel prices in the nation. Diesel prices averaged 9% to 10% above the national average in New York and Pennsylvania in 2013. Diesel prices in Ohio, Michigan and New England average about 5% above the national average, while California, Delaware and Maryland prices are 2% above the national average and Indiana prices are 3% above the national average.

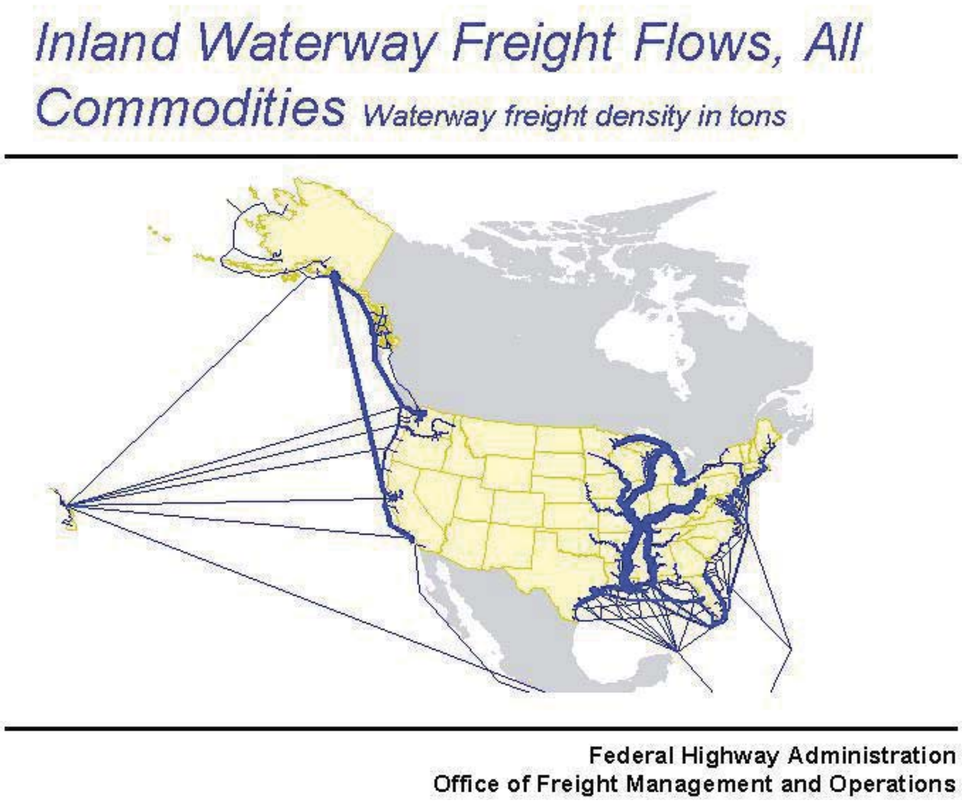
Figure 8 shows the concentration of trucking traffic on U.S. interstates with thickness of dark red shading representing those routes with the heaviest truck traffic flows. As the figure shows, California and the Great Lakes region are among the heaviest flows in the United States and therefore may have the highest potential for a new fuel.

Figure 8. Concentration of Truck Traffic.



This concentration of truck traffic in the U.S. supply chain to certain regions complements the patterns of movements of goods by ship as shown in Figure 9.

Figure 9. Waterway Freight Density. [36]



Barriers to Commercial Adoption of Natural Gas in Long-Distance Trucking

Vehicle cost

Despite some recent gains in network development, natural gas faces the same chicken-egg problem as other alternative fuels. Two major commercial barriers exist. The first commercial barrier is that LNG trucks cost significantly more than diesel trucks. The cost varies depending on the actual model. The components that add to cost are the engines,

[36] http://www.ops.fhwa.dot.gov/freight/Memphis/appendix_materials/lambert.htm

which can be either compression ignition (CI) or spark ignition (Si), and the natural gas onboard storage systems, which can be either CNG or LNG.

Ignition in the Ci engines requires injection of a small amount of diesel fuel although the engine is operated on natural gas. As shown in Table 1, the cost of the CI engine is far more expensive than a diesel engine at a $25,000–$30,000 premium. The Si engine is only $1,000–2,000 more expensive than the diesel engine of the same displacement but performs at a significantly lower rate of fuel efficiency. The fuel economy of trucks using the dual-fuel CI engines are close to those using a diesel engine, while the fuel economy with the Si natural gas engine is about 10-20% less than with the diesel engine

The cost ($/dge) of storing natural gas as LNG is 20–25% higher than storing it as CNG, but offers some advantages in lighter volume and weight. For the same size storage unit, the range using LNG will be twice that of CNG due to differences in energy content per an equal volume of each fuel. The longest range will be attained using a LNG CI truck because of the higher fuel economy of the dual-fuel CI engine and the higher energy density of the fuel. However, as indicated in Table 1, the differential cost of the LNG CI truck will be higher than that of the CNG Si unit due to higher cost of both the dual-CI engine and the LNG storage. .

The least expensive NGV option would therefore be CNG storage and Si engines. Using the cost values in Table 1, for a range of 700 miles, the cost of a CNG Si truck would be $7,900 lower than the LNG CI truck. The CNG Si truck would carry a price premium of $36,298 over a diesel truck. The more efficient CI model with the LNG storage would have a premium of $44,168.

Table 1. NGVs range, fuel economy and cost differentials respect to diesel.

Vehicle	Range (miles)	Fuel economy (mpdge)	Engine Cost ($)	Storage Cost ($)	Incremental cost to OEMs ($)	Incremental cost to Consumers ($)
Diesel	900	5.6	9,000	1,000	0	0
LNG Ci	700	5.4	20,000	35,200	45,200	67,800
LNG Si	570	4.4	10,000	35,000	35,500	38,200
CNG Ci	370	5.4	20,000	15,000	25,400	38,100
CNG Si	300	4.4	10,000	15,000	16,500	24,500

Cost of the refueling infrastructure

The second barrier is that LNG and CNG fuel cannot leverage existing filling station equipment but requires a new set of fueling apparatus.[37] Across the United States, there is a mature, robust distribution network for diesel fuel and gasoline. There are 59,739 diesel fueling stations and 156,065 gasoline stations in the United States and 2,542 truck stops where fuel is readily and conveniently available. This translates on average to about 20 truck stops for every 400 miles of Interstate freeway.

Despite attractive fuel cost differentials and freight customers' interest in cleaner transportation fuel options, the trucking industry has to date been reluctant to take the plunge on expensive equipment upgrades to natural gas.

The logistics sector operates on thin margins and tight schedules, and fueling station density is a critical issue. LNG trucks are dedicated vehicles, meaning they must have LNG station coverage that enables their full range of operations. But the penetration rate of LNG along major highways with the highest flows of goods by heavy-duty truck represents less than 0.1% of the national market. This presents a chicken and egg problem in transitioning to a significant market share for LNG trucks.

Drivers need to stop to refuel as infrequently as possible and natural gas' reduced density of fuel means more time-consuming stops for fueling. The distance to a vehicle maintenance technician with natural gas vehicle repair skills is also a consideration for a trucking route. For long-haul shippers, natural gas stations must be provided along routes every 300–400 miles, whereas diesel fuel stations can be spaced over 1,000 miles apart. Natural gas stations must be available along the entire route for it to be viable for truck fleets to shift to NGVs. To date, despite the strongest market for commercial truck sales in almost a decade, momentum towards the use of natural gas in long-distance heavy-duty truck fleets has been waning.[38] At present in the United States, there are only a few major shipping routes that have full coverage for LNG fueling (Figure 10).

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[37] It is possible to reduce some of the land and facilities cost by locating natural gas fueling infrastructure contiguous to traditional truck stops as has been done in some limited locations, but the cost of the fueling infrastructure itself remains a barrier.

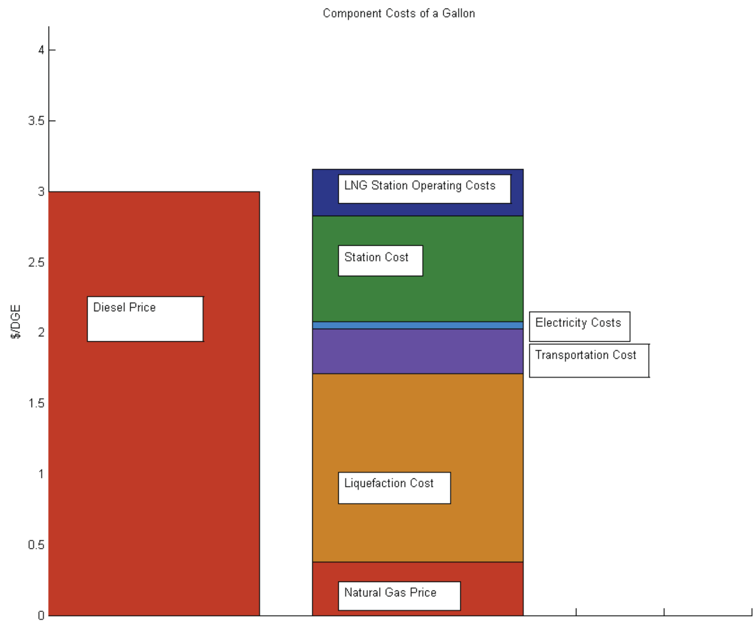
[38] Bob Tita "Slow Going for Natural Gas Powered Trucks" *The Wall Street Journal*, August 25, 2014

Figure 10. Existing Public and Private LNG Stations. [39]

A core issue blocking the construction of a comprehensive national network for natural gas fueling is the capital intensity of new fueling station investments which have to compete against sales outlets of incumbent fuels whose distribution networks are fully depreciated. In effect, natural gas' price discount would have to be large enough to cover both the high capital costs for building out new stations and higher operating costs for LNG fuel as illustrated below in Figure 11.

[39] http://www.afdc.energy.gov/locator/stations/

Figure 11. Diesel Prices Vs Natural Gas and LNG infrastructure costs.



The level of vehicle turnover and the prolific network of incumbent diesel fueling venues across the U.S. highway system limits the transition rate for alternative fuels and means that a new, alternative fuel must offer the same convenience at a lower cost. Otherwise, governments must provide public incentives to investors to provide new stations for an alternative fuel. Thus, the conversion of heavy-duty fleets to a new fuel is unlikely to take place rapidly because only 200,000 to 240,000 new vehicles come on the road each year. At present only 14% of fleets operate any vehicles on alternative fuels.[40]

Still, the annual turnover rate for heavy-duty trucks is a relevant factor in the pace at which a shift to natural gas is likely to penetrate the heavy-duty sector. The high turnover rate for heavy-duty trucks means that steady demand for new trucks could be a facilitating factor to the development of a natural gas network for heavy-duty fueling. The market for new heavy-duty trucks in the coming years will be substantial. Between 2014 and 2025 roughly 2.7 million new trucks will be purchased – or 76% of the total fleet in 2025, creating a ready market for natural gas vehicles, if commercial incentives are evident.

Building on work by the US National Petroleum Council (2012), our independent assessment shows that the cost benefit of natural gas as a direct fuel is most compelling

[40] Alt Fuels: Beyond Natural gas. Fleet Owner Magazine. April 8, 2014. http://fleetowner.com/running-green/alt-fuels-beyond-natural-gas

for heavy truck fleets whose vehicles travel 120,000 miles a year or more, given a diesel price of $4/gallon, $2.45/dge for LNG, and $2.34/dge for CNG[41]. We find that greater use of natural gas in the heavy-duty sector could potentially lower the cost of U.S. freight supply chains and thereby enhance U.S. competitiveness and energy security. In particular, we find that while natural gas vehicles can be more expensive upfront than conventional diesel powered medium- and heavy-duty vehicles, the fuel savings can produce attractive payback for natural gas fleet owners in less than three years.

The breakeven fuel prices for LNG and CNG are shown in Table 2 for the various truck designs. The results indicate that, from a fuel cost perspective, CNG is more favorable than LNG, but the range of CNG vehicles is much shorter than LNG vehicles. From the engine perspective, the economics of the CI dual fuel engine is more favorable using either CNG or LNG even though the CI engine is initially more expensive.

Table 2. Breakeven fuel prices for NGVs by technology/storage configuration and payback period based on total annual mileage.

Vehicle	2 yr./120k miles	3 yr./60k miles	3 yr./160k miles
LNG-Ci (dual fuel)	$2.60	$1.80	$3.20
LNG-Si	$2.21	$1.85	$2.60
CNG-Ci (dual fuel)	$3.50	$3.20	$3.80
CNG-Si	$3.00	$2.80	$3.30

The results in Table 2 indicate that trucks with an annual mileage greater than 120,000 miles traveled per year provide a favorable payback period for a shift to natural gas of less than three years. Note that the base price of diesel fuel for this calculation was $4/gallon. If the breakeven price is greater than the price of the fuel, the economics of that case is favorable. Trucks travelling more than 120,000 miles per year are responsible for just over 38% of the all truck miles in the United States.

At present, most fleets that are considering LNG fuel are looking at the trucks with the Si engine, which is less expensive than the dual-fuel compressed ignition engine (with a diesel pilot) (*i.e.* HPDI model). The advantage of the HPDI truck is that the vehicle operates at similar efficiency as a diesel engine even adjusting for energy content differences between the two fuels. Even though the more efficient HPDI engine would provide better economic and environmental performance, there is a disconnect between the public policy and economic objectives of a fuel switch. Right now, the dual-fuel engine is not commercially available in large numbers and it sells at a premium price. We believe that this barrier would have to be eliminated for key states, such as California, to embrace natural gas as a direct fuel. The manufacturer of the dual fuel engine, Westport,

41 Zhao H, Burke A, and Zhu L. Analysis of Class 8 Hybrid-Electric Truck Technologies Using Diesel, LNG, Electricity, and Hydrogen as the Fuel for Various Applications. EVS27. Barcelona, Spain. November 17-20, 2013. For other industry-based background on the issue, see The National Petroleum Council (2012), Advancing Technology for America's Transportation Future: Fuel and Vehicle Systems Analyses: Natural Gas Analysis.

has so far not announced any immediate plans to mass produce it. Westport Cummins, a 50-50 joint venture between Westport and Cummins, is the manufacturer of most of the Si natural gas engines. With a Si truck, the driver needs to refuel more often, which costs time, or requires larger storage capacity, which reduces cargo space. In terms of fuel storage, CNG systems are also less costly than LNG systems. But natural gas as CNG has lower energy density, thus for a given range, a NGV will require more storage space if using CNG than if using LNG. Costs for storage units and other components are expected to be reduced over time, as more industry players enter the market in the U.S. and China.

CNG trucks are generally less expensive than LNG trucks but at present are only available with the less efficient Si engines. Both lower energy density and lower engine efficiency contribute to making CNG fueled vehicles require even more frequent refueling than LNG trucks. The CNG refueling process is also more time consuming than LNG refueling. This means that, for long trips, the added initial cost for the LNG HPDI technology provides a more attractive long run payback than the higher operating costs of operating based on a CNG vehicle once downtimes are taken into account. This is another reason the Ci engine will become attractive if/when it becomes commercially available.

Infrastructure Modeling Approach

To analyze the potential for an expansion of natural gas into the heavy-duty sector and its widespread use across the country's major trucking routes, we take into consideration the barriers and constraints described above and consider the incentives that must exist or be created in order to propel natural gas as a key fuel in the U.S. freight system. To study the conditions under which either LNG or CNG fuel could be commercial in U.S. long haul trucking, we create a modeling framework that utilizes spatial mapping of existing major Interstate highways, trucking routes, key fueling routes for fleets and heavy-duty trucks, and fueling infrastructure for CNG for fleet operation and LNG for long-haul trucks to make infrastructure planning decisions. Spatial network theory and network analysis is utilized to generate all of the spatial information that is needed to calculate the most profitable trucking corridors to establish LNG infrastructure.[42]

Our spatial optimization model is designed to determine the most profitable transportation networks and locations for natural gas flows into transportation markets in California and nationally using spatial infrastructure data and comparing costs for transportation of natural gas by source, distribution method, and other market development variables through mathematical optimization. Our modeling work builds on a

[42] Allen Lee, 2014. Locating LNG Refueling Stations for US Freight Trucks Using a Flow-Based, Range Limited Facility Location Model integrated with GIS and Supply-Chain Optimization. Transportation Research Board. National Academies. January 2014

body of academic literature undertaken in the study of hydrogen fueling in the United States and only very limited study of the long haul duty NGV market. [43]

We compare the economics of natural gas transportation from supply site to refueling stations either via pipeline or truck, using data on existing natural gas pipelines and transmission systems and highway system to determine through the model solution the most profitable locations of refueling facilities. This comprehensive assessment tool is aimed to simulate the potential volumetric capacity for the natural gas transportation market in the United States, as well as optimal location of new and existing fueling facilities.

Our study considers where and when infrastructure should be deployed over a 20-year time horizon in order to satisfy demand along major trucking routes or corridors. To address both spatial and temporal dynamics, we develop a multistage mixed-integer linear programming model to optimize the process of building and operating LNG liquefaction and distribution facilities. We consider both transitions to using more LNG in the heavy-duty vehicle sector or alternatively to build a mix LNG infrastructure and CNG refueling networks that would compete against the incumbent fuel, diesel, in high volume markets. For more details about our methodology, please see the appendix to this paper.

Modeling Results and Policy Analysis

Base case scenario

To date, despite the strongest market for commercial truck sales in almost a decade and a historic gap between low natural gas prices and high oil prices, America's natural gas highway is struggling to take hold.[44] Our analysis confirms this trend and finds that only

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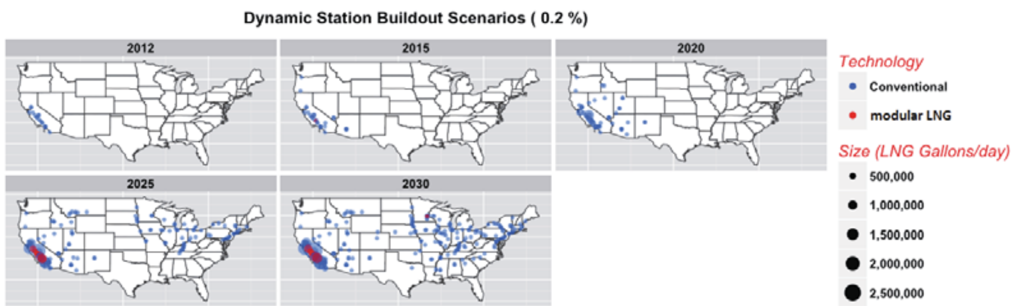
[43] As discussed by Dagdougui, the approaches for planning and designing the hydrogen supply chain can be classified as follows: 1) optimization methods (most prominent); 2) geographic information systems (GIS) based methods; and 3) scenario dependent transition models[43]. There are a small number of studies that combine the strengths of a national energy system optimization approach with a spatially explicit infrastructure optimization approach. Stachan et al. described an integrated approach linking spatial GIS modeling of hydrogen infrastructures with an economy-wide energy systems (MARKAL) model's supply and demand[43]. Parker et al. used an annualized profit maximization formulation to study the optimal distribution network for bio-waste to hydrogen[43]. Previous research on natural gas as an alternative fuel has often focused on evaluating the cost effectiveness of natural gas to achieving environmental goals in transportation.Yeh provides a review of several national markets. This literature has focused mainly on light duty, transit and refuse vehicles applications, while only a few include long haul trucking applications. Rood Werpy concludes that high costs, limited refueling infrastructure, and uncertain environmental performance constitute barriers to widespread adoption of natural gas as a transportation fuel in the US[43] but, in another substantial contribution to the literature, Krupnick finds that the move from a long-haul route structure to a "hub and spoke" structure could facilitate the development of natural gas refueling infrastructure in the highway system.

[44] Bob Tita "Slow Going for Natural Gas Powered Trucks" *The Wall Street Journal*, August 25, 2014

certain regional markets have sufficient traffic density in combination with higher diesel prices compared to the U.S. national average to give investors a sufficient return on capital to incentivize station construction without government intervention.

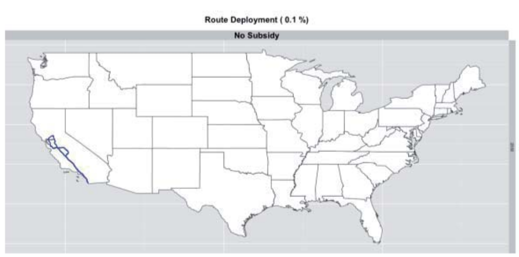
Our regional analysis, under 0.2% LNG market penetration, shows that California and the U.S. Great Lakes/Northeast regions, which have a relatively high level of demand and traffic density, have the greatest commercial potential at present and could play a key role in the network development, as shown in Figure 12.

Figure 12. Dynamic LNG station buildout scenarios under a 0.2% market penetration.



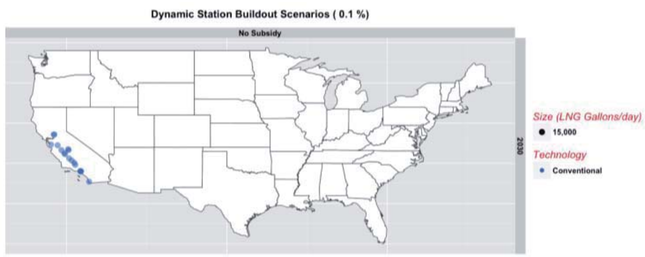
The following diagrams show the optimal network build-out for California under today's penetration rate of 0.1%, or where about 6,000 LNG trucks would be in operation across the United States. A detailed map of the California build-out network is found in Figure 13.

Figure 13. Trucking route deployment across the under current 0.1% market penetration.



Our results indicate (Figure 14) that for the California network to operate profitably under the optimal configuration, conventional station technology of the smallest capacity should be deployed.

Figure 14. Dynamic LNG station build out scenarios under 0.1% market penetration.



The regional analysis contrasts with the outlook for a national network. At today's level of market penetration of only 0.1% of the heavy-duty trucking fleet operating on LNG fuel, investors are unlikely to see a large enough fuel switchover to earn a commercial 12% return on capital in building a significant national LNG truck-fueling network until the year 2030. Our analysis finds that the majority of natural gas fueling stations along U.S. Interstate routes would be unprofitable if built under current market conditions (see appendix for detailed analysis).

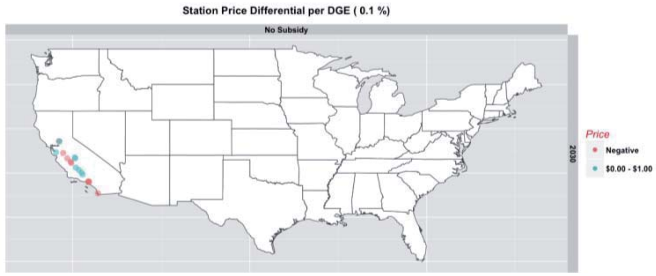
In summary, the natural gas cost advantage at present is not sufficiently large enough to launch a national network based on commercial market forces. Rather, we find that it would take roughly 15 years for fuel demand to rise sufficiently and additional technological learning to take hold before lower station equipment costs and higher rates of trucking demand would support construction of a comprehensive American natural gas highway. Although a network of LNG stations is currently in place in several locations, our analysis would suggest that many of those stations will have difficulty sustaining profitable operations.

The Potential Role of California as a Regional Launching Base for a National Network

We also tested whether the more profitable regional networks, such as the one in California, could lay the groundwork for expansion over time to a more comprehensive national network. Our results indicate that support for regional pilot programs in California and/or the Great Lakes region would hasten the development of America's natural gas highway and lower the cost of implementation in the long run.

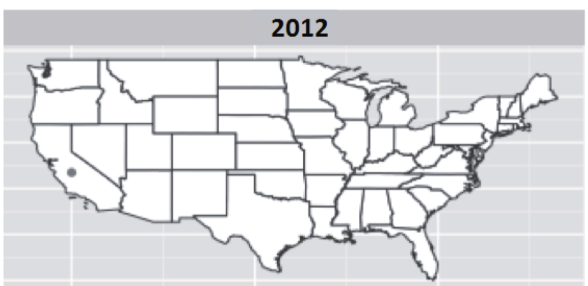
Figure 15 shows the price difference for each built station for California. Notice that still not all stations are potentially profitable, but as long as the routes as a whole are making profit, the profits from highly desirable locations will offset losses at stations experiencing less traffic, allowing the entire route to receive a 12% rate of return on capital. As discussed above, the lower volume stations are necessary to ensure trucks have sufficient coverage to travel the entire route and use only LNG fuel.

Figure 15. Dynamic LNG station price difference per diesel gallon equivalent under 0.1% market penetration.



California is a unique investment opportunity because it has a solitary main trucking artery that means truckers do not have the desire to branch out into alternative routings. This limits the number of stations that need to be provided to ensure that truckers have the full coverage needed to use LNG vehicles. We calculate that the costs to provide dedicated coverage for LNG across California are relatively low at under $100 million, were the number of LNG trucks on the road in the United States to double from 3,000 currently to 6,000. More specifically, it would cost roughly $10 million to construct all the LNG stations show in Figure 15 in our model year 2012, and roughly $80 million to construct all the micro-LNG liquefaction plants in Figure 16 in our model year 2012. Given this result, it is surprising that integrated oil companies do not see such a network as a profitable way to comply with California's Low Carbon Fuel Standard.

Figure 16. LNG liquefaction plant build out scenarios under 0.1% market penetration.



California already has several LNG fueling stations, including two at the Port of Long Beach. The California example demonstrates that station investors should be looking first and foremost for high volume routes where truckers have fewer routing options than in other parts of the country. It also confirms the corporate strategy being undertaken by fuel providers and truck manufacturers to focus marketing efforts on large corporate fleets where a couple of large early adopters could make a limited route such as California's I-5 a commercially viable, cost-effective place to introduce LNG as an alternative fuel. We find that comparable investments in the U.S. Mid-Continent would not pan out as commercially attractive without substantially higher initial investment levels. To launch a successful national network of LNG stations, where the industry would be making profit as a whole, would be prohibitively expensive in the billions of dollars, far more than might be reasonably considered by the federal government or a small number of commercial investors.

Our analysis would suggest that companies should first establish limited networks in California and the Great Lakes region in making investments in natural gas fueling infrastructure because these regions offer the highest potential concentration of fleets' adoption that could realistically direct a sufficient number of trucks to create a profitable network of stations. Eventually, a natural gas station network could extend beyond these initial LNG hotspot markets. The concept that a handful of large fleets could commit to substantial purchases of LNG trucks in a particular regional market finds evidence in today's commercial climate. For example, UPS ordered about 700 natural gas tractors in 2013, showing the viability of getting adoption of the additional trucks via a fleets purchasing model. A California network receives an extra financial boost from the existence of a liquid carbon pollution market that qualifies credits for natural gas fuel use.

Alternative Scenarios

To test the sensitivity of the profitability of a national network to the number of trucks on the road, we analyze a scenario where double the current number of trucks would be operating with LNG fuel. We compare our modeling results against four case study scenarios: 1) a 50% subsidy to station costs (or the equivalent of a 50% cost breakthrough) under current levels of demand; 2) a 50% subsidy to station costs (or the equivalent of a 50% cost breakthrough) under 100% higher levels of demand than currently seen; 3) a high diesel price scenario where regional diesel prices are at peak levels seen in 2008; 4) a high diesel price scenario where regional diesel prices are at peak levels seen in 2008 and under conditions of 100% higher demand than currently seen. Table 3 summarizes our results.

Table 3. Summary of Results by Scenario.

	0.1% Initial Penetration Rate			**0.2% Initial Penetration Rate**		
	Summary	**Route Completion 2015**	**Route Completion 2030**	**Summary**	**Route Completion 2015**	**Route Completion 2030**
No Subsidy	Network only builds in California.	0%	2%	Network begins in California and extends Eastward. Northeast and Great Lakes regions begin construction in 2025.	3%	55%
50% Subsidy	Network begins in California and extends eastward.	2%	6%	Network begins construction in California, Arizona and Nevada. Construction in the Great Lakes begins in 2015.	28%	76%
High Diesel	Network begins in California and extends eastward.	0%	6%	Network begins in California. East and West coasts connected in 2015.	69%	77%

We discuss these scenario results in more detail below:

Alternative Scenario 1: U.S. Natural Gas Fueling Networks Under a Doubling of LNG Trucks

To test the sensitivity of the profitability of a national network to the number of trucks on the road, we analyze a scenario where double the current number of trucks would be operating with LNG fuel. Figure 17 shows the location and configuration of LNG refueling network. Figure 18 shows the distribution of profitable stations over time under a 0.02% market penetration case. Not surprisingly, optimum station build-out patterns favor the regions with higher heavy trucking traffic flows (California, Midwest and the Great Lakes routes (Wisconsin-Illinois region, Kansas City region, Nashville, Dayton/Cincinnati, upstate New York) as well as areas with high diesel prices (California, New York, Ohio, and the Mid-Atlantic). Figure 19 (plants) micro LNG liquefaction plants also show strong favoritism in California, Midwest, and Mid-Atlantic/New England areas.

Figure 18 shows the respective price differentials by station and there appears to be a direct correlation between high station densities regions, like the ones described above and competitive LNG prices when compared with diesel prices. High volume routes in

Texas and Florida lag other regions as early adopters. In the case of Texas, low diesel prices may be a contributing factor. Florida lacks a high volume route into the state, despite a large flow of traffic exiting from its ports.

Figure 17. Dynamic LNG station build out scenario under 0.2% market penetration.

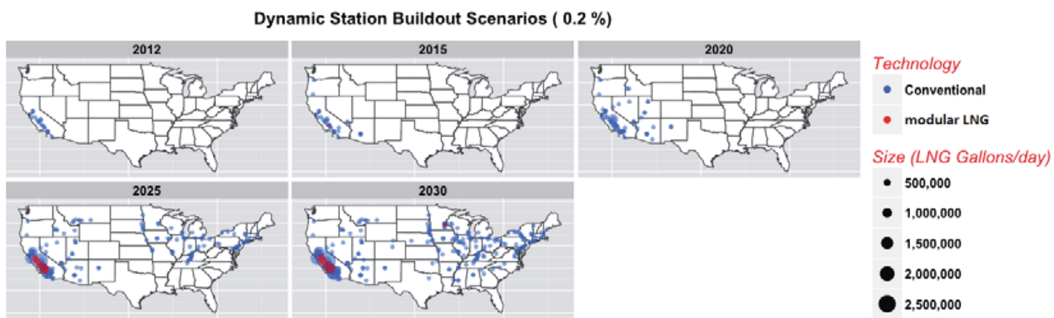


Figure 18. Dynamic LNG station price difference per diesel gallon equivalent under 0.2% market penetration.

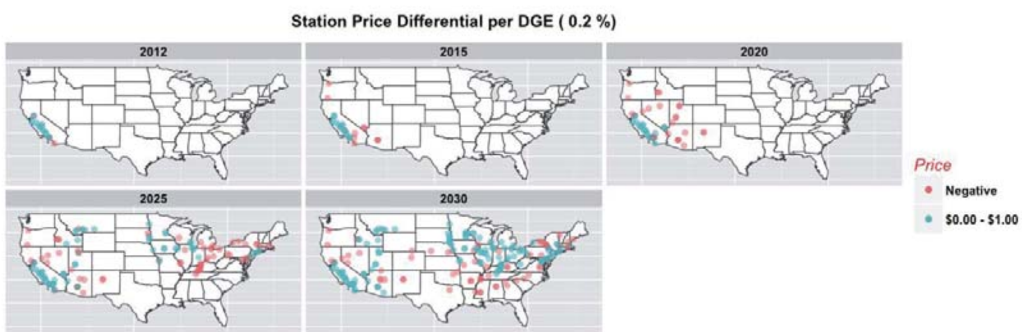


Figure 19. LNG liquefaction plant build out scenarios under 0.2% market penetration.

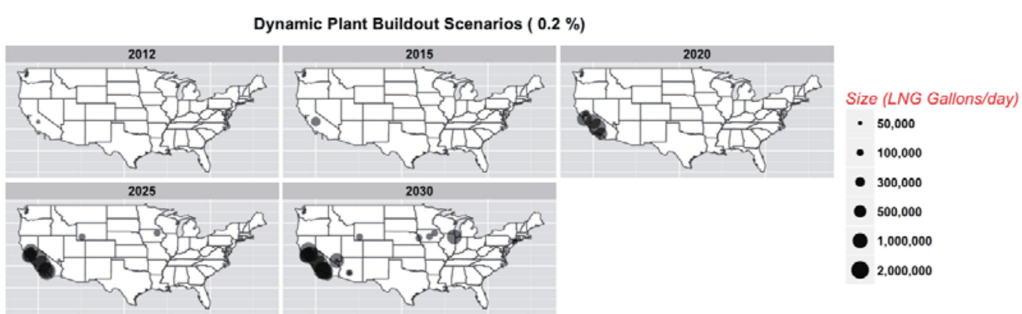
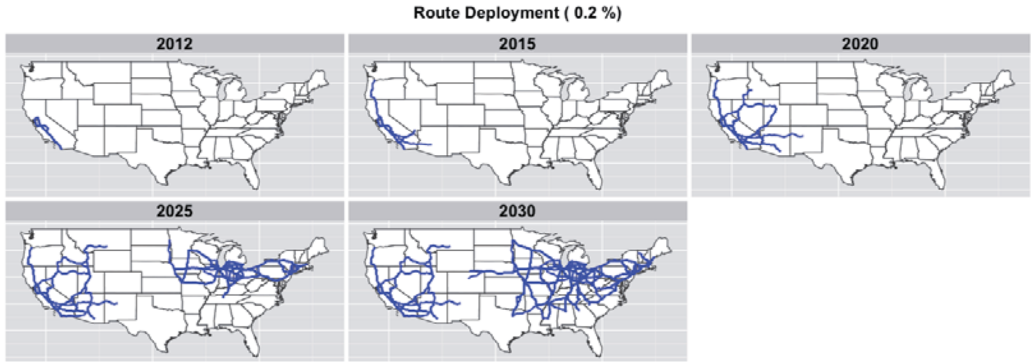


Figure 20. Trucking route deployment under 0.2% market penetration.



California's heavy density of both liquefaction plants and LNG stations can potentially serve as a launching point for a broader network of stations over time. Figures 17-20 reveal our results for how the network might develop based on solely commercial factors over time, starting in California under the 0.02% scenario where the market contains 6,000 LNG trucks in operation.

Our results reveal some interesting commercial dynamics to the temporal aspects to technology choices. Conventional technology is highly favored over small-scale, modular LNG technology small-scale modular LNG technology as can be seen in Figure 17. This is mainly due to the very high upfront cost of the LNG box technology but also because some conventional stations and liquefaction plants are partially financed already. In this process, early on, micro-LNG plants, which provide an economy of scale benefit to fuel providers, are built near these high demand seeded areas and remain concentrated in these areas even in later years. In order for small-scale, modular LNG technology to be competitive with conventional stations, they will require a faster technology learning rate or a subsidy.

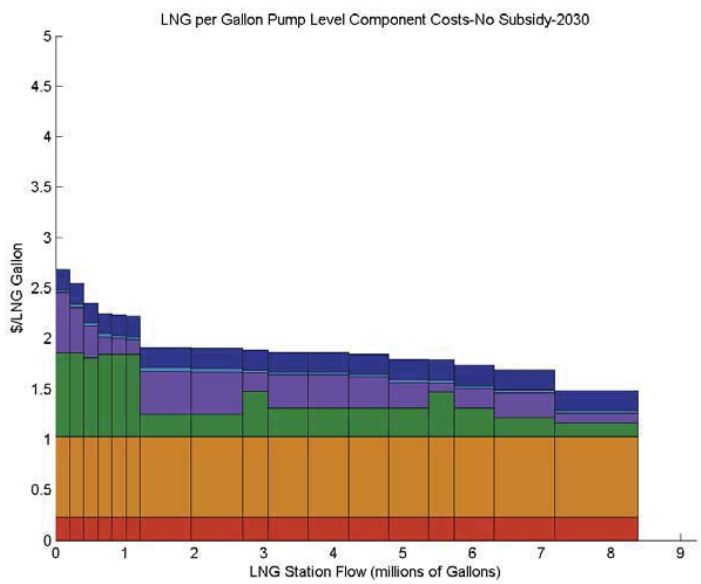
Alternative Scenario 2: Subsidy Scenarios

Using a case study approach, we study what level of investment is needed to get past the chicken-and-egg problem of station coverage sufficiently that new investment becomes sustainably profitable. Under current market conditions, we find that it is unlikely that national policy intervention of federal truck subsidies or federal station subsidies would be cost effective.

On a national basis, investors would have to be willing to build substantial facilities at a loss until those facilities reached a market concentration of over 2% to 3% of market share even under a scenario where they receive a 50% subsidy on station costs. Such a subsidy would be prohibitively expensive, in the billions of dollars. A core element of this result is the capital intensity of new fueling station investments which have to compete against sales outlets of incumbent fuels whose distribution networks are fully depreciated. In effect, natural gas' price discount would have to be large enough to cover both the high capital costs for building out new stations and higher operating costs for LNG fuel.

We do not find this result surprising because an alternative fuels station adoption cost gap exists between fuel/system operations costs for incumbent ample diesel stations that are already amortized, and the high cost of new LNG fueling infrastructure. Figure 21 demonstrates the large cost advantage the existing diesel fueling system has over LNG, even with the large discount in the underlying natural gas as compared to diesel fuel prices.

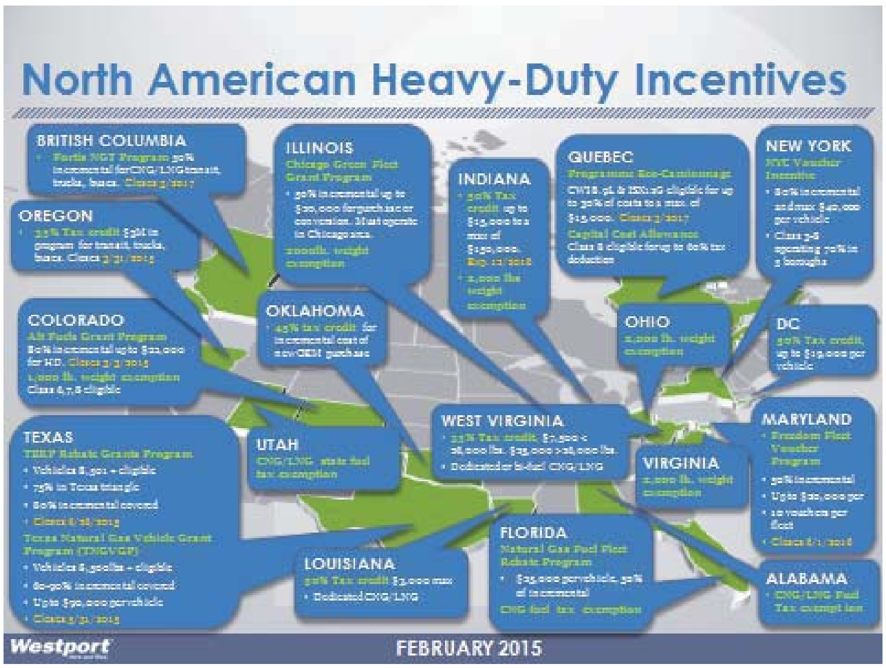
Figure 21. LNG delivered cost by station flow volume.



To date, U.S. states that have implemented programs to support natural gas as a transport fuel have provided incentives or subsidies either on vehicle purchases or retrofits or on station costs.

Figure 22 shows the range of policies used to stimulate natural gas vehicles in the United States. A number of states are offering incentives to support the expansion of natural gas as a transportation fuel. Pennsylvania, home to the rich Marcellus Shale gas basin, recently announced the Natural Gas Development Program that would provide $20 million over three years to convert or acquire heavy-duty vehicles that run on CNG and tailored the Alternative Fuel Infrastructure Grant to support mid duty vehicles conversion and fueling infrastructure financing through the Alternative and Clean Energy Fund. The state of Oklahoma, in another example, instituted a 75% subsidy on CNG fueling stations in 2012 as part of its goal to facilitate the use of natural gas in commercial vehicles. Figure 22 provides a view of available state incentives.

Figure 22. State incentives applicable to natural gas vehicles. [45]



Station Subsidy Scenario Results

When we test the robustness of our results against a 50% discount on the cost for LNG fueling stations, we find that only the profitability of a California network is greatly enhanced, with almost all stations in the state yielding a positive margin greater than $1.00. The results indicate that the carbon credit currently provided to natural gas fuel under California's current climate policies should be helpful in enabling a commercially profitable natural gas network in the state. The analysis also shows that a 50% subsidy would allow a large expansion of LNG liquefaction plants after 2025 as cumulative demand accrues over time.

A 50% reduction in station costs is not sufficient for the modeling solution to result in a build-out of a national LNG network in the next few years, indicating that the existing station costs for either traditional or small-scale, modular LNG technology are

[45] Westport.

prohibitively expensive to allow investors to realize a typical rate of return on capital of 12% given limitations on the speed to gear up LNG truck demand.

Truck Subsidy Scenario Results

We also consider an intervention where either the cost of natural gas fuel trucks falls dramatically or government subsidizes truck purchases. There is some indication that natural gas fuel truck tanks manufactured in China could cost up to 60% to 70% less than those currently manufactured in North America. We find that a doubling of the current penetration rates for LNG trucks can have significant impacts on future LNG network development. These results mimic reality and support the suggestion that policy intervention will be needed to get a national LNG network off the ground. The familiar question of whether it is more effective to reduce station prices or support higher LNG truck demand by subsidizing the vehicles is debatable. Our analysis suggests either option could influence market development. Directionally, scenarios analysis indicates that the market might be slightly more sensitive to a lowering of truck acquisition costs than to station construction costs since our scenario analysis indicates that a doubling of existing truck penetration rates would have a larger impact on network expansion than a 50% station cost subsidy.

Our scenarios also show that policy choices could influence the competition between LNG supply technologies. Generally speaking, in the early stages of natural gas fueling network buildout, conventional technology of plant and traditional fueling station technology is the least cost technology for early infrastructure implementation. Since the static model incorporates existing infrastructure, the network build out from regions that benefit from the highest densities such as California, Texas, the Midwest, and East Coast with stations connecting east and west. As penetration rates rise, the number and sizes of stations also increases in these locations but new stations emerge in other markets as well, notably Florida. The Mid-Continent remains less dense but routes become more abundant with greater station connections between the U.S. East and West Coasts. LNG modular technology starts to be deployed on high traffic routes, mainly in California, once the network gets to 3% concentration, as shown in Figure 23.

Figure 23. Static LNG station build out scenarios.

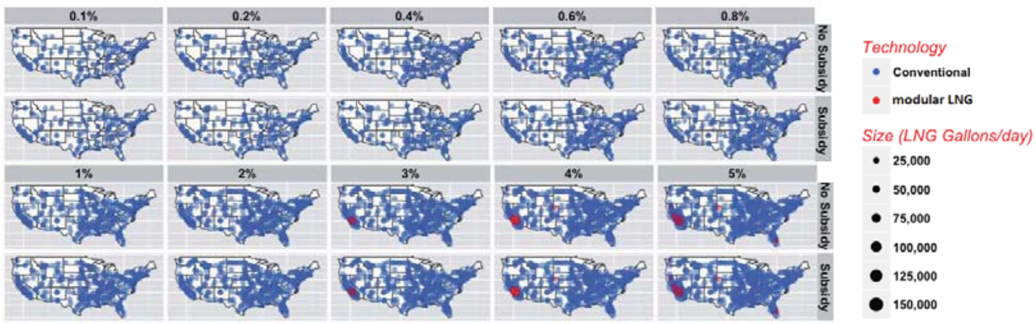
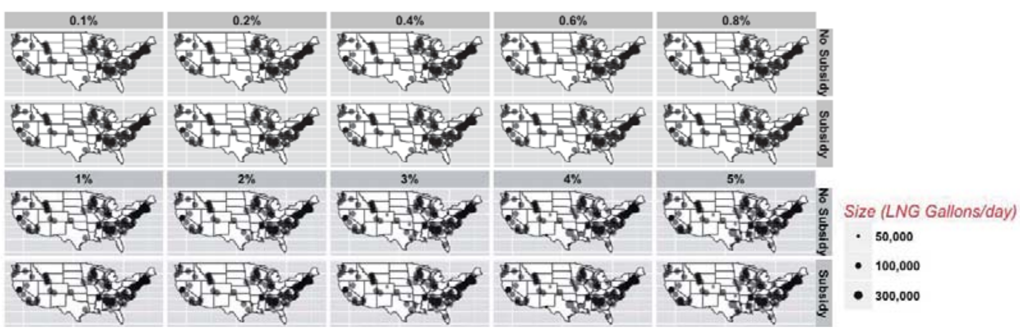


Figure 24 depicts the location build-out for micro-LNG plants under various rates of market penetration. The main visible difference in the 50% subsidy scenario is that small-scale, modular LNG technology gets built much earlier on, suggesting that the higher cost of that technology is a barrier and lowering its costs would enable the network to build faster.[46]

Figure 24. Static LNG plant build out scenarios.



Alternative Scenario 3: High Oil Price Scenario

U.S. diesel prices are currently declining as supply surpluses in global markets have put pressure on oil prices overall. But geopolitical factors could reverse this trend, raising the possibility that someday higher oil prices could potentially enhance the profitability of

[46] The reason the subsidy favors LNG box technology is that small-scale, modular LNG technology does not require an intermediate step. It directly converts gas to liquid, whereas the conventional pathway requires additional unsubsidized infrastructure (i.e. a liquefaction plant for conversion). In other words, the entire LNG pathway is contained inside a small scale modular technology, but a conventional station is only one component of its pathway. Thus, when small-scale, modular LNG technology gets a 50% reduction, it reduces the cost of the entire pathway but when a conventional station gets a 50% subsidy, its pathway is only partially subsidized. Components of the conventional pathway like the liquefaction plants and trucking costs are not factored in, only the capital deployed towards the stations gets the advantage of the subsidy so the percentage of the system capital that is subsidized is lower than the 50% enjoyed by each modular small scale unit. Thus, despite economies of scale for conventional technology, a 50% station subsidy favors small-scale, modular LNG technology development.

LNG as a trucking fuel. Using the modeling simulation, we test whether an increase in diesel prices while natural gas prices remain constant would be a sufficient condition to propel a higher level of station network construction. We find that even at higher oil prices, which creates a wider differential between the fuels is still not sufficient to overcome the alternative fuels adoption cost gap and seed initial development of an entire national network for natural gas fueling.

But under the high diesel price scenario and a U.S. fleet of 6,000 trucks (i.e. double today's level) price differential density plots for this scenario reveal stronger impetus for network development and coverage, notably in Texas and Florida, when compared to other scenarios. This high oil price scenario also results in a notably strong transcontinental density of stations connecting the eastern United States with the west.

High Oil Price Scenario Results

Our analysis indicates that significantly higher diesel prices in certain states creates an adequate threshold to promote broader LNG adoption in key hotspot locations, whereas a 50% station subsidy scenario results in a more sparsely populated network that is stretched too thinly across the nation. Under the high diesel, 6,000 truck penetration rate scenario, local hotspots develop regionally and eventually expand to nearby regions, which initially aren't experiencing as much development. Figure 25 (build-out, 0.2%) also suggests some very interesting station technology implications. Under the no subsidy, high diesel scenario, small-scale, modular LNG technology fills in network connections in the U.S. Mid-Continent (Heartland & Mountain regions) since overall traffic volumes are lower, and therefore don't support the scale economies of a larger scale hub and spoke mini-LNG plant infrastructure system.

Figure 25. Dynamic LNG refueling station build out scenarios under 0.2% LNG market penetration rate.

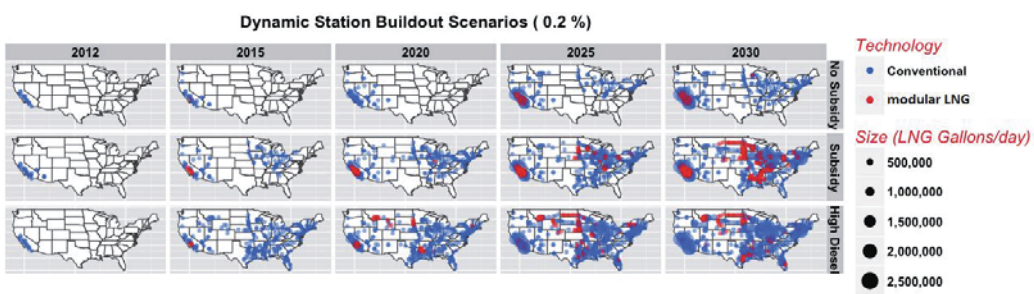


Figure 26. Dynamic liquefaction plant build out scenarios under 0.2% market penetration rate.

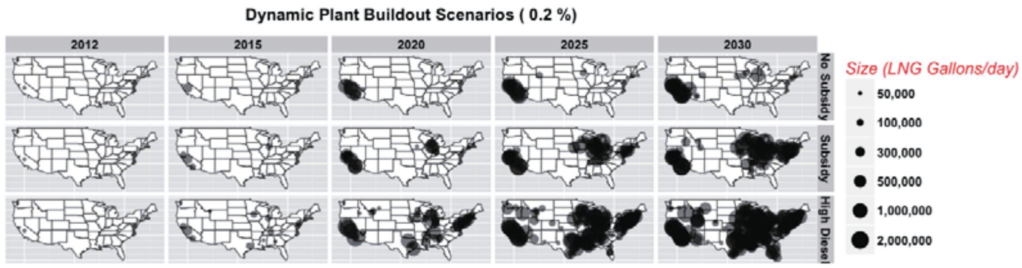
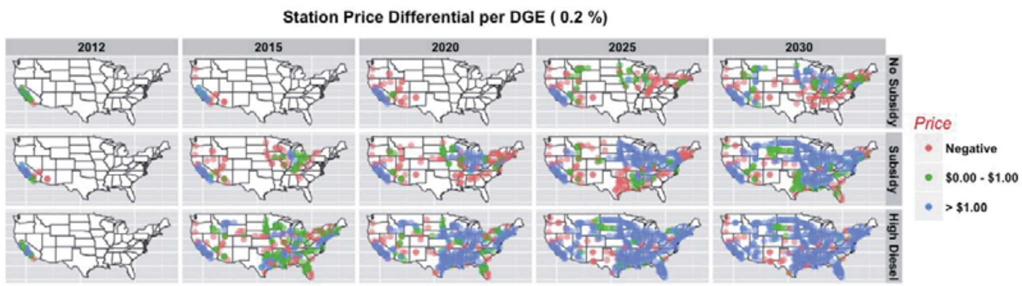


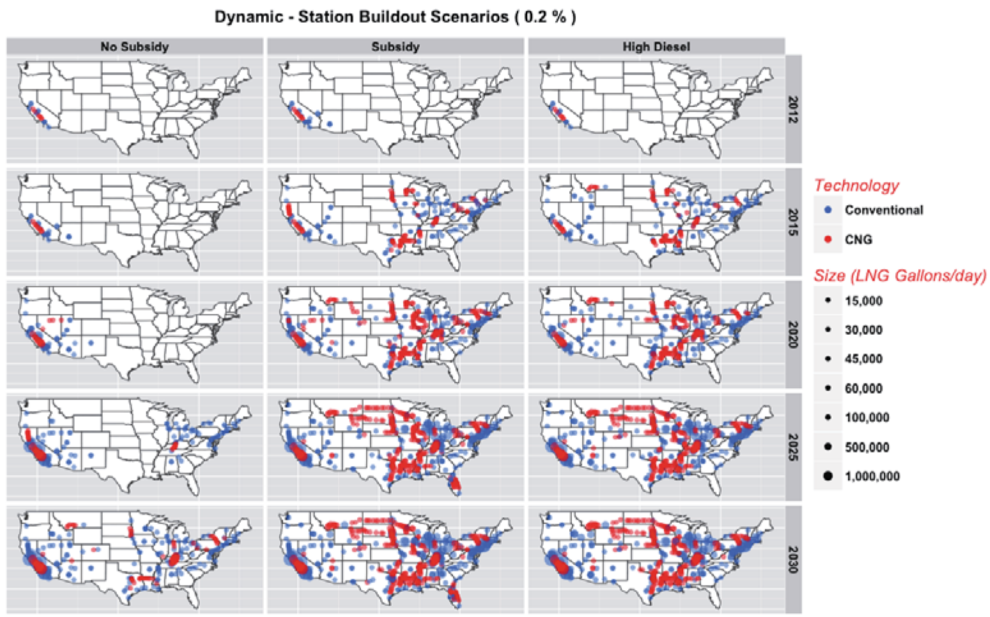
Figure 27. Dynamic LNG-Diesel price spread under 0.2% LNG market penetration ($/gde)



CNG as an Alternative to LNG Fuel

We test our results against a scenario where CNG stations are available as an alternative technology. Because CNG technology is less expensive on a supply chain per gallon basis than LNG and it can be built profitably at smaller scales, we find that CNG becomes an enabling technology in the development of broader natural gas fueling infrastructure. CNG stations can be profitable at smaller sizes than LNG and can supplement LNG networks with LCNG (liquefied-compressed natural gas) optionality to help station owners optimize revenue streams from access to natural gas feedstock. Figure 28 shows how CNG quickly becomes a competing technology to LNG in long distance trucking at the 0.2% market penetration scenario as demand for natural gas fuel develops in California and beyond, especially under scenarios where station subsidies are offered or diesel prices are high.

Figure 28. Dynamic CNG and LNG station build out under 0.2% market penetration rate.



Our results suggest that to best promote an alternative fuel into heavy-duty trucking, such as LNG, focus should begin on the highest volume freight routes such as California and the upper Midwest and then eventually commercial factors will encourage investment to branch out to other hotspot regions such as the Mid-Atlantic.

Our findings have interesting implications for California where fuel providers can earn carbon pollution credits under the LCFS and cap and trade systems. We find that if LNG could get to a limited penetration of 0.2% of the heavy trucking market, a commercial network in California could get off the ground. A subsidy in the form of carbon credits (natural gas currently is valued at a 20% savings to diesel under the LCFS) will help this process along. The state of California is currently investigating whether a build-out of natural gas fueling infrastructure across the state would facilitate higher use of renewable biogas as a low carbon transport fuel. Our initial analysis would confirm that this pathway may prove viable if the state’s network of natural gas fueling infrastructure could reach a minimum threshold. Another source of LNG fuel could come from LNG export terminals built in the northern United States to export natural gas to Asia. We do not consider this source of LNG fuel for this study but it could be a subject of future research. However, as will be discussed at length below, technological and process improvements for the natural gas supply chain would have to be made for fossil natural gas to meet California’s long term climate goals as a low carbon fuel.

Business Models for Advancing Natural Gas in Transportation

Business Model A

Private companies Clean Energy Fuels and ENN have begun building commercial fueling stations for LNG and CNG for use in long distance trucking. The business model for these stations is to seed the network with a minimum number of cross-country stations while simultaneously soliciting large trucking fleet owners and operators to switch a portion of their operations to natural gas fuel.

Clean Energy is the largest natural gas fuel provider in North America with over 330 natural gas fueling stations, serving 660 fleets and 25,000 vehicles. The company currently sells an average of 200 million gallons a year of CNG and LNG. Clean Energy says it is able to achieve a return to capital for fueling station investment and still pass on $1.00 to $1.50 a gallon in fuel savings to customers. The company's business model is to line up with return-to-base segment shipping for LNG fuel. In its presentations, Clean Energy says it engaged with trucking companies to determine optimal station locations; however, not all stations currently in operation are profitable and the momentum for its America's Natural Gas Highway has slowed some in the last year.[47]

Clean Energy's initial efforts received some support from Oklahoma Gov. Mary Fallin's initiative to promote natural gas in transportation in the state and beyond. To promote the use of natural gas in transportation, Oklahoma brought together original equipment manufacturers (OEMs), station providers and natural gas producers to create a coordinated effort that would overcome chicken and egg infrastructure issues, at least for CNG networks in the state. The state orchestrated bulk government purchasing orders of natural gas vehicles from the major automakers at a discounted level while offering a 75% station cost subsidy to station developers in exchange for a commitment to construct a credible number of fueling stations. There are currently close to 30 natural gas fueling stations in Oklahoma.

By the same token, ENN also has begun its efforts in Utah, which similarly had a state-sponsored program to enhance the use of natural gas vehicles. In February 2009, then Gov. Jon Huntsman announced that Utah would increase the state's NGV fueling infrastructure,[48] the state offered incentives to drivers to offset the higher price for the NGV vehicle and Questar offered financing and lease programs to customers to support the economics of the conversions. As a result, Utah has 99 natural gas fueling stations, public and private, many of which are located along primary highway corridors to support the fuel requirements of heavy-duty trucks.

Several national fleets are deploying natural gas trucks, including: Cisco, Pepsi, Walmart, Frito-Lay, HEB, Trimac Transportation, Truck Tire Service Corporation (TTS), Verizon,

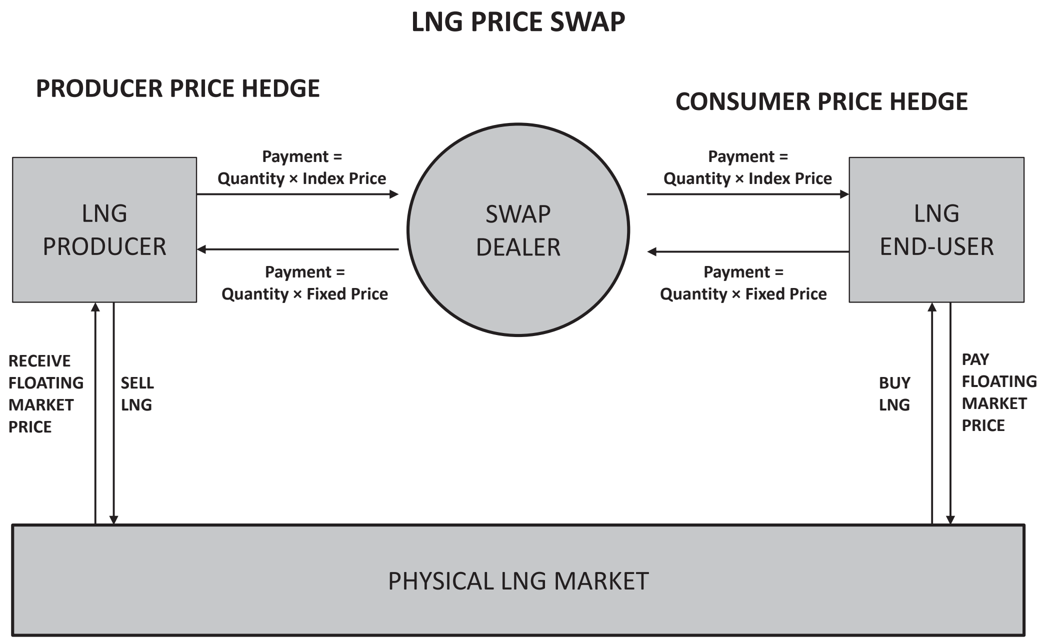
[47] Bob Tita "Slow Going for Natural Gas Powered Trucks" *The Wall Street Journal*, August 25, 2014
[48] Press Release, Office of the Governor of Utah, February 12, 2009

UPS, AT&T, Food Lion, and Ryder. One consideration for fleet truck owners is that vehicle turnover typically takes place within five years, at which time trucks are then sold to secondary and tertiary markets in the United States and Mexico. The economics of conversion to natural gas must therefore take into account resale value of the vehicle as well as lower operating costs but current rapid paybacks and the gradual emergence of buyers in the secondary market is driving more companies to consider natural gas fuel. Fleet owners also worry that supply chains for natural gas vehicles are not yet sufficiently high to avoid higher maintenance costs than traditional diesel vehicles and knowledge of the vehicle among trained maintenance workers is also lower, again potentially leading to higher fixed operating costs. Finally, fleet managers remain concerned that the gap between oil and natural gas prices will not remain at currently wide levels, adding an element of price risk.

While there have been some instances of local and state governments providing subsidies for trucking fleet owners to shift to natural gas vehicles, it seems unlikely that sufficient public funds into the billions of dollars will become available to offer incentives to truck owners to create sufficient demand to get the national long-distance natural gas fueling infrastructure to a tipping point. Instead, natural gas marketers may have to consider alternative business models such as the utilization of derivatives and swaps instruments.

At present, the oil–natural gas differential available on futures markets averages $9.50-$9.57/mmBTU from one year forward to three years forward. The eight-year long-range differential indicates natural gas is $9.18/mmBTU cheaper. Under swap arrangements, a financial intermediary could offer fleet owners a financial contract that locks in the purchase of the spread between natural gas and oil that is currently available in derivative markets. At the same time, the intermediary can offload the risk of the contract through an equal and opposite sale of the spread to a natural gas producer, who might be concerned that natural gas prices will fall relative to oil over time if surpluses continue to develop in North America and globally. By engaging in a swap arrangement, the fleet owner can guarantee that the margins needed to ensure the payback for a shift to natural gas vehicles are sustainable even if the price of oil were to fall over time.

Figure 29. LNG price swap process.



Business model B.

Another business model is for LNG providers to consider parallel investments in LNG for ships as an anchor to create demand that would support investment in LNG trucking infrastructure emanating in ports and expanding beyond them. One critical driver toward LNG adoption could come from the regulations which designate emission control areas (ECAs). ECAs regulate the emissions of sulfur and nitrogen oxides. Over time these regulations will become stricter requiring alternatives to the present fueling systems. In addition the ECA regulations specify varying emissions requirements depending on the distance from certain shorelines. The North American ECA specifies stricter emissions limits within 200 nautical miles of the shoreline. Given the strict North American ECA, some shipping companies are investigating adopting LNG for shipping trips that spend a significant amount of time near the North American shore, such as trips from the Los Angeles region to Seattle or Alaska. The Port of Tacoma will soon lease land to build an LNG bunkering facility. The Totem Ocean Trailer Express Company operates ships between the Tacoma and Alaska posts and plans to retrofit 2 ships for LNG operation. The decision was driven by the ECA requirements.

However, the cost to either purchase new LNG ships or retrofit ships to LNG is significant. Given the long turnover rates, typically 30 years or longer, relatively few ships require replacement at any given time. The same chicken-and-egg issue relevant to LNG trucks acts as a barrier for LNG shipping adoption. Both LNG bunkering terminals and ships must be installed or purchased to make the decision to adopt LNG (see appendix for additional discussion of costs for alternative means of compliance). Thus, like trucking, there are many uncertainties about the pace and scale of marine adoption of LNG fuel, making it difficult for investors to rely on port demand to serve a major anchor for developing the U.S. natural gas heavy-duty network system over the next five to ten year time frame.

Environmental Performance Analysis

As discussed, natural gas can provide benefits as a trucking fuel in terms of fuel costs and energy security. It has also been shown to play a substantive role in limiting certain kinds of air pollutants. For the California market, fuels are also judged by their carbon intensity and currently natural gas qualifies as a low carbon fuel under the LCFS for light-duty vehicles. For heavy-duty applications, the carbon intensity of natural gas as a fuel varies depending on drive cycle, engine efficiency and distribution system equipment.
In this section we discuss particulate matter, oxides of nitrogen (NOx) and carbon emissions

Particulate matter and Nitrogen Oxides

Particulate matter

EPA estimates that heavy-duty vehicles currently contribute more than 60% of the total particulate matter (PM) emissions from on-road vehicles. Mobile emissions themselves constitute 4 and 6% of the total PM2.5 and PM10 emissions, respectively, in the US. In California, mobile sources constitute 21% of total PM2.5 and 40% of total PM10[49]. According to California Air Resources Board (ARB) diesel engines and equipment rank as the 8th and 9th highest contributors[50] to PM2.5. State regulation requires diesel trucks and buses that operate in California to be upgraded to reduce emissions, and to be completely replaced by 2010 or later models progressively between 2015 and 2023. The regulation applies to nearly all privately and federally-owned diesel fueled trucks and buses and to privately and publicly owned school buses with a gross vehicle weight rating (GVWR) greater than 14,000 pounds[1].

In diesel technology, particulate matter is effectively controlled with filters, but filters, like any other emission control devices add cost and require maintenance. A shift to natural gas is an alternative to installing filters because natural gas fuel typically emits less PM and sufur oxides (SOx, which are PM precursors) than diesel without aftertreatment. A shift to LNG fuel can contribute a significant reduction in SOx tailpipe

[49] State and County Emission Summaries
http://www.epa.gov/cgi-bin/broker?_service=data&_debug=0&_program=dataprog.state_1.sas&pol=PM25_PRI&stfips=06
[50]Amendments Approved in April 2014 http://www.arb.ca.gov/msprog/onrdiesel/onrdiesel.htm

emissions as well as an almost a full-scale elimination in fine particulate matter in heavy-duty trucks. Regions with heavy use of diesel and bunker fuel (marine ECAS, ports, industrial sites, and roads with dense heavy-truck traffic or other non-attainment areas where diesel is heavily used) can achieve substantial air quality improvements by switching to natural gas-based fuel.

However, the scientific literature also suggests that engine type, aftertreatment technology, idling patterns, and drive cycle are more important than the type of fuel used, and thus this must also be taken into account for California to garner the optimum air quality benefits from a shift to natural gas in heavy-duty trucking. For example, diesel engines with particulate filters could produce lower levels of particulates than natural gas engines not equipped with aftertreatment technologies, but when NGVs are equipped with three-way catalyst technology, they produce generally much lower particulate and NOx emissions than do older NGVs without updated technology[51].

Nitrogen oxides

On-road mobile sources is the top contributor to NOx in the U.S.[52] In California, heavy-duty vehicles contribute to more than 30% of all nitrogen oxide (NOx) emissions from on-road vehicles[53]. NOx is an ozone precursor. The San Joaquin Valley and the South Coast air basins in California both surpass the federal ozone standard of 75 parts per billion (ppb)[54]. Heavy-duty on-road diesel vehicles are the largest source of NOx emissions in both these areas.[55] NOx emissions from heavy-duty trucks are limited federally to 0.2 grams NOx per brake horsepower-hour (bhp) for model years 2010 and later.

A 2009 survey of heavy-duty truck drivers at points of entry into California showed that non-California-registered trucks concentrated in the air basis that were having air quality issues[56]. Thus, the regulation applied to all trucks that operate in California even if they are not registered in California.

Strategies to comply with NOx standards include the use of alternative fuels. Biodiesel, blends of diesel with fuels made from plant oils, animal fats and waste oils have gained some attention, but studies find combustion of biodiesel blends results in slightly higher

[51] Yoon S, Collins J, Thiruvengadaem A, Gautam M, Herner J, Ayala, A, (2013) "Criteria pollutant and greenhouse gas emissions from CNG transit buses equipped with three-way catalysts compared to lean-burn engines and oxidation catalyst technologies, Journal of Air Waste Management Association, 63 (8) 926-33; Also Chandler, Eberts, Melendez, (2006) finds roughly 20 to 25 percent greenhouse gas emissions reductions for CNG transit buses compared to diesel in 2004 engine models.
[52]EPA. Part III Environmental Protection Agency 40 CFR Parts 50 and 58 Primary National Ambient Air Quality Standards for Nitrogen Dioxide; Tuesday, February 9, 2010
Final Rule. Federal Register http://www.epa.gov/ttn/naaqs/standards/nox/fr/20100209.pdf
[53] Facts About On-Road Heavy-Duty Vehicle Programs http://www.arb.ca.gov/enf/hdvip/onroad_hdtruck_factsheet.pdf
[54] http://www.epa.gov/air/criteria.html
[55] Sokolsky S, Silver F, Pitkanen W. "Heavy-duty truck and bus natural gas vehicle technology roadmap". July 2014.
[56] Lutsey N. Assessment of out-of-state truck activity in California. Transport Policy Volume 16, Issue 1, January 2009, Pages 12–18

NOx emissions than combustion of ultra-low sulfur diesel (ULSF), with variability across the different engine models tested[57]. Natural gas can also be used as alternative fuel for trucks. Academic studies generally agree that natural gas engines can achieve lower emissions than diesel trucks of the same efficiency primarily due to fundamental fuel properties and in-cylinder combustion modifications[58]. For example, in a study at West Virginia University (WVU) on trucks using a portable heavy-duty chassis dynamometer, LNG trucks averaged 80% less NOx emissions, but reductions varied across natural gas engine manufacturers[59]**.** The WVU portable laboratory was also used to test trucks and buses using Caterpillar dual fuel natural gas (DFNG) engines; it also found reduced NOx but the extent of NO_x reduction was dependent on the type of test cycle used[60].

Despite efforts, NOx attainment in the California basins is proving evasive. CARB adopted in December 2013 optional ultra-low nitrogen oxides (NOx) emission standards for diesel truck engines, with funding opportunities are available via programs such as the Carl Moyer Program[61]. Under these new optional rules, there are three new levels of optional certification corresponding to reductions respect to the current federal standard of 50%, 75%, and 90% (i.e., 0.1 g/hp-hr, 0.05 g/hp-hr, and 0.02 g/hp-hr respectively). Natural gas blended with hydrogen could meet the more restrictive NOx levels, even without aftertreatment, according to engine dynamometer tests at the University of Central Florida/Florida Solar Energy Center on and Sandia National Laboratories[62]. Other studies find that natural gas without aftertreatment has less ability to control NOx pollution[63].

NOx formation is maximized at peak temperature in diesel engines. A strategy to reduce NOx consists of introducing cooled exhaust gas that is also lower in oxygen reducing the production of NOx. However, the lower temperature produces less effective combustion and thus more CO2 and PM (and more fuel consumption). Exhaust gas recirculation (EGR) systems can be combined with particulate filters to control PM emissions, but increased CO2 will still occur. Thus, there is the concern that NOx goals can hinder efforts for fuel economy improvement in what it is sometimes referred as the NOx-GHG

[57]Venkata NG. 2010 Exhaust emissions analysis for ultra low sulfur diesel and biodiesel garbage truck. Master's Thesis. The University of Toledo

[58]Korakianitis T, Namasivayam A.M., Crookes R.J. "Natural-gas fueled spark-ignition (SI) and compression-ignition (CI) engine performance and emissions. Progress in Energy and Combustion Science
Volume 37, Issue 1, February 2011, Pages 89–112

[59] Weaver, C., Turner, S., Balam-Almanza, M., and Gable, R., "Comparison of In-Use Emissions from Diesel and Natural Gas Trucks and Buses," SAE Technical Paper 2000-01-3473, 2000, doi:10.4271/2000-01-3473.

[60] Norton, P., Frailey, M., Clark, N., Lyons, D. et al., "Chassis Dynamometer Emission Measurements from Trucks and Buses using Dual-Fuel Natural Gas Engines," SAE Technical Paper 1999-01-3525, 1999, doi:10.4271/1999-01-3525.

[61] http://www.arb.ca.gov/msprog/onrdiesel/onrdiesel.htm

[62] Hoekstra, R., Van Blarigan, P., and Mulligan, N., "NOx Emissions and Efficiency of Hydrogen, Natural Gas, and Hydrogen/Natural Gas Blended Fuels," SAE Technical Paper 961103, 1996, doi:10.4271/961103.

[63] Yoon S, Collins J, Thiruvengadaem A, Gautam M, Herner J, Ayala, A, (2013) "Criteria pollutant and greenhouse gas emissions from CNG transit buses equipped with three-way catalysts compared to lean-burn engines and oxidation catalyst technologies, Journal of Air Waste Management Association, 63 (8) 926-33; Also Chandler, Eberts, Melendez, (2006) finds roughly 20 to 25 percent greenhouse gas emissions reductions for CNG transit buses compared to diesel in 2004 engine models.

tradeoff. Older garbage trucks were found to emit more NOx and SOx but less CO and CO2 than newer trucks. A NOx-PM tradeoff also exists.

An alternative to EGR is using selective catalytic reduction (SCR). A more optimal engine timing can be procured for reduced PM emissions, but this will produce higher engine out NOx. In this case, optimal timing controls PM and an SCR reduces NOx. With this mechanism both the NOx-PM and the NOx-GHG tradeoffs are largely solved and actually allowed fuel economy to improve in newer diesel engines[64]. ARB found that SCRs realized reductions of 75% NOx reductions during cruise and transient modes, but no NO_x reductions during idle[65]. This could be due to the fact that catalysts require at least 200°C before significant NOx reduction is achieved. This temperature is not maintained right after engine start, during idling or even at low speeds,[66]thus possibly explaining why real emissions have been found higher than predicted by emissions models used in certifications[67,68]. It is becoming clear to regulators that operating parameters such as coolant temperature, fuel temperature, percent fuel, engine speed are important in determining exhaust emissions in trucks. Vehicle model, age, aftertreatment technology, and driving cycle can be as or more relevant factor than fuel type (ie natural gas or diesel) used in determining NOx emissions.[69]

One challenge for NOx regulation for both natural gas and diesel trucks is that NOx control technology can produce a fuel efficiency penalty thus emits more carbon and the new EPA/NHTSA CAFÉ-like regulations for trucks[70] requires more aggressive fuel economy. Advances in turbocharging technology, such as inertia reduction, aerodynamics

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[64] Personal communication with ARB staff.
[65]Dinh Herner J., Hu S., Robertson W.H., Huai T., Collins J.F., Dwyer J.F., and Ayala A. "Effect of Advanced Aftertreatment for PM and NO_x Control on Heavy-Duty Diesel Truck Emissions" *Environ. Sci. Technol.*, **2009**, *43* (15), pp 5928–5933"
[66] Venkata NG. 2010 Exhaust emissions analysis for ultra low sulfur diesel and biodiesel garbage truck. Masters Thesis. The University of Toledo
[67] Weaver, C., Turner, S., Balam-Almanza, M., and Gable, R., "Comparison of In-Use Emissions from Diesel and Natural Gas Trucks and Buses," SAE Technical Paper 2000-01-3473, 2000, doi:10.4271/2000-01-3473.
[68] http://researchplanning.arb.wagn.org/files/Activity_Data_HDD_SOW-20666.pdf
[69] Idling regulations restrict trucks from idling more than five minutes or idling in school zones and some technologies such as an auxiliary power unit (APU) or direct-fired heater (DFH) can be used to increase temperature and reduce NOx emissions at idling. APU and DFH have been shown to reduce NOx by 89% and 99% respectively. Emissions tests from Class 8 over-the-road tractors on a chassis dynamometer showed emissions from Idle and Creep Modes were found to be variable due to varying auxiliary loads on the engine, according to Air Resources Board-sponsored truck activity programs. Engine control unit (ECU) or on board data (OBD) loggers can help with maintenance, but more importantly they could be used to improve characterization of certification models. CalHEAT Truck Research Center at CALSTART in a roadmap prepared for The Southern California Gas Company suggests optional ultra-low NOx standards could focus on emission reduction technologies problem areas, such as thermal management of NOx emission reduction technologies. Characterize heavy-duty truck activity profiles (e.g., duty cycles, starts and soak time) for different vocational uses to identify operating conditions relevant to SCR function. Evaluate emission test cycles to represent SCR relevant operating modes. Post-combustion after-treatment technology such as optimized catalysts and improved conversion efficiencies, can be employed on natural gas engines to further reduce emissions of NOx and CO2. July 2014 Heavy duty truck and bus natural gas vehicle technology roadmap, Prepared by Steven Sokolsky, Fred Silver, and Whitney Pitkanen.
[70] EPA/NHTSA CAFÉ standards for trucks: Phase 1 (10-23% reduction in fuel consumption required model year 2014-2018) and Phase 2, which will be announced 2015, will be more stringent.

and bearing improvements- and other technologies[71] relevant to both natural gas and diesel engines-could be applicable[72]. As it is shown below, increasing fuel economy is a key strategy in order to make natural gas trucks less carbon intensive.

Greenhouse gases

In terms of climate pollution, tailpipe emissions from burning natural gas in heavy-duty trucking applications will produce between two-thirds and three-fourths the emissions of burning gasoline or diesel[73], but there are other issues that affect the well-to-wheels carbon intensity of natural gas in transportation. The variables that impact the environmental performance of natural gas include the level of methane and carbon dioxide venting and leakage from upstream production (i.e., non-combustion related) and the methane and carbon emissions associated with fuel processing (e.g., gas production, gas compression or liquefaction, etc.).

According to our analysis with GREET 2014[74] and assuming national averages of methane leakage[75], and in a case where the more efficient HPDI engine is used in LNG trucking, system-wide methane leakage from natural gas production and distribution cannot exceed 3% for natural gas to break even in carbon intensity (Figure 30). But many LNG trucks are equipped with the less efficient spark ignition engine and for this circumstance, methane leakage would need to be eliminated entirely for natural gas to match the carbon intensity of more efficient diesel engines (Figure 30).

We also find that the effects of leakage can be more significant for CNG than LNG[76]. CNG requires distribution via leaky natural gas local pipelines to the refueling stations where it is compressed, whereas LNG is transported as LNG from LNG plant to refueling station by truck. For these reasons, no carbon pollution advantage is found compared to diesel in cases where NGV trucks are equipped with the less-efficient Si engine technology and the more methane leakage-prone CNG.

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[71] Reducing the Fuel Consumption and Greenhouse Gas Emissions of Medium- and Heavy-Duty Vehicles, Phase Two: First Report. The National Academies Press, Washington, DC

[72] Arnold, S., Balis, C., Jeckel, D., Larcher, S. et al., "Advances in Turbocharging Technology and its Impact on Meeting Proposed California GHG Emission Regulations," SAE Technical Paper 2005-01-1852, 2005, doi:10.4271/2005-01-1852.

[73] Zhao et al. 2013

[74] Rood Werpy M., Santitni D., Burnham A., and Mintz M., Argonne National Laboratory "White Paper on Natural Gas Vehicle: Status, Barriers, and Opportunities" September 2009 which found that in-use emissions reductions varied by region, fuel composition and engine configurations. The authors conclude that light duty natural gas vehicles can offer up to a 15 percent reduction in greenhouse gas emissions

[75] Dominguez-Faus, R. The Carbon Intensity of C8 NGV trucks. Working paper.

[76] These results are based on national natural gas supply chain assumptions. In California, results can be different due the lower leakage in the pipeline infrastructure and the higher energy efficiencies in upstream processes.

Figure 30. 100-year carbon intensity (gCO2e/mile) of C8 diesel and natural gas under different leakages rate.

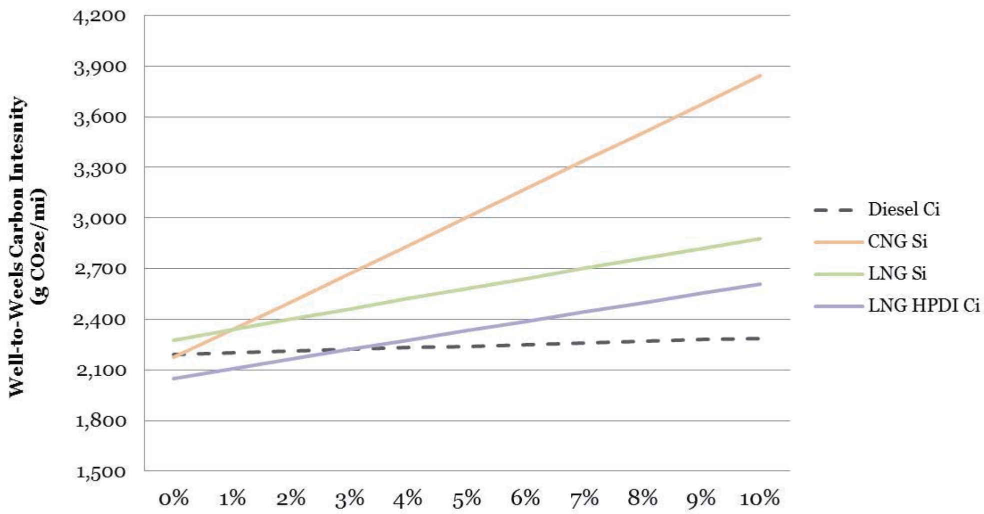
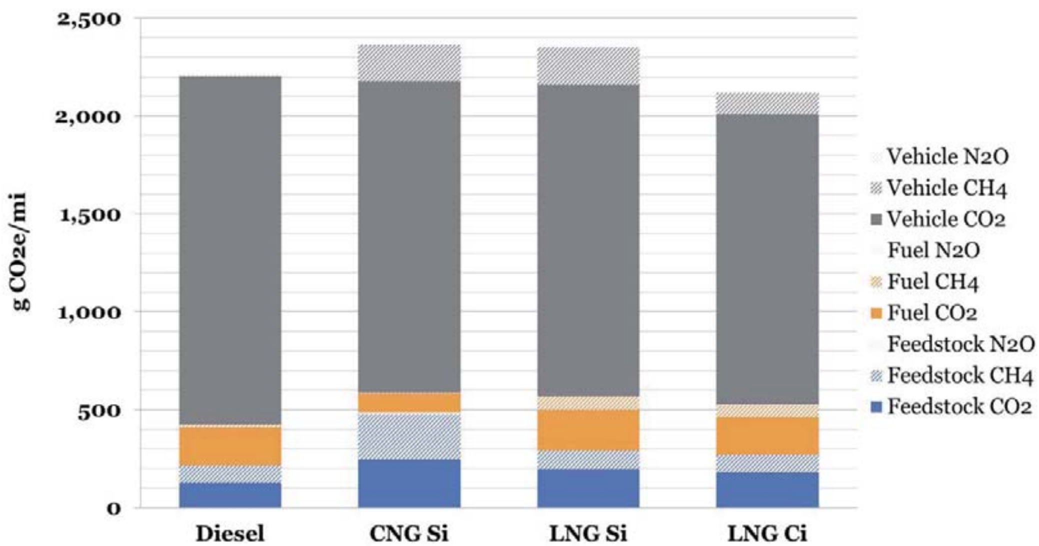


Figure 31 compares the contribution in grams of CO2 per mile to the 100 year carbon intensity (CI) of diesel and three configurations of NGV Class 8 trucks. This comparison reveals that the only vehicle-storage technology combination that would provide a beneficial carbon reduction with respect to diesel under the currently accepted Environmental Protection Agency (EPA) official methane leakage rate of 1.12%, would be the high-efficiency HPDI Ci engine using LNG.

Figure 31. Contribution to total carbon intensity of diesel and natural gas C8 trucks under current 1.12% leakage rate.



Technologies exist for industry to curb upstream methane leakage significantly. In 2012 EPA ruled that all new oil and gas wells must use green completions beginning in 2015. The rule only applies to existing or modified wells, and affects an estimated 13,000 wells every year. While designed to control smog-contributing pollutants, green completions are also able to control methane emissions at oil and gas production sites. A study by the Environmental Defense Fund (EDF) found that a large number of operators are using these best practice technologies already.[77] According to official estimates, between 2012 and 2015, when green completions were only voluntary, methane emissions were reduced by 16%, despite the increase in oil and gas production. Technologies exist to bring wellhead methane leakage to zero. However, these technologies only reduce leakage at field operations. Additional technologies will be required to eliminate leaks at processing facilities, transmission lines and local distribution pipelines which can often be leakier.

EPA is now in the process of drafting methane-specific regulations to be issued sometime in 2016. The new regulations will apply to new and modified infrastructure, and will potentially cover production and distribution operations, not just drilling. According to EPA estimates, the new regulations could achieve reductions of methane leaks in natural gas and oil systems of 40% to 45% by 2015, using 2012 as baseline.

Still, the largest potential improvements in the carbon intensity of NGVs running on fossil natural gas will come from gains in natural gas vehicle efficiency. Even if all

[77] http://www.edf.org/methaneleakage; also see A R Brandt et al, (2014) Science Vol 343, "Methane Leaks from North American Natural gas systems,"

upstream methane leakage were completely eliminated, NGVs using HPDI engines (5.36 miles per dge) would provide an 8% reduction in carbon emissions compared to diesel, while a Si engine (4.68 miles per dge) would produce only insignificant benefits. Under the higher estimates of 3% methane leakage rates, NGVs powered by the more inefficient Si engines would create a 40% increase in carbon emissions compared to diesel. Under a 3% methane leakage situation, NGVs equipped with HPDI engines would still be 20% more carbon intensive than the most efficient diesel engine. Carbon intensity of natural gas fuel may also be lowered by co-mingling fossil natural gas supplies with lower carbon intensity renewable natural gas from bio-waste sources.

The carbon intensity of NGVs in California is below the national average, leaving more leeway for natural gas vehicles to meet the state's carbon reduction goals. The leakage reported in the California pipeline infrastructure is lower than the national average. However, a comparative analysis reveals that it is the stringent air quality and energy efficiency regulations on stationary sources such as oil recovery and processing which contribute to a lower carbon intensity of all fossil transportation fuels in California, as those indirectly contribute to higher efficiency and decarbonization of energy used in upstream processes. To understand better the differences between California and national results, data uncertainties and modeling caveats, see the working paper on carbon intensities by Rosa Dominguez-Faus. [78]

Our analysis suggests that improving efficiencies in vehicle engine and during upstream processes can be more effective at reducing the carbon intensity of natural gas in transportation than a strategy based in controlling methane leaks alone.

Conclusions and Implications for Policy

The deeply entrenched incumbency of oil-based fuels and their well-established infrastructure distribution provide a formidable barrier to the transition to alternative fuels. Even for a fuel such as LNG, which currently enjoys a deep cost discount to diesel, establishing a competitive fueling network will be challenging. Moving LNG into the heavy-duty trucking fleet could prove the most pliable of the options for fuel-switching based on commercial factors. That is because the turnover rate for Class 8 vehicles is fairly rapid compared to other kinds of vehicle stocks (three years, for example, compared to 10 to 14 years for light-duty vehicles) and vehicle ownership tends to be concentrated in large corporate fleets whose vehicles have high miles utilization per year and who can scale up more quickly than individual vehicle owners to shift vehicle technologies.

[78] Rosa Dominguez-Faus working paper, "The Carbon Intensity of C8 NGV Trucks."

But large fleet owners will not be willing to make investments in alternative fuel vehicles unless they are assured of dedicated fueling station availability for their entire travel route. Thus, our scenario analysis suggests that the best way to promote an alternative fuel, such as LNG, into the heavy-duty trucking sector would be to focus initially on the highest volume freight routes such as California and the upper Midwest and then eventually commercial factors will encourage investment to branch out to other hotspot regions such as the Mid-Atlantic.

Trying to build from scratch a well-covered national network is not the most optimal approach to establishing a LNG highway, at least in the early stages. Instead, it may be beneficial to first establish limited networks in California or the Great Lakes region because these regions could benefit most from a high concentration of fleets adoption to add realistically a sufficient number of trucks to create a profitable network of stations. Eventually, a natural gas station network could extend beyond this initial LNG hotspot market.

Conceptually, focusing on a handful of large fleets that could commit to substantial purchases of LNG trucks in a particular regional market makes commercial sense and is consistent with the current commercial climate. For example, UPS ordered about 700 natural gas tractors in 2013 alone, showing the viability of getting adoption of the additional trucks via a fleets purchasing model.

Policy makers at the federal level have expressed an interest in promoting natural gas as a transport fuel in commercial fleets as a means to promote energy security, given abundant, domestic natural gas supplies that are located in geographically diverse locations. North American natural gas fuel is also expected to remain less expensive than oil-based fuel, opening the possibility of more cost-effective supply chains that can better compete with international markets. Finally, a push for natural gas into transportation will ensure that domestic producers have a ready domestic market for their gas to prevent supply overhangs from threatening profitability and associated job growth. However, to best utilize natural gas into U.S. trucking, policy makers need to consider both commercial realities in the market as well as ways to improve the environmental performance of natural gas as a direct fuel.

Successful public-private partnerships have already been utilized in some U.S. states such as Oklahoma to promote a switch to CNG vehicles for government work fleets. Policy makers can consider whether a pilot project federal-state partnership for LNG trucking could benefit the U.S. natural gas industry while at the same time promoting alternative fuel goals. The United States' recent commitment to reduce greenhouse gas emissions 25% to 28% from 2005 levels by 2030 includes stringent regulation of methane emissions, venting and flaring from U.S. domestic oil and gas production. Any shift to natural gas fuel would have to be considered in this context.

The question of what hotspot to select for a pilot project for natural gas vehicles is a complicated one. Our analysis would suggest that high access to natural gas supplies is less important than the density of freight miles traveled on local highways. Optimum station build-out patterns favor the regions with higher heavy trucking traffic flows (California and the Great Lakes routes (Wisconsin-Illinois region, Kansas City Region, Nashville, Dayton/Cincinnati, upstate New York) as well as areas with high diesel prices (California, New York, Ohio, and the Mid-Atlantic). Small scale micro LNG liquefaction plants also show strong favoritism in California, Midwest, and Mid-Atlantic/New England areas.

At present, the California natural gas heavy-duty trucking network receives an extra financial boost from the existence of a liquid carbon pollution market that qualifies credits for natural gas fuel use. California currently offers fuel providers carbon pollution credits under the LCFS and cap and trade systems. We find that if LNG could get to a limited penetration of 0.2% of the heavy trucking market, a commercial network in California could get off the ground. A subsidy in the form of carbon credits (fossil natural gas currently has a 20% lower carbon score than diesel under the LCFS) will help this process along. But the California Air Resources Board is considering regulations that will lower the credit available to natural gas fuel. Our environmental modeling suggests that this is justified based on updated analysis on methane leakage along the natural gas value chain together with efficiency penalties for typical Si natural gas engines. For LNG to meet California's goals for reducing the carbon footprint of fuels used by vehicles in the state, costs for advanced engine technologies such as the HDPI engine will need to fall further and carbon intensity of both vehicles and natural gas production and distribution infrastructure will need to be improved.

Still, interest in natural gas as a trucking fuel should not be rejected out of hand as the state of California is also investigating whether a build-out of natural gas fueling infrastructure across the state would facilitate higher use of renewable biogas as a low carbon transport fuel. Our initial analysis would confirm that this pathway may prove viable if the state's network of natural gas fueling stations could reach a minimum threshold.

Several companies are currently investing in natural gas fueling infrastructure in the state of California, and there are many major commercial fleets that are operating in the state and could profitably switch to natural gas or biogas fuels. This starting base means that the cost of building an optimal natural gas fueling system in the state is relatively inexpensive compared to the cost of building fueling infrastructure for some of the other alternative fuels.

Since the commercial costs are low for a federal/state collaboration promoting a public-private partnership that would utilize natural gas and low carbon biogas fuel in California, the development of a natural gas fueling network there could support the expansion of natural gas as a fuel in other contiguous markets over time and eventually support the build-out of a national natural gas network across the U.S. highway system. This would suggest that federal government support for California's efforts to build alternative fuels infrastructure would be justifiable as a means to promote domestic natural gas markets in the short term and to enable a faster transition to low carbon biogas over the longer run.

Participating station investors could be expected to achieve a rate of return to capital of 12%, making the network commercially sustainable once built. The experience of the state of Oklahoma with natural gas fueling is instructive. The state brought parties together simultaneously to organize orders for the vehicles and commitments to build the fueling infrastructure under a single initiative receiving some state funding and calibrated so that stations and vehicle purchases appeared simultaneously.

The construction of natural gas infrastructure would be enabling to biogas producers who would be assured that fueling networks would be available to commercialize their production. California and neighboring states have a biogas resource base that is large enough to support between 10,000 and 30,000 LNG trucks, but further study is needed to determine what distant resources could be developed and imported profitably from other states and nearby countries. The California Biomass Collaborative, a University of California Davis-led public-private partnership for the promotion of California biomass industries, estimates that 32.5 million billion dry tons (bdt) of in-state biomass feedstocks could be available for conversion to useful energy[79] In particular, estimates for methane production from landfill gas are 55 bcf/year, 4.8 bcf/year for waste water biogas, and 14.6 bcf/year for biogas from manure sources. Similar biomass resources are located in states that border California or are along routes for the transmission of natural gas to the state from major producing states.

We estimate that the methane potential from landfill gas in the Western states outside of California is 105 bcf/year based on existing and candidate landfills identified by the EPA.[80] Parker estimates an additional 100 million bdt/year of lignocellulosic biomass in the Western states which are roughly equivalent on an energy-content basis to the gasoline used by 14.5 million passenger cars a year. However, some of these in-state and external biomass sources are already committed to or could be used for the production of liquid biofuels or for dedicated power generation services to the businesses where they are co-located[81].

Other states besides California might be amenable to a pilot program for LNG trucking but many locations that have already embarked on limited investments such as Utah

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[79] Williams, R. B., Gildart, M., & Jenkins, B. M. (2008). An Assessment of Biomass Resources in California, 2007. CEC PIER Contract50001016: California Biomass Collaborative., (http://biomass.ucdavis.edu/files/reports/2008-cbc-resource-assessment.pdf)
[80] "Landfill Methane Outreach Program: Energy Projects and Candidate Landfills." US EPA, (http://www.epa.gov/lmop/projects-candidates/index.html)
[81] Parker, Nathan, Peter Tittmann, Quinn Hart, Richard Nelson, Ken Skog, Anneliese Schmidt, Edward Gray, and Bryan Jenkins. "Development of a biorefinery optimized biofuel supply curve for the Western United States." *Biomass and Bioenergy* (2010) (34), pp 1597-1607.

might find it difficult to promote sustainably commercial expansions that will link quickly to sufficiently high traffic networks. Thus, as the federal government seeks partnerships for natural gas fuel investment, it will want to consider venues such as the upper Great Lakes and Mid-Atlantic that also have the potential to contribute biogas inputs and also have highly identifiable heavy freight routes that could support a high volume trucking fleet for LNG or CNG powered vehicles.

National or state efforts to work with vehicle manufacturers to promote best in class engine efficiency and commitment to production would also be a critical component of any successful initiative to promote natural gas adoption into the heavy-duty sector. Such an effort needs to be consistent with emerging climate policies that are currently being implemented, such as carbon reduction efforts like those in the state of Colorado, which is seeking to eliminate methane leakage from oil and gas production, or recently announced plans by the White House in January 2015 of a draft federal methane regulation by the summer of 2015.

Independent Statistics & Analysis
U.S. Energy Information Administration

Marine Fuel Choice for Ocean-Going Vessels within Emissions Control Areas

June 2015

Introduction

The U.S. Energy Information Administration (EIA) contracted with Leidos Corporation to analyze the impact on ocean-going vessel fuel usage of the International Convention for the Prevention of Pollution from Ships (MARPOL) emissions control areas in North America and the Caribbean.

Leidos developed a new methodology for calculating fuel consumption by ocean-going maritime vessels in the United States within emission control areas by:

- Establishing a fuel usage methodology baseline for ocean-going vessels by U.S. Census Division and Puerto Rico for several ship types and energy and non-energy commodities
- Discussing relevant MARPOL and associated U.S. Environmental Protection Agency emissions regulations and major emissions compliance strategies, including exhaust scrubber controls, fuel switching to liquefied natural gas, and engine-based controls
- Creating a methodology for projecting ocean-going vessel travel demand by commodity and ship type, ship efficiency, and fuel choice by various compliance choices

In addition, Leidos recommended study of additional issues for future model improvements as more data become available. These include:

- Expanding the scope of the marine fuel estimates to include travel beyond North American and Caribbean emission control areas and Great Lakes and inland waterway transit
- Expanding the scope to include fuel usage estimates tied to U.S. ports for tugs, barges, and lightering vessels, fishing vessels, cruise ships, and other commercial vessels
- Fractioning the fuel purchases made in the United States versus abroad
- Improving the future projections of fuel usage, including slow steaming and auxiliary power needs, and technology adoption

EIA plans to update the upcoming *Annual Energy Outlook 2016* to include a new methodology for calculating the amount of fuel consumption by ocean-going vessels traveling though North American and Caribbean emissions control areas, including the impact of compliance strategies. Further, EIA plans to update the methodology for calculating ocean going vessel energy demand to include estimation of fuel consumption by ship type and commodity moved. The new methodology will also estimate energy consumption within and outside emission control areas. In addition, EIA will explore the interplay between refinery operation, refined product slates, and marine fuels in light of the impact of emission regulations.

Appendix A

Marine Fuel Choice for Ocean Going Vessels within Emission Control Areas

EIA Task 7965, Subtask 17

Prepared for:

Energy Information Administration
Office of Energy Analysis
Office of Energy Consumption and Efficiency Analysis

Prepared by:

Leidos Corporation
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FINAL REPORT

April 2015

Disclaimer

Certain statements included in this report constitute forward-looking statements. The achievement of certain results or other expectations contained in such forward-looking statements involve known and unknown risks, uncertainties and other factors which may cause actual results, performance or achievements described in the report to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. We do not plan to issue any updates or revisions to the forward-looking statements if or when our expectations or events, conditions, or circumstances on which such statements are based occur.

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List of Abbreviations and Acronyms

ACOE	Army Corps of Engineers
AEO	Annual Energy Outlook
Btu	British thermal units
CWA	U.S. Clean Water Act
CO_2	carbon dioxide
dwt	dead weight tonnage
C1, C2, & C3	Category 1, 2, and 3 (marine diesel engines)
dm^3	cubic decimeter (liter)
DNV	Det Norske Veritas
ECA	Emission Control Area
EEZ	exclusive economic zone
EGCS	exhaust gas cleaning system
EGR	exhaust gas recirculation
EIA	Energy Information Administration
EPA	U.S. Environmental Protection Agency
EU	European Union
GHG	greenhouse gas
GWh	Gigawatt-hours
HAM	humid air motor
HFO	heavy fuel oil
hp	horsepower
ICCT	International Council on Clean Transportation
IFO	intermediate fuel oil
IMO	International Maritime Organization
kg	kilograms
kWh	kilowatt-hours
LNG	liquefied natural gas
LPG	liquefied propane gas
LSFO	low sulfur fuel oil
m^3	cubic meters
MARPOL	International Convention for the Prevention of Pollution from Ships
MCR	maximum continuous rating
MDE	marine diesel engine
MDO	marine diesel oil
MEPC	Marine Environment Protection Committee
MGO	marine gas oil
MSAR SFO	Multiphase Superfine Atomized Residue Synthetic Fuel Oil
MT	million metric tons (million tonnes)
Mtpa	million tons per annum
MWh	Megawatt-hours
NEMS	National Energy Modeling System
nm	nautical miles
NO_x	oxides of nitrogen

NO_2	nitrogen dioxide
NPDES	National Pollutant Discharge Elimination System
NPV	net present value
ODS	ozone depleting substances
OGV	ocean going vessel
O&M	operating and maintenance
PAH	polycyclic aromatic hydrocarbons
RFO	residual fuel oil
R&D	research and development
rpm	revolutions per minute
SCR	Selective catalytic reduction
SO_x	oxides of sulfur
SO_2	sulfur dioxide
SO_3	sulfur trioxide
SSD	slow speed diesel
TDM	Transportation Demand Module
TEU	twenty-foot equivalent unit
U.S.	United States
VLCC	very large crude carrier
VSR	vessel speed reduction

Executive Summary

The National Energy Modeling System (NEMS) is the primary analysis tool for projections of domestic energy markets by the United States (U.S.) Energy Information Administration (EIA). The NEMS model can be used to understand the impacts that current energy and environmental issues and policies may have on energy markets. This particular study focuses on how a treaty/policy issue might affect the waterborne freight component of the Freight Transportation Submodule within the Transportation Demand Module (TDM) of NEMS.

The International Convention for the Prevention of Pollution from Ships (MARPOL) is the main international convention covering prevention of pollution of the marine environment by ships. Committees of the International Maritime Organization (IMO) meet periodically to consider and adopt revisions to the various annexes of MARPOL and related treaties. Annex VI (Prevention of Air Pollution from Ships) entered into force on May 19, 2005. Annex VI sets limits on sulfur oxides (SO_x) and oxides of nitrogen (NO_x) emissions from ship exhausts and prohibits deliberate emissions of ozone depleting substances (ODS).

Annex VI also designated emission control areas (ECAs), which set more stringent standards for SO_x, NO_x, and particulate matter emissions. The IMO has designated waters along the U.S. and Canadian shorelines as the North American ECA for the emissions of NO_x and SO_x (enforceable from August 2012) and waters surrounding Puerto Rico and the U.S. Virgin Islands as the U.S. Caribbean ECA for NO_x and SO_x (enforceable from 2014).[1] The ECAs ensure that foreign flagged vessels comply with IMO Tier III NO_x limits while in U.S. waters. Tier III NO_x limits will apply to all ships constructed on or after January 1, 2016, with engines over 130 kW that operate inside a NO_x ECA area.

The North American ECAs generally extend 200 nautical miles (nm) from the U.S. and Canadian ports (50 nm for the U.S. Caribbean ECA), and their requirements went into effect on January 1, 2015. The new requirements mandate that existing ships either burn fuel containing a maximum of 0.1% sulfur or use scrubbers to remove the sulfur emissions. New ships will be built with engines and controls to handle alternative fuels and meet the ECA limits.

[1] The North American ECA does not include the Pacific U.S. territories, smaller Hawaiian Islands, the Aleutian Islands and Western Alaska, and the U.S. and Canadian Arctic waters. The U.S. Caribbean ECA includes the waters adjacent to the Commonwealth of Puerto Rico and the U.S. Virgin Islands out to approximately fifty nautical miles from the coastline.

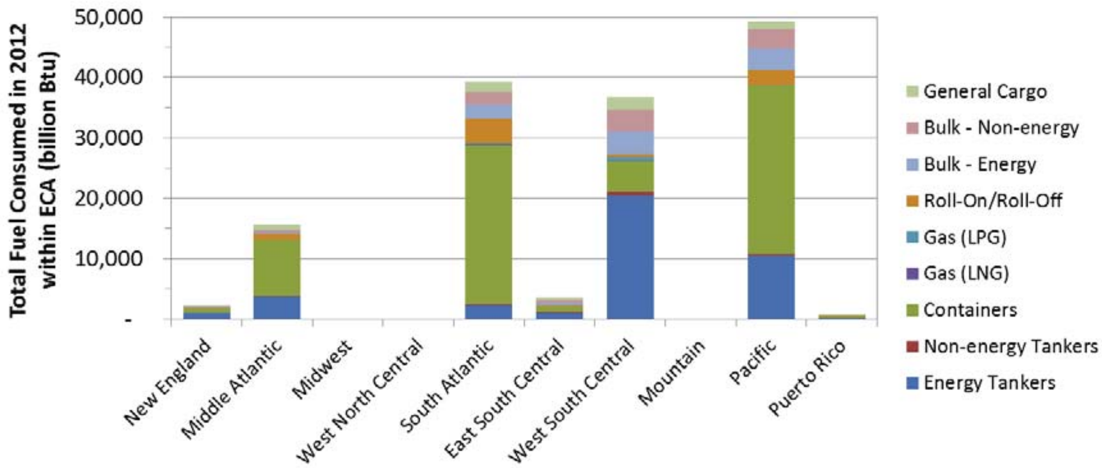

Figure ES- 1. Total 2012 Fuel Consumed by OGVs within ECAs by U.S. Census Divisions Based on Vessel Type

This report begins with an assessment of the 2012 fuel usage of ocean going vessels within the ECAs based on data about 2012 port calls in the U.S. The nautical miles traveled that year are calculated for each U.S. Census Division, and the average dead weight tonnages are used to compute the number of ton-miles traveled in ECA Waters. The ship weights determine the likely engine sizes and design speeds. Because slow steaming practices indicate significant fuel savings, 2012 estimates were used to compute the transit times and fuel requirements. Auxiliary fuel consumption was based on estimates for both the transit time and time in ports. Figure ES- 1 shows the estimate for total fuel consumed within the ECAs in the U.S. Census Divisions based on the ocean-going vessel (OGV) type.[2]

Compliance options associated with travel in the ECAs for new vessels include using exhaust controls (e.g., scrubbers and selective catalytic reduction), changing fuels to marine gas oil (MGO) or liquefied natural gas (LNG), or installing engine-based controls (e.g., exhaust gas recirculation). Other technologies (e.g., biofuels and water injection) are also under development but have not yet reached wide-scale adoption.

[2] Note that the total fuel consumed per voyage will be much greater. The ECA represents only 3.5 percent of the distance between Shanghai, China and Los Angeles and 5.9 percent of the distance between Rotterdam, NL and New York/New Jersey. Some general assumptions about speeds and times in port show that a voyage from Shanghai to Los Angeles would spend 12 to 15 percent of the time in an ECA, and a voyage from Rotterdam to New York would spend 36 to 41 percent of the time in ECAs.

Ship efficiency improvements, shipping demand changes, and fuel price fluctuations will also drive future fuel consumption predictions within the North American and U.S. Caribbean ECAs. Using the 2012 estimates as a basis and the reference case for the Annual Energy Outlook 2014 as growth projections, the fuel consumption was estimated for future years. A sample chart in Figure ES- shows that residual fuel oil consumption in the ECAs drops precipitously in 2015 when the ECA provisions begin but rises again when scrubbers are installed on the new fleet of ships.[3] Distillate fuel oil is used to cover the gap until emission controls and fuel switching systems are installed aboard ships. Implementation of the recommendations in Section 5 (e.g., quantification of emission control installation rates for retrofits) might improve the estimates.

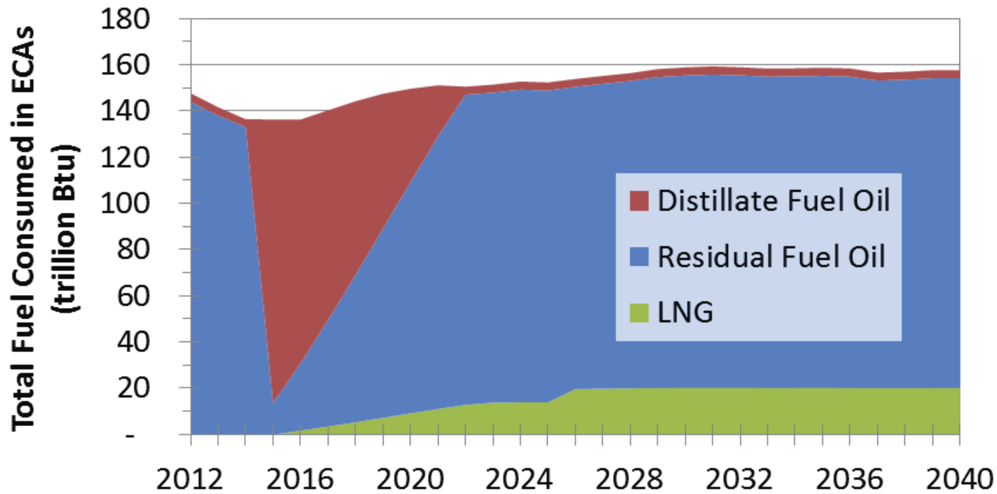

Figure ES- 2. Sample Projections of Fuel Consumed Within North American and U.S. Caribbean ECAs by NEMS Fuel Type

[3] Figure ES-2 shows a large increase in distillate fuel oil for the coastal ECA activity. However, readers should understand that other vessels at U.S. ports already operate with distillate fuel oil blends (e.g., barges and tugs on inland waterways). According to U.S. Army Corps of Engineers statistics for 2013 (http://www.navigationdatacenter.us/factcard/factcard14.pdf), U.S. coastal and inland waterborne activities were responsible for 240 and 252 billion ton-miles of transport, respectively, and inland vessels operate on distillate. Therefore, the substantial increase in distillate fuel oil shown in Figure ES-2 should not give readers the impression that a sudden demand for distillate fuels would be created in 2015.

1 Introduction

The National Energy Modeling System (NEMS) is the primary analysis tool for projections of domestic energy markets by the U.S. Energy Information Administration (EIA). The NEMS model can be used to understand impacts that current energy and environmental issues and policies have on energy markets. This particular study focuses on how a treaty/policy issue might affect the waterborne freight component of the Freight Transportation Submodule within the Transportation Demand Module (TDM) of NEMS.

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Annex VI also designated emission control areas (ECAs) which set more stringent standards for SO_x, NO_x, and particulate matter emissions. The IMO has designated waters along the U.S. and Canadian shorelines as the North American ECA for the emissions of NO_x and SO_x (enforceable from August 2012) and waters surrounding Puerto Rico and the U.S. Virgin Islands as the U.S. Caribbean ECA for NO_x and SO_x (enforceable from 2014). The ECAs ensure that foreign flagged vessels comply with IMO Tier III NO_x limits while in US waters. Tier III NO_x limits will apply to all ships constructed on or after January 1, 2016, with engines over 130 kW that operate inside a NO_x ECA area.

The North American ECAs generally extend 200 nautical miles (nm) from the U.S. and Canadian ports (50 nm for the U.S. Caribbean ECA), and their requirements went into effect on 1 January 2015. The new requirements mandate that existing ships either burn fuel containing a maximum of 0.1% sulfur or to use scrubbers to remove the sulfur emissions. New ships will be built with engines and controls to handle alternative fuels and meet the ECA limits.

This report focuses on how the introduction of North American and U.S. Caribbean ECAs will affect fuel usage by ocean going vessels (OGVs). Because fuel usage from ships is not generally reported, Chapter 2 addresses the estimates to establish a 2012 baseline of fuel consumption (by billion British thermal units [Btus]) for ships traveling in each of the U.S. Census Divisions and Puerto Rico. Section 3 discusses MARPOL Annex VI and the associated U.S. Environmental Protection Agency (EPA) regulations associated with waterborne vessels, as well as discussion about compliance options. Section 4 focuses on how future projections can be made that account for ship efficiency improvements, shipping demand changes, and fuel price fluctuations. Section 5 gives recommendations for future model improvements as more data become available.

2 Baseline Current Estimates

The methodology used to calculate the baseline for energy consumption by ships calling on the U.S. ports that traveled through the North American and U.S. Caribbean ECAs is explained in this Section. Even though the ECAs were not in effect in 2012, the numbers, types and sizes of the vessels used in the baseline were based on the ships calling on the U.S. ports during the year 2012. The most recent year for which these data are published by the U.S. Maritime Administration (MARAD) is 2012. These data are contained in the MARAD '2012 Total Vessel Calls - U.S. Ports, Terminals and Lightering Areas Report.' Based on these data, the typical engine size and design speed of each ship type can be determined. Studies conducted by the IMO and collaborated by other sources have established fuel consumption rates based on engine output and have also documented the average speed (as a percentage of ship design speeds) that was used by each type and size ship during 2012.

The ship types in the MARAD report are:

- Tanker (both petroleum and chemical tankers),
- Container (container carriers and refrigerated container carriers),
- Gas (liquefied natural gas [LNG], liquefied petroleum gas [LPG] and LNG/LPG carriers),
- Dry Bulk (bulk vessels, bulk container ships, cement carriers, ore carriers, and wood-chip carriers),
- Roll-On/Roll-Off (roll-on/roll-off vessels, roll-on/roll-off container ships, and vehicle carriers), and
- General Cargo (general cargo carriers, partial container ships, refrigerated ships, barge carriers, and livestock carriers).

Through the use of U.S. Army Corps of Engineer's Waterborne Commerce of the United States, Calendar Year 2012, Part 5– National Summaries and MARAD's Vessel Calls Snapshot-2011 (Revised: November 2013), the number of Tanker and Dry Bulk ships transporting energy products and the number of Gas ships transporting Liquid Natural Gas (LNG) were determined. The 2012 fuel consumption baseline yields fuel consumption by Census Divisions and ship types (Figure 2-1).[4]

This section discusses the calculations and assumptions used in developing the energy consumption baselines, considerations of issues that can induce error into the final calculations, and recommendations for refining the model over time.

The baseline current estimates are not envisioned to be calculated directly within NEMS modules, so this Section does not directly refer to programming variables and matrices. However, there may be a need to update the baseline with new information as the protocols are implemented. Therefore, Appendix A shares how matrix-based variables might be related to computation of these baseline estimates.

[4] The MARAD report showed no vessels with DWT over 10,000 tons calling on seaports in the Midwest (IL, IN, MI, OH, and WI), West North Central (IA, KS, MN, MO, NE, ND, and SD), or Mountain (AZ, CO, ID, MT, NV, NM, UT, and WY) Census Divisions, so the tables and figures in this chapter do not include these Census Divisions.

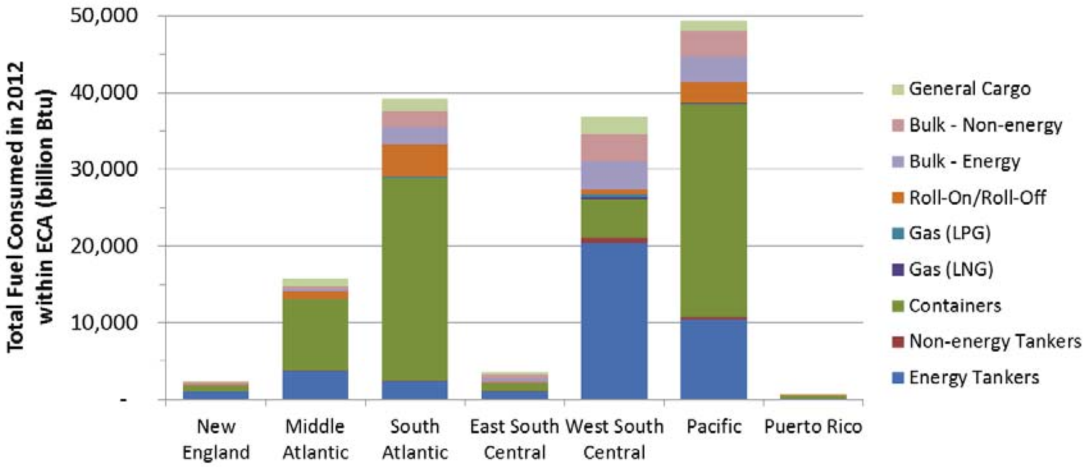


Figure 2-1. Total Fuel Consumed in 2012 by Ship Type in Census Divisions That Have Seaports

2.1 Grouping the Ships

The average dead weight tonnage (dwt) of each vessel type making port calls to deepwater ports in the U.S. was derived from data in the U.S. Maritime Administration (MARAD) 2012 Total Vessel Calls - U.S. Ports, Terminals and Lightering Areas Report – for vessels over 10,000 dwt.[5] The MARAD data provides the total number of port calls and total dwt (listed under capacity) for each ship type by port. For example, Table 2-1 lists the ports in the Pacific Census Division and tanker ship calls. Figure 2-2 provides the results of the calculations of this process that were repeated for each Census Division and type of ship.

Table 2-1. Estimating Average DWT of Tanker Ships Operating in the Pacific Census Division

Port	State	ECA distance (nautical miles/call)	Tankers	
			Calls	Capacity
Anacortes	WA	586	-	-
Anchorage	AK	764	9	476,000
Cherry Point Refinery	WA	616	248	26,138,862
Columbia River	OR	572	104	4,403,989
Coos Bay	OR	400	-	-
Drift River Terminal	AK	400	7	324,358
Dutch Harbor	AK	400	11	490,752
El Segundo Offshore Oil Terminal	CA	400	304	30,487,664
Everett	WA	624	-	-
Ferndale	WA	610	80	10,846,865
Grays Harbor	WA	400	1	27,000

[5] U.S. Department of Transportation Maritime Administration. 2012 Total Vessel Calls - U.S. Ports, Terminals and Lightering Areas Report. Last accessed from http://www.marad.dot.gov/library_landing_page/data_and_statistics/Data_and_Statistics.htm on January 22, 2015.

Port	State	ECA distance (nautical miles/call)	Tankers	
			Calls	Capacity
Hilo	HI	400	-	-
Honolulu	HI	400	118	10,612,636
Kahului	HI	400	-	-
Kalaeloa (Barbers Point)	HI	400	120	12,487,384
Kenai	AK	616	6	277,416
Kodiak	AK	400	-	-
Long Beach	CA	400	965	102,829,099
Los Angeles	CA	400	222	11,280,721
Manchester	WA	648	21	1,219,033
March Point	WA	618	276	25,738,712
Nikiski	AK	616	76	3,918,520
Olympia	WA	732	-	-
Point Wells	WA	618	13	606,295
Port Angeles	WA	512	271	31,707,930
Port Hueneme	CA	400	14	653,866
Red Dog Mine	AK	400	2	128,159
San Diego	CA	100	3	98,285
San Francisco Bay Area	CA	400	1,601	110,513,536
Seattle	WA	640	27	1,137,244
Tacoma	WA	680	37	4,376,035
Valdez	AK	400	260	33,378,365
		TOTAL	**4,796**	**424,158,726**
			AVERAGE DWT PER CALL	**88,440**

Considerations in the calculations:

1. The classification of 10,000 dwt (and above) will essentially capture all international and coastal ship commerce and nearly all barge operations to Puerto Rico, Hawaii, and Alaska from the continental United States.
2. The size of an LNG ship normally is stated as the ship's obtainable volumetric capacity of liquid natural gas in cubic meters (m^3). Multiplying the dwt by a factor between 1.8 and 2.1 (depending on the ship size and tank configuration) will provide a rough approximation of the volumetric LNG capacity in m^3 of the LNG ship.
3. Waterborne commerce on the inland rivers is generally excluded from these data reports, but the following deep water ports on rivers are included in this analysis:
    a. Albany, New York located on Hudson River
    b. Philadelphia, Pennsylvania located on Delaware River
    c. Baton Rouge, Louisiana located on Mississippi River
    d. Portland, Oregon located on the Columbia River

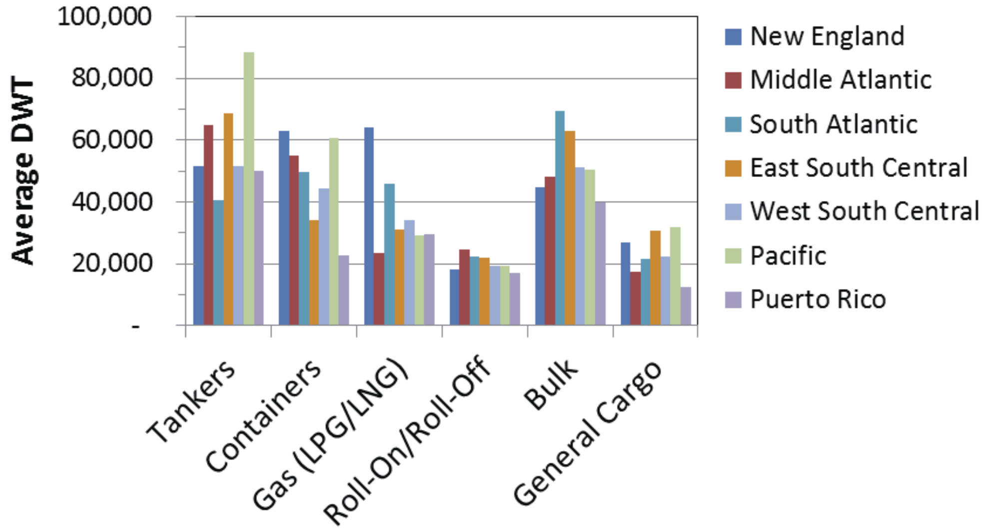


Figure 2-2. Average DWT of Each Vessel Type by Census Division

4. The waterborne commerce on the inland rivers (other than the deep water ports listed) generally operates outside the ECA.
5. Tug (tow) boats involved in barge operations to/from Puerto Rico, Hawaii, and Alaska from continental United States are not captured in these data. However, those barges are generally over 10,000 dwt and therefore the shipments are captured in the data. Generally barges designed for ocean service are at least 330 feet in length and at least 10,000 dwt.
6. Vessels operating on the Great Lakes are not operating in the designated North American ECA and are not included in these data.
7. Cruise ships, fishing vessels, offshore supply boats, and harbor tug boats are not considered in the model because they are not generally involved in the commerce of coastal or international transport of goods within the scope of this project.
8. The four lightering areas off the coasts of California, Louisiana, and Texas were not included in this study because the tanker vessels traveling from the lightering areas to the ports are already counted in the port data.

2.2 Determining Engine Size and Design Speed of Each Ship Grouping

The speed at which a ship will be operated is contingent on many factors, including the type of service (e.g., container, tanker or other) the ship will operate, customer expectations, daily operating/bunker costs, and economic climate. "Fuel consumption for a ship can be approximated by a cubic function of the ship's speed."[6] Generally tanker and dry bulk ships operate at slower speeds than container ships. Roll-on/Roll-off, gas, and general cargo ships

[6] 'Ship Speed Optimisation with Time-Varying Draft Restrictions', by Elena Kelareva, Philip Kilby, Sylvie Thiébaux, http://www.nicta.com.au/pub?doc=6886

operate at speeds faster than tankers and slower than container ships. General guidelines matching vessel types to engine output by dwt are published by MAN Diesel & Turbo[7] and other major engine manufacturers. In addition, detailed analyses have been published by Gdynia Maritime University[8] and others.

The size of the engine required for each ship profile (Table 2-2) and their design speeds (Table 2-3) used in the model were derived from data published by Gdynia Maritime University and MAN Diesel & Turbo. The design speed is a trend based on assumptions by the industry of the maximum sustained speed that ships of a certain size and vessel type should be capable of operating at under normal economic and physical conditions. During normal economic conditions (those upon which the trends were developed), ships were expected to operate at or near their design speeds.[9] However, the considerations below discuss the common practice of slow steaming.

Table 2-2. Ship Engine Output (kW) for Each Ship Profile

Census Division	Tankers	Containers	Gas (LPG/LNG)	Roll-On/ Roll-Off	Bulk	General Cargo
New England	9,400	42,000	8,000	10,000	8,400	12,000
Middle Atlantic	10,500	37,600	8,000	12,000	8,700	8,000
South Atlantic	8,500	33,600	12,000	10,000	10,000	10,000
East South Central	10,800	21,700	8,000	10,000	9,700	14,000
West South Central	9,400	30,100	8,000	10,000	9,000	10,000
Pacific	12,500	41,500	8,000	10,000	8,900	14,000
Puerto Rico	9,400	14,000	8,000	8,000	7,200	7,000

Table 2-3. Ship Design Speed (Knots) for Each Ship Profile

Census Division	Tankers	Containers	Gas (LPG/LNG)	Roll-On/ Roll-Off	Bulk	General Cargo
New England	15.0	24.7	17.5	18.0	14.5	18.0
Middle Atlantic	15.0	24.2	15.0	18.0	14.5	18.0
South Atlantic	15.0	23.8	17.0	18.0	14.5	18.0
East South Central	15.0	22.0	15.0	18.0	14.5	18.0
West South Central	15.0	23.0	15.0	18.0	14.5	18.0
Pacific	15.0	24.6	15.0	18.0	14.5	18.0
Puerto Rico	15.0	20.0	15.0	18.0	14.5	18.0

[7] Propulsion Trends' in LNG Carriers, container, bulk Two-stroke Engines series published by MAN Diesel & Turbo, Teglholmsgade 41, 2450 Copenhagen SV, Denmark; info-cph@mandieselturbo.com; www.mandieselturbo.com
[8] 'Analysis of Trends In Energy Demand For Main Propulsion, Electric Power And Auxiliary Boilers Capacity Of General Cargo And Container Ships,' Zygmunt Górski, Mariusz Giernalczyk, Gdynia Maritime University 83 Morska Street, 81-225 Gdynia, Poland, e-mail: magier@am.gdynia.pl, zyga@am.gdynia.pl
[9] Collected data indicates that ships have not been operating near design speeds for the last six years.

Considerations in the calculations and variations from design speeds:

1. Minor changes in ship speed can impact ship engine output requirements significantly.

> *Reducing the nominal ship speed from 27 to 22 knots (-19%) will reduce the engine power to 42% of its nominal output. This results in an hourly main engine fuel oil savings of approximately 58%.*
>
> *A further reduction down to 18 knots could save 75% of the fuel. The reduced speed however results in a longer voyage time; therefore the fuel savings per roundtrip (for example AsiaEurope-Asia) are reduced by 45% at 22 knots, or 59% at 18 knots. These are calculated values, and the actual values depend also on a number of external factors, such as the loaded cargo, vessel trim, weather conditions, and so on."*[1]
>
> **An example of the results of slow speed steaming provided by Wärtsilä**

2. The optimal load range of the two-stroke engine lies between 70 and 85 percent of its design load.[10] Engine loads below 60 percent are generally considered to be slow steaming.[11] The IMO reported that the average ratio of operating speed to design speed was 0.85 in 2007 and 0.75 in 2012.[12] This ratio (expressed as a percentage) for each vessel type in 2012 is provided in Table 2-4.
3. Table 2-5 provides the percentage of engine output/load that each vessel type was operating at during 2012.

Table 2-4. Slow Speed Steaming Reduction in Ship Speed by Vessel Type (Percentage of Design Speed)

Census Division	Tankers	Containers	Gas (LPG/LNG)	Roll-On/ Roll-Off	Bulk	General Cargo
New England	80%	68%	68%	73%	82%	82%
Middle Atlantic	81%	68%	73%	73%	82%	82%
South Atlantic	80%	68%	68%	73%	83%	82%
East South Central	81%	70%	70%	73%	83%	82%
West South Central	80%	68%	70%	73%	82%	82%
Pacific	78%	68%	70%	73%	82%	82%
Puerto Rico	80%	73%	70%	73%	82%	82%

[10] Slow steaming – a viable long-term option?; Andreas Wiesmann; Wärtsilä Technical Journal; February 2010. www.wartsila.com

[11] There is some variation in the definitions used to define slow steaming. Some definitions link slow steaming to speeds below a certain nautical miles per hour (knots) while others link it to a percentage of engine output/load. Engine load is used in the calculations in this model.

[12] International Maritime Organization, Marine Environment Protection Committee. Reduction of GHG Emissions from Ships: Third IMO GHG Study 2014 – Final Report. 67th session Agenda item 6, MEPC 67/INF.3, July 25, 2014.

Table 2-5. Slow Speed Steaming Reduction in Ship Power Output by Vessel Type (Percentage of Design Power)

Census Division	Tankers	Containers	Gas (LPG/LNG)	Roll-On/ Roll-Off	Bulk	General Cargo
New England	55%	36%	36%	45%	58%	59%
Middle Atlantic	57%	36%	45%	45%	58%	59%
South Atlantic	55%	36%	36%	45%	60%	59%
East South Central	57%	39%	39%	45%	60%	59%
West South Central	55%	36%	39%	45%	58%	59%
Pacific	51%	36%	39%	45%	58%	59%
Puerto Rico	55%	45%	39%	45%	58%	59%

4. A rule of thumb calculation indicates that a 10 percent decrease in speed will result in a 19 percent reduction in engine power (on a tonne-mile basis).[13] The rule of thumb is valid for most engine loads that exceed 25 percent of the maximum continuous rating (MCR), so it should be appropriate in these calculations.

2.3 Calculating Fuel Oil Consumption

Fuel oil consumption rates (Table 2-6) for ship main propulsion engines (commonly called the marine diesel engine [MDE]) were based on IMO data[12] and assume:

1. MDEs are two-cycle engines that burn IFO (Figure 2-3),
2. MDEs are slow speed diesel (SSD) engines,
3. Ships have one engine with one propeller and are direct drive (no transmission), and
4. Engines were built after 2001.

Table 2-6. Fuel Oil Consumption Rates for Slow, Medium and High Speed Diesel Engines (kg/kWh)[12]

Engine Age	Slow speed diesel	Medium speed diesel	High speed diesel
Before 1983	0.205	0.215	0.225
1984-2000	0.185	0.195	0.205
After 2001	0.175	0.185	0.195

[13] Faber, J., M. Freund, M. Kőpke, and D. Nelissen. Going Slow to Reduce Emissions: Can the current surplus of maritime transport capacity be turned into an opportunity to reduce GHG emissions?; January 2010; Seas At Risk, Copyright © 2010; The production of the report was supported by the Dutch Ministry for Environment, Spatial Planning and Housing (VROM) and the European Commission (DG Environment). Last accessed from http://www.seas-at-risk.org/1mages/GoingSlowToReduceEmissions_1.pdf on January 22, 2015.

INDUSTRIAL NAME	ISO NAME	COMPOSITION
Intermediate Fuel Oil 380 (IFO 380)	MRG35	98% residual oil 2% distillate oil
Intermediate Fuel Oil 180 (IFO 180)	RME 25	88% residual oil 12% distillate oil
Marine Diesel Oil	DMB	Distillate oil with trace of residual oil
Marine Gas Oil	DMA	100% distillate oil

These fuels are also available as low sulfur

LS380 1% LS180 1% LSMGO 0.1%

Figure 2-3. Most Common Ship Bunker Fuels

To calculate fuel oil consumption (kg) for the MDEs, the slow steaming engine output (kW) was multiplied by 0.175 kg/kWh and the time operating in the ECA (hours).

Considerations in the calculations:

1. The fuel oil consumption rates (0.175 kg/kWh) for the MDEs matched those in the IMO studies, but the IMO reports a range of observed rates from 0.165 to 0.185 kg/kWh.
2. The heating values of ship bunker fuels are not set by standards and vary by supplier. The heating value is generally agreed upon in the purchase agreement between the buyer and seller, so the kilogram basis is only a placeholder for a later conversion on a Btu basis.
3. Ships used to transport LNG generally are equipped with one of three engine configurations options. The older ships use forced natural gas boil-off from the cargo tanks in steam boilers to produce steam for steam turbines. Although the conventional steam propulsion system has a low efficiency of about 28% compared to the approximately 50% for a conventional slow speed diesel engine, this option had the advantage of simplicity (no additional fuel tanks, or equipment to convert a SSD to run on LNG). As the selling price of natural gas began to rise, some ships were built to utilize the naturally occurring boil-off gas in a dual fuel (heavy fuel and compressed natural gas) diesel engine for main propulsion. In some of the largest LNG ships, an SSD engine for ordinary heavy fuel oil was used for main propulsion. Because few LNG port calls occurred in 2012, the difficulty of determining the engine option being used in each port call, and the acknowledgement that the introduced error would be insignificant in the national and Census Division totals, the increased fuel consumption required for forced gas boil-off/boilers/steam turbine propulsion was not calculated.

2.3.1 Time ship will be operating in the ECA

The computed hours of operation in the ECA are found by multiplying the number of port calls by the distance traveled and vessel travel speed. The U.S. Caribbean ECA waters extend 50 nautical miles (nm) from the shoreline, so the ECA distance traveled to the four Puerto Rican ports was assumed to be 100 nm (50 nm reaching and 50 nm leaving the port). The North

American ECA waters generally extend 200 nm from the shoreline, so the traveled distance is assumed to be 400 nm for other ports.[14]

The vessel travel speeds are computed by multiplying the design speeds (Table 2-3) by the slow steaming reductions (Table 2-4). Figure 2-4 shows the travel times for the fleets by vessel type for each Census Division. The largest bar (time for tanker calls in the West South Central Census Division) in Figure 2-4 is much larger than other bars because 20 percent of the nation's 2012 port calls were by tankers to Texas and Louisiana ports.

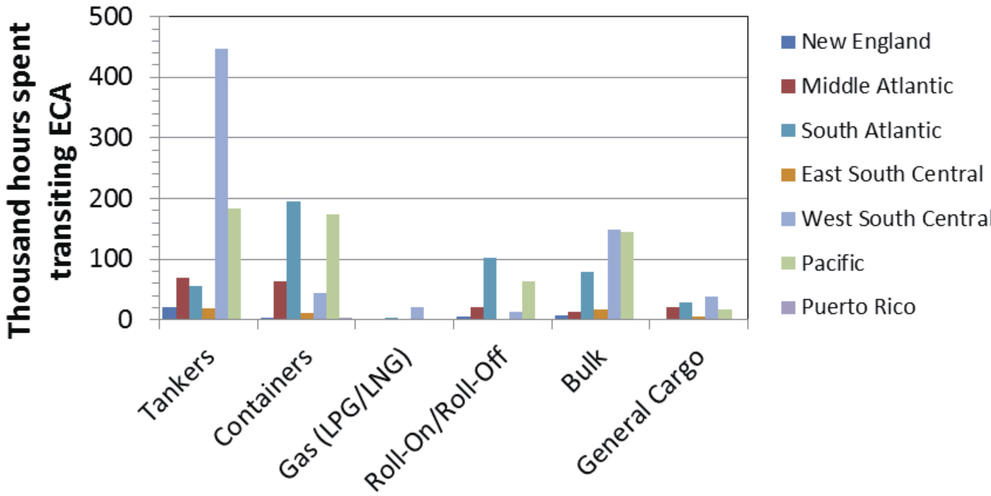


Figure 2-4. Time (in Thousands of Hours) Each Vessel Type Operated in the ECA Waters in 2012

Considerations in the calculations:

1. The following ports can be accessed by avoiding part of the ECA (Appendix B):

Port	Reason ECA is Abridged	Total Effective ECA
San Diego, CA	Proximity to Mexican waters (Figure B-1)	10 nm
Brownsville, TX	Proximity to Mexican waters (Figure B-1)	7 nm
Miami, FL	Proximity to Bahamian waters (Figure B-2)	25 nm
Port Everglades, FL	Proximity to Bahamian waters (Figure B-2)	25 nm
Palm Beach, FL	Proximity to Bahamian waters (Figure B-2)	25 nm

2. Some ports have longer effective ECAs as a result of their placements significantly inland of the shore baseline. Waterways that link the oceans to these deepwater ports would be considered to be U.S. navigable waters.[15] The EPA regulations used to implement the ECA requirements also apply to U.S.-flagged vessels wherever located and to foreign-flagged vessels operating in the U.S. navigable waters or the U.S. Exclusive Economic Zone (EEZ). These situations occurred in the following regions: Cook Inlet in Alaska, Puget Sound in Washington, Columbia River in Oregon,

[14] Several exceptions with different travel distances are discussed in the Considerations section.
[15] This is not an exclusive definition of navigable waters; there are many other waterways that are also considered to be navigable waters.

Mississippi River in Louisiana, Chesapeake Bay in Maryland, Delaware River for Delaware and Pennsylvania, and the Hudson River in New York.

3. Some ships that call on more than one U.S. port may opt to transit from one port to another without leaving the ECA. This might introduce error into the model, but the introduced errors are expected to be mostly insignificant because:
   a. Most major port areas in the U.S. are spaced apart by more than 200 nm, so travel outside the ECA would often be economical.
   b. Using a ship to move goods short distances is generally not cost effective due to added port fees and terminal fees. Transport of cargo across short distances is usually conducted by truck, rail, or pipelines.
4. Ships may choose to operate at speeds slower than their slow steaming speed for many reasons, including: regulatory speed limits, ship traffic, weather/sea conditions, navigational requirements, or to take on a tugboat assist. Such ship speed reductions would inflate estimated consumption totals but only near the ports.

2.3.2 Power consumption in propelling the ships through the ECA

Table 2-7 estimates the energy in GWh used to propel ships through the ECA and was calculated by multiplying the total time (by vessel type) that the ships operated in the ECA by the engine slow steaming output for each vessel type.

Table 2-7. Power Spent for Propulsion Through the ECA (GWh)

Census Division	Tankers	Containers	Gas (LPG/LNG)	Roll-On/ Roll-Off	Bulk	General Cargo
New England	110	56	4.1	21	33	7.7
Middle Atlantic	420	850	6.0	110	70	100
South Atlantic	260	2,400	17	460	470	170
East South Central	120	97	3.7	11	100	41
West South Central	2,300	480	62	61	770	220
Pacific	1,200	2,600	6.2	287	750	140
Puerto Rico	13	21	0.6	5.4	2.1	3.7
Nationwide	**4,400**	**6,500**	**99**	**950**	**2,200**	**680**

2.3.3 Auxiliary power consumption

In addition to fuel consumed by the MDE, ships are generally operating auxiliary power units that provide ship electricity, running water, and warm the IFO so that it burns efficiently. In this model the auxiliary power required was assumed to be equal to 5 percent of the MDE design output.[16] Auxiliary power systems operate when the MDEs are operating and while ships are in port or at anchor. This model initially assumed that the ship would be in port and/or at anchor for

[16] Same assumption used in footnote 12. The 5 percent assumption is also supported by Table 1 of the California regulation calling for airborne toxic control measures from ocean-going vessels; the default auxiliary power requirements listed in that table (4000-4999 TEUs) closely match 5 percent of the propulsion engine estimates for average vessels in New England, Middle Atlantic, and Pacific Census Divisions (representing more than half of the 2012 container vessel capacity).

72 hours (3 days) for each port call, but Appendix D describes how the estimates were refined based on available data indicating that port times are mandated to be short:

- 1.8 days for container ships
- 1.5 days for tanker vessels
- 2.6 days for general cargo vessels
- 0.88 days for roll-on/roll-off vessels
- 1.5 days for gas vessels
- 2.0 days for bulk vessels

The auxiliary power spent in an ECA was calculated by multiplying the hourly auxiliary power times the sum of the number of transit hours in the ECA and the port time.

Table 2-8 lists the auxiliary power estimates by Census Division for each vessel type. The large number of container ship port calls into Hampton Roads, Virginia and Savannah, Georgia yield the highest numbers for the South Atlantic Census Division.

Table 2-8. Auxiliary Power Spent in ECA and Port (GWh)

Census Division	Tankers	Containers	Gas (LPG/LNG)	Roll-On/ Roll-Off	Bulk	General Cargo
New England	21	22	1.2	3.9	7.0	2.1
Middle Atlantic	71	320	1.1	20	13	23
South Atlantic	49	950	4.7	82	90	45
East South Central	22	33	0.9	2.1	21	11
West South Central	420	170	15	12	150	59
Pacific	220	920	1.4	51	140	34
Puerto Rico	6	17	0.4	1.2	1.2	3.2
Nationwide	**820**	**2,400**	**25**	**170**	**420**	**180**

Fuel consumption rates for auxiliary power are assumed to be 0.225 kg/kWh (based on Table 2-9). This number is used to convert the power spent into fuel consumption.

Table 2-9. Fuel Oil Consumption Rates (grams/kWh) for Auxiliary Power[12]

Engine Type	RFO	MDO/MGO
Gas turbine	305	300
Steam boiler	305	300
Auxiliary engine	225	225

Considerations for calculations:

1. Auxiliary power fuel consumption remains less documented than consumption rates by the MDE. While this study and the IMO are basing the size of the auxiliary power units as 5 percent of the MDE size, some reports have indicated auxiliary power may be up to 10 percent or higher of the size of the MDE. Auxiliary power warms the IFO prior to injection into an engine and provides the ships with electricity, hot water, and heat.

Container ships and ships with large refrigeration systems will consume more electricity than comparably sized dry bulk and tank ships.

2. Auxiliary power fuel consumption will exceed 5 percent of the total fuel consumption of the 2012 baseline totals because:
    a. MDEs are operated below design loads;
    b. Auxiliary power has a higher fuel consumption rate per kW than the MDE; and
    c. Auxiliary power continues operation while the ship is in port or at anchor.
3. Ships with waste heat capture units may greatly reduce the amount of fuel consumed by auxiliary power. Future IMO studies will probably study auxiliary power in more detail, and these baseline estimates should be revised if the IMO changes its estimates for auxiliary power.

2.3.4 Fuel consumed in 2012

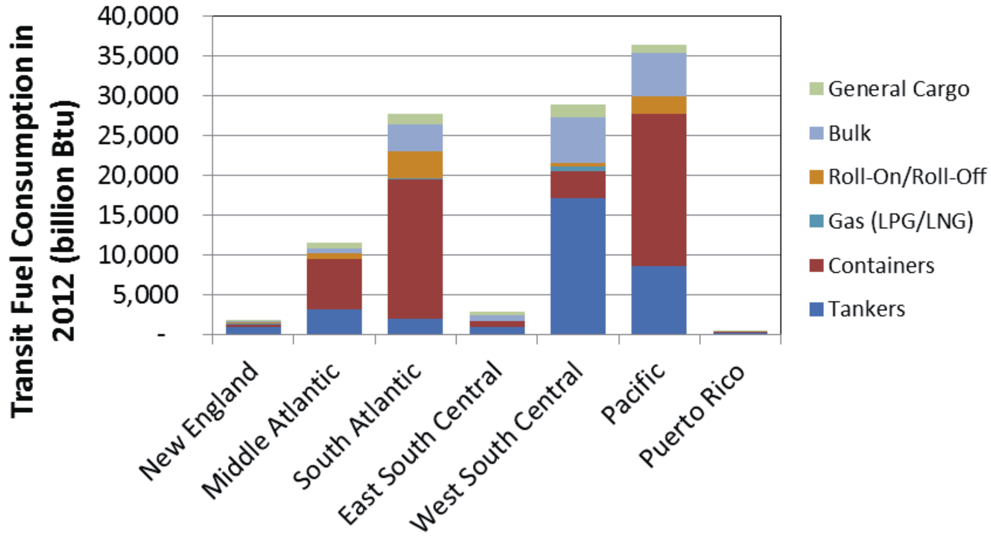
The 2012 fuel consumption numbers for transiting the ECA were calculated by multiplying the spent power for propulsion (GWh) by the fuel consumption rate of 0.175 kg/kWh and the conversion of 42,195 Btu/kg (based on the NEMS heating value for residual oil[17]). The 2012 fuel consumption numbers for auxiliary engines are calculated in a similar manner using a fuel consumption rate of 0.225 kg/kWh. Both sets of data are presented in Figure 2-5.

To obtain the total fuel oil consumption used in each of the Census Divisions by vessel type, the fuel consumption values used for transiting the ECA were added to those used for auxiliary power. Table 2-10 displays the combined totals by Census Divisions, nationally, and by vessel type.

Table 2-10. Total Fuel Consumed in 2012 for Transit and Auxiliary Power (Billion Btus)

Census Division	Tankers	Containers	Gas (LPG/LNG)	Roll-On/ Roll-Off	Bulk	General Cargo	Total
New England	1,000	620	41	190	310	77	**2,300**
Middle Atlantic	3,800	9,300	55	980	640	980	**16,000**
South Atlantic	2,400	26,000	170	4,200	4,400	1,700	**39,000**
East South Central	1,100	1,000	36	100	940	410	**3,600**
West South Central	21,000	5,100	610	560	7,200	2,200	**37,000**
Pacific	11,000	28,000	60	2,600	6,800	1,300	**49,000**
Puerto Rico	150	320	8	60	27	57	**630**
Nationwide	**40,000**	**71,000**	**980**	**8,700**	**20,000**	**6,700**	**150,000**

[17] Energy Information Administration. "Conversion Tables" from Annual Energy Outlook 2014. Last accessed from http://www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO2014&subject=0-AEO2014&table=20-AEO2014&region=0-0&cases=ref2014-d102413a on January 16, 2015.



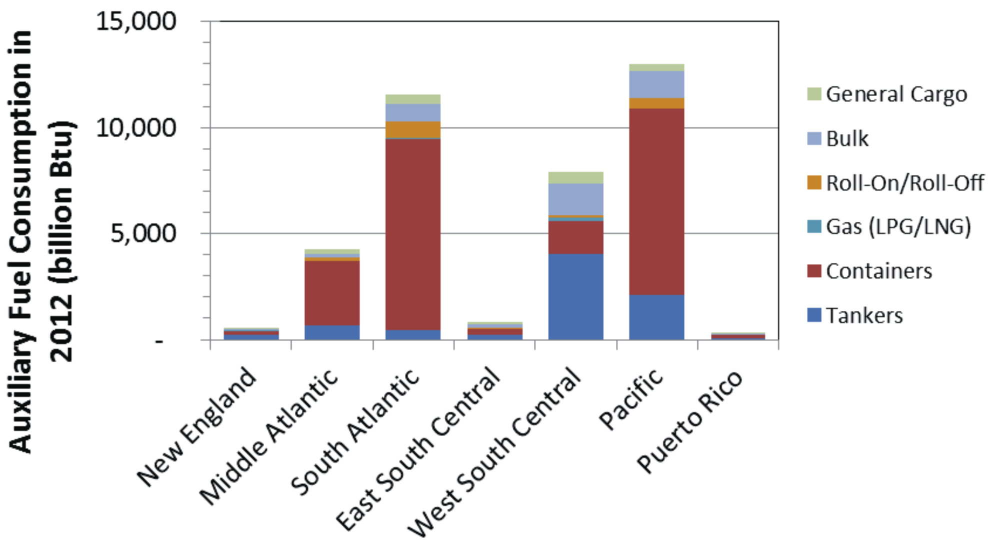


Figure 2-5. Fuel Consumption in ECA Waters in 2012

2.4 Distribution Between Energy and Non-Energy Products

The NEMS model tracks energy product demands, imports, and exports in modules related to specific fuels (e.g., Coal Market Module and Liquid Fuels Market Module). Therefore, future projections of energy product imports and exports may be aligned directly with annual demands within the appropriate NEMS modules. Therefore, this section discusses the allocation of the 2012 numbers between energy and non-energy products. Tankers, gas, and bulk ships will be divided into vessel subtypes.

2.4.1 Determining percentage of tankers and dry bulk ships transporting energy products

Tankers and dry bulk ships transport both energy and non-energy products. To determine the number of tankers and dry bulk ships that transported energy products in 2012, the U.S. Army Corps of Engineer (ACOE) Waterborne Commerce of the United States, Calendar Year 2012, Part 5– National Summaries[18] was reviewed and the total tonnage of products that are generally[19] transported on tanker and on dry bulk ships was compared to the total tonnage of energy products transported (foreign inbound, foreign outbound, or in coastal trade) as freight.

Table 2-11 lists the products and tons shipped and illustrates that 97 percent of the tankers and 51 percent of the dry bulk ships involved with U.S. port calls were transporting energy products. The total port calls by tankers and dry bulk ships were multiplied by these percentages to allocate the energy consumption within the ECAs between energy and non-energy products.

Considerations in calculations:

1. The ACOE statistics list products transported by commodity code, but not by the type of ship being used to transport the commodity. Relatively small amounts of these commodities may be shipped in drums or packages on container, roll-on/roll-off, or general cargo vessels. Likewise, shipment of commodities not normally shipped on dry bulk ships may be loaded onto a dry bulk ship under certain conditions. Tankers generally are certificated to transport specific products and are less likely to be used for other commodities.
2. The list of products used in this section may be revised over time as the issue is studied further.

[18] U.S. Army Corps of Engineers. Waterborne Commerce of the United States: Calendar Year 2012 Part 5—National Summaries. Last accessed from http://www.navigationdatacenter.us/wcsc/pdf/wcusnatl12.pdf on January 22, 2015.
[19] Based on professional opinion.

Table 2-11. Percentage of Product Moved on Tank Ships That Are Energy Products (Top). Percentage of Product Moved on Dry Bulk Ships That Are Energy Products (Bottom).

Product	Non-energy (thousand short tons)			Energy (thousand short tons)		
	Import	Export	Coastal	Import	Export	Coastal
Crude oil	--	--	--	361,000	80	34,700
Gasoil	--	--	--	39,200	27,700	40,500
Kerosene	--	--	--	924	479	177
Distillate	--	--	--	64,000	71,200	20,500
Residual	--	--	--	5,310	5,580	9,880
Naphtha	1,270	2,540	1,140	--	--	--
Benzene	1,950	178	99	--	--	--
Sulfuric acid	503	47	3	--	--	--
Alcohols	8,800	4,140	3,000	--	--	--
Subtotal	**12,500**	**6,900**	**4,250**	**471,000**	**105,000**	**106,000**
Total		**23,700**			**682,000**	
Percentage		**3%**			**97%**	
Product	**Non-energy (thousand short tons)**			**Energy (thousand short tons)**		
	Import	**Export**	**Coastal**	**Import**	**Export**	**Coastal**
Petroleum coke	--	--	--	2,530	36,200	751
Coal	--	--	--	9,210	120,000	4,510
Wood chips	2	1,480	259	--	--	--
Gypsum	3,580	66	232	--	--	--
Sand/gravel	8,140	689	2,960	--	--	--
Iron ore	7,530	9,870	--	--	--	--
Copper ore	14	546	4	--	--	--
Aluminum ore	16,400	1,760	406	--	--	--
Magnesium ore	479	4	--	--	--	--
Other ore	945	344	--	--	--	--
Grains	2,610	58,200	--	--	--	--
Oil seed	588	52,200	--	--	--	--
Subtotal	**40,300**	**125,000**	**3,863**	**11,700**	**156,000**	**5,260**
Total		**169,000**			**173,000**	
Percentage		**49%**			**51%**	

2.4.2 Determining number of gas carriers (ships) that are transporting LNG and LPG

LNG terminals are located in each of the Census Divisions except the Middle Atlantic (New York, New Jersey, and Pennsylvania). The ACOE statistics assign the same commodity code (2640) to LNG and LPG and the 2012 Total Vessel Calls Report does not separate LNG and

LPG. However, a periodic report[20] does provide annual totals for gas carriers (LNG and LPG) and breaks out LNG carriers for the years from 2006 to 2011. The total port calls for gas carriers were subtracted from this total and the average number of 'total gas carrier' port calls was computed and compared to the LNG carrier port calls. During this period it appears that LNG carriers accounted for 26 percent of the 'total gas carrier' port calls outside of the Middle Atlantic District (Table 2-12).

Table 2-12. LNG Carriers as a Percentage of Total Gas Carriers

Year	Total Gas Carriers	LNG Carriers	Percentage of LNG Vessels
2006	875	213	
2007	804	202	
2008	703	171	
2009	640	201	
2010	670	202	
2011	779	157	
Average	**745**	**191**	**26±4%**

In 2012 there were 747 total gas carrier port calls outside of the Middle Atlantic District and this equates to an estimated 194 LNG carrier port calls nationally. The total fuel consumption for gas ships in each Census Division (except the Middle Atlantic) were multiplied by 26 percent to allocate fuel consumption for LNG shipments, and the remainders were allocated to LPG shipments.

Considerations:

1. LNG ships tend to be larger than LPG ships, but this should not impact overall model projections. Gas ships are only responsible for less than 1 percent of the total fuel consumed in Table 2-10.
2. The computed percentage of LNG carriers as part of the larger total gas carrier numbers may be subject to rapid change due to fluctuations in both oil and natural gas pricing.

Table 2-13 shows the calculated 2012 fuel consumption numbers by vessel type and subtype (for tankers, gas ships, and bulk ships) among the Census Divisions. Nationally container ships represented almost half of the fuel consumed.

[20] Vessel Calls Snapshot, 2011, Released: March 2013, Revised: November 2013, Office of Policy and Plans, Maritime Administration, U.S. Department of Transportation, www.marad.dot.gov/data_statistics.

Table 2-13. Total Fuel Consumed (Billion Btu) in 2012 by Vessel Type and Subtype (by Product Type)

Census Division	Energy Tankers	Non-energy Tankers	Containers	Gas (LNG)	Gas (LPG)	Roll-On/ Roll-Off	Bulk - Energy	Bulk - Non-energy	General Cargo	**Total**
New England	1,000	31	620	11	30	190	160	150	77	**2,300**
Middle Atlantic	3,700	110	9,300	-	55	980	330	310	980	**16,000**
South Atlantic	2,300	72	26,000	43	120	4,200	2,200	2,100	1,700	**39,000**
East South Central	1,000	32	1,000	9	27	100	480	460	410	**3,600**
West South Central	20,000	630	5,100	160	450	560	3,700	3,500	2,200	**37,000**
Pacific	10,000	320	28,000	15	44	2,600	3,500	3,300	1,300	**49,000**
Puerto Rico	150	5	320	2	6	60	14	13	57	**630**
Nationwide	**39,000**	**1,200**	**71,000**	**240**	**740**	**8,700**	**10,000**	**10,000**	**6,700**	**150,000**
Fraction	26%	0.8%	48%	0.2%	0.5%	6%	7%	7%	5%	--

3 Compliance Strategies

Marine vessels are significant sources of air pollutant and greenhouse gas (GHG) emissions. The regulations governing vessel emissions in the North American and U.S. Caribbean ECAs will alter the ship fuels consumed in the future as well as alter the control devices operating on board the ships. This section details some of the provisions within the regulatory framework and also presents the most likely compliance strategies.

3.1 Regulatory Framework

This section describes both the U.S. EPA regulations and the IMO protocols.

3.1.1 U.S. EPA regulations

The U.S. emissions from compression-ignition MDEs have been regulated through a number of U.S. EPA regulations, the first of which was issued in 1999. Marine engine regulations overlap those for mobile, land-based non-road engines, but marine engines have no emission control requirements for particulate matter (smoke).

Marine engines are divided into three categories in EPA regulations based on their displacement per cylinder, as shown in Table 3-1. Category 1 and Category 2 marine diesel engines typically range in size from about 500 to 8,000 kW (700 to 11,000 hp). Categories 1 and 2 (C1 and C2) are further divided into subcategories, depending on displacement and net power output. These engines are used to provide propulsion power on many kinds of vessels including tugboats, pushboats, supply vessels, fishing vessels, and other commercial vessels in and around ports. They are also used as stand-alone generators for auxiliary electrical power for many vessel types. Category 3 (C3) MDEs are very large and used for propulsion power on OGVs such as container ships, oil tankers, bulk carriers, and cruise ships. Category 3 engines typically range in size from 2,500 to 70,000 kW (3,000 to 100,000 hp).

Table 3-1. Marine Engine Categories

Category	Displacement per Cylinder (D)		Engine Technology Basis
	Tier 1-2 Emission Standards	Tier 3-4 Emission Standards	
1	$D < 5$ dm^3 and power ≥ 37 kW	$D < 7$ dm^3	Land-based non-road diesel engines
2	5 dm^3 ≤ D < 30 dm^3	7 dm^3 ≤ D < 30 dm^3	Locomotive engines
3	D ≥ 30 dm^3		Unique marine engine design

The 1999 Marine Engine Rule adopted Tier 2 standards for C1 and C2 engines that are based on the standard for land-based non-road engines. At that time the largest C3 engines were expected to comply with IMO's MARPOL Annex VI Tier I standards set in 1997 but were not required to meet standards by the rule. In 2003, EPA introduced the C3 Engine Rule "Control of Emissions From New Marine Compression-Ignition Engines at or Above 30 Liters Per Cylinder" [40 CFR Part 9 and 94][68 FR 9745-9789, 28 Feb 2003]. The rule established Tier 1 emission standards for marine engines that were virtually equivalent to the IMO MARPOL Annex VI limits.

In 2008 EPA finalized a three-part program that further reduced emissions from MDEs with per-cylinder displacements below 30 liters. This rule addressed marine propulsion engines used on vessels from recreational and small fishing boats to towboats, tugboats and Great Lake freighters, and marine auxiliary engines ranging from small generator sets to large generator sets on OGVs. The rule included the first-ever national emission standards for existing commercial MDEs, applying to engines larger than 600 kW when they are remanufactured. The rule also set Tier 3 emissions standards for newly built engines that were phased in beginning in 2009. Finally, the rule established Tier 4 standards for newly built commercial marine diesel engines above 600 kW, phasing in beginning in 2014. The Tier 4 emission standards were modeled after the 2007/2010 highway engine program and the Tier 4 non-road rule, with an emphasis on the use of exhaust control technology.

To enable catalytic aftertreatment methods, EPA established a sulfur cap in marine fuels (as part of the non-road Tier 4 rule). The sulfur limit of 500 ppm became effective in June 2007, and the sulfur limit of 15 ppm replaced that in June 2012 (these sulfur limits are not applicable to residual fuels).

EPA's 2009 Category 3 Engine Rule (published April 30, 2010) revised the standards that apply to C3 engines installed on U.S. vessels and to marine diesel fuels produced and distributed in the U.S. The rule added two new tiers of engine standards for C3 engines: Tier 2 standards that were enforceable in 2011 and Tier 3 standards that begin in 2016. Under this regulation, both U.S.-flagged and foreign-flagged ships which are subject to the engine and fuel standards of MARPOL Annex VI (shown in Table 3-2) must comply with the applicable Annex VI engine and fuel sulfur limits provisions when they enter U.S. ports or operate in most internal U.S. waters, including the Great Lakes.

Table 3-2. MARPOL Annex VI NO_x Emission Standards

Tier	Effective Date	NO_x Emission Limit (g/kWh)		
		RPM (n < 130)	RPM (130 ≤ n < 2000)	RPM (n ≥ 2000)
I	2004	17.0	$45 \cdot n^{-0.2}$	9.8
II	2011	14.4	$44 \cdot n^{-0.23}$	7.7
III	2016 *	3.4	$9 \cdot n^{-0.2}$	1.96

* In NO_x ECAs only (Tier II standards apply outside of ECAs).

The 2009 Category 3 Engine rule also revised EPA's diesel fuel program to allow for the production and sale of diesel fuel with up to 1,000 ppm sulfur for use in C3 marine vessels, phasing in by 2015. Vessels were allowed to use other methods to achieve SO_x emissions reductions equivalent to those obtained by using the lower 1,000 ppm sulfur fuel. In the final action, EPA provided an exclusion of the application of the ECA-level fuel sulfur standards in MARPOL Annex VI to existing steamships operating on the Great Lakes and Saint Lawrence Seaway. An additional economic hardship relief provision was included in the regulation for vessels with diesel engines operating on the Great Lakes and Saint Lawrence Seaway. This option provides temporary relief from the 2015 ECA-level fuel sulfur standards upon demonstration that the burden of compliance costs would cause serious economic hardship.

In 2012, EPA revised the large marine engine regulation by adding a provision to provide an incentive to repower Great Lakes steamships with new, more efficient diesel engines. This consisted of an automatic, time-limited fuel waiver that allows the use of residual fuel in the replacement diesel engines that exceeds the global and ECA sulfur limits that otherwise apply to the fuel used in ships operating on the U.S. portions of the Great Lakes. This automatic Great Lakes steamship repower fuel waiver is valid through December 31, 2025. After that date, repowered steamships will be required to comply with the Great Lakes ECA fuel sulfur limits for diesel engines. This automatic fuel waiver is available only to steamships that operate exclusively on the Great Lakes, that were in service on October 30, 2009, and that are repowered with a Tier 2 or better diesel engine.

3.1.2 IMO protocols

On the international front, the Marine Environment Protection Committee (MEPC) of the International Maritime Organization (IMO) is the United Nations agency concerned with the prevention of marine pollution from ships. The EPA participates on the U.S. delegation to the IMO and submits position papers to the IMO's MEPC suggesting measures to reduce air pollution and GHG emissions from ships.

The International Convention for the Prevention of Pollution from Ships (MARPOL) is the main international convention covering pollution prevention of the marine environment by ships. The MARPOL Convention was adopted on November 2, 1973 at IMO. Committees of the IMO meet periodically to consider and adopt revisions to the various annexes of MARPOL and related treaties. Annex VI (Prevention of Air Pollution from Ships) entered into force on May 19, 2005. Annex VI sets limits on sulfur oxides (SO_x) and oxides of nitrogen (NO_x) emissions from ship exhausts and prohibits deliberate emissions of ozone depleting substances (ODS).

The IMO emission standards are commonly referred to as Tiers I through III standards. The Tier I standards were defined in the 1997 version of Annex VI, while the Tier II/III standards were introduced by Annex VI amendments adopted in 2008. Annex VI applies retroactively to new engines greater than 130 kW installed on vessels constructed on or after January 1, 2000, or which undergo a major conversion after that date. In anticipation of the Annex VI ratification, most marine engine manufacturers had been building engines compliant with Tier I standards since 2000. Annex VI amendments were adopted in October 2008 and ratified by 53 countries (including the U.S.), representing 81.88 percent of the tonnage. The amendments became enforceable on 1 July 2010. They introduced:

- New fuel quality requirements beginning from July 2010,
- Tier II and Tier III NO_x emission standards for new engines, and
- Tier I NO_x requirements for existing pre-2000 engines.

Annex VI also designated ECAs, which set more stringent standards for SO_x, NO_x, and particulate matter emissions. The IMO has designated waters along the U.S. and Canadian shorelines as the North American ECA for the emissions of NO_x and SO_x (enforceable from August 2012) and waters surrounding Puerto Rico and the U.S. Virgin Islands as the U.S. Caribbean ECA for NO_x and SO_x (enforceable from 2014). The ECAs ensure that foreign flagged vessels comply with IMO Tier III NO_x limits while in U.S. waters. Tier I and Tier II limits are global standards, while the Tier III standards apply only in NO_x ECAs. Tier III NO_x limits will apply to all ships operating within a NO_x ECA area constructed on or after 1 January

2016 with engines over 130 kW. Table 3-2 shows the Annex VI adopted NO_x emissions standards, which are set based on the engine's maximum operating speed (number of rpm).

The ECA also triggers IMO and US EPA low sulfur fuel requirements for vessels in U.S. waters. Table 3-3 shows the fuel sulfur content limits.

Table 3-3. MARPOL Annex VI Fuel Sulfur Limits Globally and Within a SO_x ECA

Global		Within SO_x ECA	
Effective Date	Sulfur Fuel Limits	Effective Date	Sulfur Fuel Limits
2004	45,000 ppm	2005	15,000 ppm
2012	35,000 ppm	2010	10,000 ppm
2020*	5,000 ppm *	2015	1,000 ppm

* Subject to a feasibility review in 2018; may be delayed to 2025.

IMO has developed guidelines for the use of exhaust gas cleaning systems (EGCS), such as SO_x scrubbers, as an alternative to operating on lower sulfur fuel. These guidelines include a table of sulfur dioxide (SO_2) limits intended to correspond with various fuel sulfur levels. For existing ECAs, the corresponding limit is 0.4 g SO_2/kW-hr for a 1,000 ppm fuel sulfur limit. This limit is based on an assumed fuel consumption rate of 200 g/kW-hr and the assumption that all sulfur in the fuel is converted to SO_2 in the exhaust. The IMO guidelines also allow for an alternative approach of basing the limit on a ratio of SO_2 to CO_2. This has the advantage of being easier to measure during in-use monitoring. In addition, this ratio holds more constant at lower loads than a brake-specific limit, which would approach infinity as power approaches zero. For the existing 15,000 ppm fuel sulfur limit in ECAs, an SO_2 (ppm)/CO_2 (%) limit of 65 was developed. The equivalent limit for a 1,000 ppm fuel sulfur level is 4.0 SO_2 (ppm)/CO_2 (%).

In summary, a 0.1 percent low sulfur fuel requirement applies to all ships entering an ECA after January 1, 2015. Prior to this date and since 2010, ships were required to use a fuel with no more than 1 percent sulfur content. Additionally Tier III NO_x emission standards that apply only to new ship constructions (and major engine rebuilds) will become effective in 2016.

3.2 Major Compliance Strategies

This section details some of the major compliance strategies available for the OGVs traveling within the North American and U.S. Caribbean ECAs. The following section mentions some additional technologies that are not expected to have significant early market penetration.

3.2.1 Strategy A – Exhaust Controls

Emission control technologies that can be used on C3 MDEs are limited. In addition to using distillate fuel to meet the fuel sulfur content limit in the ECA, one available option is to use a SO_x scrubber. For meeting the NO_x emission limits required in the North American ECA, selective catalytic reduction (SCR) was the control technology that EPA envisioned would be used to meet the Tier 4 emission standards. The following discussion describes these two control technologies.

3.2.1.1 Compliance with sulfur limits

Currently most OGVs use residual fuel as the main component in their main propulsion engines because this fuel is relatively inexpensive and has a good energy density. Residual fuels typically are composed of heavy and very heavy hydrocarbons and can contain contaminants such as heavy metals and sulfur compounds. If the vessel does not employ a control technology, such as a sulfur scrubber, it will most likely operate using a marine distillate fuel while in an ECA in order to meet the sulfur emission requirements.

The SO_x scrubbers are capable of removing up to 95 percent of SO_x from ship exhaust using the available seawater to absorb SO_x. The SO_x scrubbers have been widely used in stationary source applications for SO_x reduction. In the stationary source applications, lime or caustic soda are typically used to neutralize the sulfuric acid in the water. While SO_x scrubbers are not widely used on OGVs, there have been prototype installations to demonstrate their viability (e.g., the Krystallon systems installed on the P&O ferry Pride of Kent and the Holland America Line cruise ship the ms Zaandam). These demonstrations have shown scrubbers can replace and fit into the space occupied by the exhaust silencer units and can work well in marine applications.

There are two main scrubber technologies for OGVs. The first is an open-loop design, which uses seawater as exhaust washwater and discharges the treated washwater back to the sea. Such open loop designs are also referred to as seawater scrubbers. In a seawater scrubber, the exhaust gases are brought into contact with seawater, either through spraying seawater into the exhaust stream or routing the exhaust gases through a water bath. The SO_2 in the exhaust reacts with oxygen to produce sulfur trioxide (SO_3) which then reacts with water to form sulfuric acid. The aqueous sulfuric acid then reacts with carbonate and other salts in the seawater to form solid sulfates which may be removed from the exhaust. The washwater is then treated to remove solids and raise the pH prior to its discharge back to the sea. The solids are collected as sludge and held for proper disposal ashore.

A second type of SO_x scrubber uses a closed-loop design and is also feasible for use on marine vessels. In a closed-loop system, fresh water is used as washwater, and caustic soda is injected into the washwater to neutralize the sulfur in the exhaust. A small portion of the washwater is bled off and treated to remove sludge, which is held and disposed of at port, as with the open-loop design. The treated effluent is held onboard or discharged at open sea. Additional fresh water is added to the system as needed. While this design is not completely closed-loop, it can be operated in zero discharge mode for periods of time.

Water-soluble components of the exhaust gas, such as SO_2, SO_3, and NO_2, form sulfates and nitrates that are dissolved into the discharge water. Scrubber washwater also includes suspended solids, heavy metals, hydrocarbons and polycyclic aromatic hydrocarbons (PAH). Before the scrubber water is discharged, several approaches are available to process the scrubber water to remove solid particles. Heavier particles may be trapped in a settling or sludge tank for disposal. The removal process may include cyclone technology similar to that used to separate water from residual fuel prior to delivery to the engine. Sludge separated from the scrubber water would be stored on board until it is disposed of at proper facilities. The IMO guidelines for the use of exhaust gas cleaning devices such as SO_x scrubbers recommended monitoring and water discharge practices. The washwater should be continuously monitored for pH, PAHs, and turbidity. Further, the IMO guidance includes limits for these same measurements, as well as nitrate content when washwater is discharged in ports, harbors or estuaries. Finally, the IMO guidance recommends that washwater residue (sludge) be delivered ashore to adequate reception facilities and not discharged to the sea or burned on board. Any discharges directly into U.S. waters may be subject to Clean Water Act (CWA) or other U.S. regulation. To the extent that the air pollution control technology results in a wastewater discharge, such discharge will require a permit under the CWA's National Pollutant Discharge Elimination System (NPDES) permit program.

Achieving a reduction of sulfur by using a wet scrubber means increasing power usage significantly due to the use of pumped water, which indirectly results in an increase in other pollutant emissions associated with power production (e.g., GHGs).

3.2.1.2 Compliance with Tier 3 emission standards – SCR system

Among presently available after-treatment technologies, the urea-based Selective Catalytic Reduction (SCR) system represents the most mature and available solution to meet the marine engine Tier 3 NO_x emissions standards. An SCR uses a catalyst to chemically reduce NO_x to nitrogen using urea as a reagent in the presence of high-temperature exhaust gases. The SCR technology is compatible with higher sulfur fuels and may be equipped with a soot blower to remove particulate matter. The SCR systems require intermediate inspections approximately every 2.5 years and full inspections every five years. Because heavy metals deposit on the catalysts over time, the catalyst disposal process has created an industry to regenerate spent catalysts and reintroduce them into the supply chain. The useful life of a marine SCR catalyst can be five to six years, and manufacturers typically guarantee catalysts for up to 16,000 hours of service.[21] For vessels operating only part of the time within ECAs, the catalyst lifetime may be extended, in particular where 0.1% sulfur fuel is available.

Like many pollution control systems, the operation of SCR can be sensitive to *engine exhaust temperature*. Common practices of slow steaming could potentially contribute to SCR operational issues with low-load operation. Marine SCR applications have been designed to operate over a range of exhaust temperatures depending on fuel type, engine and catalyst design, and operating conditions. General minimum operating temperature ranges are between 260°C and 340°C, but systems may operate at lower temperatures for limited times. For marine engines, a variety of strategies are under development to expand the range of operating load conditions under which the SCR system functions normally. Exhaust gas temperatures can be boosted by several means, including:

- Reducing the amount of air and using a system to preheat the exhaust before entry into the SCR system;
- Adjusting injection timing;
- Bypassing part of the exhaust through a heated hydrolysis catalyst which allows urea to be injected at exhaust gas temperatures as low as 150°C;
- Heating the urea dosing system prior to injection to maximize efficiency; and,

[21] Wärtsilä, "IMO Tier III Solutions for Wärtsilä 2-Stroke, Engines—Selective Catalytic Reduction (SCR)," 2011.

- For ships with multiple engines, shutting down one or more engines and running fewer engines at higher power.

In another approach, at low loads, a portion of the catalyst can be bypassed by condensing the exhaust gas volume and forcing it through a smaller catalyst volume, maintaining turbulent flow and high catalyst temperature. Hitachi Zosen and MAN Diesel recently completed a successful sea trial with SCR systems in use to operate at a 10 percent engine load.[22]

Engine architecture may allow specific strategies. For four-stroke engines, the SCR catalyst can be mounted after the turbocharger. Four-stroke engines have also been developed which allow SCR operation down to a 10–15 percent load. For two-stroke engines, the catalyst is mounted before the turbocharger inlet where the exhaust gas temperatures and pressures are higher. This has the added benefit of allowing the system to be operated using a smaller reactor. For two-stroke engines, the placement of the SCR catalysts upstream of the exhaust turbine can ensure effective NO_x reduction down to at least a 25-percent load. The "pre-turbocharger" SCR approach has been used successfully for over a decade on vessels equipped with slow-speed engines that required NO_x control when operating at low loads near coastal areas. Recently, Hitachi Zosen certified an engine design utilizing a compact, high-pressure, high-temperature SCR system that meets Tier III standards while producing minimal additional CO_2 emissions down to a 10-percent engine load.[22]

Overall, demand for urea for marine SCR applications is expected to be modest compared to other applications. The EPA estimates that urea use in the North American NO_x ECA will total approximately 454,000 tons in 2020 (which would constitute less than 10 percent of the 2015 on-road consumption levels and an even smaller fraction of projected 2020 use).[23] Because road transport is expected to consume no more than 5 percent of 2020 worldwide urea production, this suggests that marine urea consumption in 2020 will be significantly less than 1 percent of the worldwide total. Because the IMO regulation applies to new builds only (and to new engines installed on existing vessels), there should be adequate time for a urea supply chain to develop further in the future as marine SCR application slowly grows in step with the global vessel new-building program.

In October 2013, Caterpillar Marine announced that their C280 and 3516C models will meet EPA Tier 4 using SCR after-treatment systems.[24] Cummins Marine already uses SCR and indicates their planned use for higher horsepower marine engines to achieve EPA's Tier 4 standards. Other engine manufacturers have also indicated SCR as their planned approach to compliance.

[22] Hitachi Zosen Corporation. "First ever marine vessel equipped with Pre-Turbo SCR system achieves compliance with Tier III NO_x emission standards certified by Nippon Kaiji Kyokai." 6 December 2011. Last accessed from http://www.hitachizosen.co.jp/english/news/2011/12/000568.html on January 22, 2015.
[23] U.S. Environmental Protection Agency. Proposal to designate an Emission Control Area for Nitrogen Oxides, Sulfur Oxides, and Particulate Matter: Technical Support Document. EPA-420-R-09-007. Last accessed from http://www.epa.gov/nonroad/marine/ci/420r09007-chap5.pdf on January 19, 2015.
[24] Marine Log. "Cat unveils Tier 4 marine engines." 8 October 2013. Last accessed from http://www.marinelog.com/index.php?option=com_k2&view=item&id=5236:cat-unveils-tier-4-marine-engines&Itemid=231 on January 22, 2015.

3.2.2 Strategy B – LNG-fueled vessels

As the shipping industry considers alternatives to HFO, part of the market will shift toward marine gas oil (MGO) and part toward LNG or other alternative fuels. Marine vessels equipped with scrubbers will retain the advantage of using lower-priced HFO. Shipping that takes place outside ECA areas might choose HFO or low-sulfur fuel oil (LSFO) depending on future global regulations. Ships operating partly in ECA areas will likely choose MGO as a compliance fuel. Heavy shipping within ECA areas, however, might provide enough incentive for a complete shift to LNG.

LNG-fueled engines burn cleaner and do not require after-treatment or specialized NO_x abatement measures to meet EPA Tier 4 (IMO Tier III). The potential lack of emission controls, in conjunction with its significantly lower fuel cost, makes LNG an attractive option for compliance. The only large ships currently using LNG as a fuel on international voyages are LNG cargo carriers. For LNG to become an attractive fuel for the majority of ships, a global network of LNG bunkering terminals must be established. If not, LNG-fueled ships will be limited to coastal trades where LNG bunkering networks are established.

The ability of LNG engines to meet Tier III NO_x requirements depends on the engine technology. While all LNG engine manufacturers do not yet have Tier III-compliant offerings, they are all likely to have introduced Tier III compliant engines within a few years.[25] The marine LNG engines currently available are almost exclusively dual-fuel engines that use a pilot fuel (MDO) to provide an ignition source for natural gas in the engine's cylinders. The amount of pilot fuel required varies based on engine technology, engine load, and pilot fuel quality. While some engines need a load of at least 30 percent before they can burn natural gas,[26] one of the most recent engine introductions can burn gas at any load, with pilot fuel energy consumption that is around 2 percent of the primary fuel energy consumption.[27] For the purposes of fuel demand modeling, it is reasonable to assume that virtually all LNG new-builds operating in an ECA will use dual-fuel engine designs that are equivalent to the current most advanced designs that meet Tier III without the addition of SCR, are able to burn natural gas at all engine loads, and have pilot fuel use equivalent to 2 percent of the total engine energy use.

When LNG is considered with its storage and support systems, the volumetric energy density of LNG can be up to three times higher than diesel fuels. This space penalty can be too large to

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[25] The most recent dual-fuel LNG marine engines introductions by both Wärtsilä and MAN meet Tier III without SCR:
Hagedorn, M. "LNG Engines: Specifications and Economics." Presented at LNG shipping Rostock. October 13, 2014. Last accessed from http://www.golng.eu/files/Main/20141017/Rostock/LNG%20Shipping%20Session%20II%20-%20LNG%20Engines-Specifications%20and%20Economics-%20W%C3%A4rtsil%C3%A4,Ship%20Power%20-%20Hagedorn.pdf on January 22, 2015.
The Motorship. "MAN goes for Tier III compliance." 30 October 2014. Last accessed from http://www.motorship.com/news101/engines-and-propulsion/man-goes-for-tier-iii-compliance on 22 January 2015.

[26] MAN Diesel. "ME-GI Dual Fuel MAN B&W Engines: A Technical, Operational and Cost-effective Solution for Ships Fuelled by Gas." Last accessed from http://www.dma.dk/themes/LNGinfrastructureproject/Documents/Bunkering%20operations%20and%20ship%20propulsion/ME-GI%20Dual%20Fuel%20MAN%20Engines.pdf on 22 January 2015.

[27] Stiefel, R. "Wärtsilä awarded milestone order to supply 2-stroke dual-fuel engines for large LNG carriers." Press release on 9 September 2014. Last accessed from http://www.wartsila.com/en/press-releases/wartsila-awarded-milestone-order-to-supply-2-stroke-dual-fuel-engines-for-large-lng-carriers on 22 January 2015.

overcome for many vessels. If technically feasible, a total ownership cost analysis is needed to evaluate whether this approach would result in a low enough payback period to justify the higher investment cost.

It has been suggested that about half the commercial fleet of marine vessels could be converted to LNG. However, these conversions would not involve the largest vessels and likely not OGVs. Thus, in terms of amount of converted fuel use, the percentage would be much lower than half the fleet. One estimate on marine LNG consumption in 2020 is 2.4 megatonnes (MT) of LNG in 2020. [28]

A report from the IEA Advanced Motor Fuels Implementation Agreement[29] stated:

> "A major concern with LNG is the possibility for de-bunkering (or emptying the fuel tanks). This step is necessary when a ship is to be anchored for an extended period of time. Unless special LNG de-bunkering facilities are available in the port, the gas would boil off, causing huge methane losses to the atmosphere. In the case of grounding accidents, a technique for de-bunkering would also be necessary. Another concern is the pressure increase when consumption occurs below the natural boil-off rate, which will happen if there is no re-liquefaction plan available onboard. Re-liquefaction of boil-off gas requires about 0.8 kWh/kg gas. One large LNG carrier, such as Qatar Q-max, requires 5–6 MW of re-liquefaction power, corresponding to a boil-off rate of 8 tons/hour.
>
> "A third concern that needs to be addressed with LNG conversions is methane slip from larger marine engines burning the gas. Methane slip will occur, especially on four-stroke, dual-fuel engines (Figure 13 *[not shown]*), partly from the scavenging process in the cylinder and partly from the ventilation from the crank case, which is being led to the atmosphere. In addition, there is some uncertainty as to whether future regulations will allow LNG tanks to be situated directly below the outfitting/accommodation of the ship. If not, this constraint could cause difficulties in retrofitting certain ships."

3.2.3 Strategy C – Engine-based controls

Engine modifications to meet Tier III emission levels will most likely include a higher percentage of common rail fuel injection systems coupled with the use of two-stage turbocharging and electronic valving. Engine manufacturers estimate that practically all slow-speed engines and 80 percent of medium-speed engines will use common rail fuel injection. Two stage turbocharging will probably be installed on at least 70 percent of all engines produced to meet Tier III emission levels. Electronically (hydraulically) actuated intake and exhaust valves for medium-speed engines and electronically actuated exhaust valves for slow-speed engines are necessary to accommodate two-stage turbocharging.[30]

[28] "North European LNG Infrastructure Project," Danish Maritime Authority, accessed at the following link: http://www.dma.dk/themes/LNGinfrastructureproject/Sider/Papersandpresentations.aspx

[29] "Alternative Fuels for Marine Applications," A report from the IEA Advanced Motor Fuels Implementation Agreement, May 2013. Last accessed from http://www.iea-amf.org/app/webroot/files/file/Annex%20Reports/AMF_Annex_41.pdf on January 18, 2015.

[30] U.S. Environmental Protection Agency, Costs of Emission Reduction Technologies for Category 3 Marine Engines. Final Report EPA-420-R-09-008. May 2009.

The on-engine approach requires the addition of an Exhaust Gas Recirculation (EGR) system. EGR is a mature technology that has widely been used for on-road engines. By using EGR, a portion of the exhaust gas is recirculated back to the engine cylinders. The recirculated gases lower the oxygen content at the engine intake resulting in lower combustion temperatures and less thermal NO_x production. A heat exchanger is used to cool the recirculated exhaust air before entering the air intakes. The net of effect of this recirculated air is a less efficient combustion process due to the lower combustion pressure. Consequently EGR usage presents a fuel consumption penalty. To offset the lower combustion pressure, manufacturers are implementing improved engine designs such as new generation common rail direct fuel injection systems with higher pressures (15,000-40,000 pounds per square inch). The common rail allows finer electronic control over the fuel injection to provide multiple controlled injections per stroke. The fuel is further atomized to allow improved combustion. EGR allows the engine user to avoid the use of a urea-based SCR system, but it adds weight and complexity on the engine. In addition, EGR requires higher quality fuel with lower sulfur content for proper operation. Though not an issue in the U.S., this fuel requirement could create complications for vessels operating abroad where low sulfur diesel may not be available.

3.3 Other Compliance Options Considered

Alternative fuels are being developed as replacements to marine oil to help with compliance with the low sulfur fuel standard and to reduce operating costs in the long run. Quadrise Canada has developed a low-cost alternative to heavy fuel oil called Multiphase Superfine Atomized Residue Synthetic Fuel Oil (MSAR® SFO™).[31] The MSAR® SFO™ fuel technology renders heavy hydrocarbons easier to use by producing a low-viscosity fuel oil using water instead of expensive oil-based diluents, and also produces a superior fuel with enhanced combustion features. The process involves injecting smaller fuel droplets in a stable water-based emulsion into the cylinder, resulting in a complete combustion that produces lower NO_x and particulate exhaust gas emissions. MSAR® SFO™ can be air-atomized into 80-micron drops that contain thousands of small 5-micron fuel droplets that have seventeen times more surface area than a standard steam atomized drop. This property provides a much larger surface for contacting the combustion air with the fuel, leading to the need for low excess oxygen, quicker and more complete combustion, and less char formation (lower particulate emissions). In addition, since the fuel contains liquid water, the combustion temperature is lower, leading to lower NO_x formation.

Biofuels are one of the options to lower carbon intensity in the propulsion of ships and to reduce the effect of emissions to local air quality. However, the shipping sector is still in a very early stage of orientation towards biofuels. Currently no significant consumption of biofuels for shipping is taking place. However, there are R&D initiatives[32] in Europe that are investigating the possibilities. For example, under the TEN-T Priority Project 21: Motorways of the Seas,[33]

[31] Quadrise Canada Corporation. “Low Cost Alternative Fuel (MSAR ® SFO™).” Last accessed from http://www.quadrisecanada.com/fcs-low-cost.php on January 22, 2015.
[32] European Biofuels Technology Platform. “Use of Biofuels in Shipping.” Last accessed from http://www.biofuelstp.eu/shipping-biofuels.html#proj on January 22, 2015.
[33] Innovation and Networks Executive Agency, European Commission. “Priority Project 21: Motorways of the Sea.” Last accessed from http://inea.ec.europa.eu/en/ten-t/ten-t_projects/30_priority_projects/priority_project_21/priority_project_21.htm on January 22, 2015.

pilot tests on methanol as a marine fuel of the future[34] are currently being carried out. Biomethanol potentially could be used as well as methanol from fossil sources. These potential solutions should be followed in the future as they may become viable options.

Other potential NO_x emission reduction techniques that may have some merit include water injection, which could consist of the introduction of water into the combustion chamber either through fumigation or as fuel emulsions, or direct water injection. Another alternative is to use EGR and a Humid Air Motor (HAM) system, a combination that resulted in NO_x emission reductions approaching those for SCR.[35]

3.4 Compliance Cost Issues

As discussed in the preceding sections, as of January 2015, vessels operating in designated ECAs and in regions with ECA-equivalent regulations are required to use fuels with sulfur levels that do not exceed 0.1% or use exhaust treatment technologies (i.e., scrubbers) to remove SO_x. Options for meeting these regulations include the use of low-sulfur MDO, the use of HFO with scrubbers, or the use of LNG (a naturally low-sulfur fuel). Beginning in 2016, new-build vessels operating in the North American ECA will additionally need to meet stringent IMO Tier III (or EPA Tier 4) NO_x regulations which require use of after-treatment technologies (i.e., SCR or EGR) for MDO and HFO combustion. It is assumed that the 2016 new-build LNG engines will be able to meet Tier III without the use of SCR.

Compliance with these new emission requirements will raise operating costs for ship owners and operators in the North American ECA as they upgrade their aging shipping fleet with new ships. The new ships will have more complicated fuel systems, potentially post-treatment control equipment, and more expensive low sulfur fuels. Existing ships that do not have dual tanks may require retrofits with dual fossil fuel systems to allow fuel switching when they enter an ECA.

In general, the costs to ship owners for complying with the 2015 sulfur fuel limits are substantially greater (e.g., at least ten-fold) than the additional costs for implementation of strategies to comply with the lower NO_x limits dictated by IMO's Tier III standards (equivalent to EPA Tier 4 NO_x standards). It should be noted that the confidence that can be placed in economic feasibility comparisons of marine compliance strategies at the present time is substantially limited by the immaturity of the technologies associated with some of the key strategies that were identified in the previous section.

The low sulfur fuel ECA requirement applies to all ships entering an ECA after January 1, 2015, but the Tier III NO_x emission standards only apply to new ship builds (and major engine rebuilds) that are initiated starting in 2016. Consequently some studies assessing compliance strategies have assumed that fuel selections will essentially be determined based on sulfur compliance strategies (i.e., low sulfur MDO, scrubbers, or LNG).[36]

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[34] Innovation and Networks Executive Agency, European Commission. "2012-EU-21017-S Methanol: The marine fuel of the future." Last accessed from http://inea.ec.europa.eu/en/ten-t/ten-t_projects/ten-t_projects_by_country/multi_country/2012-eu-21017-s.htm on January 22, 2015.
[35] Presentation of Ulf Hagstrom, Marine Superintendent, Technical sector, Viking Line Apb, "Humid Air Motor (HAM) and Selective Catalytic Reduction (SCR) Viking Line," at Swedish Maritime Administration Symposium/Workshop on Air Pollution from Ships (May 24-26, 2005)
[36] Danish Ministry of the Environment, 2012. "Economic Impact Assessment of a NO_x Emission Control Area in the North Sea." http://www2.mst.dk/Udgiv/publications/2012/06/978-87-92903-20-4.pdf

Appendix C briefly describes current (i.e., 2014/2015) perspectives on compliance strategy selection, provides summary results of studies that examine and estimate future adoption of scrubbers and LNG technologies, and concludes with a summary of recently published cost analyses of the compliance strategies. Some costing information was available for smaller ships (engine sizes around 10,000 kW), but more information (and possibly vendor quotes) would be necessary to understand the costs to ships as large as the average container ships (engine sizes around 36,000 kW in Table 2-2). Because some technologies are still relatively new, the costs are expected to decrease with market penetration.

4 Projections to Future Years

Section 2 discussed the method for determining fuel consumed by OGVs traveling in the North American ECA based on port calls in 2012. However, the IMO protocol requirements for ships traveling in the North American ECA did not take effect until January 1, 2015. In addition, shipping patterns change with time, and newer vessels will be more efficient than older ones. This section explores a method that NEMS model developers could use to estimate future fuel usage within the North American and U.S. Caribbean ECAs.

Because the average age of ships calling on the U.S. between 2006 and 2011 was 10.5 years based on MARAD data,[37] the fleet turnover rate of 9.5 percent each year was considered rapid. Older ships have been routed to non-U.S. ports after the service life to the U.S. ended; the world fleet's average age in 2014 was 20.2 years.[38] Ships built for use in the North American ECA after 2015 must meet at least one of the compliance options, but older ships without scrubbers were assumed to opt against retrofit technologies in favor of either operation with MGO fuel or operation elsewhere in the world outside the North American ECA.[39] This assumption may result in higher MGO and lower IFO fuel use from 2015 to 2025 than would an approach that considers retrofitted units as a significant fraction of the fleet.

4.1 Increased Efficiency of New Vessels

As mentioned in the preceding paragraph, the fleet turnover (*FLEETTO*) variable (default value of 9.5 percent per year) was computed from MARAD data to represent the rate of introduction of new vessels into the fleet moving through the North American ECA. The new vessels are assumed to be more efficient than their predecessors.

Some technologies that the International Council on Clean Transportation (ICCT) suggests will reduce fuel use (and CO_2 emissions)[40] appear in Table 4-1. Under the implementation of the mandatory regulations on Energy Efficiency for Ships in MARPOL Annex VI, it is expected that ship efficiency will result in an average 1 percent increase in ship operating efficiency each year above a 2000-2010 reference case.[41]

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[37] Vessel Calls Snapshot, 2011, Released: March 2013, Revised: November 2013, Office of Policy and Plans, Maritime Administration, U.S. Department of Transportation, www.marad.dot.gov/data_statistics

[38] United Nations Conference on Trade and Development. Review of Maritime Transport 2014. ISBN 978-92-1-112878-9. Last accessed from http://unctad.org/en/PublicationsLibrary/rmt2014_en.pdf on March 5, 2015.

[39] Ships built on or before 1 August 2011 that are powered by propulsion boilers that were not originally designed for continued operation on marine distillate fuel or natural gas are exempted from the ECA regulations until 1 January 2020 (according to IMO -RESOLUTION MEPC.202(62)- Adopted on 15 July 2011). In addition, conditional waivers granting additional time to comply with the ECA regulations have been issued by the U.S. EPA and U.S. Coast Guard to Totem Ocean Trailer Express and to Horizon Lines (Horizon Lines is being divided for sale to Matson and to Pasha Group). Totem, Horizon Lines and Matson represent a majority of the U.S. container ship fleet.

[40] Wang, H. and N. Lutsey. "Long-term potential for increased shipping efficiency through the adoption of industry-leading practices." 2013 International Council on Clean Transportation. www.theicct.org

[41] International Maritime Organization. "Technical and Operational Measures." Last accessed from http://www.imo.org/OurWork/Environment/PollutionPrevention/AirPollution/Pages/Technical-and-Operational-Measures.aspx on January 22, 2015.

Table 4-1. ICCT List of Potential Fuel Reduction Technologies

Area	Technology	Potential CO_2 and Fuel Use Reduction
Engine Efficiency	Engine controls	0-1%
	Engine common rail	0-1%
	Waste heat recovery	6-8%
	Design speed reduction	10-30%
Thrust efficiency	Propeller polishing	3-8%
	Propeller upgrade	1-3%
	Rudder	2-6%
Hydrodynamics	Hull cleaning	1-10%
	Hull coating	1-5%
	Water flow optimization	1-4%
Aerodynamics	Air lubrication	5-15%
	Wind engine	3-12%
	Kite	2-10%
Auxiliary power	Auxiliary engine efficiency	1-2%
	Efficient pumps, fans	0-1%
	Efficient lighting	0-1%
	Solar panels	0-3%
Operational	Weather routing	1-4%
	Autopilot upgrade	1-3%
	Operational speed reduction	10-30%

This improved efficiency was translated in the computations to be expressed in new fleet vessels by calculating the 1 percent improvement per year for the average age of a vessel since the 2012 baseline. The *EFFINC* variable (default of 1 percent per year) can be used with the constant *FLEETTO* variable to compute the fuel consumption associated with a new fleet for a different year (*YR*):

$$FUELCONS'_{YR,class,CD} = fuel\ by\ 2012\ fleet + fuel\ by\ post\text{-}2012\ fleet$$

$$\begin{aligned} FUELCONS'_{YR,class,CD} &= FUELCONS_{2012,class,CD} \times maximum[0,1-(YR-2012)*FLEETTO] \\ &+ FUELCONS_{2012,class,CD} \times \{1- maximum[0,1-(YR-2012)*FLEETTO]\} \\ &\times [1-EFFINC]^\wedge[(YR-2012)/2] \end{aligned}$$

4.2 Changes in Shipping Demands

The variable $FUELCONS'_{YR,class,CD}$ in the previous section included an apostrophe because a second step to predicting the future fleet demands for total fuel consumption by a class is accounting for changes in market growth. The NEMS market growth numbers on imports and exports might vary by U.S. Census Division but are more easily collected on a national basis. Table 4-2 shares some baseline 2012 estimates from the ACOE about shipments to indicate whether the larger markets are by imports or exports.

Table 4-2. Weight (Million Short Tons) Transported in 2012 Through U.S. Waters Now under the North American ECA[42]

Commodity	Foreign Inbound	Foreign Outbound	Domestic Coastwise	Associated Vessel Class
Total petroleum and petroleum products	***482***	151	110	Energy tankers
Other chemicals and related products	35	***54***	9	Non-energy tankers
Total all manufactured equipment, machinery and products + total primary manufactured goods - vehicles and parts	***128***	41	16	Containers
Hydrocarbon and petrol gases, liquefied and gaseous	5.7	***6.3***	0.06	Gas (LNG)
Hydrocarbon and petrol gases, liquefied and gaseous	5.7	***6.3***	0.06	Gas (LPG)
Vehicles and parts	***12***	6	0.8	Roll-on/roll-off
Total coal + petroleum coke	12	***156***	5	Bulk - Energy
Total food and farm products	41	***155***	4	Bulk – Non-energy
Total all manufactured equipment, machinery and products + total primary manufactured goods - Vehicles and parts	***128***	41	16	General cargo

Examination of Table 4-2 indicates that imports might represent the larger ECA activity for energy tankers, container ships, roll-on/roll-off vessels, and general cargo. Fuel usage from these four vessel classes represents 85 percent of the 2012 energy profile from Section 2.

NEMS predicts imports and exports of the Table 4-2 commodities to change at different rates for future years, so the recommended approach is to distinguish these commodities using some parameters associated with NEMS. For energy commodities, the growth rates for the market imports/exports will change based on the AEO scenarios. Table 4-3 shows how the AEO 2014 reference case predicts that energy commodities might change with time.

Table 4-3. Energy Commodity Changes in the AEO 2014 Reference Case

Year	Crude Oil Gross Imports (million bbl per day)	LNG Exports (trillion cf)	Steam Coal Export (million short tons)
2012	8.49	0.03	55.9

[42] Table 2-1 in "Waterborne Commerce of the United States: Calendar Year 2012 Part 5—National Summaries." U.S. Army Corps of Engineers. Last downloaded from http://www.navigationdatacenter.us/wcsc/pdf/wcusnatl12.pdf on January 14, 2015.

Year	Crude Oil Gross Imports (million bbl per day)	LNG Exports (trillion cf)	Steam Coal Export (million short tons)
2013	7.48	0.01	49.6
2014	6.59	0.01	45
2015	6.31	0.11	47
2016	5.92	0.31	48.9
2017	5.97	0.76	51.1
2018	5.96	1.26	53.4
2019	5.91	1.77	53.4
2020	5.94	2.08	55.2
2021	6.04	2.32	55.4
2022	6.08	2.32	57
2023	6.11	2.52	58.8
2024	6.17	2.72	60.5
2025	6.18	2.72	62.3
2026	6.32	2.92	63.7
2027	6.46	3.12	63.6
2028	6.58	3.32	63.5
2029	6.7	3.5	67.4
2030	6.77	3.52	73.6
2031	6.91	3.52	77.3
2032	6.99	3.52	77.9
2033	7.02	3.52	78.5
2034	7.12	3.52	81.4
2035	7.27	3.52	83.8
2036	7.43	3.52	82.6
2037	7.53	3.52	74.2
2038	7.74	3.52	76.1
2039	7.79	3.52	83.7
2040	7.87	3.52	86.9

Therefore, the fuel consumption from the various vessel classes may be directly related to AEO 2014 scenario outputs. As an example, the calculations for energy tankers could be based on the projections of petroleum imports:

$$FUELCONS_{YR,energy\ tankers,CD} = FUELCONS'_{YR,energy\ tankers,CD} \times [MGPETR_{YR} / MGPETR_{2012}]$$

where $MGPETR_{YR}$ represents the imports of "Petroleum and Products" in the Macroeconomic Activity Module. A list of NEMS variables that might be associated with the different vessel types is presented in Table 4-4.

Another option for the non-energy vessel classes would be to base growth rates on population growth rates within the U.S. Census Divisions. The U.S. Census last predicted national growth to rise from 321 million in 2015 up to 380 million by 2040.[43]

[43] U.S. Census Bureau. "Population Projections: 2014 National Population Projections: Summary Tables." Last accessed from http://www.census.gov/population/projections/data/national/2014/summarytables.html on January 14, 2015.

Table 4-4. Potential NEMS Variables That Could Indicate Fleet Growth in Future Years

Vessel Class	Parameter	Module	Parameter Description
Energy tankers	MGPETR	Macroeconomic Activity Module	Real Imports of "Petroleum and Products"[44]
Non-energy tankers	XGINR	Macroeconomic Activity Module	Real Exports of "Industrial materials and supplies"
Containers	MGCR	Macroeconomic Activity Module	Real Imports of "Consumer goods except motor vehicles"
Gas (LNG)	NGLEXP	Liquid Fuels Market Module	Natural Gas Liquid export
Gas (LPG)	NGLEXP	Liquid Fuels Market Module	Propane export
Roll-on/roll-off	MGAUTOR	Macroeconomic Activity Module	Real imports of "Motor vehicles & parts"
Bulk - Energy	--	Coal distribution submodule in Coal Market Module	"CEXPRT" generates reports from the export portion of the linear program (plus petroleum coke exports)
Bulk – Non-energy	XGFFBR	Macroeconomic Activity Module	Real exports of "Foods, feeds and beverages"
General cargo	MGKR	Macroeconomic Activity Module	Real imports of "Capital goods except motor vehicles"

4.3 Compliance Choices

The final element in the determination of fuel projections is the allocation of energy consumption among the different fuel choices. Before describing the resultant profiles, several assumptions about the projections are discussed below:

1. Protocol takes effect:
    a. The North American ECA went into effect on January 1, 2015. It requires existing ships to either burn fuel containing a maximum of 0.1% sulfur or to use scrubbers to remove the sulfur emissions.
    b. On January 1, 2020 the IMO will require the sulfur content of fuel used outside of the ECA to be reduced to 0.5% (a possible five-year delay is possible and would be based on a 2018 re-evaluation).
2. Technology Introduction Year to Fleet
    a. EPA Tier 3: On January 1, 2016 all new build ship engines used in the ECA are required to be EPA Tier 3 compliant.
    b. LNG Vessels enter U.S. Fleet: In 2015 the first LNG-fueled container ship is due to become operational.

[44] NEMS also tracks ethanol and biodiesel imports and exports. These variables could be added to the petroleum values to track total activity projections of energy tankers.

c. Scrubber: While the exact date that emission scrubber technology was installed on commercial freight ships was not reported, DNV[45] estimated in a 2012 report that 30-40 percent of all new builds will have emission scrubber technology installed by 2016. After 2016, all new ships that consume fuel oil and will operate within the ECA are required to have scrubber and other emission control technologies installed.

3. Conventional engine using IFO: Prior to 2015 ships calling on the U.S. could operate on fuel used internationally and their ships did not require scrubbers to remove sulfur emissions. Nearly all large OGVs were powered by slow speed diesel engines that burned IFO 380 or IFO 180. IFO is 88-98 percent residual fuel oil with 2-12 percent distillate added to achieve proper viscosity. IFO for use outside an ECA has a maximum sulfur content of 3.5%.

4. Conventional engine using MGO: Existing ships can continue to operate in the ECA without scrubbers if they use MGO as their fuel oil.

5. Conventional engine with operating scrubber using IFO: Ships in existence before 2016 can continue to use a conventional engine and burn IFO within the ECA if the ship has installed sulfur scrubbers. Ships that enter service after January 1, 2016 must be equipped with sulfur scrubbers and NO_x controls technology.

The projection that new ships built after 2015 would install and operate scrubbers instead of burning MGO in the ECAs is based on a BIMCO study that presented the investment function for scrubbers versus MGO.[46] Calculations conducted for this project show that container ships from Asia and Europe would spend 16-21 percent and 43-49 percent of their operating time on voyages within ECAs.[47] The AEO 2014 reference case, high oil price case, and low oil price cases all showed high spreads between HFO and MGO prices after 2015 (over $600/metric ton), and the BIMCO summary indicated that such voyages and price spreads would justify the investment in scrubber technologies for new ships.[48]

These assumptions were used to build fleet profiles for the activity of OGVs within the North American ECA. The profiles appear in Table 4-5 for three scenarios developed by DNV.[49] The first scenario estimated that, if the price if LNG was 10 percent above the price of HFO, that 7.5 to 9 percent of new builds would use LNG as their fuel. The second scenario estimated that, if the price of LNG was 30 percent below the price of HFO, that 13 percent of new builds would use LNG as their fuel. The third scenario estimated that, if LNG was 70 percent below the price of HFO, that 30 percent of new builds would use LNG as their fuel. All three scenarios assume that any subsidies for a particular fuel or technology have already been incorporated into the cost comparison.

[45] DNV, Report of Shipping 2020: http://www.dnv.nl/binaries/shipping%202020%20-%20final%20report_tcm141-530559.pdf; last accessed on January 20, 2015.
[46] "Business Case: Marine Gas Oil or Scrubbers When Operating in an ECA?" BIMCO. Published on April 25, 2013. Last accessed from https://www.bimco.org/Reports/Market_Analysis/2013/0424_ECAStory.aspx on January 22, 2015.
[47] Calculations done for voyages from Shanghai to Los Angeles and from Rotterdam to New York/New Jersey.
[48] Note that the BIMCO study reflects tanker ships, but similar curves could be derived for container ships.
[49] DNV report shipping 2020; Det Norske Veritas; NO-1322 høvik, Norway; www.dnv.com

Table 4-5. Fleet Profiles of Compliance Strategies under Three Scenarios

Year	Conventional engine using IFO (includes vessels with non-operating scrubbers)	Conventional engine using MGO	LNG Price 10% above HFO Price		LNG Price 30% below HFO Price		LNG Price 70% below HFO Price	
			Conventional engine with operating scrubber using IFO	LNG engine	Conventional engine with operating scrubber using IFO	LNG engine	Conventional engine with operating scrubber using IFO	LNG engine
2012	100%	--	--	--	--	--	--	--
2013	100%	--	--	--	--	--	--	--
2014	100%	--	--	--	--	--	--	--
2015	--	90%	10%	--	10%	--	10%	--
2016	--	77%	22%	1%	22%	1%	20%	3%
2017	--	64%	34%	1%	33%	2%	30%	6%
2018	--	51%	46%	2%	45%	4%	40%	9%
2019	--	39%	59%	3%	56%	5%	50%	11%
2020	--	26%	71%	4%	68%	6%	60%	14%
2021	--	13%	83%	4%	80%	7%	70%	17%
2022	--	--	95%	5%	91%	9%	80%	20%
2023	--	--	95%	5%	91%	9%	79%	21%
2024	--	--	95%	5%	91%	9%	79%	21%
2025	--	--	95%	5%	91%	9%	79%	21%
2026 and beyond	--	--	93%	8%	87%	13%	70%	30%

Table 4-5 shows that engines with scrubbers are more prevalent in the fleets in 2022 through 2025 than they are in years beyond that point. These high percentages occur because scrubbers were introduced to the new fleet before LNG vessels.

Scrubbers and other control devices do require energy, as do fuel chillers associated with the use of MGO. The model has been constructed to impose energy penalties for the use of MGO, LNG, and scrubbers. Such an energy penalty might also take the form of a decreased *cargo* footprint aboard vessels with the alternate fuels and control technologies. However, the energy penalties have not yet been well characterized and reported in the published literature. The energy penalties have been initially set to zero, except the penalty for scrubbers is set to 2 percent.[50,51] Designs are changing very rapidly with the introduction of these technologies aboard larger ships, so EIA should consider energy penalties for these systems that decrease over time.

[50] ABS. Exhaust Gas Scrubber Systems: Status and Guidance. Last accessed from https://www.eagle.org/eagleExternalPortalWEB/ShowProperty/BEA%20Repository/References/Capability%20Brochures/ExhaustScrubbers on January 22, 2015.
[51] "EffShip Project Final Seminar." Published on 21 March 2013. Last downloaded from http://www.effship.com/PublicPresentations/Final_Seminar_2013-03-21/09_EffShip-Handout.pdf on January 16, 2015.

An energy penalty for older LNG gas ships could be approximated because they use a forced natural gas boil-off from the cargo tanks in steam boilers to produce steam for steam turbines. A steam turbine propulsion system has an energy efficiency of about 28 percent compared to the approximately 50 percent for a conventional slow-speed diesel engine. However, the number of LNG ships calling on U.S. ports is very small compared to total vessel calls and quantifying the declining number of older LNG gas ships using steam turbine propulsion systems would not significantly impact the overall report projections.

4.4 Fuel Estimates

Total fuel consumptions in each Census Division were multiplied by the fleet profiles and energy penalty corrections to determine the amount of each fuel consumed (as billion Btu) within the North American and U.S. Caribbean ECAs for each Census Division:

$$MARFUEL_{YR,CD,MFtype} = FLTPROF_{YR,MFtype} \times \left(1 + ENPEN_{MFtype}\right) \times \sum_{class=energy\ tankers}^{general\ cargo} FUELCONS_{YR,class,CD}$$

where $MARFUEL_{YR,CD,MFtype}$ = marine fuel consumed in ECA transit using *MFtype* fuel in year *YR* across Census Division *CD*

$FLTPROF_{YR,MFtype}$ = fraction of the fleet using *MFtype* fuel in year *YR*

$ENPEN_{MFType}$ = energy penalty associated with *MFtype* fuel[52]

Using the scenario where the LNG price is 30 percent below the HFO price, Table 4-6 shows the marine fuels consumed in the North American and U.S. Caribbean ECAs in 2021. That year is the last one in which MGO fuel is likely to be used (Table 4-5).

Table 4-6. Total Fuel Consumed (Billion Btu) in North American and U.S. Caribbean ECAs in 2021 by Marine Fuel Type

Census Division	IFO	LNG	MGO	Total
New England	2,200	200	350	**2,700**
Middle Atlantic	12,000	1,100	1,800	**14,000**
Midwest	-	-	-	**-**
West North Central	-	-	-	**-**
South Atlantic	33,000	3,000	5,200	**41,000**
East South Central	3,100	290	500	**3,900**
West South Central	34,000	3,100	5,300	**42,000**
Mountain	-	-	-	**-**
Pacific	37,000	3,400	5,900	**46,000**
Puerto Rico	590	53	90	**730**
Nationwide	**120,000**	**11,000**	**19,000**	**150,000**

[52] The previous section discusses that the energy penalties were initially assigned as zero percent for LNG and MGO options.

The numbers in Table 4-6 were converted to the fuel types tracked in NEMS: residual fuel oil, distillate fuel oil, and LNG. Based on global estimates of marine fuel use,[53] the assumption was that low-sulfur IFO would be used in 2021 but that it would be composed of 10 parts IFO500 (0% distillate), 60 parts IFO 380 (2% distillate), and 6 parts IFO 180 (12% distillate). The results for 2021 using the scenario where the LNG price is 30 percent below the HFO price appear in Table 4-7.

Table 4-7. Total Fuel Consumed (Billion Btu) in North American and U.S. Caribbean ECAs in 2021 by NEMS Fuel Type

Census Division	Residual Fuel Oil	Distillate Fuel Oil	LNG	Total
New England	2,100	400	200	**2,700**
Middle Atlantic	11,000	2,100	1,100	**14,000**
Midwest	-	-	-	**-**
West North Central	-	-	-	**-**
South Atlantic	32,000	6,000	3,000	**41,000**
East South Central	3,100	570	290	**3,900**
West South Central	33,000	6,200	3,100	**42,000**
Mountain	-	-	-	**-**
Pacific	36,000	6,800	3,400	**46,000**
Puerto Rico	570	110	50	**730**
Nationwide	**120,000**	**22,000**	**11,000**	**150,000**

[53] IEA-AMF Organization. A Report from the IEA Advanced Motor Fuels Implementing Agreement- Alternative Fuels for Marine Applications. May 2013. Last accessed from http://www.iea-amf.org/app/webroot/files/file/Annex%20Reports/AMF_Annex_41.pdf on March 31, 2015.

5 Recommendations

The recommendations for EIA's path forward include expanding the scope of the marine fuel estimates, fractionating the fuel purchases made in the U.S. versus abroad, and improving the future projections of fuel usage. An initial recommendation would be to consider a sensitivity analysis and determine the factors (e.g., slow steaming reductions and auxiliary power needs) that would most affect the fuel consumption estimates. A sensitivity analysis would help determine the factors for later investigations and also the best ways to relate the model to EIA's model scenarios.

The expansion of the scope would likely center on improving EIA's estimates of fuel usage in waters beyond the North American and U.S. Caribbean ECAs:

1. Remainder of ocean voyages beyond the ECAs
2. Great Lakes transit[54]
3. Inland waters transit

The expanded scope might also include fuel usage estimates for additional ships that may be more tied to U.S. ports for fuels:

1. Tugs, barges, and lightering vessels
2. Fishing vessels (most operate with C1 engines)
3. Cruise ships
4. Other commercial vessels

While the number of ships that operate full-time or nearly full-time in the North American ECA is small, they may exert a disproportionate influence on total energy consumption within the ECA due to the time that they spend in the ECA. Many of these will be U.S.-flagged vessels and include non-cargo vessels such as port tugboats and ferries. Their fuel consumption would be calculated with different assumptions about time spent within the ECA.

The U.S. commercial deep draft fleet and the U.S.-flagged oceangoing tug and barge operations to Alaska, Hawaii, Puerto Rico, and the Virgin Islands were considered very small and likely captured as port calls by the larger ships in the MARAD data.

A future study might examine fuel purchasing to better understand what fraction of the fuel consumed within the ECAs was purchased at U.S. ports.

Many factors affect the total fuel consumption estimates (e.g., transit time, engine efficiency, loads, and auxiliary power usage). The recommendations below address changes that could be made to baseline fuel consumption estimates (and those through 2014/2015):

1. Update the estimates to give consideration to active vessel speed reduction (VSR) programs which are currently required at a number of ports, which are mostly on the west

[54] These vessels and the inland fleet were excluded from this current model. The inland fleet (about 3,000 towboats) is using generally using domestically procured diesel oil for fuels, while the large Great Lake ships (about 76 North American ships full-time and 800 foreign port calls/year from Europe) are using IFO. The U.S. EPA has allowed some alterations to the ECA regulations in the Great Lakes.

coast (including Ports of Long Beach, Los Angeles, and San Diego), and by the Port Authority of New York and New Jersey. VSR has also been evaluated at the Ports of Seattle and Tacoma, as well as the Port of Houston Authority. These speed reductions would be applied on a port-by-port basis and not scaled directly to the entire U.S. Census Division.

2. Update the estimates to give consideration to the expanding use of on-shore power (cold ironing). The Ships at Berth Regulation (California Air Resource Board) began requiring use of on-shore power by OGVs by 50 percent of the fleet visits to California ports starting in 2014. Fleets affected by this regulation include container vessels, passenger vessels, and refrigerated cargo vessels.
3. Give future consideration in the model to congestion issues and delays at sea or at berth due to local infrastructure constraints or labor issues.

Other investigations might yield better estimates of the fuel types consumed in the baseline estimates. Worldwide numbers might be distributed to North America and the U.S. using the resources of BIMCO, IMO, and United Nations Conference on Trade and Development. An appropriate fraction of those numbers could be applied to the North American and U.S. Caribbean ECAs.[55]

Additionally some recommendations would apply to estimates in the future projections:

1. According to the baseline estimates in this study, 26 percent of the energy used for port calls was for auxiliary power. Auxiliary power requirements are the least documented on an international scale, but there is sufficient documentation available on a ship-by-ship basis to create typical auxiliary power needs by ship class. In addition, auxiliary power requirements can be greatly reduced by implementing new practices such as waste heat reclamation, cold ironing, solar panels, and switching to distillate fuels that do not require preheating.
2. Fully analyze the BIMCO report that chooses between using scrubbers versus burning MGO in ECAs.[56] Perform a similar set of cost calculations for container ships because they represent almost half of the fuel consumption within ECAs in 2012.
3. Ship design speeds and engine sizes: A new study might predict potential cost savings or energy efficiencies based on multiple changes to ship design trends (e.g., ship speed, ship size, engine types, new technologies, adoption of best practices, and new environmental safeguards), their installation/operational costs, and confidence in the technologies involved (expressed as a probability of expected performance). This new study with an economics basis would allow for gaming potential changes and be based on the highest levels of expected return.

[55] A 2008 report prepared for the U.S. EPA (Global Trade and Fuels Assessment—Future Trends and Effects of Requiring Clean Fuels in the Marine Sector, EPA420-R-08-021, November 2008) stated that Houston's heavy fuel oil for marine activities was mostly imported from refineries in Venezuela, Mexico, and Aruba, so an understanding of U.S. imports for marine fuel might also be important.
[56] BIMCO. "Business Case: Marine Gas Oil or Scrubbers When Operating in an ECA?" Published on 25 April 2013. Last accessed from https://www.bimco.org/Reports/Market_Analysis/2013/0424_ECAStory.aspx on January 22, 2015.

4. Add a Technology Adoption Model (TAM) to project the selection of strategies and associated fuel type for meeting marine environmental regulations. The primary TAM outputs would be marine demand for HFO, MDO, and LNG. The model would enable analyses of the effects of fuel prices, capital cost changes, and policy measures on the proportionate use of the different marine fuels. Model inputs and availability of these inputs are summarized in the Table 5-1. The TAM would also consider fuel incentives and low emissions shipping incentives.

Table 5-1. Model Inputs for a Possible Technology Adoption Model for Fuel Use Projections

Model Input	Data Availability
Number of vessels by census region and ECA/non-ECA trade partner	Readily available at national level – assumptions would likely be needed for regional level
Number of vessels by type and size class for tankers and container ships	Readily available at national level – regional level is available with additional effort
Number of vessels by age class	Readily available at national level – assumptions would likely be needed for regional level
Total marine energy demand by region	An input from the output of the current project
Inland and coastal vessel energy demand by fuel type	An input variable as manual entry or from a separate coastal/inland technology adoption model
Fuel prices	An input from NEMS
Average engine efficiency	Available – some assumptions would be needed for applying to each vessel type and size class
Strategy capital costs	Available – some assumptions would be needed for applying to each vessel type and size class
Strategy operating costs	Available – some assumptions would be needed for applying to each vessel type and size class
Representative industry discount rate	Available

Appendix A. Matrix-Based Derivations of Baseline Estimates

A.1 Notation

Class = Tanker, Container, Gas (LPG/LNG), Roll-on/Roll-off, Bulk, or General Cargo

CD = 9 U.S. Census Divisions and Puerto Rico

Year = 2012

A.2 Formulas

For the total nautical miles traveled:

$TOTNMI_{2012,class,CD} = \sum_{all\ ports\ in\ CD} CALLS_{2012,class,port} \times ECADISTPERCALL_{port}$

where

$CALLS_{2012,class,port}$ = number of calls to MARAD-tracked port in 2012 (by class and port)

$ECADISTPERCALL_{port}$ = distance traveled across ECA for port entry and exit (nautical miles)

For the average dead weight tonnage:

$AVGDWT_{2012,class,CD} = TOTALDWT_{2012,class,CD} / CALLS_{2012,class,CD}$

where

$CALLS_{2012,class,CD}$ = number of calls to all MARAD-tracked ports in 2012 (by class and CD)

$TOTALDWT_{2012,class,CD}$ = total dead weight tonnage for all MARAD-tracked ports in 2012 (by class and CD)

For the total work associated with transit (ton-miles):

$ECATRANSITWORK_{2012,class,CD} = TOTNMI_{2012,class,CD} \times AVGDWT_{2012,class,CD}$

For the time transiting the ECA (hours):

$TIMETRANSITINGECA_{2012,class,CD} = TOTNMI_{2012,class,CD} /[ENGDESSPD_{class} \times SLOWSTMSPDRED_{class,CD}]$

where

$ENGDESSPD_{class}$ = engine design speed (knots)

$SLOWSTMSPDRED_{class,CD}$ = percentage of engine design speed achieved during slow steaming

For the engine sizes (kW):

$ENGINESIZE_{2012,Class,CD}$ is a function of $AVGDWT_{2012,class,CD}$ and read from MAN tables

For the energy spent during transit (kWh):

$$TRANSITENERGY_{2012,class,CD} = ENGINESIZE_{2012,Class,CD} \times SLOWSTMPWRRED_{class,CD} \times TIMETRANSITINGECA_{2012,class,CD}$$

where

$SLOWSTMPWRRED_{class,CD}$ = percentage of engine power reduction achieved during slow steaming

The transit fuel consumption is computed by multiplying the transit energy by the specific fuel oil consumption for transit (e.g., 0.175 kg/kWh for post-2001 slow-speed diesel engines):

$$TRANSITFUELCONS_{2012,class,CD} = TRANSITENERGY_{2012,class,CD} \times SFOC_{transit}$$

where

$SFOC_{transit}$ = specific fuel oil consumption for main propulsion engines

The auxiliary power usage of ships is generally reported as a percentage of the power used for transit under design conditions (e.g., 5%). The auxiliary power is assumed to continue operating while in port or at anchor within the ECA (e.g., 21 to 62 hours for loading/unloading in port). Therefore, the auxiliary power spent while in the ECA can be calculated with the formula:

$$AUXENERGY_{2012,class,CD} = [ENGINESIZE_{2012,class,CD} \times PCTAUX] \times [TIMETRANSITINGECA_{2012,class,CD} + PORTTIME_{class} \times CALLS_{2012,class,CD}]$$

where

$PCTAUX$ = percentage of the power used for transit under design conditions

$PORTTIME_{class}$ = average time spent in port or at anchor by a specific vessel class

The auxiliary fuel consumption is computed by multiplying the auxiliary energy by the specific fuel oil consumption for auxiliary engines (e.g., 0.225 kg/kWh):

$$AUXFUELCONS_{2012,class,CD} = AUXENERGY_{2012,class,CD} \times SFOC_{aux}$$

where

$SFOC_{aux}$ = specific fuel oil consumption for auxiliary engines

For the total fuel consumption while in the ECA (Btu):

$$FUELCONS_{2012,class,CD} = TRANSITFUELCONS_{2012,class,CD} + AUXFUELCONS_{2012,class,CD}$$

Appendix B. Ship Routes to Avoid Significant Travel in North American ECA

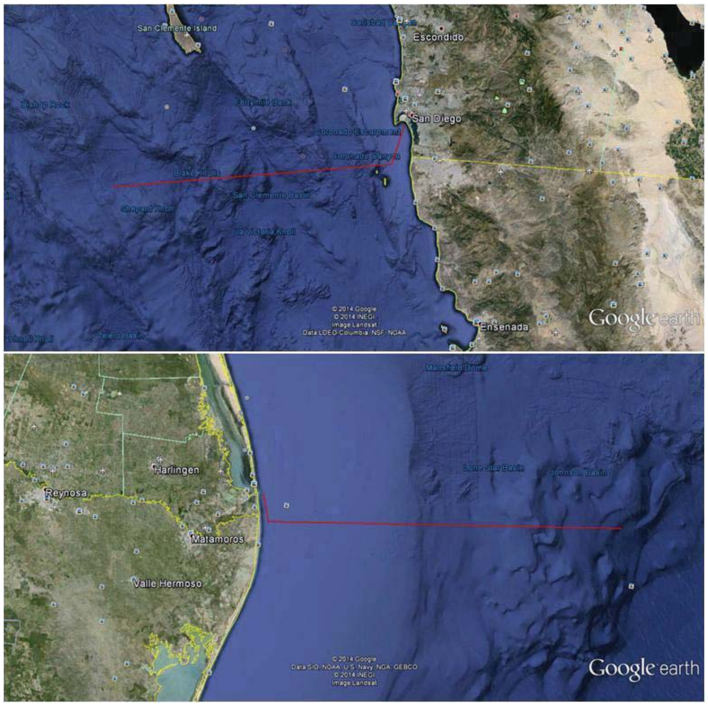

Figure B-1. Ship routes (to San Diego- top and Brownsville- bottom) that would avoid most of the North American ECA by staying south of the ECA until jogging north to cross from Mexican into U.S. waters (shown as red lines)

Figure B-2. Approximate boundary (yellow) of North American ECA as a result of proximity to the Bahamas. White line shows a 20-nautical mile scale.

Appendix C. Adoption of Compliance Strategies by Ship Industry

C.1 Strategy Selection: Current Status

A typical economic evaluation for the selection of emissions compliance strategies includes standard economic measures of the capital and operating and maintenance (O&M) costs, savings associated with the use of cheaper fuels (i.e., HFO or LNG), and summary measures of payback and net present value (NPV). However, the confidence that can be placed in economic feasibility comparisons of marine compliance strategies at the present time is substantially limited by the immaturity of the technologies associated with two of the key strategies: exhaust scrubbers and LNG propulsion systems. While these strategies have been applied to land-based systems for decades, they have only been applied to relatively few ships within the last few years. The harsh marine environment (e.g., corrosive seawater), tight space limitations, and a high degree of design customization on marine vessels are significant factors to which manufacturers must adapt their products. Marine sulfur scrubbers and SCR systems and LNG propulsion systems can be described as being in the demonstration phase of development. Although multiple products are on the market for these strategies, it is estimated that there were fewer than 100 ships with LNG propulsion systems in 2013.[57] With respect to scrubbers, according to the Exhaust Gas Cleaning Systems Association, as of November 2014, there are around 300 scrubber systems installed or on order, with greatest growth among ferries, cruise ships, and roll-on/roll-offs that spend a substantial portion of their time in ECAs.[58] Experience with SCR on marine vessels is more substantial – it has been applied to marine vessels for about 25 years, primarily as a retrofit. In 2013, there were 519 vessels operating with SCR worldwide.[59] With a longer history of marine applications, and installation costs that are roughly one-tenth the costs for scrubbers, SCR represents a much lower financial risk than sulfur scrubbers or LNG, and is only needed for new builds beginning in 2016.

The tight profit margins associated with the highly competitive shipping industry mean the risks associated with adoption of a multi-million-dollar new technology can make or break a shipping company. With this understanding, a cautious adoption of scrubbers and LNG propulsion systems is expected, and most shippers will "test" one or both of these new technologies on a few of their vessels before making firm decisions regarding adoption for the remainder of their fleet. Further, since sulfur scrubbers and LNG substitution are strategies that comply with the 0.1% fuel sulfur requirements for both existing and new-build vessels operating in ECAs, retrofits are viewed as a key near-term developing market for these strategies in addition to new-builds. While some new builds on order incorporate sulfur scrubbers or LNG propulsion systems, others are being dubbed as "LNG conversion-ready" and "scrubber-ready," thereby postponing the determination of an optimal compliance strategy.[60]

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[57] Shaw, Jim, May 1, 2013. "Propulsion: Is LNG the Future?" Pacific Maritime Magazine, http://www.pacmar.com/story/2013/05/01/features/propulsion-is-lng-the-future/152.html

[58] The Maritime Executive, November 30, 2014. "Scrubber Sales Accelerate." http://www.maritime-executive.com/article/Scrubber-Sales-Accelerate-2014-11-30

[59] Alyson Azzara, Dan Rutherford, Haifeng Wang, March 2014. "Feasibility of IMO Annex VI Tier III implementation using Selective Catalytic Reduction," ICCT Working Paper 2014-4, http://www.theicct.org/sites/default/files/publications/ICCT_MarineSCR_Mar2014.pdf

[60] Ship & Bunker, September 17, 2014. "Construction Underway for "LNG-Conversion-Ready" Eco-Tankers," http://shipandbunker.com/news/am/519431-construction-underway-for-lng-conversion-ready-eco-tankers

Common reasons for postponing selection of LNG and scrubber strategies include the lack of technology maturity for both of these strategies; uncertainty in regulations for LNG bunkering as well as for scrubber waste handling and disposal;[61] the availability of trained crews (for both LNG and scrubbers); LNG fuel availability; and uncertainty in fuel price.[62] While the general difference in HFO and MDO fuel prices is typically viewed as likely to continue, the magnitude of this difference is more uncertain, and there is yet more uncertainty in the relative price of LNG both over time and among global regions. The recent introduction of new financial instruments that shift fuel price risk from ship owners (or charterers) to financiers who pay for LNG or scrubber capital costs and collect the fuel savings as borrowers pay for the MDO that would have been burned[63] may help to reduce the current avoidance of strategy selections that promise long-term savings.

Many analysts are suggesting that the optimal compliance strategy will vary by individual ship depending on typical routes, proportion of time traveling in an ECA, frequency of use on other routes, engine design (i.e., ease of conversion to LNG), vessel design and balance,[64] and vessel age. With respect to routes, the availability of fuel and maintenance services will influence strategy selections, and percent time in an ECA will substantially affect the magnitude of potential fuel savings and associated payback for both scrubbers and LNG.

While it will take years for adoption of strategies using currently immature technologies to become a significant portion of the OGV fleet, the technology options suggest the possibility that the marine transportation sector may ultimately demand three primary fuel types: distillate fuel, residual fuel, and LNG.

C.2 Projections of LNG and Scrubber Adoptions

Both scrubbers and LNG strategies are thought to be at the beginning of the traditional technology adoption “S-curve.” Several studies have projected that the adoption of scrubbers and LNG will initially be greatest among inland and coastal fleets that spend most of their time in ECAs or in regions with ECA-equivalent regulations (i.e., inland US waterways) where it would be easiest to build out the LNG bunkering. Regional liners with fixed routes are among the key targets for LNG. Some analysts suggest that scrubbers will be more prevalent in the regional European Union (EU) fleet than in the U.S., where LNG prices are expected to be more favorable.[62,63] The more expensive closed-loop or hybrid scrubbers associated with low alkalinity (fresh) water supplies will also facilitate LNG competitiveness in inland waters.

A number of groups have developed models for examining compliance strategy economics with regard to LNG market penetration, and some of these extend their analyses to project strategy

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[61] Maritime Denmark, November 12, 2014. “Shipowners want information on scrubbers.” http://www.maritimedenmark.dk/?Id=18087
[62] Semolinos, Pablo, et al., 2013. LNG as marine fuel: Challenges to be overcome. 17th International Conference and Exhibition on Liquefied Natural Gas (LNG17), Houston, TX, April 16-19, 2013. http://www.gastechnology.org/Training/Documents/LNG17-proceedings/7-2-Pablo_Semolinos.pdf
[63] Ship & Bunker, June 26, 2014, "Industry Insight: Financing the Cost of ECA Compliance," http://shipandbunker.com/news/features/industry-insight/263088-industry-insight-financing-the-cost-of-eca-compliance
[64] Some vessels may become unstable with the additional weight of a scrubber(s) at the top of the exhaust stack, others may not have enough space in the funnel casing for a scrubber system, and still others do not have the space to accommodate the larger footprint needed for LNG.

adoption over time. These collective results are summarized below for the next five years and then the subsequent ten years (2020 to 2030).

***2015 to 2020* --** Inland ships and short sea ships (coastal shipping) with fixed routes are expected to be the first significant adopters of scrubber and LNG strategies due to the more rapid payback for vessels that operate almost entirely in regions with ECA-equivalent regulations.[62,65,66] There will be a preference for LNG among vessels that are unable to install scrubbers due to design and stability issues (i.e., more common among ferries, roll-on/roll-offs, and product tankers).[62] Other analysts have identified ferries and offshore supply vessels as prime candidates for the initial phase of LNG adoption in the U.S.[67]

A study by DNV that considers global LNG bunker demand for new-build OGVs estimates that in 2020, LNG demand will be in the range of 8 to 33 million tons per annum (Mtpa), or 400 to 1,700 TBtu/yr. Corresponding HFO demand is estimated to be 80 to 110 million tons (13,000 to 20,000 ships with scrubbers) assuming the global sulfur rule begins in 2020. Other analyses that consider a wider range of vessel types suggest more favorable economics for LNG among small and mid-size ships versus large and very large ships.[62,65] The expected proportion of new-builds versus retrofits is expected to vary among vessel types and will likely be determined by both fuel price spreads and early reports of experiences with both scrubbers and LNG. A study by Angola LNG and Total that considers vessel types and adoption behaviors estimates that by 2020, bunker LNG demand will be in the range of 3 to 5 Mtpa (150 to 250 TBtu/yr) in North America and 5 to 8 Mtpa in Europe.[62] While these total LNG demand estimates are similar to DNV's 2020 low-end LNG demand estimates, the critical distinction is where the demand is located. In the view of the Angola LNG and Total paper, smaller ports will gradually develop sufficient LNG demand to invest in larger LNG bunkering operations that will facilitate LNG adoption among deep-sea liners in the next decade.

***2020 to 2030* --** After LNG becomes available in several ports in a region (i.e., North America, Europe and Asia), some short sea ships without fixed routes may begin to convert as well as some deep sea liners (intercontinental shipping). The latter, in particular, are expected to be primarily new or recently built vessels designed to be "conversion-ready." Major container-ship operators will begin ordering a few LNG ships to test this strategy, and if the tests prove positive, will likely diversify their fuel and technological risks by switching part of their fleet to LNG.[62] However, the need for route flexibility limits the use of LNG among deep sea very large crude carriers (VLCCs) and bulk carriers, suggesting a higher rate of scrubber use among these categories.

A study by Marine and Energy Consulting has projected that globally about 6,000 marine scrubber systems will operate on ships by 2025, consuming 28 million metric tons of HFO per year (a slower adoption rate than the low end of 80 million tons estimated by DNV for 2020). The Marine and Energy Consulting study also suggests that in 2025, about 1,700 smaller vessels

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[65] Andersen, Mads Lyder *et al*., 2011. "Costs and benefits of LNG as ship fuel for container vessels: Key results from a GL and MAN joint study." http://www.gl-group.com/pdf/GL_MAN_LNG_study_web.pdf
[66] Zeus Intelligence, May 27, 2014. "LNG Ready: The Key to Deep-Sea LNG Fuel?" http://member.zeusintel.com/ZLFMR/news_details.aspx?
[67] Zeus Intelligence, July 23, 2013. "Economic Analysis of LNG Vessel Costs in North America," http://member.zeusintel.com/ZLFMR/news_details.aspx?newsid=30096

will consume 8 Mtpa (400 TBtu/yr) of LNG, representing about 11% of total bunkers.[68] In contrast, the study by Angola LNG and Total estimates that by 2030, global bunker LNG demand will be considerably higher, in the range of 20 to 30 Mtpa (1 to 1.5 QBtu/yr).[62]

C.3 Compliance Strategy Cost Estimation

The three Tier III compliance strategies could employ a total of four technologies: LNG propulsion systems, exhaust scrubbers, MDO adaptations, and SCR (the latter of which is used in conjunction with the previous two technologies). The additional uncertainties that surround the use of immature technologies for scrubbers and LNG compliance strategies limit the confidence in cost estimates for these strategies. Technology improvements in production and installation of engines and fuel systems are expected to largely decrease the installation costs for LNG and scrubbers, reducing the payback period for projects. The costs provided in this section do not attempt to adjust for anticipated cost-reductions as these technologies mature. Costs associated with each of the four technologies are briefly discussed below followed by a summary table of "typical" costs for the technology (Table C- 1).

MDO Adaptation **--** Most OGV are designed to operate on HFO, but can burn MDO with the addition of a fuel cooler or chiller and associated piping prior to the fuel pump to decrease fuel viscosity.[69] This retrofit typically requires about fourteen days in the shipyard.[70] The cost of modification for a medium range tanker (38,500 dwt, 9,4800 kW MCR) to use MDO has been estimated to be around $800,000, including the fuel cooler, piping, shipyard services, etc.[70] This cost will vary with vessel size and design, and the ability to include this conversion during regularly scheduled shipyard visits. MDO is already available in ports and there are no problems regarding regulations, logistics or operations. However, if demand for MDO rises significantly, infrastructure expansions would be needed, and refining balances in some regions may be disrupted with resulting price impacts until new equilibriums are established.[71] This increases the fuel price risk for operating with MDO.

SCR **--** The costs of SCR are driven by capital costs, which vary with engine design. In general, the larger the engine, the less expensive the installation costs per kW. SCR operating expenses are dominated by the cost of the reducing agent (urea). Additional operational costs are incurred for catalyst replacement (typically every five or six years) and for the additional fuel consumption associated with SCR use.[72]

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[68] Ship & Bunker, April 7, 2014. "$15 billion in Scrubber Sales Predicted by 2025," http://shipandbunker.com/news/world/707962-15-billion-in-scrubber-sales-predicted-by-2025

[69] The International Council on Combustion Engines (CIMAC), 2013. "Guideline for the operation of marine engines on low sulfur diesel," http://www.cimac.com/cms/upload/workinggroups/WG7/CIMAC_SG1_Guideline_Low_Sulphur_Diesel.pdf

[70] Kotakis, Nikolaos K. 2012, "Cost Comparative Assessment Study between Different Retrofit Technologies applied on Model Ship to Conform to IMO MARPOL 73/78, Annex VI, Reg. 14," Masters Thesis, University of Greenwich. https://www.academia.edu/8507275/Cost_Comparative_Assessment_Study_between_Different_Retrofit_Technologies_applied_on_Model_Ship_to_Conform_to_IMO_MARPOL_73_78_Annex_VI_Reg._14

[71] It should be noted that refining balance issues are more commonly cited as a concern for Europe than for North America.

[72] IACCSEA, 2012. "White Paper: The Technological and Economic Viability of Selective Catalytic Reduction for Ships", http://www.iaccsea.com/fileadmin/user_upload/pdf/iaccsea_white_paper.pdf .

In a study of the North Sea fleet adoption of NO_x strategies, technologies considered include SCR, EGR, and LNG.[36] The analysis did not require application of the same technology to both the main and auxiliary engines. It was found that for 2-stroke engines, annual total (i.e., levelized) costs of EGR were only 68% of the SCR costs (on average), while SCR costs for 4-stroke engines were 83% of EGR costs.[73] Levelized costs of the most cost-efficient NO_x strategy were found to vary greatly by both ship size and type. In the North Sea Fleet analysis, the fleet's total compliance costs were estimated for comparison to total benefit costs, and compliance capital costs were linked to the number of new ships projected to be built from 2016 to 2030, with consideration of efficiency changes and slow steaming. Throughout the analysis timeframe, fuel and capital costs represented 12-14% and 58-59% of the total costs, and the non-fuel operating costs ranged from 27-30%. This distribution suggests that fuel price changes over time are a relatively minor cost component for NO_x compliance.

With respect to capital costs for SCR installation on 2-stroke, slow speed engines, the following linear relationship to engine size has been found (using Euros): €/kW = -0.71a + 59.5 where "a" is the engine size (kW).[36] This relationship suggests a relative reduction in SCR cost with engine size.

Sulfur Scrubbers -- The capital costs of scrubber installation vary significantly with vessel design. Scrubbers may treat one or more engines. Scrubber retrofit costs are increased when there is a need for major modification of the ship's exhaust funnel to accommodate the scrubber system. Advances in both scrubber size reduction and multi-streaming configurations that enable the use of one scrubber unit for multiple engines[74] and varying loads are promising developments for capital cost reductions. Furthermore, new scrubber designs that are lighter and lower the system's center of gravity enable compatibility of scrubber systems on a wider range of existing vessels.

The retrofit of a typical vessel with a 10-MW engine includes around 25 days in the shipyard, with roughly half of the installation costs associated with the scrubber system equipment, and the remainder for the shipyard account, certifications, inspections, etc.[70,75] Initial scrubber purchases were dominated by open-loop designs, but hybrid scrubbers are becoming more common to provide the greatest flexibility in routes by enabling travel in ECA coastal and inland waters with low alkalinity. Recognizing this trend, the cost summary table below (Table C- 1) assumes a hybrid scrubber, which typically costs around 20% more than an open loop scrubber.[76]

In addition to capital costs, the use of scrubbers has incrementally higher operating costs due to the added logistics and maintenance for water treatment products and sludge management, and

[73] In general, 2-stroke engines are more common for the main engines of larger vessels, while 4-stroke engines are more common for auxiliary engines and smaller vessel main engines.
[74] Exhaust Gas Cleaning Systems Association (EGCSA), November 18, 2014. "CR Ocean Industries Scrubber – Lighter, Smaller, More Efficient," http://www.egcsa.com/another-egcsa-member-cr-ocean-engineering-llc/
[75] Nielsen, Christian Klimt and Christian Schack, 2012. "Vessel Emission Study: Comparison of Various Abatement Technologies to Meet Emission Levels for ECA's", 9th annual Green Ship Technology Conference, Copenhagen 2012. http://www.greenship.org/fpublic/greenship/dokumenter/Downloads%20-%20maga/ECA%20study/GSF%20ECA%20paper.pdf
[76] Aminoff, Tomas, 2014. "A glance at CapEx and OpEx for compliance with forthcoming environmental regulations," 16th Annual Marine Money Greek Forum, October 15, 2014, http://www.marinemoney.com/sites/all/themes/marinemoney/forums/GR14/presentations/1220%20Tomas%20Aminoff.pdf

fuel consumption increases of 1 to 3%. Over the years, new-generation scrubbers with more efficient operation resulting in less frequent catalyst replacement and a lower fuel penalty may gradually reduce these costs.[77] As scrubber technology for marine applications matures, both the capital and operating costs of this compliance strategy are expected to decrease in terms of real dollars.

Achieving a reduction of sulfur by using a wet scrubber means increasing power usage significantly to pump water.

LNG **--** The capital costs of new-build LNG vessels are currently estimated to be about 20% more than conventional vessels.[76] Approximately one sixth of the incremental capital costs for LNG relate to the vessel engines, while the remainder is for the LNG storage tanks, safety systems, and other ship modifications.[78] Vessel retrofits to use LNG typically take around 45 days, but this will likely be reduced for the new "conversion-ready" vessels. The immaturity of LNG technology for marine applications substantially limits the confidence in current engine and storage costs to be representative of capital costs several years in the future. For example, one engine manufacturer has claimed that their recently introduced LNG engine provides a 15 to 20% reduction in capital costs as a result of design improvements.[27]

The lower energy density of LNG compared to MDO and HFO means the fuel tank has a larger footprint. As such, conversion of existing vessels to LNG requires a higher threshold of fuel savings to compensate for greater cargo losses with LNG, which are of greatest concern for container ships and bulk carriers. The medium-sized container vessels (4,600 TEU to 8,500 TEU) are estimated to have the largest proportionate cargo losses, equivalent to as much as 3% of cargo capacity.[65] Cargo losses are reduced for new-builds that are designed for LNG use, and the ongoing development of membrane fuel tanks that conform to the ship's hull can further reduce cargo losses.[62] For retrofits, some types of tankers and roll-on/roll-offs are thought to be able to relatively easily install type C LNG storage tanks on the deck with no or minimal cargo losses.[62]

Maintenance costs for the LNG propulsion system are general estimated to be around 15% lower than those costs for conventional vessels,[76] but experience with these vessels has not been extensive enough to provide substantial field confirmation of the magnitude of this expected benefit. Other non-fuel operation costs such as crew and spare parts have been estimated to be 10% higher than for MDO.[65] Additional costs associated with the learning curve for use of a cryogenic fuel are also not well established.

LNG bunker costs include the regional LNG fuel price and port logistics costs. For ports with small LNG bunkering operations, these costs are estimated to be in the range of $2 to $3.5/MMBtu. Unit costs can be lower for larger ports but initial investment is higher, and the risk of overinvestment is viewed as particularly high when the market supplied is less than 0.25 Mtpa. An incremental growth in port capabilities for LNG bunkering is viewed as a means to control these risks, with initial bunker operations supplied by trucks. Investment in port infrastructure for LNG buffer storage, LNG bunker vessels, and port-side liquefaction becomes more appealing as LNG bunker demand approaches and exceeds 1 Mtpa.[62]

[77] Exhaust Gas Cleaning Systems Association (EGCSA), November 18, 2014. "CR Ocean Industries Scrubber – Lighter, Smaller, More Efficient," http://www.egcsa.com/another-egcsa-member-cr-ocean-engineering-llc/
[78] American Clean Skies Foundations (ACSF), 2012, Natural Gas for Marine Vessels, US Market Opportunities," http://www.arcticgas.gov/sites/default/files/documents/2012-clean-skies-lng-marine-fuel.pdf .

The table below provides typical costs for each of the discussed compliance strategies for an average vessel with a 10-MW main engine. The point costs shown in this table are an average of the referenced sources, which are for engines within 20% of the target size (i.e., 10 MW).

Table C- 1. Typical Preliminary Cost Estimates for an "Average" Ship with a 10,000 kW Engine

Control Option	Capital Costs		Incremental Operating Costs *(non-fuel, 100% time in ECA)*	
	$ millions	*Source*	$ millions/ year	*Source*
MDO *(i.e., fuel chiller and piping)*	0.8	*a*	*minimal*	
Scrubber (hybrid)	6.5	*a, b, c, e*	0.1 *(sludge handling)* 0.1 *(catalyst, levelized cost)* 0.2 *(caustic soda)*	*c, e*
LNG	9.3	*a, b, c*	*15% maintenance reduction*	*e*
SCR	0.5	*d*	0.2 *(urea)*	*c, d*

a. Kotakis, Nikolaos K., 2012. "Cost Comparative Assessment Study between Different Retrofit Technologies applied on Model Ship to Conform to IMO MARPOL 73/78, Annex VI, Reg. 14," Masters Thesis, University of Greenwich. https://www.academia.edu/8507275/Cost_Comparative_Assessment_Study_between_Different_Retrofit_Technologies_applied_on_Model_Ship_to_Conform_to_IMO_MARPOL_73_78_Annex_VI_Reg._14

b. Nielsen, Christian Klimt and Christian Schack, 2012. "Vessel Emission Study: Comparison of Various Abatement Technologies to Meet Emission Levels for ECA's", 9th Annual Green Ship Technology Conference, Copenhagen 2012. http://www.greenship.org/fpublic/greenship/dokumenter/Downloads%20-%20maga/ECA%20study/GSF%20ECA%20paper.pdf

c. Hagedorn, Matthias, 2014. "LNG Engines, Specifications, and Economics", Rostock LNG Value Chain Seminar, Klaipeda 2014. http://www.golng.eu/files/Main/20141017/Rostock/LNG%20Shipping%20Session%20II%20-%20LNG%20Engines-Specifications%20and%20Economics-%20W%C3%A4rtsil%C3%A4,Ship%20Power%20-%20Hagedorn.pdf

d. International Association for Catalytic Control of Ship Emissions to Air (IACCSEA), Marine SCR – Cost Benefit Analysis. http://www.iaccsea.com/fileadmin/user_upload/pdf/SCR_cost_calculation_model2_v1.pdf

e. Aminoff, Tomas, 2014. "A glance at CapEx and OpEx for compliance with forthcoming environmental regulations," 16th Annual Marine Money Greek Forum, October 15, 2014, http://www.marinemoney.com/sites/all/themes/marinemoney/forums/GR14/presentations/1220%20Tomas%20Aminoff.pdf

Appendix D. Computation of Port Times

During the time a ship is at anchor or is at berth the main propulsion engine is usually shut down, but the auxiliary power units continue to operate. Initially the combined time at anchorage and in port was assumed to be 72 hours. The time the ship spends in port is usually dependent on the time it takes to load/unload the ship and contingent on the volumes involved and the efficiency of the loading/unloading operations. Both times at anchor and times in port are impacted by peak loading periods. While port data are not available from all ports regarding these times, there are sufficient data available to better approximate these times by terminal types (i.e., large west coast container terminals, large east coast container terminals petroleum terminals, and coal loading terminals).

Ships are sometimes diverted to ship anchorages in or near the port prior to going to the terminal where they will load or unload cargo. The primary reason for going to an anchorage is that the ship berth at the destination terminal is not available (another ship is there). Other reasons include the need to wait until high tide if channel depth is not adequate, or the U.S. Coast Guard requires a ship inspection prior to the ship entering port. The first two reasons for a ship going to anchorage are schedule-related and are avoided or minimized, in most cases, by proper planning. Inspections by the Coast Guard do not normally require the ship to go to anchorage ‘unless there is a compelling reason (high interest vessel, specific intelligence, or other intelligence that renders the risk of a vessel entering port to be high without a Coast Guard exam for safety and/or security); the exams will be conducted either in port or sometimes while *en route* to the facility.’[79] Because of the infrequency associated with anchorage, anchorage times are not reflected in the calculations.

D.1 Container Ships

Port times for container ships were based on berth productivity rates (container handling speed) and volume of containers moved/handled.[80] A Journal of Commence sponsored study[81] determined that berth productivity was generally based on the average ship size (capacity) being worked. MARAD data[5] was used to calculate the average ship size (in TEUs) for each of the 32 ports that were used to estimate the port times for the model. Six ports also had berth productivities listed in the white paper. By assuming two eight-hour shifts for loading/unloading, the berth productivity per day was computed by multiplying by sixteen hours per day. The time in port was computed by dividing the number of TEU handled per call by the berth productivity (TEU per day).

The number of containers moved when a ship calls on a port includes containers being offloaded, loaded, or repositioned on the ship. In theory, a port can unload and load 200 percent of a

[79] Email from USCG headquarters on February 24, 2015; Michael.L.Blair@uscg.mil

[80] Berth arrival and departure refer to “lines down” and “lines up” — that is, the actual arrival and departure of the ship at berth. The calculation of moves per hour between these two times is referred to as unadjusted gross berth productivity.

[81] JOC Group Inc. “Berth Productivity: The Trends, Outlook and Market Forces Impacting Ship Turnaround Times,” July 2014. Accessed from http://www.joc.com/whitepaper/berth-productivity-trends-outlook-and-market-forces-impacting-ship-turnaround-times-0.

vessel's capacity (100% off, 100% on) in one port call.[82] An American Association of Port Authorities (AAPA) Advisory[83] was used to determine the total number of TEUs handled at the individual container ship ports. The number of containers handled in each port divided by the daily berth rate and number of container ship port calls yielded the average port time in days for container ships.

Data on container handling at six ports (Anchorage, Honolulu, Palm Beach, San Diego, San Juan, and Wilmington Delaware) produced outcomes that did not align with normal practices, so the schedules for those ports were examined in greater detail in order to compute the true times spent in port. Explanations for their deviations from standard container ship operations revealed that those average ships had not spent an inordinate number of days in ports, and the port times were adjusted based on reported values rather than on berth productivity.

The call-weighted average port times for the 32 ports were computed to be 1.8 days for container ships.

Note that fuel usage during port times has decreased significantly in California in recent years based on regulation requiring shore power[84] at the Ports of Hueneme, Los Angeles, Long Beach, Oakland, San Diego, and San Francisco.[85] This regulation affects the corporate fleets as follows:

- From 2014 through 2016, at least fifty (50) percent of the fleet's visits to the port shall connect to shore power.
- From 2017 through 2019, at least seventy (70) percent of the fleet's visits to the port shall connect to shore power.

State regulations were not the subject of this investigation, but adjustments could be made to the calculations to account for such measures in the years beyond the baseline. Connecting to shore power, also referred to as 'cold ironing', is a fairly rare occurrence outside of container and cruise ship terminals in California. A few cruise ship terminals in Washington, Alaska, New York, and elsewhere have shore power, but there was no indication that cargo ships are using shore connection outside of California, with the exception of one cargo ship operator in Tacoma.[86]

D.2 Tanker Ships and Tank Barges

Port times were generally based on the "Allowed Laytimes" published by Exxon, Phillips 66, Shell, and APEX oil.[87] Allowed Laytimes are the lengths of time vessels may occupy berths at a

[82] Diagnosing the Marine Transportation System – June 27, 2012 Research sponsored by USACE Institute for Water Resources & Cargo Handling Cooperative Program www.tiogagroup.com/215-557-2142

[83] "NAFTA Region Port Container Traffic 2012." May 6, 2013. Published at http://aapa.files.cms-plus.com/Statistics/NAFTA%20REGION%20PORT%20CONTAINER%20TRAFFIC%20PROFILE%202012.pdf

[84] Section 93118.3 of Title 17, Chapter 1, Subchapter 7.5 of the California Code of Regulations. *Airborne Toxic Control Measure for Auxiliary Diesel Engines Operated on Ocean-Going Vessels At-Berth in a California Port.* Last accessed from http://www.arb.ca.gov/ports/shorepower/finalregulation.pdf, on February 27, 2015.

[85] The Ports of Hueneme, Los Angeles, Long Beach, San Diego, and San Francisco represented 73 percent of the 2012 dead weight tonnage of container ships in the Pacific Census Division (based on MARAD data).

[86] TOTEM Ocean Trailer Express uses shore power for two of its ships when they are in Tacoma; http://www.portseattle.org/Environmental/Air/Seaport-Air-Quality/Documents/nw_ports_clean_air_implementation_2013.pdf

[87] Information collected from multiple online documents: http://www.apexoil.com/mp.pdf, http://www.exxonmobil.com/files/corporate/bsa_marineprovisions_and_specialprovisions.pdf,

terminal in order to conduct transfer operations without incurring additional charges. Allowed Laytimes are essentially contract terms, often listed as 'Provisions for U.S. Delivery and Loading.' The contractual terms are fairly consistent across different companies. Tank barges are allotted 12-36 hours depending on size (24 hours was used for tank barge port time). If the average tank vessel calling on a port was 27,000 DWT (about 180,000 barrels) or less, the vessels were assumed to be barges.

All ports with larger average vessels were assumed to be tanker ships. Tanker ships are normally allotted 36 hours at berth. Exceptions to the standard port times were used for:

- Valdez Alaska (crude oil loading port) where 12 hours port times are documented, [88] and
- Louisiana Offshore Oil Port where published discharge rate requirements indicated 48 hours were necessary.[89]
- Offshore lightering areas: South Sabine Point and Galveston Lightering Areas (near Texas coast), the Southwest Pass Lightering Area (near Louisiana coast), and the Southern California Lightering Area (near California coast). Offshore lightering normally takes place 20 or more miles and involves transferring oil from Very Large or Ultra Large Crude Carrier (VLCC or ULCC) tank ships that are too large to come into port to four to six smaller tank ships (80,000 DWT). Oil is transferred one ship at a time while both ships move at 4 to 6 knots.[90] The VLCC or ULCC never actually enter the port. The smaller tank ships and the crude oil from the VLCC or ULCC do enter port and are recorded as ship arrivals. The VLCC or ULCC were excluded from the calculation of port times, but their activity levels within the ECAs may be a subject for future characterization.

The call-weighted average port times for 70 ports with tankers and tank barges were computed to be 35.9 hours, or 1.5 days.

D.3 General Cargo

General Cargo ships transport many types of cargos ranging from sacks, to drums, to oversized fabricated structures, as well as trees, and steel products such as rebar. The three ports with the most General Cargo ship port calls are: Houston, Philadelphia, and New Orleans. These ports represent about 30% of the General Cargo Ship U.S. port call in 2012. The Port of Houston states on their website that "the average turnaround time for a ship at the terminal (General Cargo) is two to three days." Philadelphia does not list average turnaround times on their website, but a review of vessel AIS data[91] for ships that departed between February 27 and March 2, 2015 indicated the average turnaround time was 65 hours. The port operations

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http://www.phillips66.com/EN/products/Documents/Phillips%2066%20Crude%20Oil%20Marine%20Provisions.pdf, and http://www.shell.com/content/dam/shell-new/local/corporate/corporate/downloads/doc/shell-trading-company-domestic-marine-crude-oil-may-2013.pdf

[88] Marine Exchange of Alaska. "Valdez Harbor Information." From http://www.mxak.org/ports/southcentral/valdez/valdez_facilities.html, the transfer rates from fixed platform were 100,000 bbl/hr and from floating units were 80,000 bbl/hr.

[89] Loop LLC. "Tanker Offloading Services." From https://www.loopllc.com/Services/Tanker-Offloading, the tank ships of 170,000 DWT or greater must have a minimum average discharge rate of 43,000 bbl/hr.

[90] Center for Tankship Excellence. "CTX Glossary." From http://www.c4tx.org/ctx/gen/glossary.html

[91] MarineTraffic. "Live Map." http://www.marinetraffic.com/

manager at the Port of New Orleans stated in an email[92] that "Within the Port of New Orleans jurisdiction, most general cargo ships are container and break-bulk vessels. Container ship average 1-1.5 days, while break bulk ships average 2-3 days." Based on the ranges stated above, an average port time for General Cargo ships of 62 hours (2.6 days) was used.

D.4 Roll-On/Roll-Off Vessels

The configuration of roll-on/roll-off ships varies significantly. Some roll-on/roll-off ships are designed specifically to only transport automobiles, others are designed to transport truck trailers and intermodal containers on truck chassis, and some are designed to transport truck trailers, containers and break bulk cargo. A review of vessel tracking data[93] was conducted for the ports of Baltimore, Jacksonville, New York, Brunswick Georgia, Tacoma, Norfolk (Hampton Roads), and Portland (Columbia River). These ports accounted for 3276 of the 6247 roll-on/roll-off vessel port calls in 2012. An average port time for roll-on/roll-off vessels of 21 hours was observed. In general it appeared that roll-on/roll-off vessels moving only vehicles (cars, trucks, and trailers) were in port 12 to 16 hours and mixed use roll-on/roll-off vessels were in port 24 to 30 hours.

D.5 Gas Vessels

Gas vessels include both LPG and LNG ships. The allowed laytime for an LNG ship at the Sabine Pass Terminal is 36 hours.[94] At the Lake Charles LNG terminal the allowed laytime is 24 hours.[95] The 'Report to Cook Inlet Risk Assessment Advisory Panel, version: January 2012" reports that LNG ships calling on the ConocoPhilips LNG loading terminal in Alaska during 2010 spent 36 days in the Cook Inlet to conduct 12 port calls (average 3 days in the Cook Inlet). Since the terminal is 115 nm up the Inlet (230 nm round trip) it would take the ship about 29 hours to transit in and out of the Inlet (leaving an average of 42 hours berth time for each ship at the terminal). Based on these data, LNG ships were assumed to be in port 36 hours for each port call.

At this time LNG ships generally load at a single port and unload at another single port. On the other hand, LPG ships may carry products destined for multiple ports, but ascertaining which ships would be resource-intensive. Because little data were available for LPG ship laytimes, the port times for LPG vessels were conservatively chosen to match those for the LNG ships conducting full loading/unloading (36 hours or 1.5 days).

[92] Email from: Paul Zimmermann [ZIMMERMANNP@portno.com] 3/2/2015 to O'Malley, Steve J. (Leidos) on Monday, March 2, 2015 1:58 PM
[93] For the period 2/26/2015 – 3/1/2015, this period included 43 port calls, http://www.marinetraffic.com/ais/details/ports/1326/USA_port:BRUNSWICK
[94] U.S. Securities and Exchange Commission. "Master Ex-Ship LNG Sales Agreement Between Cheniere Marketing, Inc. and Gaz de France International Trading S.A.S." http://www.sec.gov/Archives/edgar/data/3570/000119312507106384/dex102.htm
[95] Decker, John. Letter to Sally Kornfeld, U.S. Department of Energy. Last accessed online at http://www.fossil.energy.gov/programs/gasregulation/authorizations/2004_Applications/04-40-LNG.pdf on March 5, 2015.

D.6 Bulk Vessels

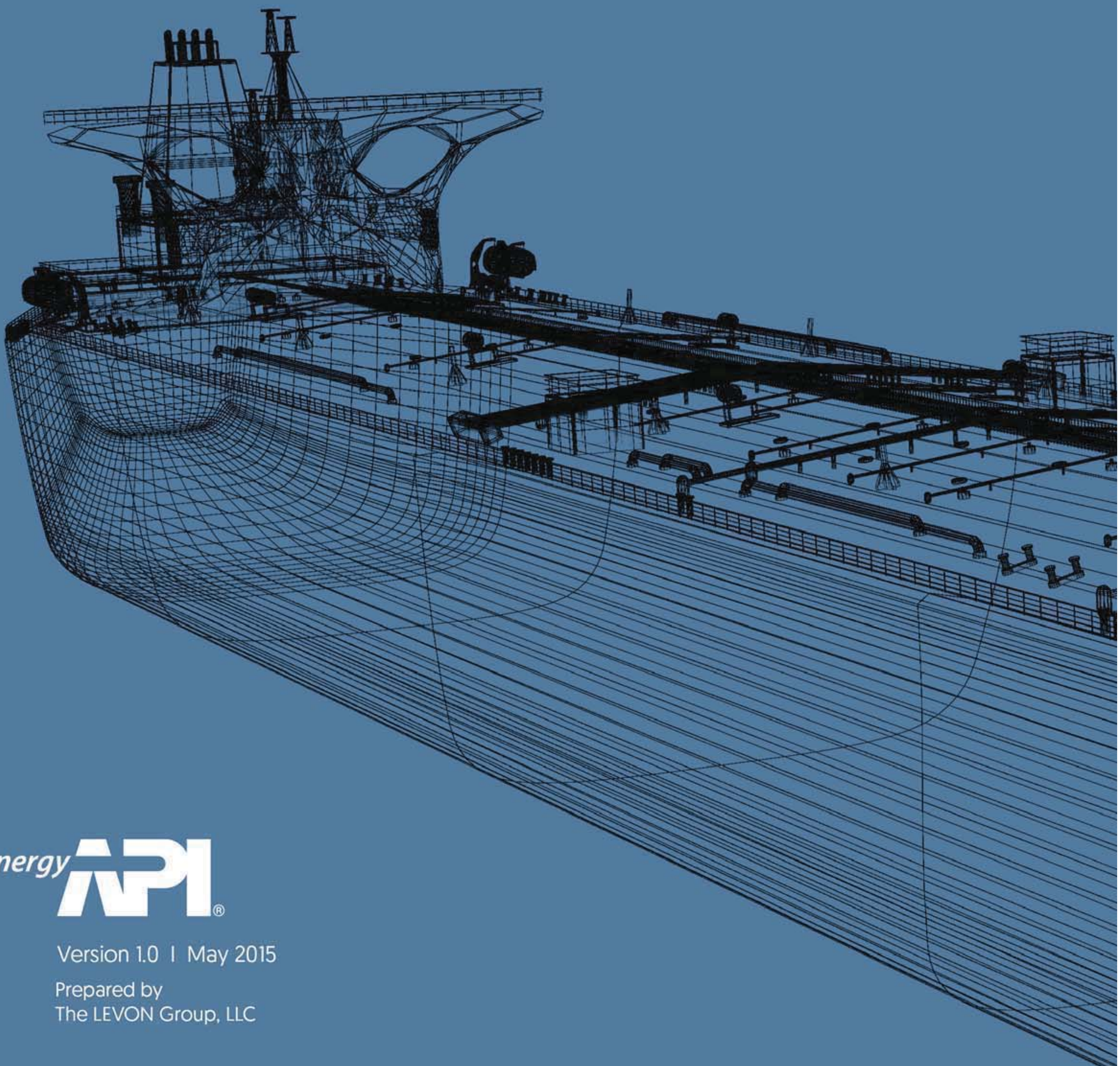
The average DWT and ship capacity (in tons) was calculated for 65 ports using the U.S. Maritime Administration's 2012 Total Vessel Calls in U.S. Ports, Terminals and Lightering Areas Report.[5] The average DWT was multiplied by 0.85 in order to estimate cargo capacity of the ships.[96] The rate at which bulk cargo would be loaded or unloaded is based on ton-per-hour (tph) rates posted by the ports[97] (assumed to be 800 tph if no information was posted). All posted rates are multiplied by 80 percent for probable efficiency unless the posted rates are actual averages. In addition, preparation times of four hours were added to the computations.[98]

The call-weighted average port times for 65 ports with bulk cargo vessels were computed to be 47.9 hours, or 2.0 days.

[96] Agerschou, Hans. Planning and Design of Ports and Marine Terminals, 2nd Edition, 2004, Thomas Telford Publisher

[97] The web site www.worldportsource.com provided the data or provided a link to the specific port website

[98] The preparation times were already included in the calculations for the other types of vessels when reporting laytimes and berth productivity.



energy API

Version 1.0 I May 2015

Prepared by
The LEVON Group, LLC

Liquefied Natural Gas (LNG) Operations

Consistent Methodology for Estimating Greenhouse Gas Emissions

FOREWORD

The American Petroleum Institute (API) has extensive experience in developing greenhouse gas (GHG) emissions estimation methodology for the Oil and Natural Gas industry. API's Compendium of GHG Emissions Methodologies for the Oil and Gas Industry (API Compendium) is used worldwide by the industry and is referenced in numerous governmental and non-governmental protocols and procedures for calculating and reporting GHG emissions.

The API Compendium includes methods that are applicable to all sectors of the Oil and Natural Gas Industry from the exploration and production at the wellhead through transmission, transportation, refining, marketing and distribution. API has developed this document in order to enable consistent and comprehensive internationally-accepted methodologies to estimate GHG emissions from the liquefied natural gas (LNG) operations segment including its specialized facilities, processing techniques, and associated infrastructure.

API's objectives in developing this guidance document are:

- Develop and publish technically sound and transparent methods to estimate GHG emissions from LNG operations, accounting for the diversity of operations;
- Align methodologies with API Compendium structure and organization;
- Maintain consistency with globally recognized GHG accounting systems and those in LNG importing and exporting countries.

The guidance document is organized around four main chapters:

1. LNG Overview
2. LNG Sector Background
3. GHG Emissions Inventory Boundaries
4. Emission Estimation Methods

Supplemental information is provided in five appendices:

A - Glossary of Terms

B - Unit Conversions

C - Acronyms

D - Global Warming Potential (GWP)

E - Emission Factors Tables for Common Industrial Fuels

This document is released now as a “Pilot Draft” for one year to encourage broad global testing of the approach and to gather feedback from early users. API is also seeking comments through participation in public forums and presentation of the methodology. Following this ‘pilot’ period of feedback collection API will revise the relevant chapters of the document and publish a final guidance document based on feedback received.

API has initiated this effort as part of its contribution to the Asia Pacific Partnership for Clean Development and Climate Change, where it participated in the Cleaner Fossil Energy (CFE) Task Force as part of a project that aimed to evaluate GHG emissions from LNG operations that may lead to technological fixes to minimize natural gas wastage, reduce GHG emissions, and improve energy efficiency.

ACKNOWLEDGEMENT

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American Petroleum Institute

Washington DC

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1.0 OVERVIEW

With increased scrutiny of greenhouse gas (GHG) emissions from the consumption of fossil fuels, there is a growing realization that the consumption of natural gas, including its use as a fuel for electricity generation, is set to rise. Growing global need for liquefied natural gas (LNG) to supplement regional natural gas supplies will lead to increased levels of activities to liquefy, ship, store and regasify LNG for its ultimate use. LNG – as a clean energy alternative – will play an increasingly important role in helping nations improve their air quality and ensure a secure and diverse energy supply in the coming years.

1.1 LNG Applications

There are a diverse range of applications that can use LNG, and in its liquefied form it is ideal for transporting natural gas over large distances to bring it to consumers. Important applications of LNG include power generation; industrial and residential demand; storage of natural gas to balance out peaks in market demands; fuel for road, rail, and marine transportation.

1.1.1 Power Generation

Sourcing of LNG for power generation enables many regions and countries to switch their power generation systems to natural gas. LNG as a globally traded commodity is being made available over long distances by efficient transportation of an energy-dense liquid from its point (or country) of origin to be regasified and used in the natural gas delivery system throughout intended power markets globally. This global reach makes it possible to increase the use of natural gas while lessening reliance on more carbon-intensive fossil fuels. According to the U.S. EPA[1] burning of natural gas results in lower quantities of nitrogen oxides, carbon dioxide and methane emissions, where the latter two are greenhouse gases.

Global transport of LNG is predicated on close attention to the regional difference of the heating values of distributed natural gas with which the regasified LNG must be compatible:

- Asia (Japan, Korea, Taiwan – distributed gas typically has an HHV that is higher than 1,090 BTU/SCF (40.6 MJ/m^3)[2],

[1] U.S. EPA, Clean Energy, Natural Gas, http://www.epa.gov/cleanenergy/energy-and-you/affect/natural-gas.html
[2] Multiply BTU/SCF by 0.037259 to get MJ/m^3

- U.K. and the U.S. - distributed gas typically has an HHV that is less than 1,065 BTU/SCF (39.7 MJ/m^3),
- Continental Europe - the acceptable HHV range is quite wide: 990 – 1,160 BTU/SCF (36.9 to 43.2 MJ/m3).

Several methods may be used to modify the heating value of regasified LNG so it can be adjusted to the desired level. For example, increasing heating value can be accomplished by injecting propane and butane into the gas. Conversely, to decrease natural gas heating value, nitrogen can be injected. Blending different gas or regasified LNG streams can also lead to adjustment of the heating values to the desired levels.

The regional differences in heating value of the natural gas would need to be taken into consideration when accounting for GHG emissions from power generation using natural gas with varied carbon compositions and GHG emissions intensity per unit of thermal or electrical power production.

1.1.2 Natural Gas Storage (Peak-Shaving) Facilities

In the U.S., natural gas utilities and interstate pipeline companies operate "peak shaving" facilities where they liquefy and store pipeline natural gas for use during high demand periods. Such "peak shaving" typically relies on either trucking LNG for storage at local utilities, or drawing from natural gas transmission or distribution pipelines during low demand periods for local liquefaction, storage, and later regasification when demand peaks. LNG from peak shaving facilities can be regasified for injection into the transmission or distribution grids when natural gas demand is high, or used directly as liquid fuel for transportation.

According to the EIA there are 105 "peak shaving" plants in the U.S that serve also as LNG storage facilities. These facilities primarily serve areas of the U.S. where pipeline capacity and underground gas storage are insufficient for periods of peak natural gas demand. These facilities are divided into two categories, those with and without liquefaction capabilities. The EIA lists 59 such facilities with the capacity to liquefy natural gas and store the LNG. This category of liquefaction facilities tend to be larger than the remaining "satellite" facilities that are located in 31 states across the U.S. and which rely on receiving LNG for storage directly in its liquid form.

The LNG peak-shaving facilities with liquefaction equipment are typically built to allow continuous liquefaction at a relatively low rate, and regasification amounting to about 10% of storage capacity every day of operation, thus increasing the natural gas delivery capacity of the system (storage and transmission pipelines) during high demand periods such as for winter cold snaps. The main sources of GHG emission from these facilities are expected combustion devices used for regasification and compressors operation.

1.1.3 Road, Rail and Marine Vessels

Over the past 15 years, the role of LNG as a fuel for heavy-duty vehicles has grown due to the emergence of economic incentives for alternative-fuel vehicles and tighter vehicle emission standards. Because of LNG's increased driving range relative to compressed natural gas, it is used in heavy-duty vehicles, typically vehicles that are classified as "Class 8" (33,000 - 80,000 pounds, gross vehicle weight). LNG is used primarily as fuel for refuse haulers, local delivery (grocery trucks), and transit buses.

LNG is an alternative fuel for the heavy-duty vehicle market, including delivery trucks, transit buses, waste collection trucks, locomotives, and multiple off-road engines. When compared to other fuels, LNG fueled heavy duty vehicles produce fewer emissions of nitrogen oxides (N_2O and NOx), particulate matter (PM), sulfur oxides (SOx), and carbon dioxide (CO_2). Nitrous Oxide (N_2O) is a greenhouse gas, whereas the mixture of nitrogen oxides denoted as NOx (primarily NO and NO_2) contribute to the formation of ground level ozone and are not considered greenhouse gases. A typical LNG-fueled truck will have 90% lower NOx and PM emissions than a diesel-fueled truck, 100% lower SOx emissions, and 30% lower CO_2 emissions.

The growing global concern over air pollution and greenhouse gas emissions from ships has driven regulatory change at the international level. The International Maritime Organization (IMO) has adopted regulations that (a) limit the sulfur content in marine fuels to reduce SOx emissions; (b) specify standards for new marine diesel engines to reduce NOx emissions; and (c) require new ships to meet an Energy Efficiency Design Index to reduce GHG emissions. These three changes, along with the price advantage of LNG over marine fuels, have driven a strong interest in LNG fueled vessels as a viable alternative to meet these new standards.

As of 2008 shipping emissions accounted for 2-4% of CO_2, 10-20% of NOx and 4-8% of SOx global emissions. LNG-fueled ships, in the gas burning mode, result in the elimination of essentially all SO_2 emissions, and leads to reduced NOx, CO_2, and PM emissions when compared to the emissions from a typical vessel powered by marine diesel. Consequently, the number of LNG-fueled non-carrier vessels is growing globally. These vessels represent all ship classes for a variety of applications such as: ferries, offshore service vessels, tugs, barges, patrol vessels, and tankers.

Due to LNG's high energy density its use is growing globally in many areas demanding high horsepower applications, including rail locomotives, tug boats, platform support vessels, inland waterway tow boats, mine trucks, hydraulic fracturing pumps and well drilling rigs.

1.2 LNG Greenhouse Gas Emissions

In 2006, the U.S. EPA commissioned a study to assess the contribution of LNG operations to methane emissions in the U.S[3]. The study concluded that current emission estimation methods might be over-estimating GHG emissions from LNG operations, and that despite some similarities between natural gas processes and LNG operations, there is a growing need to more fully characterize GHG emissions from the various segments of LNG operations.

As LNG becomes a more substantial fraction of the overall natural gas market, the need to characterize GHG emissions from the LNG operations chain is becoming more evident. The development of robust emission estimation methods for the different operational segments of the LNG sector would contribute to consistent assessment and reporting of GHG emissions for LNG operations.

For example, the 2011 U.S. GHG Inventory estimates that the contribution of methane from LNG operations amounts to close to 1.9 million metric tonnes (MMT) in units of CO_2 equivalent emissions (CO_2e), which represents 1.3% of methane emissions from all the segments that make up the Natural Gas Systems[4]. These emissions are due to fugitive emissions from station operations, along with venting and fugitive emissions from operating LNG compressors and engines. The LNG methane emissions is comprised of 1.5 MMT CO_2e from seventy (70) LNG

[3] ICF, 2006, "Methane Emissions from LNG Operations", Discussion Paper, November 7, 2006, Virginia, USA
[4] U.S. EPA, National Greenhouse Gas Emissions Data, "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2011", Annex 3, Washington DC, April 2013;
http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html

storage stations (including peak-shaving plants with liquefaction capacity), and 0.4 MMT CO_2e from the operation of eight (8) imports/export terminals.

This document is designed to provide guidance for the quantification of GHG emissions associated with operations along the LNG value chain, i.e. liquefaction; shipping; loading/unloading; regasification; and storage. The guidance provided includes:

- Mapping out of the GHG emission sources associated with the LNG operations chain;
- Compilation and description of relevant methods for estimating GHG emissions including generic emission factors that may be useful when site specific information is lacking.

The main GHGs considered in this document are CO_2 that is primarily associated with process heat and combustion emissions, and CH_4 that is primarily associated with venting, leakage and fugitive emissions. All other GHGs are of lower significance though they should be considered if they are relevant for specific circumstances or are subject to local requirements.

2.0 LNG SECTOR BACKGROUND

This section provides a brief description of LNG, its properties along with the "LNG operations chain." The material presented here defines the boundaries for this industry sector and the corresponding emission sources that will be included when estimating GHG emissions from LNG operations.

2.1 What is LNG?

Liquefied natural gas, or LNG, is simply natural gas in its liquid state. When natural gas is refrigerated to a temperature of about minus 160°C (or minus 260°F) at atmospheric pressure, it becomes a clear, colorless, and odorless liquid. This reduces its volume by a factor of more than 600, allowing it to be efficiently stored for multiple uses and transported in tanks by sea or land. LNG is non-corrosive and non-toxic but requires storage in specially-designed cryogenic tanks in order to maintain it in its liquid state. The density of LNG is roughly 0.41 to 0.50 kilograms per liter (kg/L), depending on temperature, pressure and composition, which is about half that of water (1.0 kg/L). Produced natural gas is composed primarily of methane (80 – 99 mol%) and generally contains up to 20 mole% total of ethane, propane and heavier hydrocarbons, and other minor non-hydrocarbon substances. Prior to the liquefaction process, natural gas is treated to remove essentially all of its non-hydrocarbon components (carbon dioxide, mercury, sulfur compounds, and water) with the exception of nitrogen, and some heavier hydrocarbons contained within the natural gas, resulting in an LNG composition that is typically over 95% methane and ethane with less than 5% of other hydrocarbons (ethane, propane, and butanes) and nitrogen. The nitrogen content of the LNG is reduced to typically one percent or less prior to storage at the liquefaction facility.

The composition of LNG is a function of the production formation from where the liquefied gas originates, and the market for which the LNG is intended. Its ultimate composition and heating value will depend on the processing (or gas "conditioning") steps employed for the removal of pentanes and heavier hydrocarbons to very low levels, and the natural gas heating value specifications for the intended markets of the LNG, which drives the decision of whether to include natural gas liquids (e.g. ethane, propane and butanes) removal capabilities in the overall liquefaction plant design. Many hydrocarbons in the hexane or heavier range are normally solids at LNG temperatures, and are relatively insoluble in LNG; hence, components such as benzene must be removed to a few parts per million to prevent them from freezing during the liquefaction process. Similarly, some pentane range hydrocarbons may also form solids at LNG temperatures and have limited solubility in LNG. When designing LNG liquefaction plants, great care is taken to make sure that solubility limits are considered for a range of possible feedstocks.

The data presented in Table 1 provides examples of selected compositions and heating values for LNG originating from different locations around the world[5].

Table 1. Selected LNG Compositions and Higher Heating Values for Different Origins (mole %)

SPECIES	ABU-DHABI	ALASKA	ALGERIA	AUSTRALIA	BRUNEI	INDONESIA	MALAYSIA	OMAN	QATAR RICH	TRINIDAD
N_2	0.11%	ND	0.28%	0.01%	0.00%	0.09%	0.32%	0.00%	0.19%	0.00%
CH_4	87.07%	99.80%	91.40%	87.82%	89.40%	90.60%	91.15%	87.66%	89.87%	92.26%
C_2H_6	11.41%	0.10%	7.87%	8.30%	6.30%	6.00%	4.28%	9.72%	6.65%	6.39%
C_3H_8	1.27%	ND	0.44%	2.98%	2.80%	2.48%	2.87%	2.04%	2.30%	0.91%
i-C_4H_{10}	0.06%	ND	0.00%	0.40%	ND	ND	0.70%	0.29%	0.41%	0.21%
n-C_4H_{10}	0.08%	ND	0.00%	0.48%	1.30%	0.82%	0.66%	0.30%	0.57%	0.22%
i-C_5H_{12}	0.00%	ND	0.00%	0.00%	0.00%	ND	0.01%	0.00%	0.01%	0.00%
n-C_5H_{12}	0.00%	ND	0.00%	0.00%	0.00%	0.01%	0.00%	0.00%	0.00%	0.00%
Total	100.00%	99.90%	100.00%	100.00%	99.80%	100.00%	100.00%	100.00%	100.00%	100.00%
HHV Gas (Btu/SCF)	**1,123.00**	**1,010.80**	**1,078.40**	**1,142.90**	**1,121.00**	**1,110.80**	**1,118.50**	**1,127.60**	**1,115.60**	**1,082.10**

Source: D. McCartney, Black & Veatch Pritchard, Inc., 2002

ND = Not Determined

For gas entering the LNG liquefaction facility, key quality concerns include CO_2 and sulfur content, in addition to nitrogen, water, and mercury. Due to the sensitivity of liquefaction facilities to mercury, gas sent to a liquefaction process is treated to ensure that it contains an extremely low concentration (sub-parts per billion) of this element. The specifications for pre-processing the gas feeding a liquefaction plant are more stringent than for pipeline gas; all impurities must be removed to levels much lower than needed for pipeline gas to prevent problems in the liquefaction process. Additionally, there is typically no gas treating facilities at

[5] D. McCartney, Gas Conditioning for Imported LNG, 82nd Annual Convention Gas Processors Association, San Antonio, Texas, March 11, 2002

LNG receiving terminals, so the LNG should be compatible with the specification of the sales gas at the receiving terminal.

For the product LNG that is shipped, or otherwise transported, quality specifications are primarily designed to address end-use considerations. For LNG that is intended to be blended with pipeline natural gas, consideration of the interchangeability of the gases distributed is important. The interchangeability of different natural gas streams can be represented using the Wobbe Index[6], which is coming into wider use in the U.S. as in the rest of the world.

2.2 LNG Operations Chain

The LNG operations chain consists of several interconnected elements as shown schematically in Figure 1. However, the figure depicts the gas fields as being closely connected to the liquefaction plants, which is not uniformly the case. Similarly the LNG operations chain does not always terminate in transfer to a pipeline system.

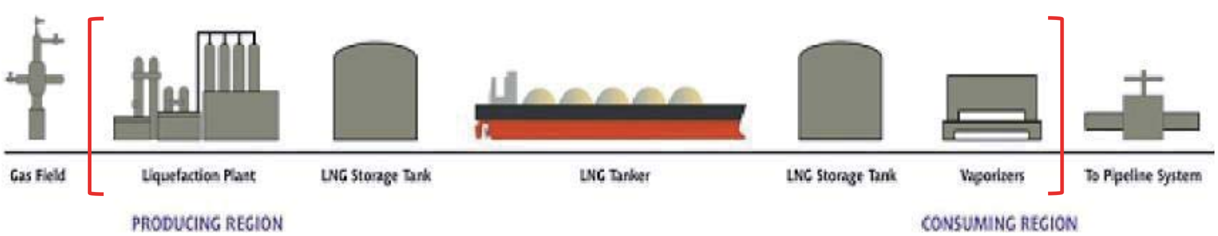


Figure 1. LNG Operations Chain ***Source***: CMS Energy

For the purpose of this document we structured the discussion of LNG operations and its associated GHG emissions into five stages, as illustrated by the operations depicted within the brackets in Figure 1. These operations include:

- **Liquefaction -** Plants where natural gas is treated to remove impurities and higher molecular weight hydrocarbons, and then liquefied and stored for subsequent shipment;

[6] The Wobbe Index is defined as the higher heating value of the gas divided by the square root of the specific gravity of the gas, i.e. its molecular weight relative to air. If two fuels have the same Wobbe Index, then at a given combustor inlet pressure and valve setting, the flame stability resulting from combustion of the two fuels will be identical.

- **Storage -** Storage tanks that are designed to store LNG at atmospheric pressure;
- **Loading and Unloading -** Marine or inland terminals designed for loading LNG onto tankers, or other carriers or unloading it for regasification;
- **Shipping -** LNG tankers used for transporting LNG;
- **Regasification -** Plants, typically co-located with unloading terminals, where LNG is pressurized, regasified, and injected into pipelines, or other receiving systems, for delivery of natural gas to end users.

The GHG estimation methods to be discussed in this document pertain to the sources in the LNG operations chain and encompass those operations extending from the point of entry of the natural gas into a liquefaction plant and through to the regasification stage, where the vaporized natural gas enters either a transmission pipeline system or other mode of conveyance to the ultimate users. Methodologies for estimating GHG emissions associated with routine gas processing operations that are designed to bring the natural gas directly to the market are addressed in the API GHG Methodology Compendium[7] and are not repeated in this document. Similarly, the API Compendium includes methods that are relevant to natural gas pipeline transmission and distribution along with methods that may be relevant to LNG plants that would augment the methods provided in Section 4.0 of this document.

The sub-sections below provide brief descriptions of the operations and equipment associated with each of the five interconnected LNG operations elements, and start to outline potential GHG emission sources in each of these stages.

2.2.1 Liquefaction

Natural gas arriving at a liquefaction plant may either be raw material from dedicated gas fields, or, in some cases, has already been through some initial processing. Prior to liquefaction, the natural gas is further treated to remove water, sulfur-containing species (primarily hydrogen sulfide), and any residual CO_2 that might be present. It is also treated to remove other components that could freeze (e.g., benzene) under the low temperatures needed for liquefaction, or that could be harmful (e.g. mercury) to the liquefaction facility.

[7] API, "Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry", 3rd Edition, Washington DC, August 2009

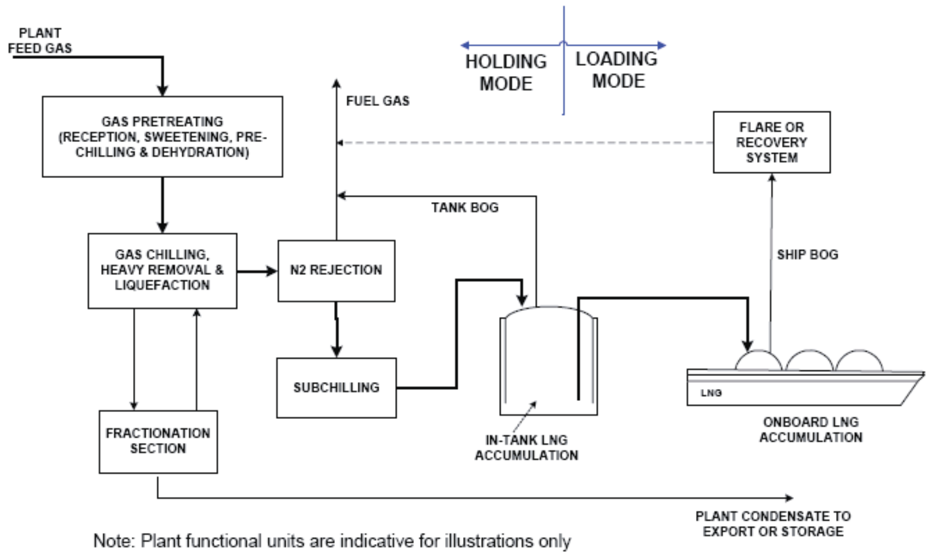
Figure 2 illustrates an example liquefaction process, including recovery of Boil-Off Gas (BOG) during LNG ship loading[8]. The BOG can either be routed to the plant's fuel gas system, or compressed and returned to the inlet of the process. LNG typically contains at least 90% methane, along with smaller and decreasing amounts of ethane, propane, and butanes. Even when producing a high heating value (rich) LNG, the LNG contains no more than 0.5 mole% pentanes and heavier hydrocarbons. The liquefaction process entails treating the natural gas followed by chilling it using refrigerants, which are typically hydrocarbons, although non-hydrocarbons (e.g. nitrogen) may also be used as refrigerants. The liquefaction plant uses multiple compressors, condensers, pressure expansion valves, isentropic expanders and evaporators. The natural gas goes through stages of pre-cooling, liquefaction and sub-cooling until it reaches the desired temperature, and is then stored as LNG in near-atmospheric pressure tanks prior to ship loading.

Liquefaction process GHG emissions are primarily due – but not limited - to:

- **(a)** Fuel gas combustion to power refrigeration compressors and electrical generators;
- **(b)** Fired heaters, flares, incinerators, and other fired process heat generators;
- **(c)** Venting of low pressure carbon dioxide;
- **(d)** Fugitive losses of natural gas from the process due to leakage; and
- **(e)** Fugitive losses of other GHG's used in the facility (i.e., SF_6 used for switchgear).

The liquefaction process may consist of one or more 'LNG trains' and can be designed to produce a rich (high in heating value) or lean (low in heating value) LNG, as desired, even approaching 100% methane depending upon the composition of the feed gas and the level of hydrocarbon recovery practiced. It is important to note some LNG facilities produce a Domestic Gas stream as a product, where they may also produce surplus power for export to local areas. Similarly if the facility extracts a natural gas liquids stream and fractionates it for sale of ethane, propane, butane, and pentane plus products these ought to be accounted for in the overall material balance as products and not emission sources.

[8] Huang, S. H., Hartono, J., Shah, P., "Recovering BOG during LNG Ship Loading", Paper presented at GPA 86th National Convention in San Antonio, Texas, March 11-14 (2007).



Source: Huang et al, 2007

Figure 2. Schematics of an Example Liquefaction and Vessel Loading Process

2.2.2 Storage

LNG storage tanks are located at liquefaction plants to store LNG prior to loading onto tankers. Receiving terminals also have storage tanks to hold LNG prior to regasification. In addition, LNG storage tanks may be used in natural gas distribution systems for surge capacity to help meet peak demand; such tanks are part of a "peak-shaving" facility.

LNG storage tanks are typically double-walled tanks (i.e., a tank within a tank), with the annular space between the two tank walls filled with insulation. The inner tank, in contact with the LNG, is made of material suitable for cryogenic service such as 9% nickel steel or aluminum. The outer tank includes a dome that, with the outer tank wall and floor, and its lining, provides containment for the vapor that exists in equilibrium with the LNG. The outer tank wall is typically constructed of carbon steel (in the case of single containment or double containment design) or reinforced concrete that is lined with a combination of 9% nickel steel (up to a certain height) and carbon steel in the case of a full containment design. LNG storage tanks are operated at essentially atmospheric pressure. The annular space, typically a meter or more thick, is filled with insulation.

Greenhouse gas emissions from LNG storage tanks are minimal since:

(a) There is no systematic venting from the tanks: gas is fully contained within the outer container of the overall tank design;

(b) Gas displaced during tank loading or boiled off due to heat leakage is captured and either used for fuel gas onsite; compressed and sent to a transmission or distribution system pipeline; or reliquefied and returned to the storage tank;

(c) Most piping connections associated with LNG tanks are welded rather than flanged;

(d) LNG storage tanks are operated near atmospheric pressure with a slight overpressure so there is minimal pressure differential between the tank and the atmosphere to drive leaks;

(e) The tanks are double-walled and heavily insulated to minimize evaporative losses, while their tank in a tank design minimizes the potential for liquid leaks.

In addition to the double wall design, storage tanks also have different containment provisions for handling emergencies. Most LNG storage tanks in the United States are built above ground; they are commonly used both in liquefaction and in regasification plants. These tanks are cheaper and faster to construct relative to in-ground tanks because minimal site excavation and drainage systems are required. In-ground tanks are more common at receiving terminals located at seismically sensitive areas with limited land area like Japan, South Korea, and Taiwan. At these locations, in-ground tanks can be spaced closely together. Also, in-ground tanks have minimal visual impact (i.e., they can be totally invisible to the public), and landscaping can be used for camouflage[9]. Table 2 provides a summary of the types of LNG tanks' containment design as used globally with an indication of the U.S. market share of these tanks.

The GHG emissions methodology that is the scope of this document (and discussed in Section 4.0 below) considers storage emissions but does not address emissions during highly unlikely storage failures. Fugitive emissions (gas leakage) from LNG storage tanks are primarily determined by the number and type of piping and valve connections used. LNG vaporization within the tanks is due to heat gain from the surroundings, and from energy input from the pumping process. Ambient heat gain is a function of the type and amount of insulation used.

[9] Huang, S., Chiu, C.-H., Elliot, D., "LNG: Basics of Liquefied Natural Gas", University of Texas, Continuing Education, Petroleum Extension Services (PETEX), Austin, Texas (2007).

The resulting gas from such heat input to the LNG is called boil-off gas (BOG). Stored LNG will stay at the same temperature in spite of such heat input because of the "auto refrigeration" process[10]. BOG production is managed with BOG compressors and interconnecting piping.

Table 2. Types of LNG Storage Tanks In-Use Globally [(a)]

	PRIMARY CONTAINMENT	MAX D.P. (mbar) [(B)]	MARKET SHARE [(C)]
Single-Containment	Self-support	160	64%
Double-Containment	Self-support	190	18%
Full-Containment	Self-support	210/290	
PC/PC [(d)]	Self-support	300	1%
Above-ground Membrane	Supported	300	6%
In-ground Membrane	Supported	300	11%

[(a)] Huang, S., Chiu, C.-H., Elliot, D., "LNG: Basics of Liquefied Natural Gas", University of Texas, Continuing Education, Petroleum Extension Services (PETEX), Austin, Texas (2007).
[(b)] D,P. = Delta Pressure (or pressure differential); mbar = millibars
[(c)] Data estimates for global market share
[(d)] PC = pre-stressed concrete construction

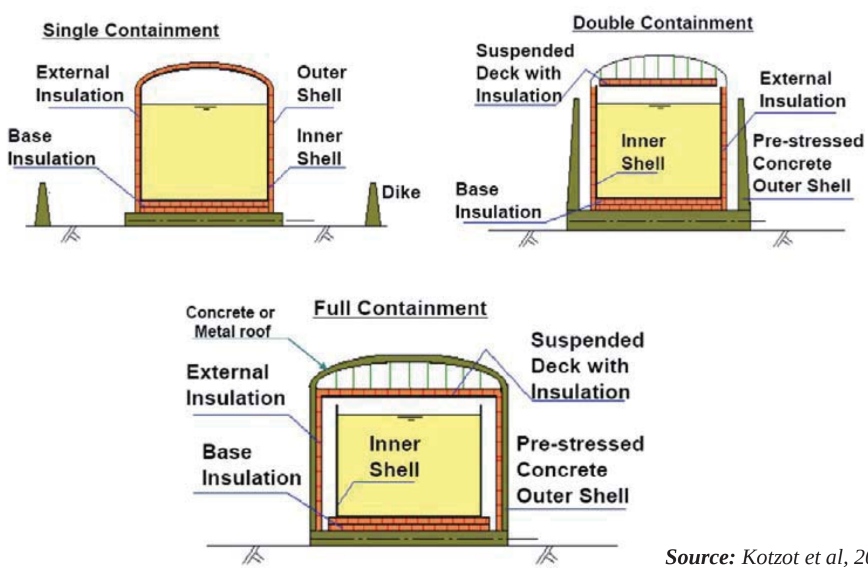
Figure 3 provides schematics for the three basic containment types for above-ground LNG tanks[11], including:

- **Single-containment tanks** are the lowest cost option if sufficient plot space is available for earthen dikes as secondary containment. The primary containment is the inner shell that is made of 9% nickel steel. The outer shell is made of carbon steel, which is incapable of withstanding the low temperature of LNG, but which serves as the gas-tight container for BOG and keeps the insulated space dry. In the unlikely event of failure of the inner shell,

[10] **Auto refrigeration** is the process in which the LNG is kept at its boiling point so that any added heat is countered by energy lost from *boil-off* of the stored liquid.
[11] Kotzot, H. J., "Overview of the LNG Industry – Gas Treatment, Liquefaction, and Storage", paper presented in GPA Annual Convention, San Antonio, TX (2003).

liquid will be impounded within the dike, where the LNG would evaporate. Therefore, the open space requirements around single containment tanks are greater than those for other categories of containments.

- **Double containment tanks** are only required to provide liquid tightness in case of an LNG spill from the inner tank, and gas tightness to contain BOG. The existence of an outer wall that is capable of containing LNG significantly reduces the traveling distance and dispersion of vapors should the inner tank fail.
- **Full-containment tanks** are designed such that the outer tank can contain both the liquid and the vapor. In the event of inner tank failure, the outer wall is capable of sustained containment of the liquid while retaining vapor tightness. In the unlikely event of an inner tank failure, some of the vapor generated as the outer tank cools to LNG temperature might be released through the tank relief vents if the tank's primary gas management system, the BOG compressors, and its secondary system, a flare, are not able to handle the excess.



Source: *Kotzot et al, 2003*

Figure 3. Schematics of Above Ground LNG Storage Tanks Containment Design

2.2.3 Loading and Unloading

Marine loading terminals are located adjacent to liquefaction plants where LNG is initially stored, while unloading takes place at receiving terminals prior to LNG regasification. LNG loading arms, typically constructed from pipe with cryogenic swivels, are used to transfer LNG between onshore or offshore facilities and LNG tankers, both in liquefaction and regasification plants. LNG is maintained at cryogenic temperature throughout the loading and unloading process. Specially designed and well-insulated loading racks and vessel connectors are used to minimize generation of boil-off gas and to ensure safety of the LNG transfer process. Figure 4 shows articulated LNG loading arms at a terminal.

The handling capacity of a marine loading arm varies between 4,000 and 6,000 m^3/hr. A loading or unloading terminal would normally consist of two or three loading arms in liquid transfer service, a vapor return arm and a common liquid/vapor spare.

Courtesy: FMC Technologies, *SA*

Figure 4. Articulated LNG Loading Arms

With the emergence of offshore LNG operations, different designs are used for loading and offloading LNG under different conditions, such as from regasification or liquefaction plants in environments that are more severe than the protected harbors typically employed with onshore liquefaction plants and receiving terminals. New types of loading arms have been designed for

'Side by Side' LNG transfer between a floating production storage and offloading (FPSO) terminal and a ship, a floating storage and regasification unit (FSRU) and an LNG carrier, or a gravity-base LNG receiving terminal and an LNG ship. These systems can be used in moderate sea states. 'Tandem' LNG transfer systems have been designed for use between an FPSO or an FRSU and a dedicated LNG carrier, e.g. the Boom to Tanker (BTT) system[12]. The latter will be used in more severe environmental conditions.

The operations at a loading or unloading terminal are comprised of the following steps:

(a) Moorage of an LNG vessel at the terminal;

(b) Connection of cryogenic loading arms, arranged for continuous recirculation of LNG from the plant storage tanks;

(c) Transfer of LNG via the cryogenic loading arms between the LNG storage tanks on board the LNG carrier and the LNG storage tanks at the liquefaction plant site or the receiving terminal; the initial LNG transfer rate onto a ship depends on the temperature of the tanks within the ship upon its arrival;

(d) Compressing boil-off gas, with or without flaring and/or venting of displaced tank gas during loading;

(e) Discontuation of the LNG transfer operation, followed by draining of the liquid-filled loading arms;

(f) Disconnection of the LNG vessel from the loading arm for its onward sea journey.

Fugitive emissions associated with the ship loading or unloading process are minimal, due primarily to the welding of all associated piping systems.

2.2.4 Shipping

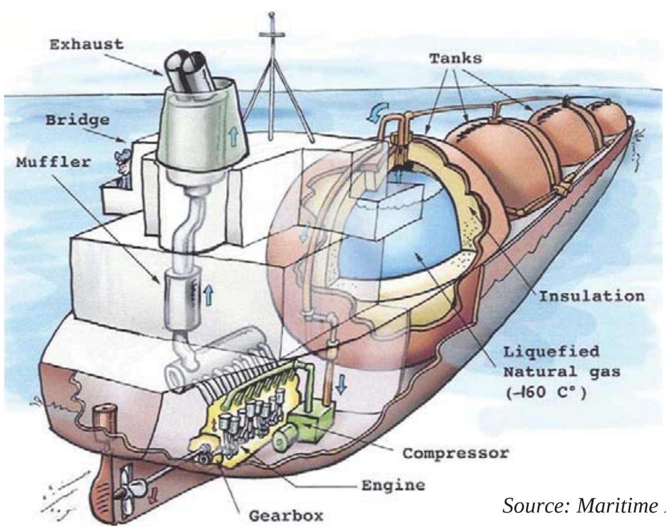
LNG is shipped in double-hulled vessels that are specially designed and insulated to enable safe and reliable transport of LNG from liquefaction facilities to receiving terminals, while minimizing the amount of LNG that boils off. The tankage and BOG management systems are designed to maintain the cargo tank pressure below the maximum allowable relief valves (MARVS) settings or to safely utilize or dispose of the natural LNG boil-off gas at all times, including while in port, maneuvering or standing.

[12] Pashalis, C., *Latest Developments for Offshore FMC Loading Systems*, LNG Journal, July/August 2004

LNG tankers typically burn the natural gas boiled off from the stored LNG as fuel, supplemented by fuel oil, to power their propulsion system. Many of the new LNG tankers, including the Q-Flex (capacity to 216,000 m^3) and Q-Max LNG carriers (capacity to 266,000 m^3), both first delivered in 2007, are much larger than the LNG carriers in service prior to that point in time. These newer ships utilize slow speed diesel-powered propulsion systems and have onboard reliquefaction facilities to reliquefy boil-off gas and return it to the ship's LNG tanks as LNG.

The LNG containment system designed in LNG carriers can be categorized as either a spherical (Moss) design; a membrane design; and a structural prismatic design. Although the spherical design is the most identifiable one for LNG ships, the majority of recently built ships have employed the membrane design.

Figure 5 shows a cut-away view of an LNG tanker with Moss spherical storage tanks, and offers insights into potential GHG emission sources from the shipping portion of the LNG value chain. As discussed above, during the voyage, the main source of GHG emissions from an LNG ship is the combustion of boil-off gas (BOG) and other fuels used for vessel propulsion and gas compression.



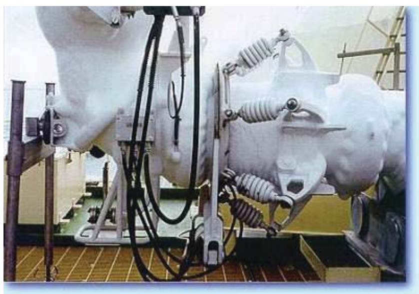
Source: Maritime Propulsion

Figure 5. LNG Tanker Cross-Section (Moss Design)

Prevalent propulsion systems on LNG carriers include: steam, dual-fuel, slow speed diesel with reliquefaction and gas turbines. Dual-fuel electric propulsion systems have become the preferred design for new-built LNG carriers in the range from 140,000 m^3 to 200,000 m^3, with slow speed diesel propulsion with reliquefaction becoming more popular for vessels over 210,000 m^3 capacity. All these different propulsion systems require high-voltage power plants, either to supply only the cargo handling (tank unloading) pumps and/or reliquefaction plant or combined with electric propulsion[13]. The choice of the specific propulsion type, its design, capacity and rate of utilization will impact GHG emissions associated with LNG ship voyages.

LNG ship operations generate GHG emissions while traveling at sea, while berthing and/or un-berthing from the docks, and while loading and unloading their cargo. One should account for the GHG emissions associated with any routine operations at dock (i.e.'hoteling' operations), the duration of operation, and the power demand of the cargo transfer pumps, in addition to the loading/unloading operations discussed in Section 2.2.3 above.

For berthing and unberthing operations the LNG ships use specialized couplings to ensure safe LNG transfer, which are known as quick coupling (QC) and quick release (QR). Vessels also are equipped with powered quick release couplings for emergency disconnects of products transfer if it becomes necessary. Figure 6 shows examples of such couplings, which are located at the mating point between the loading arms and the ship.



Courtesy: Chevron

Figure 6. Loading arm couplings: QC/QR (left**), and Powered Emergency Release coupling (**right**)**

[13] J. F. Hansen, R. Lysebo, "Comparison of Electric Power and Propulsion Plants for LNG Carriers with Different Propulsion Systems ",ABB AS, Oslo, Norway, www.abb.com/marine

To estimate GHG emissions during LNG ship voyages one has to evaluate emissions associated with each of the typical systems that may be present onboard. Such systems may include one or any combination of the following, with aggregate capacity for BOG utilization or disposal that is no less than the ship's normal boil-off rate (NBOR)[14]:

(a) A steam boiler with a common propulsion steam turbine and steam dump system;

(b) A slow speed diesel or dual fuel diesel engine plant for propulsion and power generation;

(c) A gas turbine plant for propulsion and power generation;

(d) A re-liquefaction system;

(e) A gas combustion unit;

(f) Other units, such as an auxiliary steam boiler capable of burning boil-off vapors.

2.2.5 Regasification

Regasification plants, which return the LNG back into the gaseous state, are typically incorporated into LNG receiving terminals. Figure 7 provides a schematic of a composite example of a regasification plant. Most plants do not have all of the processing capabilities shown on the chart. For example, the ethane-plus extraction step shown in the figure is an option that is used at very few potential locations due to the lack of local infrastructure or markets. Most LNG receiving terminals are only capable of pumping and vaporizing LNG. Some have the ability to blend nitrogen into the send out gas to reduce its heating value, or to blend in propane and/or butanes into the LNG to increase its heating value. A limited number of receiving terminals have facilities to separate higher hydrocarbons from rich LNG, or are considering adding the facilities needed to effect that separation.

For all LNG regasification plants, LNG is initially pumped from the LNG ship into the receiving terminal's LNG storage tanks. Subsequently, LNG is either transferred further in its liquid phase, e.g. loaded onto trucks for transport to smaller storage facilities at a customer's site, or pumped to higher pressure through in-tank and high pressure pumps, vaporized at high pressure, and delivered into the send out gas pipeline.

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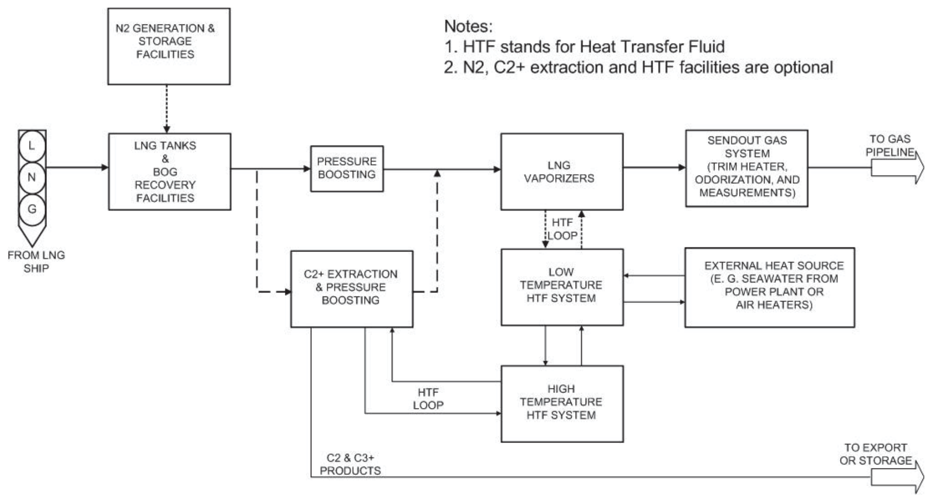
[14] American Bureau of Shipping (ABS), "Guide for Propulsion System for LNG Carriers", September 2005 (Updated February 2011), New York, NY, USA



Source: Huang et al, 2007

Figure 7. Schematic of a Composite LNG Receiving Terminal

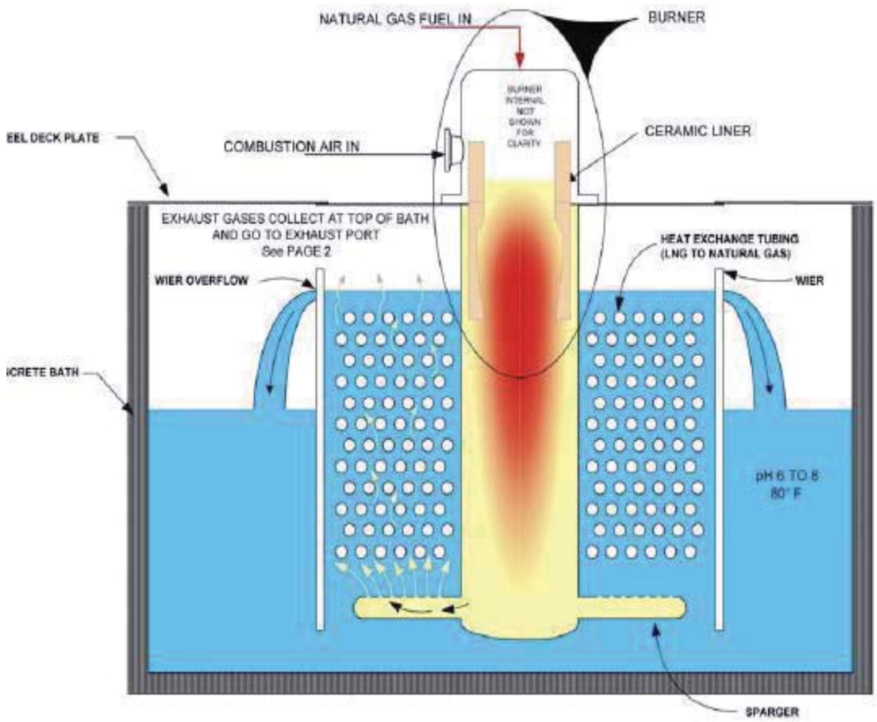
The vaporizers commonly in use throughout the world are summarized in Table 3. The table includes a brief description of the operating mode for each type.

Vaporizers presently in use in the U.S. are mostly submerged combustion or shell and tube design. Elsewhere in the world, other types like open rack seawater type and intermediate fluid type are in use. The pressurized natural gas from the regasification process is either delivered to adjacent consumers, or enters into a natural gas pipeline transmission and distribution system.

Table 3. Summary of Common Types of LNG Vaporizers

VAPORIZER TYPE	MODE OF OPERATION
Submerged Combustion Vaporizers (SCV)	▪ Pressurized LNG is vaporized in stainless steel tube coils immersed in a hot water bath that is heated by combusting natural gas. ▪ The combustion takes place in a distributor duct immersed in the water bath, into which the combustion products are directly sparged. The water in the bath serves as the heat transfer media for vaporizing the LNG in the tube coil. ▪ The pressurized and vaporized natural gas can go directly to a transmission pipeline without further compression.
Open Rack Vaporizers (ORV)	▪ An ORV consists of two horizontal headers connected by a series of vertical finned heat transfer tubes made of aluminum alloy that use seawater as the heat source. ▪ LNG enters the bottom header and moves upward through the vertical tubes. Meanwhile seawater flows downward along the outer surface of the tubes. The vaporized gas is collected and removed from the top header.
Shell & Tube Vaporizers (STV)	▪ The STVs can be categorized as either direct or indirect heating. Different designs offer different solutions to prevent the possible consequences of freeze-up, as follows: 1. **Direct heating:** The LNG flows on the tube side, with seawater on the shell side. The design utilizes the partially heated LNG as a buffer fluid between seawater and the cold inlet LNG. 2. **Indirect heating:** In this category of STVs an intermediate liquid is used as the heat transfer media for vaporization. They are known as: – <u>Traditional Intermediate Fluid Design</u> – typically uses a 36% ethylene glycol/fresh water solution as the intermediate fluid in a circulating loop for vaporizing LNG, while the cooled solution can be reheated by direct heat exchange with seawater or ambient air. – <u>Double Tube Bundle Shell and Tube Vaporizer</u> – comprised of a lower and an upper set of tube bundles, and uses an intermediate heat transfer fluid (e.g. propane, iso-butane, Freon, or NH_3) between the LNG (upper tubes) and the seawater or glycol water (lower tubes).
Ambient Air Vaporizers (AAV)	▪ This vaporization system design takes heat from ambient air to vaporize the LNG. ▪ The AAVs also come in two categories: direct and indirect heat exchange with air. Since the LNG temperature is dramatically lower than the dew point temperature of ambient air, different designs offer different solutions to prevent the possible icing-up: **1. Direct heating with ambient air**. AAVs use two modes for drawing ambient air: natural draft, or forced draft. They typically are designed as either single units or multiple units arranged in banks with common interconnecting piping. **2. Indirect heating with ambient air**. LNG exchanges heat with a circulating intermediate fluid that is heated by ambient air. The selection of the intermediate fluid is based on its freezing point and good heat transfer properties.

Figure 8 shows a schematic of a typical submerged combustion vaporizer in which the LNG flows through the tube bundle that is submerged in the water bath together with the gas burner flue gas tube. The gas burner discharges the combustion flue gases into the water bath, thus heating the water and providing the heat for the vaporization of the LNG.



Courtesy: Dominion

Figure 8. Submerged Combustion Vaporization of LNG

Open rack vaporizers use seawater as a heat source for the vaporization of LNG. These vaporizers use once-through seawater flow on the outside of a heat exchanger as the source of heat for the vaporization, and are widely used in Japan. Their use in the U.S. and Europe is less common due to environmental permitting limitations.

Vaporizers of the intermediate fluid type use a refrigerant like Freon or Propane with a low melting point to transfer heat from a warm water stream to the LNG. Here a liquid refrigerant "reboiler" type heat exchanger is used in conjunction with ambient once-through water in the tube bundle. The process is based on the heat of condensation of the refrigerant to provide the heat of vaporization of the LNG. These type vaporizers have some of the same permitting constraints in the U.S. as the open rack types.

Other types of vaporizers include ambient air vaporizer systems that utilize ambient air to provide the heat for the vaporization process. Such systems can also include supplemental heaters for heating the cooled water from the heat exchanger. These systems are designed to extract heat from the environment for the vaporization of large quantities of LNG with reduced fuel gas usage relative to submerged combustion vaporizers. This also results in reduced effect on the environment and on marine and terrestrial life.

As presented earlier in Table 1, the composition of LNG varies based on the originating production formation and the level of separation and processing at the liquefaction plant. Additional processing or dilution steps may be required after regasification in order to meet national or local gas quality specifications and the needs of end-users. These additional processing steps could also lead to additional GHG emissions, which would have to be assessed based on the local operational boundaries for the regasification plants. For many regasification facilities, the vast majority of GHG emissions stem from combustion processes, with minimal venting due to compressor operations. Yet, one should note that some regasification plants also have power generating capability, with its associated emissions.

3.0 GHG EMISSIONS INVENTORY BOUNDARIES

Generic guidance for establishing GHG emissions inventories at the facility or company level is available from the joint initiative of the World Resources Institute (WRI) and the World Business Council for Sustainable Development (WBCSD)[15]. Industry relevant guidance for establishing GHG emissions inventory boundaries for the petroleum and natural gas sector is provided in the Petroleum Industry Guidelines for Greenhouse Gas Reporting[16]. The Industry Guidelines recognize that GHG emissions may be aggregated across a range of dimensions including organizational and operational boundaries, geographic boundaries, industrial sectors, company divisions, facilities, and source types. Companies typically set their overall organizational boundaries for reporting either on the basis of operational control, financial control, or by equity share. For reporting LNG GHG emissions companies could include emissions from their LNG operations as part of a comprehensive GHG emissions report, or as a separate report highlighting emissions from their LNG operations chain.

At the most basic level, a GHG emissions inventory is comprised of calculated and estimated emissions from individual emission sources that are aggregated to produce the inventory. Emissions information is typically obtained either through direct on-site measurement of emissions, or the combination of an emission factor and some measure of the activity that results in the emission (referred to as the activity factor). Emission factors describe the emission rate associated with a given emission source, which may be either based on site-specific measurements or published data. Activity factors are generally a measured quantity, such as a count of equipment or amount of fuel consumed.

When selecting methods for quantifying GHG releases to the atmosphere, a four stage hierarchy is usually used for selecting appropriate approaches consistent with data availability,

- **(a)** Direct Measurements;
- **(b)** Mass Balance;
- **(c)** Emission Factors;
- **(d)** Engineering Calculations.

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[15] WRI/WBCSD, GHG Protocol Initiative, *A Corporate Accounting and Reporting Standard*, Revised June 2004
[16] API/IPIECA/OGP, *Petroleum Industry Guidelines for Reporting Greenhouse Gas Emissions, Revised Edition, London, October 2011*

One of the major challenges for complex GHG emission inventories, such as those for oil and natural gas companies, is the identification of the specific emission sources associated with each facility and the appropriate methods for estimating these emissions. The guidance provided in this document is designed to aid in estimating GHG emissions from the LNG sector and its chain of operations. It is not intended to supplant guidance provided by local regulators or other climate schemes that have jurisdiction over the applicable LNG operations. The LNG sector is expected to have multiple reporting challenges due to its complexity and the fact that its operations typically cross jurisdiction lines such as national, provincial or state boundaries.

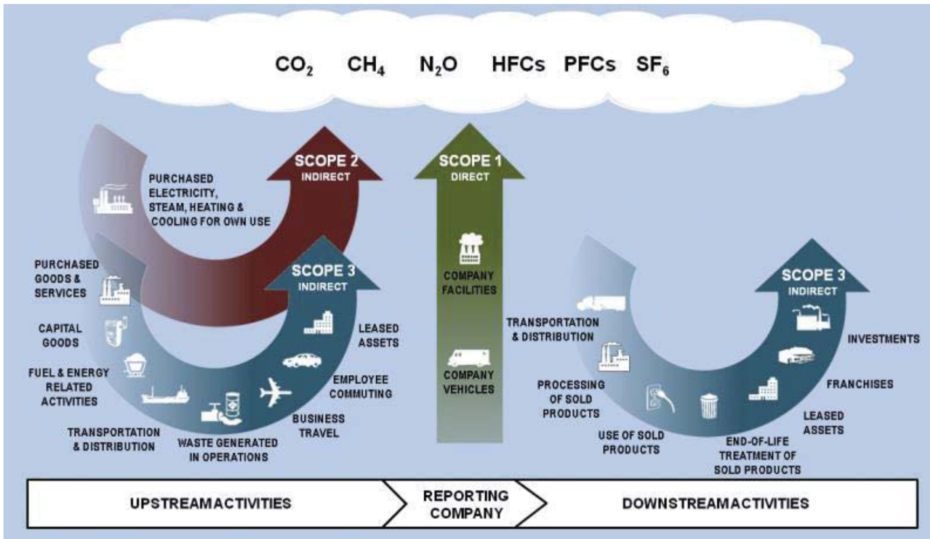
The data provided in this document serves to augment existing oil and natural gas industry method compilations by presenting data and guidance that is applicable for emitting sources within the LNG operations chain. This document is not intended to replace local requirements or other mandatory protocols for various GHG programs.

3.1 Operational GHG Emissions

In defining the scope for developing a GHG emissions inventory, companies must first determine which emission sources should be included within the selected organizational boundary for the inventory. This process is referred to as setting the operational boundaries of the GHG emissions inventory. A key step in setting the operational boundaries is the categorization of GHG emission sources as either direct or indirect. The distinction is that direct GHG emission are those that are due to sources that are either operated or under the control of the organization compiling the inventory, while indirect GHG emissions are a consequence of the activities of the reporting organization, but occur from sources owned or controlled by a third party.

Over the past decade, a global practice has emerged leading to categorizing GHG emissions into three major ’scopes’, as depicted in Figure 9 and which comprise of:

- **Direct GHG Emissions (Scope 1) -** Direct GHG emissions that occur from sources that are owned or controlled by the company. Such sources are further categorized into: stationary combustion; process/equipment venting; fugitive emissions; and operated mobile sources (vessels, aircraft, cars, trucks, construction equipment, etc.).



Source: GHG Protocol

Figure 9. Categories of Company's Operations by Scopes

- **Indirect GHG Emissions from Purchased and Consumed Energy (Scope 2**) **-** Indirect GHG emissions attributable to purchased electricity; purchased heat/steam; and purchased cooling water.
- **Other Indirect GHG Emissions (Scope 3)** – Indirect emissions due to emission sources that are not owned or operated by the company but are essential for conducting the company's business and are not accounted for in Scope 1 and 2.

The emission estimation methods provided in this document pertain primarily to direct emissions from operations that are part of the five stages of the LNG value chain with emphasis on operations where companies have operational control and can obtain the needed information to calculate GHG emissions.

If companies wish to account for their contribution to indirect GHG emissions, which are due to operations undertaken by others on their behalf, similar estimation methods to the ones described here may apply. If such is the case, companies ought to be cognizant of the potential of "double counting" of emissions that may be independently reported by the company's supply-chain providers. The final content of companies' emissions inventories and their extent will be dependent on applicable requirements and specifications along with the intended data use.

3.2 GHG Emission Sources

Devices and processes being used throughout the LNG operations chain consist both of equipment used in other segments of the oil and natural gas industry as well as specially designed equipment for the liquefaction, storage, loading, shipping, offloading, and revaporization of the LNG. Since there is some similarity in equipment and operating characteristics, certain emissions estimating methods provided in other industry guidance can be used in addition to the methods provided in Section 4.0 below for LNG operations.

The rate and extent of GHG emissions for the LNG sector are primarily attributable to the quality and quantity of the fuels used, thermal efficiency of the process design, feedstock throughput, “boil-off” rate, and extent of recovery of “boil-off” gases (BOG) generated due to energy input to and heat ingress into the chilled product. Therefore, emissions could also be affected by the volatility of the compounds handled, inspection/maintenance operations along with equipment design for control and containment.

3.2.1 Emission Sources Categories

Per United Nations’ guidance, all non-combustion emissions, including flaring and venting (both intentional and unintentional) are defined as fugitive emissions. However, this definition is counter-intuitive and contravenes established regulatory definitions used for controlling emissions of volatile organic compounds in many countries around the world, including the U.S. Therefore, this document follows the format established by the API Compendium[7] and includes flaring emissions with combustion sources and distinguishes fugitive emissions clearly from vented emissions.

Emissions from sources in the LNG operations chain can be classified into the following main categories:

- **Combustion-related emissions -** Emissions resulting primarily from fuel fired equipment. This may include fuel use in engines or turbines that provide power to compress gases, pump liquids, or generate electricity; and for firing heaters and boilers. Combustion of gases in flares and incinerators is included with combustion-related emissions in the API Compendium but it is more routinely reported with ‘vented emissions’, which is more consistent with the IPCC recommended format.

- **Vented Emissions -** Designed releases of CH_4 and/or CO_2 including but not limited to process emissions where vented gas streams are not recovered, or rerouted back to the fuel gas system. It also includes operations such as blowdown from compressors or other equipment for maintenance, and direct venting of gas used to power equipment such as pneumatic controllers. According to the IPCC recommendations for national GHG inventories, this category includes also all gas flaring in addition to emergency venting that is not routed to a flare.
- **Fugitive emissions** - Emissions that occur unintentionally and could not reasonably pass through a flare or exhaust stack, chimney, vent, or other functionally-equivalent opening. This would include leaks from piping components and other equipment.
- **Transportation-related emissions -** Emissions associated with operations of a wide variety of mobile sources operated by the company including ships, barges and tank trucks, along with transfers into transmission or distribution pipelines.
- **Non-routine emissions -** Non-routine emissions associated with LNG operations are primarily a result of start-up, shut-down, or plant upset. These emission sources are generally routed to the flare system.

3.2.2 Emission Sources in the LNG Operations Chain

A descriptive list of GHG emission sources associated with each of the segments of the LNG operations-chain (as discussed in Section 2.2) is provided below, mapping them to the main source categories discussed above. The specific emitting equipment to be accounted for in each of these segments would ultimately depend on facility design. For example, some aspects of natural gas processing are hard to separate from an LNG liquefaction facility, due to integrated design and operation, as may also be the case for on-site power generation at regasification facilities.

- **Liquefaction** - Sources include primarily combustion emissions from mechanical drive turbines, power generators, or other process drivers; combustion emissions from fired heaters, flares, and other heat generation sources; emissions from the CO_2 removal process; venting from compressors used for cryogenic cooling; venting from the "cold box" where liquefaction occurs (applicable for some but not all liquefaction processes); fugitive emissions from LNG pumps and compressors; venting from LNG storage (in extreme upset conditions only); and fugitive emissions from flanges, valves, and fittings within the process. If the facility inlet is integrated with natural gas production additional GHG emission sources would have to be accounted for in the overall inventory to address such integrated operations.

- **Storage -** Sources include flaring and venting of excess BOG from storage tanks; combustion emissions and venting from compressors used to recover BOG; and fugitive emissions from compressors;
- **Loading and Unloading -** Sources include combustion emissions from power generation facilities needed to provide electricity to a ship's cargo pumps; venting when ship loading connection is broken; venting when connection to other means of conveyance such as barges or trucks are broken; and fugitive emissions from piping flanges, valves, and fittings.
- **Shipping -** Sources include venting of unconsumed and un-reliquefied BOG during voyage, combustion emissions from power generation, venting from compressors used to recover BOG, fugitive emissions from compressors, emissions from fuel combustion used for ship propulsion or for other carriers used to transport the LNG; and combustion emissions from the power plant used to power the ship's other systems, e.g. its living quarters.
- **Regasification -** Sources include fugitive emissions from flanges, valves, and fittings in the piping used within the terminal, venting emissions from LNG pumps during maintenance, flaring of BOG from storage tanks during ship unloading (if BOG rate exceeds BOG compressor capacity), emissions from fuel combustion used for the vaporization process, venting from the vaporization process during maintenance, venting from BOG compressors during maintenance, and fugitive emissions from compressors. If the facility is integrated with on-site power generation the emission sources associated with power generation would also have to be accounted for.

Mapping of these emission sources is provided in the tables below. Table 4 presents a list of stationary combustion-related emissions sources for each of the LNG operations segments.

Table 4. Mapping of Combustion Emission Sources in the LNG Operations Chain [a]

SOURCE CATEGORY	POTENTIAL EMISSION SOURCES	LIQUEFACTION	STORAGE[B]	SHIPPIN G	REGASIFICATION
Boilers/Heaters	Process heaters • Submerged combustion vaporizers • Glycol-water heaters	X			X
	Line heaters		X		X
	Water heaters, e.g. Submerged Combustion Vaporizers				X
Compressors	Gas Turbine driven compressors	X	X	X	X
	Engine driven compressors	X	X	X	X
Generators	IC engine generators	X	X	X	X
	Turbine generators	X	X	X	X
Flares and Incinerators *(could be included with vented sources)*	Flares	X	X		X
	Thermal oxidizers	X	X	X	X
	Catalytic oxidizers	X	X	X	X
Miscellaneous	Fire water pumps (diesel)	X		X	X
	Power generation	X	X	X	X

[a] This table lists sources that might be of interest for LNG operations. For most of these sources, estimation methods are already identified in the 2009 revision of the API compendium. Specific methods and Emission Factors applicable to LNG sources will be provided in the sections that follow.
[b] Storage includes sources from Loading and Unloading of LNG.

The GHG emissions sources associated with LNG operations for vented and fugitive emissions are listed in Tables 5 and 6. This is followed by a list of transportation related emission sources in Table 7.

Table 5. Mapping of Vented Emission Sources in the LNG Operations Chain [a]

SOURCE CATEGORY	POTENTIAL EMISSION SOURCES	LIQUEFACTION	STORAGE[B]	SHIPPING	REGASIFICATION
Pumps & Compressors	Compressor venting and blowdowns	X	X	X	X
	Pump venting and blowdowns	X	X	X	X
	Compressor starts	X	X	X	X
Process Vents	CH_4 from processing	X			X
	CO_2 from processing	X			
	Cryogenic Exchangers	X			X
	Vaporization				X
Storage Tanks	BOG venting	X	X	X	X
	Vapor recovery units	X	X	X	X
Vessel docking	Coupling connectors		X	X	
Safety	Pressure Relief Valves (PRVs)	X	X	X	X
	Emergency vents	X	X	X	X
Miscellaneous Vents	Gas sampling and analysis	X	X		X

[a] This table follows the source categorization used in the API Compendium (Version 3.0, August 2009), which provides guidance and calculation methods for many similar sources.

- GHG emissions from these sources consist primarily of CH_4,
- Venting of CO_2 will depend on its content in the feed gas and the acid removal process utilized and whether it is vented or injected into a disposal well
- If gas flaring and incineration is reported with the vented emissions – in accordance with IPCC guidance - these emissions will consist primarily of CO_2.

[b] Storage includes sources from Loading and Unloading of LNG.

Table 6. Mapping of Fugitive Emission Sources in the LNG Operations Chain [a]

SOURCE CATEGORY	POTENTIAL EMISSION SOURCES	LIQUEFACTION	STORAGE (B)	SHIPPING	REGASIFICATION
Compressors	Rod packing	X	X	X	X
	Dry Seals	X	X	X	X
Pumps	Mechanical seals	X			
	Barrier fluid seals	X			
Valves	Gas service	X	X	X	X
	Light liquid service	X	X	X	X
	Heavy liquid service			X	
Pressure Relief	Pressure relief valves	X	X	X	X
	Misc. devices	X	X	X	X
Air Separation Units	Flanges	X		X	X
Refrigeration and A/C Systems	Flanges	X	X	X	X
Instrumentation	Meter connectors	X	X	X	X
	M&R Stations		X		X
Spills	Startup & Shutdown	X	X	X	X
	Accidental	X	X	X	X

[a] This table follows the source categorization used in the API Compendium (Version 3.0, August 2009), which provides guidance and calculation methods for many similar sources.

– GHG emissions from these sources consist primarily of CH_4,

[b] Storage includes sources from Loading and Unloading of LNG.

Table 7. Mapping of Transportation Related Sources in the LNG Operations Chain [a]

SOURCE CATEGORY	POTENTIAL EMISSION SOURCES	LIQUEFACTION	STORAGE[B]	SHIPPING	REGASIFICATION
LNG carriers	Propulsion systems, On-board power plants			X	
Rescue Boats	Propulsion systems		X	X	X
Coast guard escort	Propulsion systems		X	X	X
Support Vessels	Propulsion systems		X	X	X
Helicopters	Propulsion systems			X	X
Tugs	Propulsion systems		X	X	X
Bathymetric survey boats	Propulsion systems		X	X	
Dredging equipment	Propulsion systems		X	X	

[a] This table follows the source categorization used in the API Compendium (Version 3.0, August 2009), which provides guidance and calculation methods for many similar sources.

- GHG emissions from these sources consist primarily of CO_2,
- Limited emissions of CH_4 and N_2O for different engines and catalysts.

[b] Storage includes sources from Loading and Unloading of LNG.

The equipment classification in Tables 4 through 7 are similar to the ones used in the API Compendium[13] with the sources listed cross-referenced to the specific segments within the LNG operations chain. Based on local requirements companies may include gas flaring and incineration emissions with vented emissions, which is consistent with IPCC guidance.

3.2.3 GHGs Emitted from LNG Operations

The most commonly recognized and globally reported GHGs are those covered by the Kyoto Protocol:

(a) Carbon Dioxide, CO_2

(b) Methane, CH_4

(c) Nitrous Oxide, N_2O

(d) Hydrofluorocarbons, HFCs

(e) Perfluorocarbons, PFCs

(f) Sulfur Hexafluoride, SF_6

Notably, GHG emissions from the LNG segments are likely to consist primarily of CO_2 CH_4 and N_2O. The other listed GHGs would potentially be contributing a very minor amount. The main sources for the GHG emissions are:

- **Carbon Dioxide (CO_2) -** from process CO_2 in addition to combustion of fuels in engines, boilers, heaters, turbines and other and compressor drivers;
- **Methane (CH_4) –** from venting and equipment leaks in all segments of the LNG operations chain;
- **Nitrous Oxide (N_2O)** - from combustion devices, of primary importance for stationary engines including gas turbines and combustion of non-gaseous fuels;
- **Other GHGs** – these typically include SF_6, HFCs and PFCs as required by international GHG reporting frameworks, and should be included if they are germane to company's LNG operations.

Quantification of respective GHG emissions from each of the sources within the source categories in each of the LNG operations segments, as listed in Tables 4, 5, and 6, can be complicated by the variability of site operations and the potential lack of information about the quantity and quality of the fuels consumed especially since some of the fuels combusted are self-generated either during processing or as 'boil off' during storage and shipping. In most cases, they are rerouted to combustion devices used in the facilities, and in rare cases, they are flared or vented as a safety precaution. Such fuels tend to be variable in composition which makes it hard to characterize their GHG emissions using average emission factors that are based on an assumed average composition for the combusted fuels.

Similar to other sectors of the oil and natural gas industry operations, CO_2 emissions from combustion devices are typically the largest contributors to total GHG emissions from the LNG operations-chain. These are followed by methane emissions, which although may be smaller in absolute terms, are important due to methane's higher Global Warming Potential (GWP). Other very high GWP GHGs such as SF_6, hydrofluorocarbons (HFCs) or perflurohydrocarbons (PFCs) can also be important in special instances if their use is part of the facility design.

Global warming potentials are a comparative index of cumulative radiative forcing of targeted GHGs as compared to CO_2, over a specified time horizon. The 100-year time horizon is most commonly used for national GHG emission inventories and for corporate GHG reporting.

Appendix D provides GWPs from both the IPCC Second Assessment Report (SAR), which is currently used for national GHG inventories and is recommended for corporate reporting. The recalculated GWPs provided in the IPCC Fourth Assessment Report (4AR) are shown for comparison and for use by local or regional programs that mandate their use. The reference to HFCs and PFCs denotes potential emissions from any of a family of compounds, as presented in Appendix D. The Appendix also includes recommended GWPs for selected commercial blends of commonly used refrigeration liquids.

In order to enable comparison of the relative impact of emissions from different GHGs, and to ultimately sum them, an international metric measure termed "carbon dioxide equivalents" (CO_2e) is used. The CO_2e for a gas is derived by multiplying the metric tons of the emitted gas by its associated GWP, and then summed over all the GHGs included in the summary.

$$\textbf{EMISSIONS}\ (\text{MMTCO}_2\text{e}) = \sum_i (\text{MMT GHG}_i) * (\text{GWP}_i)$$

Where,
GHG_i is the applicable mass of the i^{th} GHG, and
GWPi is its corresponding 100-years' time horizon GWP

4.0 EMISSIONS ESTIMATION METHODS

As discussed in Section 3.0 GHG quantification methods selected will depend on data availability and the intended use of the data. A typical method selection hierarchy (which could also be associated with increased uncertainty) consists of direct measurements including mass balance approaches; emission factors including those provided by equipment manufacturers; and engineering calculations that are based on process knowledge.

It practice, overall plant GHG emissions would be estimated using a combination of the methodologies briefly listed below:

- **Calculations using Emission Factors -** For calculating CO_2 combustion emissions when using commercial fuels, a valid approach is to use published emission factors that are based on known fuels properties including their carbon content and heating values. This Emission Factor approach requires valid information about the amount of fuel used. Such information could be obtained from on-site measurements or from a third-party meter of the fuel supplier.

  For calculating CH_4 non-combustion emissions one would primarily use published or manufacturers' emission factors based on equipment type and its expected leakage rate. This would be especially suitable for estimating emissions from pneumatic controllers using natural gas as the controller's gas source (not common in LNG operations), or for assessing fugitive emissions from piping component leaks.

- **Measurements, Sampling and Analysis over a Range of Conditions -** Calculating CO_2 emissions from stationary combustion sources can be performed with a high degree of certainty when using site specific fuel consumption data along with its carbon content or heating value, especially for operations that use fuels with varied characteristics. This is a highly reliable method for distinct emission sources that contribute substantially to overall emissions, though it might not be practical for all smaller combustion sources.

  For CH_4 emissions from non-combustion sources vented emissions could be calculated based on periodic vent volume and duration measurements or knowledge of inlet and outlet concentrations, and total flow rate, for calculating a total material mass balance. Such approaches would be useful for large process or blow-down vents that are key contributors to facility emissions but would generally not be practical for many small sources.

- **Engineering calculations -** For both CO_2 and CH_4 emissions, engineering calculation methods based on process knowledge could be reliable for specific emission sources. However many process simulations may require detailed input data which might not be readily available.

  Engineering calculation could be most useful for estimating emergency venting and flaring emissions, based on process design and atmospheric release settings for emergency relief devices. They could also inform the calculations of CH_4 emissions from storage tanks 'cool down' at terminals and on-board ships. For example, engineering specification can be used to estimate the large amount of BOG (mainly CH_4) generation as cold LNG is sprayed into a warm ship's storage tanks.

As discussed above, although measurements could be an essential component of obtaining robust emissions data, they are expected to be applied only for sources that have a significant contribution to the overall inventory. Direct emissions measurements are only relevant for facilities with existing monitoring systems that were installed either for process control or to meet regulatory requirements.

Regardless of the approach employed, it is essential that entities report consistently over time to ensure the comparability of temporal emissions data and to allow for trends analysis. Emission inventories are advised to list periodic changes made in order to have it documented and to ensure data transparency.

The methods described here represent extracts from the API Compendium yet do not reproduce all of the methods provided therein[7]. The user is referred to the API Compendium for a more expanded discussion of methodology and other technical considerations, especially when LNG operations are integrated with other sectors of the oil and natural gas industry.

4.1 Stationary Combustion Emissions Estimation

This section is designed to be complementary to Section 4.0 of the API Compendium[7] and it is intended to augment that methodology as applicable to combustion emissions for the LNG operations chain. The approaches presented here are applicable to a wide range of geographically diverse LNG operations representing a range of fuel heating values, carbon content and ultimate applications.

Carbon dioxide (CO_2) and water (H_2O) are produced and/or emitted as a result of combustion of hydrocarbon fuels. The combustion stoichiometry follows the general formula below, assuming complete combustion of a generic hydrocarbon (with or without embedded oxygen):

$$C_xH_yO_z + \left(x + \frac{y}{4} - \frac{z}{2}\right)O_2 \rightarrow (x)\,CO_2 + \left(\frac{y}{2}\right)H_2O$$

Where,
x represents the number of carbon atoms in the combusted molecule
y represents the number of hydrogen atoms in the combusted molecule
z represents the number of oxygen atoms (if any) in the combusted molecule

During the combustion process, nearly all of the fuel carbon is converted to CO_2, and this conversion is relatively independent of the fuel or firing configuration. Incomplete combustion of the fuel may result in a portion of that fuel remaining in the exhaust, along with generation of other products of incomplete combustion such as carbon monoxide (CO). The presence of nitrogen in the combustion air, especially when catalysts are not used to limit NO_x emissions, could lead to the emission of small quantities of nitrous oxide N_2O. The methodology described below is somewhat conservative since it is assumes that all the carbon in the fuel is transformed into CO_2 while at the same time it allows for calculating emissions of some minor trace constituents due to incomplete combustion.

Typically the conditions that favor formation of CH_4 emissions (assuming methane is the primary hydrocarbon in the fuel used) may also lead to CO, N_2O, and NO_x formation, and these emissions tend to vary with the type of fuel and firing configuration. Overall, CH_4, CO, N_2O, and NO_x emissions from combustion sources are many times lower than CO_2 emissions.

Options for calculating CO_2 emissions from stationary combustion devices:

(a) Using an emission factor that is multiplied by the annual fuel use, with a default heating value for that fuel; or

(b) Using an emission factor that is based on average carbon content for a given type of fuel along with a measured or estimated annual fuel use; or

(c) Using measured fuel use with periodic measurements of the carbon content of that fuel.

Options for calculating CH_4 emissions from stationary combustion units:

(a) Using an emission factor that is based on annual fuel use and heating value of fuel;

(b) Using an applicable equipment/technology-based emission factors.

4.1.1 CO_2 Emissions Estimation using Emission Factors

Emissions for a particular source or device are calculated as the product of the applicable emission factor (EF) and the activity factor (AF). Emissions for a particular facility or operation are the sum of these individual products:

$$\textbf{Emissions} = \sum \mathbf{AF_i} * \mathbf{EF_i}$$

Where,
Emissions is the estimated emissions for all sources
EF_i represents the emission factor for source i
AF_i represents the activity factor for source i (e.g., source heat load, or fuel consumption per year)

Appendix E provides copies of Table 4.3 and Table 4.5 from the API Compendium (Version 3.0, August 2009). These tables list emission factors for estimating CO_2 and CH_4/N_2O, respectively, for common industry fuels. The data are presented both in US and SI units for ease of application globally. The emission factors used for these calculations could either be those provided in the tables in Appendix E or by other applicable reporting programs.

Each company or project may also develop specific emissions factors based on knowledge of the BOG and LNG hydrocarbon species profiles and their properties. Fuel properties in terms of heating values and carbon content are provided in Table 3-8 of the API Compendium (Version 3.0, August 2009)[7] for commercial fuels. As stated above, the convention used to calculate CO_2 emissions are based on the assumption of full oxidation (i.e. conversion of 100% of the fuel carbon content to CO_2).

Other important considerations when estimating emissions using emission factors include:

- **Standard Gas Conditions -** When converting from a volume basis to a mass basis for a gas stream, the standard conditions used in this document are 14.696 psia and 60°F (101.325 kPa and 15.6°C). At standard conditions one pound-mole has a volume of 379.3 cubic feet. Similarly, one kg-mole occupies 23.685 m^3 at standard conditions.

- **Heating Value Specifications -** When converting between fuel volume and energy, higher heating value (HHV) or gross calorific value is the preferred North America convention. However, lower heating value (LHV) or net calorific value can also be used, and the conversion convention adopted internationally[17] is that LHVs are 10% lower than HHVs for gaseous fuels. Care should be taken to use the heating value that is consistent with the way the emission factor is expressed.
- **Units -** Calculations may be performed in either English or SI units. Users should take care to use a consistent set of units throughout the emissions estimation process in order to ensure that the results are expressed in metric tons (or 'tonnes'). Appendix B of this document summarizes unit conversions that are applicable for LNG operations. Additional guidance on conversions that are generally applicable for emission estimation is available in Section 3.6 of the API Compendium (version 3.0, August 2009)[7], which provides a tabulation of unit conversions useful for such calculations.

The API Compendium documents the carbon contents for natural gas and similar gaseous fuels in different heating value ranges. In the United States, pipeline quality natural gas is classified as having an HHV greater than 970 Btu/scf but less than 1,100 Btu/scf[18], although many pipelines in the U.S. have broader specifications than these heating value ranges. Globally, LNG streams consist of mixtures of hydrocarbons that contain different percentages of hydrocarbon species as shown by the compositional profiles of LNG from different origins presented earlier in Table 1.

Table 8 presents carbon content and emission factors data for use when estimating CO_2 emissions from the combustion of LNG fuels based on information about their higher heating values ranges. LNG streams with higher heating values tend to have a higher content of higher molecular weight hydrocarbons which affects the carbon content of the gas and its emissions per unit of energy consumed.

[17] IPCC, *2006 Guidance for National GHG Emission Inventories*, Volume 2, Chapter 2, Table 2.6, 2007
[18] Environmental Protection Agency (EPA), *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2007*, Annex A, Table A-38, April 15, 2009.

Table 8. Natural Gas Carbon Contents and Emission Factors for Different Higher Heating Value Ranges [(a)]

HIGHER HEATING VALUES	Carbon Content [a] g C/10^3 Btu	CO_2 EMISSION FACTOR tonnes CO_2/10^6 Btu	tonnes CO_2/TJ
U.S. Average [(b)]	14.47	0.05306	50.29
1,000 to 1,025 Btu/scf	14.43	0.05291	50.15
1,025 to 1,050 Btu/scf	14.47	0.05306	50.29
1,050 to 1,075 Btu/scf	14.58	0.05346	50.67
1,075 to 1,100 Btu/scf	14.65	0.05372	50.92
1,100 to 1,125 Btu/scf	15.07	0.05526	52.38
1,125 to 1,150 Btu/scf	15.09	0.05533	52.44
1,150 to 1,175 Btu/scf	15.15	0.05555	52.65
1,175 to 1,200 Btu/scf	15.27	0.05599	53.07
1,200 to 1,225 Btu/scf	15.38	0.05639	53.45
1,225 to 1,250 Btu/scf	15.52	0.05691	53.91
Greater than 1,250 Btu/scf	16.33	0.05988	56.76

[(a)] Based on data from worldwide LNG operations including U.S. produced gas. The data is provided on an HHV (higher heating value) basis.
[(b)] The gas compositions included in this analysis does not include H_2.

4.1.2 CO_2 Emissions Estimation using Fuel Composition

This section discusses estimating CO_2 emissions from information about fuel properties and its quantity. This approach is based on a material balance in which the metered, or estimated, fuel consumption data is used together with information about fuel composition to derive CO_2 emissions.

LNG streams are mixtures of different hydrocarbons. The carbon content of a fuel mixture is a weighted average of the individual component carbon contents. This is determined by first calculating the weight percent carbon of each of the fuel components, which is accomplished by multiplying the molecular weight of carbon by the number of moles of carbon and dividing by the molecular weight of the compound.

Table 9 below lists the carbon content, molecular weights and higher heating values (HHV) for species that are typical components of LNG streams, and which are the building blocks for deriving emissions based on LNG composition. The data are provided both in U.S. and international units at standard conditions of 60^{o}F (15.6^{o}C) and 1 atmosphere.

Table 9. Carbon Content and Higher Heating Values for LNG Constituents [(a)]

Compound	Moles Carbon per Mole	Carbon Content (Wt. %)	MW	HHV (Btu/scf)	HHV MJ/standard-m^3
Nitrogen	0	0.0%	28.01	0	0
Carbon Dioxide - CO_2	1	27.3%	44	0	0
Methane - CH_4	1	74.8%	16.04	1,010	37.620
Ethane - C_2H6	2	79.8%	30.07	1,770	65.904
Propane - C_3H_8	3	81.6%	44.1	2,516	93.799
Iso-Butane - i-C_4H_{10}	4	82.6%	58.12	3,252	121.17
n-Butane - n-C_4H_{10}	4	82.6%	58.12	3,262	121.54
Iso-Pentane - i-C_5H_{12}	5	83.2%	72.15	4,001	149.07
n-Pentane - n-C_5H_{12}	5	83.2%	72.15	4,009	149.39
n-Hexane - n-C_6H_{14}	6	83.5%	86.18	4,756	177.21

[(a)] Higher Heating Value at 60°F, 1 atm. Data taken from *API MPMS* Chapter 14, Section 5, Table 1; Gas Processors Suppliers Association *Engineering Data Book*, Figure 23-2,; Perry's *Chemical Engineers' Handbook*, Table 3-207..

The following steps are used to perform these calculations:

(a) Speciation for the mixture (for gaseous and light liquid fuels)using gas chromatography to obtain the compositional analysis for each fuel component in mole percent;

(b) Calculation of the weight percent of the hydrocarbon constituents for the mixture by multiplying the mole percent of each component by its molecular weight;

(c) If complete speciation of the mixture is not available, an average molecular weight, $MW_{Mixture}$, may be estimated from species profiles tables for similar LNG streams.

Table 10 provides examples of a range of LNG streams with their species profiles, which were used to derive the $MW_{Mixture}$, fuel weight percent C, mixture HHV and conversion factors (in different units) for calculating CO_2 emissions from the combustion of these LNGs.

One of the features of LNG operations is that the carbon content of the combusted fuel fractions may vary throughout the operations chain - from processing to shipping and on to regasification. During liquefaction, the fuel used to fire the combustion devices typically has lower carbon content and heating value than the feed stream used for producing the LNG, since it consists mostly of lower molecular weight boil-off gas and most of the inlet gas stream's inert nitrogen.

The carbon content and heating value of the finished LNG differs from the feed gas due to removal of excess trace contaminants, e.g. CO_2, H_2S, and nitrogen and higher molecular weight hydrocarbons. During LNG shipping, if BOG is used as ship's fuel, the carbon content of the fuel that is used for propulsion and compression consists also of the lighter hydrocarbon fraction that is captured as boil-off gas (BOG), and is enriched in nitrogen due to nitrogen's low boiling point relative to methane, making its composition somewhat different from that of the LNG being transported. For regasification operations, the fuel used would again have somewhat different carbon content due to removal of the BOG during the voyage.

Table 10. Compositions and Emission Factors for Select LNG Streams [(a)]

LNG COMPOUNDS	CHEMICAL FORMULA	EXAMPLES OF LNG STREAMS COMPOSITION (WT %)					
		(A)	(B)	(C)	(D)	(E)	(F)
Nitrogen	N_2	0.05%	0.43%	0.10%	0.02%	0.31%	ND
Methane	CH_4	92.07%	84.55%	91.43%	92.63%	91.02%	99.80%
Ethane	C_2H_6	6.89%	10.93%	7.42%	6.89%	7.53%	0.10%
Propane	C_3H_8	0.97%	3.21%	0.87%	0.35%	0.95%	ND
iso-Butane	$i\text{-}C_4H_{10}$	0.00%	0.47%	0.08%	0.02%	0.08%	ND
n-Butane	$n\text{-}C_4H_{10}$	0.00%	0.38%	0.09%	0.03%	0.08%	ND
iso-Pentane	$i\text{-}C_5H_{12}$	0.02%	0.02%	0.01%	0.02%	0.01%	ND
n-Pentane	$n\text{-}C_5H_{12}$	0.00%	0.00%	0.01%	0.04%	0.01%	ND
	TOTAL	100.00%	99.99%	100.00%	100.00%	100.00%	99.90%
Fuel mixture MW		17.30	18.89	17.42	17.16	17.48	16.04
Fuel weight % C		75.53%	75.93%	75.54%	75.50%	75.31%	74.82%
Heating Values							
HHV (Btu/scf)		1,077.40	1,156.70	1,082.90	1,070.60	1,082.80	1,009.80
HHV (MJ/std-m^3)		40.13	43.09	40.35	39.89	40.35	37.62
LHV (TJ/Gg)		48.75	52.35	49.01	48.45	49.01	45.70
Emission Factors							
Lbs CO_2 /10^6 Btu		117.25	119.89	117.46	117.01	117.54	114.88
tonnes CO_2 /10^6 Btu		0.0532	0.0544	0.0533	0.0531	0.0533	0.0521
tonnes CO_2 / TJ		50.41	51.54	50.50	50.31	50.53	49.39
Tg C / QBtu		14.50	14.83	14.53	14.48	14.54	14.21

[(a)] Examples consist of six LNG streams and are based on confidential data
[(b)]) Units: MJ = 10^6 Joules; TJ = 10^{12} Joules; Gg = 10^9 grams; TG = 10^{12} grams = million tonnes; QBtu = 10^{15} Btu

Due to the strict dependence and tight correlation between the CO_2 emissions factors and the heating values of the constituents comprising the LNG product, it is possible to derive empirical relations to represent this correlation. These correlations were derived both for the North America convention of specifying fuels in terms of HHV and energy throughput in terms of

Btu/scf (Figures 10) and also in Standard International (SI) units where fuel heating value is specified in terms of LHV and energy throughput in terms of units of TJ/Gg (Figure 11).

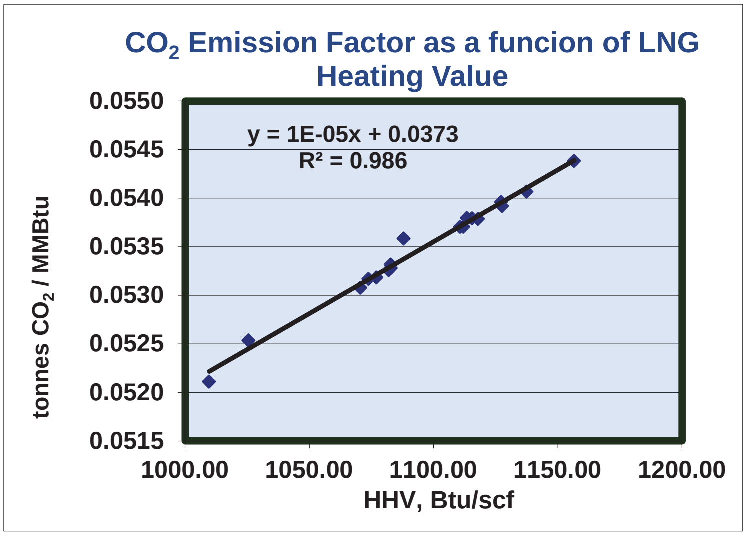


Figure 10. CO_2 Emission Factors (EF) as a Function of LNG Higher Heating Values (HHV) [EF ($TCO_2/10^6$ Btu) = $1*10^{-5}$ HHV(Btu/Scf) + 0.0373]

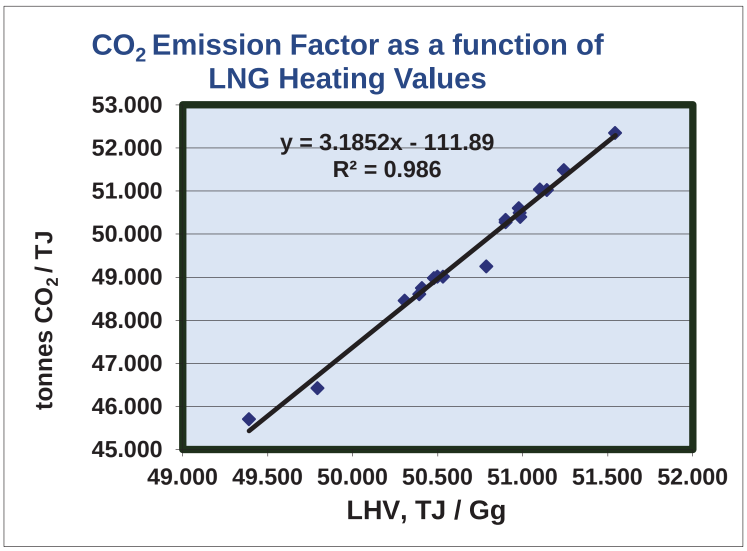


Figure 11. CO_2 Emission Factors (EF) as a Function of LNG Lower Heating Values (LHV) [EF (TCO_2 /TJ) = 3.185 LHV(TJ/Gg) – 111.9]

The correlation equations provided above may be used for deriving site-specific emission factors, on either an HHV or an LHV basis respectively, for estimating CO_2 emissions from the combustion of the produced LNG. This approach will allow companies to tailor their calculations to their specific circumstances based on the availability of data on the heating values of the LNG fractions produced, transported, stored and used. For example, for LNG production, the higher the LNG product HHV, the **less** energy it takes to liquefy it, and therefore, fuel consumption and CO_2 emissions are reduced relative to a lower HHV LNG product, which is exactly the opposite of what happens when combusting a higher HHV LNG product. .

Using actual fuel consumption data in conjunction with its composition is the preferred method for estimating combustion emissions.

When metering all of the streams to measure fuel consumption is not practical, alternative approaches are needed for engineering estimates of fuel consumption. Equipment fuel consumption rates could be estimated by the following:

(a) Equipment rating (horsepower) using actual horsepower is the most accurate approach. Manufacturer or maximum horsepower rating and load can be used to estimate fuel usage, recognizing that these may overestimate emissions.

(b) Operating hours can be based on recorded monthly operating hours from which yearly operating hours can be calculated. Alternatively, an estimator for total operating hours may be percent run time or downtime hours;

(c) Equipment thermal efficiency allows the estimation of required heat input per energy output, with conversion factors that are usually available from equipment vendors. A list of conversion factors that may be used for this calculations are available in Table 4-2 of the API Compendium (version 3.0, August 2009)[7].

4.1.3 Emissions from Flares

Flares are used in all segments of the oil and natural gas industry to manage the disposal of unrecoverable gas via combustion of hydrocarbon products from routine operations, processing, upsets, or emergencies. A wide variety of flare types are used in the industry, ranging from small open-ended pipes at production wellheads, to large horizontal or vertical flares with pilots and air- or steam-assist, such as in processing plants. Emissions of CO_2, N_2O, and NO_x are formed as products of combustion, and CH_4 emissions may result from incomplete combustion or from time periods where there is no flame at the flare tip due to operational problems.

Flares have been documented to achieve 98% combustion efficiency, and where no site-specific data is available, the IPCC[19] recommends using this destruction efficiency in conjunction with "generic" gas composition at gas processing plants to calculate GHG mass emission rates for flares.

Table 11 presents emission factors that are applicable to estimate flaring emissions for sweet and sour gas processing, and could also be applicable to LNG processing and liquefaction plants. For classifying gas streams into sweet and sour, the most common specification is based on the hydrogen sulfide content of 0.25 grain H_2S per 100 cubic feet of gas, or approximately 4 ppmv. The data in Table 11 follows the IPCC guidance and recommends also that different sets of emission factors be applied to operations in developed countries vs. other countries (such as developing countries and countries with economies in transition) to reflect different levels of flaring based on presumed local practices.

[19] IPCC. 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 2, Chapter 4 (Fugitive Emissions), Table 4.2.4, 2006 Revised November 2008.

Table 11. GHG Emission Factors for Gas Flares in Gas Processing and Liquefaction [(a)]

Flare Source	Units [(b)]	CO_2	CH_4	N_2O
Developed Countries				
Sweet Gas Processing (H_2S < 4ppm)	$Gg/10^6\ m^3$ (raw gas feed)	$1.8*10^{-3}$	$1.2*10^{-6}$	$2.5*10^{-8}$
	tonnes/ 10^6 scf (raw gas feed)	$5.1*10^{-2}$	$3.4*10^{-5}$	$7.1*10^{-7}$
Sour Gas Processing (H_2S > 4ppm)	$Gg/10^6\ m^3$ (raw gas feed)	$3.6*10^{-3}$	$2.4*10^{-6}$	$5.4*10^{-8}$
	tonnes/ 10^6 scf (raw gas feed)	0.10	$6.8*10^{-5}$	$1.5*10^{-6}$
Other Countries				
Sweet Gas Processing (H_2S < 4ppm)	$Gg/10^6\ m^3$ (raw gas feed)	$1.8*10^{-3} – 2.5*10^{-3}$	$1.2*10^{-6} – 1.6*10^{-6}$	$2.5*10^{-8} – 3.4*10^{-8}$
	tonnes/ 10^6 scf (raw gas feed)	$5.1*10^{-2} – 7.1*10^{-2}$	$3.4*10^{-5} – 4.5*10^{-5}$	$7.1*10^{-7} – 9.6*10^{-7}$
Sour Gas Processing (H_2S > 4ppm)	$Gg/10^6\ m^3$ (raw gas feed)	$3.6*10^{-3} – 4.9*10^{-3}$	$2.4*10^{-6} – 3.3*10^{-6}$	$5.4*10^{-8} – 7.4*10^{-8}$
	tonnes/ 10^6 scf (raw gas feed)	0.10 – 0.14	$6.8*10^{-5} – 9.3*10^{-5}$	$1.5*10^{-6} – 2.1*10^{-6}$

[(a)] IPCC, 2006 IPCC Guidelines (footnote 19)
[(b)] Extracted from Tables 14-11 and 14-12 of the 2009 API Compendium which converted the metric units presented by the IPCC to English Units
[(c)] Per IPCC designation this refers to developing countries or countries with economies in transition

4.2 Vented Emissions

Vented emissions are releases to the atmosphere as a result of the process or equipment design or operational practices. Vented emissions may come from a variety of non-fired stacks and vents, which tend to be very specific to the type of operation. A broader discussion of emission sources and estimation methods that apply in general to vented emission sources in the oil and natural gas industry are presented in Section 5.0 of the API Compendium (Version 3.0, August 2009). However, for LNG operations the primary design characteristic is that all BOG is captured and returned to storage tanks, consumed as fuel, or fed into a boil-off gas recondenser. As a consequence routine continuous venting from operations is minimized, as discussed in the subsections below, which provide a brief recap of some of the key vented sources that are applicable to LNG operations.

4.2.1 Gas Treatment Processes

To optimize effectiveness and efficiency of developing an emissions inventory, operators may choose to use a mix of estimation approaches relying on methods presented here, additional methods that are available in the API Compendium or specific company information that is available for a particular operation. Whatever the method selected, it is important to document the specific method used for each vent source, and to ensure consistency in the application of methods among similar sources for a given inventory period.

(i) Dehydration Emissions

These include emissions attributable to glycol dehydrators, glycol pumps, solid bed desiccant dehydrators and other dehydration alternatives. Glycol dehydrators are used to remove water from gas streams by contacting the gas with a liquid glycol stream in an absorber. The liquid glycol absorbs the water from the gas stream, and the water is driven from the glycol by heating the glycol in the reboiler (or regenerator). A small amount of CH_4 is absorbed by the glycol; most of the absorbed methane is removed from the glycol upstream of the regenerator in a flash drum (common to all glycol units) and used as fuel in the glycol reboiler. A much smaller proportion is driven off to the atmosphere in the glycol regeneration step. Methane emissions from uncontrolled glycol dehydration units occur because the CH_4 that is not removed from the glycol stream in the upstream flash drum passes directly through the regenerator and is vented to the atmosphere. Additional methane emissions can occur if stripping gas is used to reduce the residual water content of the regenerated glycol.

Combustion emissions from the glycol reboiler are responsible for most of the CO_2 emissions, and those are accounted for separately using one of the combustion methods discussed in Section 4.1 above. Similarly, if the dehydration vents are routed to a flare, these emissions should be estimated separately using applicable techniques.

Dehydration within natural gas liquefaction plants is generally performed via solid bed desiccant systems (molecular sieve). These systems typically have lower CH_4 (and CO_2) emissions than glycol-based systems. Molecular sieves remove water from natural gas by surface adsorption. Molecular sieve units use granules of a porous material comprised primarily of alumina and silica. Wet gas is passed over the granules, which are contained inside a vertical pressure vessel. Water contained in the gas is adsorbed onto the surface of the desiccant materials. Once loaded, i.e. saturated with water, the beds are regenerated by passing hot gas through the bed of granules to drive the water off the surface of the granules. GHG emissions are limited by cooling the regeneration gas to condense the desorbed water, separating the condensed water from the regeneration gas, and returned the regeneration gas to the process. CO_2 emissions from the molecular sieve regeneration process are typically minimized by using a waste heat source, e.g. gas turbine exhaust, to heat the regeneration gas.

Estimating emissions from each glycol or solid bed desiccant dehydrator will require the following data for the period of interest:

- **(a)** Glycol dehydrator feed natural gas flow rate in 10^6 scf;
- **(b)** Glycol dehydrator absorbent circulation pump type;
- **(c)** Whether stripper gas is used in glycol dehydrator;
- **(d)** Whether a flash tank separator is used in glycol dehydrator;
- **(e)** Total time the glycol dehydrator is operating in hours;
- **(f)** Type of absorbent used;
- **(g)** Temperature (degrees Fahrenheit) and pressure (psig) of the wet natural gas;
- **(h)** Concentration of CH_4 and CO_2 in wet natural gas;
- **(i)** Efficiency of vent gas controls used, if any.

A more detailed description of the emission estimation methods for glycol dehydrators, glycol pumps, solid bed desiccant dehydrators or alternative dehydrators are provided in Section 5.1.1, 5.1.2, 5.1.3, and 5.1.4, respectively, in the API Compendium (Version 3.0, August 2009)[7].

(ii) Acid Gas Removal/Sulfur Recovery Units

Natural gas (which contains H_2S and CO_2), must be treated to reduce their concentration to a level that allows for continuous LNG production and meets LNG product specifications, typically less than 50 ppmv for CO_2 and 4 ppmv for H_2S. Acid Gas Removal (AGR) units remove H_2S and CO_2 by contacting the sour gas with a liquid solution (typically amines). AGR units have similar equipment to those in glycol dehydrator units (an absorber, liquid circulation pump, and a reboiler to regenerate the absorber liquid), although the solvent regeneration system in an AGR generally employs additional equipment relative to the regeneration system in a glycol unit.

Sulfur Recovery Units (SRUs) can also be used to recover elemental sulfur from H_2S and other organic sulfur species, e.g. mercaptans. The most commonly used sulfur recovery process is the Claus process, in which the H_2S undergoes thermal and catalytic oxidation processes, both of which form elemental sulfur through the conversion of H_2S to sulfur and water. During the thermal oxidation process, H_2S is partially combusted by intentionally providing insufficient air for complete combustion. In so doing, only some of the H_2S is converted into sulfur, water, and SO_2. The SO_2 is then consumed in the catalytic process steps downstream of the thermal oxidation step (typically multiple reactor beds in series), reacting with remaining H_2S to form sulfur and water. A tail gas treating unit is typically used with Claus units to maximize total sulfur recovery. It does so by converting all non-H_2S sulfur species back into H_2S, then using another amine unit to capture that H_2S and recycle it back to the inlet of the Claus unit.

If hydrocarbons are present in the H_2S-rich stream feeding the Claus unit, those hydrocarbons are combusted in the thermal oxidation step, producing incremental CO_2 emissions. CO_2 present in the feed to the Claus unit is an inert that does not participate appreciably in the Claus reaction.

Many LNG facilities vent CO_2 removed from the feed gas to the atmosphere; depending on the feed gas concentration of CO_2, this can be a very significant contributor to total facility GHG emissions. In some LNG plants, the CO_2-rich acid gas stream, which can include appreciable quantities of H_2S, is sequestered using compressors to inject the gas into a disposal well.

When there is only trace quantities of H_2S in the feed gas to an LNG facility, any H_2S or other sulfur species removed from the feed gas in the AGR unit is generally either combusted by routing it to an incinerator, or sequestered in a disposal well.

For each acid gas removal unit the preferred emissions estimation approach relies on a mass balance that is based on the following data:

(a) Throughput of the acid gas removal unit using either a meter or engineering estimate, in 10^6 scf;

(b) Average volumetric fraction of CO_2 content of the natural gas into and out of the acid gas removal unit.

A more detailed description of the emission estimation methods applicable for acid gas removal or sulfur recovery units are provided in Section 5.1.5 in the API Compendium (Version 3.0, August 2009). Use of Acid Gas Injection should be accounted for by subtracting those injected volumes from the calculation.

(iii) Other Generic Process Vents

These vents represent a generic class of process vents through which gas may be vented, or released, without combustion. As a result, these emission sources are more likely to contain CH_4 than CO_2. These emission sources may include small, miscellaneous vents that occur on an intermittent basis, or may encompass an overall process vent. Normally all but small vented gas streams are routed to a flare system and would be included in the combustion emissions.

Due to the wide variability of sources that could be considered, there are no emission factors or default values for estimating CH_4 and/or CO_2 emissions. A general material balance approach is required, based on source-specific measurements or estimates of the vent rate and concentrations.

For estimating emissions from such vents one has to assess the following during the period of interest for developing an emissions inventory:

(a) Is the venting continuous or periodic?

(b) Rate of continuous venting or duration and number of periodic venting;

(c) Unique physical volumes that are characteristic for each event (or categories of events);

(d) Average CO_2 and CH_4 content of each physical volume vented (or categories of such events);

(e) Total CO_2 and CH_4 vented associated with these events expressed in terms of mass CO_2e.

A more detailed description of emission estimation methods from such non-combustion vents is provided in Section 5.3 of the API Compendium (Version 3.0, August 2009).

4.2.2 Compression, Storage, Loading and Unloading

Throughout the LNG operations chain, there are nominal methane emissions due to the liquefaction and revaporization of natural gas. LNG being a cryogenic liquid requires maintenance of a thermodynamic equilibrium near its boiling point. For example, for LNG storage tanks, BOG may be either flared or (less commonly) vented, if the vapor generation rate exceeds BOG compressor(s) or reliquefaction unit capacity. Similarly, during LNG loading or unloading, compression is required to capture BOG which is either returned it to a storage tank, used as fuel, reliquefied, or routed it to a recondenser.

In this section we will address such potential methane emission sources targeting primarily emissions associated with compressors blowdown and loading/unloading of LNG.

(i) Compressors Venting

Emissions from reciprocating compressors are typically associated with rod packing and unflared blowdown venting in its operating mode; blowdown venting in its pressurized standby mode; and leakage through its isolation valve in its shut-down depressurized mode.

Centrifugal compressors may either include oil seals that require periodic degassing, or dry seals that pump gas between the seal rings creating a high pressure barrier to leakage. Emissions are associated with blowdown venting in its operating mode, wet-seal degassing in its operating mode and leakage through the isolation valves in its shut-down depressurized mode.

In LNG facilities most, if not all, of the venting is either captured and rerouted to storage vessels or else is sent to a flare to minimize release of cryogenic liquid vapor to the atmosphere. If atmospheric venting does occur emissions could be estimated based on the following information:

(a) Rate of venting in scf/hour;

(b) Vent time (hours) for each venting event;

(c) Mole fraction of GHG in the vent gas;

(d) Total mass emissions in terms of CO_2e corresponding to the emissions inventory period.

(ii) Pipeline Transfers

Methane and potentially small amounts of CO_2 are also vented or lost to the atmosphere if the BOG is not captured during pipe transfer of LNG, either during loading for transport, off-loading for storage or vaporization, or from gathering lines at terminals and peak-shaving plants.

Table 12 lists typical loss rates for storage, loading and unloading of LNG if BOG is not captured during any of these operational steps (note this is the exception, not the normal design approach). The listed loss rates provided in Table 12 and the composition of the LNG stream being handled, should be used to estimate potential CH_4 and CO_2 emissions only if these emissions are not captured or routed to flare. The data in Table 12 could also be useful to assess the potential for GHG emission reductions when operational changes are being implemented.

Table 12. Storage, Loading and Unloading: Typical Loss Rates

Source	Typical Venting or Loss Rate	Units
BOG from storage tanks [a]	0.050%	Of total tank volume per day
BOG from vessels during shipping [b]	0.15%	Of total ship storage volume per day
Transfer pipe loss - foam insulation [c]	0.0012%	per km LNG transfer pipe[d]
Transfer pipe loss - powder insulation [c]	0.0006%	per km LNG transfer pipe[d]
Transfer pipe loss – vacuum insulation [c]	0.00012%	per km LNG transfer pipe[d]

[a] D. Féger, “An innovative way of reducing BOG on existing or ’new built’ LNG storage tanks”, , Proceedings LNG16 Congress, Algeria, April 2010
[b] Sempra LNG, “GHG life-cycle emissions study: U.S. Natural Gas Supplies and International LNG”, November 2008
[c] B. Kitzel, “Choosing the right insulation”, LNG Industry, Spring 2008
[d] Based on LNG transfer rate of 228m^3/min and heat transfer coefficient of pipe wall insulation, U(w/m^2k) = 0.26 (foam), 0.13 (powder), and 0.026 (vacuum),
[e] EPA, Natural Gas Star, “Liquefied Natural Gas Emissions Reduction Opportunities: Lessons Learned” Natural Gas STAR Technology Transfer Workshop, Alaska, May 2006

4.3 Fugitive Emissions

Fugitive emissions are defined as unintentional emissions that could not reasonably pass through a flare or exhaust stack, chimney, vent, or other functionally-equivalent opening. Any pressurized equipment has the potential to leak where two surfaces meet in a non-welded or otherwise non-bonded manner; these leaks generally occur through valve stems, flanges, threaded connections, pump or compressor shaft seals, or related equipment. Fugitive emissions also originate from non-point evaporative sources. Section 6.0 of the API Compendium (Version 3.0, August 2009) presents a thorough discussion of the different methods available for the quantification of fugitive emissions at the installation, equipment or leaking component level. Systems handling LNG generally require welded rather than flanged or threaded connections, thereby minimizing fugitive emissions.

This section presents a list of the available approaches with a compilation of published emission factors for estimating emissions from LNG operations. The discussion focuses primarily on estimating CH_4 emissions with CO_2 emissions being of secondary consideration with the exception of gas processing for the removal of CO_2 when the gas is sourced from CO_2-rich reservoirs.

Options for estimating fugitive GHG emissions include:

(a) Component counts and emission factors;

(b) Monitoring to detect leaking components; and

(c) Engineering calculations using process model simulations.

4.3.1 Component Counts and Emission Factors

This method is based on counts (or estimates) of the population of different component types (e.g. threaded connectors, valves, etc.) and applying the corresponding emission factors to the components population (without distinction between leakers or non-leakers) to derive total emissions. Emission factors that are provided in terms of total hydrocarbon may be scaled based on knowledge of stream composition to obtain CO_2 and CH_4 fugitive emissions.

This method is easy to apply since it requires only knowledge of the counts of valves, threaded connectors, etc. The disadvantage of using these population factors is that they only provide an estimate of potential emissions, not actual emissions. This approach is also inadequate for providing trends in changes in emissions over time, since the only variable is equipment/ component count, which in most operations does not change significantly.

Table 13 presents a set of default CH_4 emission factors for components and devices in LNG storage and loading or unloading at import/export terminals. These factors represent average emissions per hour per component. For quantifying total fugitive CH_4 emissions for these operations, the number of components in each of the specified categories and their hours of operation will have to be taken into account. The component counts should be applied to all ‘non-vapor recovery compressors’ for which a separate integrated emission factor is provided. Table 13 also presents separately an emission factor for vapor recovery compressors based on the compressors (and not component) counts.

These emission factors should not be used for LNG terminals with supplies of inert gas (such as nitrogen), which typically use the inert gas – rather than natural gas - for seals and packing. Most natural gas liquefaction plants and LNG receiving terminals have such nitrogen systems. Also, it is important to note that in LNG service when a PRV leaks the leakage will typically be into the relief header going to a flare, which may result in CO_2 being emitted to atmosphere, but no hydrocarbons.

Table 13. Default Methane Emission Factors per Component Population For LNG Storage and Import/Export Terminals

Component/ Device	Emission Factor [a] (scf/hour/component)
Valve	**1.19**
Pump Seal	**4.00**
Connectors (*flanges and threaded fittings*)	**0.34**
Other[b]	**1.77**
Vapor Recovery Compressors [c]	**4.17** *(per compressor)*

[a] See Reference 20; based on an assumed methane content of 93.4%
[b] Emission factor is in terms of scf/hour/compressor
[c] Emission factor is in terms of scf/hour/compressor

4.3.2 Monitoring to Detect Leaking Components

Emissions may be estimated by conducting a survey to identify leaking components and 'leaker' emission factors to those sources found to be emitting hydrocarbon above a given threshold. Estimating emissions using leaker emission factors is more accurate than population factors because leaker factors are applied to leaks once they are identified. Since equipment leaks occur randomly within a population of components, determining the number of actual leaking component improves the emissions estimate and can be used to improve site performance by accelerating maintenance on known leak sources.

For applying this method for LNG service, emissions can be calculated by a simplified approach outlined by the U.S. EPA[20]:

(a) All applicable components are monitored at least once during the inventory period,

(b) Components classified as ‘leakers’ (>10,000ppm) in each of the component categories are counted and multiplied by the respective ‘leaker’ emission factors and hours of operation to derive total emissions

(c) Additional emissions from the vapor recovery compressors should be accounted for by applying to population emission factor to the total vapor recovery compressor count.

Table 14 provides a set of generic emission factors that can be used to estimate fugitive emissions from identified leakers at natural gas processing plants[21]. These factors are applicable for LNG facilities including liquefaction and regasification of LNG and could also be applied for leakers at gathering pipelines and compressors.

These factors also assume that facilities are monitored periodically to detect leaking components (> 10,000ppm) using an appropriate screening device. The emission factors in Table 14 are provided in terms of total hydrocarbon and should be converted to CO_2 and CH_4 emissions and ultimately summed up as CO_2e based on site-specific gas composition data.

[20] US Environmental Protection Agency, Federal Register, Volume 76, page 80594, December 23, 2011 and amended at Volume 77, 51495, August 24, 2012 ; Tables W-5 and W-6

[21] US Environmental Protection Agency, Federal Register, Volume 76, page 80594, December 23, 2011; Table W-2

Table 14. Default Total Hydrocarbon Emission Factors for Detected Leaking Components in Gas Processing [a]

	Natural Gas Processing Service (scf/hour/component)
Compressor "Leaker" Components	
Valve [b]	14.84
Connectors (*flanges and threaded fittings*)	5.59
Open-ended Line	17.27
Pressure Relief Valve	39.66
Meter	19.33
Other "Leaker" Components, Non-Compressor, Gas Service	
Valve [b]	6.42
Connectors (*flanges and threaded fittings*)	5.71
Open-ended Line	11.27
Pressure Relief Valve	2.01
Meter	2.93
Gathering Pipelines [c]	2.81 *(scf/hour/mile)*

(a) See Reference 21
(b) Valves include control valves, block valves and regulator valves
(c) Only this factor is in units of "scf/hour/mile"

4.4 Transportation Emissions

Transportation GHG emissions associated with motor vehicles, vessels, barges, tank trucks, rail cars or tankers, should be accounted for in an overall GHG emissions inventory when they are germane to company operations. Emissions from such mobile sources are due to the type of fuels used to propel them.

Table 15 provides a collection of emission factors that are applicable to the transportation of LNG by land or sea, while utilization a variety of fuels, including LNG or BOG, to propel the transport carriers. The emission factors listed are based on GREET (Greenhouse gases, Regulated Emissions, and Energy use in Transportation), which is a full life-cycle model sponsored by the Argonne National Laboratory (U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy). It is designed to fully evaluate energy and emission impacts of advanced and new transportation fuels and their fuel cycle from well to wheel and more. The emission factors in Table 15 are those embedded in version 1.8b of the model as updated by the California Air Resources Board (CARB) for estimating the carbon intensities of transportation fuels as part of the Low Carbon Fuels Standard (LCFS) rule[22]. The GREET modeling approach has also been integrated by the U.S. EPA into their Motor Vehicle Emissions Simulator (MOVES) to account for the fuel cycle “well to pump” energy use and contribution to emissions[23].

[22] CARB, Low Carbon Fuel Standard, http://www.arb.ca.gov/fuels/lcfs/lcfs.htm#modeling; updated May 23, 2013
[23] U.S. EPA, Office of Transportation and Air Quality, MOVES (Motor Vehicle Emission Simulator); http://www.epa.gov/otaq/models/moves/index.htm; updated May 30, 2013

Table 15. GHG Emission Factors for Combustion of Fuels for LNG Transportation [(a)]

	Fuel	CO_2	CH_4	CO_2	CH_4
		tonnes/ 10^6Btu	tonnes/10^6Btu	tonnes/TJ	tonnes/TJ
Ocean Tanker					
	Bunker Fuel	0.0845	0.0000046	80.11	0.00434
	Diesel	0.0776	0.0000046	73.59	0.00434
	Natural Gas/BOG	0.0576	0.0000916	54.57	0.08684
Barge					
	Residual Oil	0.0848	0.0000019	80.37	0.00180
	Diesel	0.0779	0.0000019	73.85	0.00180
	Natural Gas	0.0579	0.0000381	54.90	0.03610
Locomotive					
	Diesel	0.0777	0.0000039	73.62	0.00374
	Natural Gas	0.0577	0.0000788	54.65	0.07469
	LNG	0.0583	na	55.29	na
Trucks Class 8B)					
	Diesel	0.0778	0.0000015	73.75	0.00144
	LNG	0.0593	0.0000305	56.24	0.02889
Trucks (Class 6)					
	Diesel	0.0779	0.0000015	73.85	0.00145
	LNG	0.0594	0.0000307	56.29	0.02909

[(a)] Extracted from the California GREET adaptation (CA-GREET 1.8b) that is a modified version of the latest GREET 1.8b model (released 9/05/2008) by Argonne National Laboratory

4.5 Non-routine Emissions

Non-routine emissions associated with LNG operations are primarily associated with start-up or shut-down emissions along with flaring during plant upset. There is very minimal open literature data on this topic; therefore the data provided in Table 16 should be viewed only as an example. Site specific data that better reflects an entity's facility design and operating practices are more suitable for calculating GHG emissions for specific inventory applications. The data presented in Table 16 is only for combustion/flaring emissions; it does not account for any direct venting during plant upset, start-up, or shutdown. It should be noted that peak rate CO_2 emissions associated with flaring during an emergency event could exceed 3000 tonnes/hour, but this will be only for a short period (5 – 20 min). Hence, using a single emission factor for an inherently transient event like flaring is not very accurate. Emissions can be estimated from the number of events, and total CO_2 emissions per event. A better approach would be to install flow meters in the flare headers and measure the total volume of the flared gas.

Table 16. Example of Emission Factors for Non-routine Emissions (per million tons per year capacity) [(a)(b)]

Source	CO_2 (Tonnes/hour)	CH_4 (Tonnes/hour)	N_2O (Tonnes/hour)
Heaters			
Start-up regeneration gas heater	0.282	0.0000242	0.0000005
Start-up hot oil heater	3.25	0.00028	0.0000060
Marine Flares			
Warm ship cool-down	12.17	0.015	0.000025
Cold ship cool-down	5.70	0.0069	0.000011
Maintenance	0.000927	0.00113	0.0000019
Plant Upset			
Wet flare	53.10	0.059	0.000098
Dry flare	44.51	0.050	0.000083

[(a)] Based on Darwin LNG public environmental report; values are rounded-off and normalized per 1 MTPA capacity to provide an indication of the order of magnitude of the respective GHG emissions.
[(b)] Assumption: all emissions are due to combustion/flaring of natural gas and LNG with no direct venting

5.0 METHODOLOGY IMPLEMENTATION AND IMPROVEMENTS

Improving the estimation of GHG emissions from the LNG operations chain would require improved data availability of relevant information of activity patterns such as volume of gas liquefied, number and duration of ship loadings/unloadings, storage, emergency equipment counts, etc. A more detailed list of potential emission sources in the LNG operations chain is provided Tables 4 – 7. Knowledge of these equipment counts and activities, along with the applicable emission factors, are needed for the quantification of actual emissions. Caution should be exercised when using activity data for new and existing sources from publicly available permit applications or EIS studies, since actual emissions would likely vary from values stated in permits that are designed to enable operation at full capacity.

5.1 Implementation Considerations

When implementing the methodology described in this document one has to consider the following for the different source categories:

- **Combustion Sources -** Activity factors and emissions for combustion sources generally depend on the size and the operating time of the equipment. Compressor exhaust emissions require knowledge of the compressor power and operating time. Fired vessels such as vaporizers require knowledge of the heat rate. These factors can incorporate some of the specifics of the way in which equipment is operated at LNG facilities. For example, a large ‘boil off gas’, or BOG, compressor may operate only during ship loading or unloading at LNG terminals. The activity factor will have to incorporate the shortened operating time of such a compressor and differentiate it from something like a transmission compressor that is run continuously throughout the year. It is also important to account for additional fired vessels and electricity generation equipment that are present at a given facility.
- **Methane Emissions from Fugitive Leaks -** Activity factors for potential fugitive emissions from equipment leaks could be obtained either from generic models relying on gross counts of sources e.g. number of plants, number of reciprocating compressors, number of centrifugal compressors, or number of pumps. Additionally compressor counts could be estimated by applying an average number of compressors per facility for each type of LNG operation.

Although such an approach would be less burdensome when developing a GHG inventory it may result in the estimation of very high emissions due to the conservative assumptions embedded in many of the generic equipment counts models. It is advisable to conduct actual surveys of facility equipment and components to more realistically represent the fugitive emission leaks from a given facility.

- **Methane Emissions from Venting -** Activity factors for vented emissions will depend on the number of upsets, compressors and other equipment blowdowns, and LNG loading/unloading activities. LNG facilities in operation need to keep track of the frequency and number of upsets that result either in gas flaring or venting on an annual basis. Documentation is also required of the number of LNG vessels and trucks loading and unloading activities. The truck loading/unloading operations is especially important for 'Peak Shaving' plants and satellite storage facilities. It could also become a factor if LNG is used to fuel heavy duty trucks and railcars.

5.2 Recommended Areas for Improvement

The document provides a compilation of current methods for estimating LNG emissions. Since the methods listed are based to a large extent on other natural gas GHG emission estimates additional research is needed to improve the emission estimating methods for the types of activities that are unique to the LNG operations chain.

Emission sources for which improved emission estimation methods and emission factors may be required include:

(a) Liquefaction – emission associated with dehydration systems, venting or leakage due to tank overpressure**,** displacement of uncombusted vapors during operations;

(b) Storage - venting from pressure relief valves not connected to a flare system, venting from BOG compressors, and fugitive emissions from flanges, valves, and fittings.

(c) Loading/unloading operations – flaring or venting from excess BOG generation during a loading or unloading operation or from storage tank balancing, venting when vessel loading connections are broken, fugitive emissions from BOG compressor seals and rod packing;

(d) **Regasification -** venting from maintenance within the regasification process, venting and fugitive emissions from the BOG compressors, fugitive emissions from the flanges, valves, and fittings, and venting from maintenance on LNG pumps;

(e) **Start-up and Malfunctions -** flaring during liquefaction process start-up, chilling of storage tanks and regasification equipment, pressure relief (essentially all of which route to a flare system) and related venting, and upset events

(f) **Transportation -** leakage during transfer to an LNG transport truck or other means of LNG conveyance to a direct consumer of LNG.

It is expected that the GHG intensity of the various stages of the LNG value chain will be reduced as new technologies and more energy efficient technologies are implemented. Hence, updates of emission factors will be required as part of the continual improvement process.

APPENDICES

Appendix A

Glossary of Terms [a,b,c]

TERM	DEFINITION
BCF	Billion s cubic feet of natural gas at standard conditions. One BCF is equivalent to roughly 2.64 million pound-moles of natural gas.
Boil-off	LNG that is lost from storage during transport or storage due to revaporization resulting from heat gain (from the ambient surroundings through insulation, or from energy input by pumping the fluid)
British Thermal Unit (BTU)	The amount of heat required to change the temperature of one pound of water one degree Fahrenheit.
Carbon Dioxide	A product of combustion and a greenhouse gas.
Cryogenics	Refers to low temperature and low temperature technology. There is no precise temperature for an upper boundary but -50°F is often used.
Cryogenic liquid	A liquefied gas that is kept in its liquid form at very low temperature and has a normal boiling point below -50^{o}F (- 46^{o}C)
Density	Mass per unit volume of a fluid. The energy industry usually relies on two expressions of liquid density: specific gravity (density of the fluid divided by the density of water) and degrees API. The larger the specific gravity and the smaller an API number, the denser the liquid.
Fahrenheit degrees (F)	A temperature scale at which water boils at 212° and freezes at 32° Fahrenheit. Convert to degrees Celcius (C) by the following formula: (°F-32)/1.8= °C.
Greenhouse Gases	Gases in the atmosphere that absorb and emit radiation within the thermal infrared range. This process is the fundamental cause of the greenhouse effect. The main greenhouse gases in the atmosphere are water vapor, carbon dioxide, methane, nitrous oxide and ozone.
Heat Content	The amount of useful energy measured in British Thermal Units (BTU) or Joules (J)
Higher Heating Value (HHV)	The amount of energy released when a specific volume of gas is combusted completely and all resulting water vapor is condensed. Commonly measured in units of Btu/scf or MJ/m^3
Hydrocarbon	Chemical compound containing carbon and hydrogen
Impoundment	Spill control for tank contents designed to limit the liquid travel in case of release. May

	also refer to spill control for LNG piping or transfer operations.
Joule	Metric (SI) unit of work and energy. One Joule is equivalent to 0.2390 calories, and 1 Btu is equal to 1,055 Joules.
Liquefaction	The process of altering the state of a gas into a liquid by cooling the gas. For methane, this requires decreasing its temperature to approximately -260˚F (-162˚C) at atmospheric pressure.
Liquefied Natural Gas (LNG)	Natural gas that is stored and transported in liquid form, at essentially atmospheric pressure, at a temperature of approximately -260˚F (-162˚C).
Methane	The main component of natural gas. Methane also is a potent greenhouse gas.
Mole Percent	A mole is a standard number of molecules: 6.022×10^{23}. Mole fraction or mole percent is the number of moles of a component of a mixture divided by the total number of moles in the mixture.
MTPA	Million Tonnes per Annum.
MW	Molecular Weight
Natural Gas	A combustible gaseous mixture of simple hydrocarbon compounds, primarily methane.
Natural Gas Liquids	Hydrocarbons heavier than methane found in raw natural gas. The term is generally used to include ethane, propane, and butanes, but can also include pentanes and heavier.
Peak-shaving LNG Facility	A facility for both storing and vaporizing LNG intended to operate on an intermittent basis to meet relatively short term peak gas demands on a distribution system. A peak-shaving facility may also have liquefaction capacity, which is usually quite small compared to its vaporization capacity.
Regasification	The process of altering the state of natural gas from liquid to gas by warming it and converting it back into a gaseous state.
Standard Cubic Foot	One cubic foot of gas at standard conditions of 60 degrees Fahrenheit and 14.696 pounds per square inch absolute, containing 1/379.3 = 0.00264 pound-moles of gas.
Stranded Gas	Gas is considered stranded when it is not near a market, and a pipeline to market is not economically justified.
Sweetening	Gas treating to remove sulfur compounds. Aqueous amine solutions, for instance, can be used to absorb H_2S and other sulfur species, e.g. mercaptans, from natural gas to produce a sweet liquefaction feed.

Well	A hole drilled into the earth's surface to access a specific resource.
Wobbe Index	A measure of the interchangeability of different fuel gas streams. It is defined as the gross calorific value (higher heating value) of a gas divided by the square root of the ratio of the molecular weight of the gas to that of air.

[a] Phillips Petroleum Company;

[b] Poten & Partners

[c] Understanding Today's Global LNG Business, Enerdynamics

Appendix B

Unit Conversions

From …	Multiply by	To obtain …
1 tonne LNG	**46,467**	**cubic feet gas**
1 cubic meter LNG	**21,189**	**cubic feet gas**
1 cubic meter LNG	**23.3079**	**million Btu**
1 cubic meter LNG	**0.4560**	**tonne LNG**
1 tonne LNG	**2.1930**	**cubic meter LNG**
1 tonne LNG	**14.04**	**Barrels LNG**
1 tonne LNG	**51.1138**	**million Btu**
1 tonne LNG	**78.827**	**cubic feet LNG**
1 million cubic feet gas	**21.5206**	**tonnes LNG**
1 million cubic feet gas	**47.1943**	**cubic m LNG**
1 nautical mile	**1.1508**	**statute miles**
1 horsepower (HP)	**0.7457**	**kW**
1 kW	**1.3410**	**horsepower (HP)**
1 million cubic feet gas per day	**7,885**	**tonnes LNG per year**
1 tonne	**1.1023**	**short (US) tons**
1 kg	**2.2046**	**lb**
1 tonne CO_2	**18,314**	**cubic feet gas**
1 cubic meter	**35.3147**	**cubic feet**
Average Emissions[a]		
Combustion of 1 Bcf	**54,602**	**tonnes CO_2**
Combustion of 1 cubic meter LNG	**1.1570**	**tonnes CO_2**
Combustion of 1 tonne LNG	**2.5372**	**tonnes CO_2**

[a] Averages based on: *U.S. Dept of Energy (2005) "Liquefied Natural Gas: Understanding the Basic Facts";*
Detailed methods incorporating actual fuel properties are provided in Section 4.0 of this document

Appendix C

Acronyms

Bcf	Billion standard cubic feet
Btu	British thermal units
BOG	Boil-off Gas
C	Celsius (Centigrade)
Cf	Cubic feet
CH_4	Methane
CNG	Compressed Natural Gas
CO_2	Carbon dioxide
DOE	U.S. Department of Energy
EIA	Energy Information Administration
EPA	Environmental Protection Agency
F	Fahrenheit
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse Gas
GJ	Gigajoule
GTL	Gas-to-Liquid
GWP	Global warming potential
IMO	International Maritime Organization
J	Joule
LDAR	Leak detection and repair
LDC	Local distribution company
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
m^3	Cubic meter
Mcf	Thousand standard cubic feet
MMBtu	Million British thermal units
MMcf	Million standard cubic feet
MTPA	Million tonnes per annum
NO_x	Nitric oxide (NO, NO_2)
N_2O	Nitrous oxide
NGL	Natural gas liquids
ORV	Open rack vaporizer
Psi	Pounds per square inch
Psig	Pounds per square inch gauge
PUC	Public Utilities Commission
SCV	Submerged combustion vaporizer
Tcf	Trillion standard cubic feet

Appendix D

Global Warming Potential (GWP)

I. List of Commonly Reported GHGs and their 100-year GWPs

Greenhouse Gas	SAR [(a)] GWP	AR4 [(b)] GWP
Carbon Dioxide (CO_2)	1	1
Methane (CH_4)	21	25
Nitrous Oxide (N_2O)	310	298
HFCs		
HFC-23	11,700	14,800
HFC-32	650	675
HFC-125	2,800	3,500
HFC-134a	1,300	1,430
HFC-143a	3,800	4,470
HFC-152a	140	124
HFC-227ea	2,900	3,220
HFC-236fa	6,300	9,810
HFC-4310mee	1,300	1,640
PFCs		
CF_4	6,500	7,390
C_2F_6	9,200	12,200
C_3F_8	7,000	8,830
C_4F_{10}	7,000	8,860
C_5F_{12}	7,500	9,160
C_6F_{14}	7,400	9,300
Sulfur Hexafluoride (SF_6)	23,900	22,800

(a) IPCC Second Assessment Report (SAR), 2001; used for reporting through 2012
(b) IPCC, Forth Assessment Report (4AR), 2007; for reporting in 2013 and beyond

II. List of Common Commercial Refrigeration Liquid Blends and their GWPs

Designation	Blend Content	GWP [(c)]
R404A	52:44:4 blend of HFC-143a, -125 and -134a	3,260
R407C	23:25:52 blend of HFC-32, -125 and -134a	1,526
R408A	47:7:46 blend of HCFC-22, HFC-125 and HFC-143a	2,795
R410A	50:50 blend of HFC-32 and -125	1,725
R507	50:50 blend of HFC-125 and HFC-143a	3,300
R508B	46:54 blend of HFC-23 and PFC-116	10,350

(c) UK Defra / DECC's, “2011 Guidelines: GHG Conversion Factors for Company Reporting”, Version 1.2, August 19, 2011 (Annex 5)

Appendix E

Emission Factors Tables for Common Industrial Fuels

(from API GHG Compendium, Version 3.0, August 2009)

Table 4-3. CO_2 Combustion Emission Factors (Fuel Basis) for Common Industry Fuel Types

Fuel	Carbon Emission Factor from Original Source Document			CO_2 Emission Factor[a,b], US Units		CO_2 Emission Factor[a,b], SI Units	
	Emission Factor		Source	tonnes/10^6 Btu (LHV)	tonnes /10^6 Btu (HHV)	tonnes /10^{12} J (LHV)	tonnes /10^{12} J (HHV)
Aviation Gas	18.87	MMTC/10^{15} Btu; Tg C/10^{15} Btu	Table 6-1, EIA, 2007; Table A-32, EPA, 2008; Table 12.1, TCR, 2008.	0.0728	0.0692	69.0	65.6
Bitumen	22.0	kg C/10^9 J (LHV)	Table 1.3, IPCC, 2007	0.0851	0.0809	80.7	76.6
Coke	31.00	kg C/MMBtu	Table B-1, EPA, 2008b; Table 12.1, TCR, 2008.	0.1199	0.1139	113.7	108.0
Coke (Coke Oven/Lignite/Gas)	29.2	kg C/10^9 J (LHV)	Table 1.3, IPCC, 2007	0.1130	0.1073	107.1	101.7
Crude Oil	20.33	MMTC/10^{15} Btu; Tg C/10^{15} Btu	Table 6-1, EIA, 2007; Table A-32, EPA, 2008; Table 12.1, TCR, 2008.	0.0785	0.0745	74.4	70.7
Distillate Fuel (#1,2,4)	19.95	MMTC/10^{15} Btu or Tg C/10^{15} Btu	Table 6-1, EIA, 2007 Table A-32, EPA, 2008; Table 12.1, TCR, 2008.	0.0770	0.0732	73.0	69.3
Electric Utility Coal	25.98	MMTC/10^{15} Btu	Table 6-1, EIA, 2007	0.1003	0.0953	95.0	90.3
	25.76	Tg C/10^{15} Btu	Table A-32, EPA, 2008; Table 12.1, TCR, 2008.	0.0994	0.0945	94.2	89.5
Ethanol[c]	19.3	kg C/10^9 J (LHV)	Table 1.3, IPCC, 2007	0.0747	0.0709	70.8	67.2
Flexicoker Low Btu Gas	278	lb CO_2/10^6 Btu (LHV)	Petroleum Industry Data	0.1261	0.1135	119.5	107.6
Fuel Oil #4	45.8	lb C/10^6 Btu	Derived from fuel property data in Table 3-8	0.0802	0.0762	76.0	72.2
Gas/Diesel Oil[d]	20.2	kg C/10^9 J (LHV)	Table 1.3, IPCC, 2007	0.0781	0.0742	74.1	70.4
Jet Fuel	19.33	MMTC/10^{15} Btu; Tg C/10^{15} Btu	Table 6-1, EIA, 2007; Table A-32, EPA, 2008; Table 12.1, TCR, 2008.	0.0746	0.0709	70.7	67.2
Kerosene	19.72	MMTC/10^{15} Btu; Tg C/10^{15} Btu	Table 6-1, EIA, 2007; Table A-32, EPA, 2008; Table 12.1, TCR, 2008.	0.0761	0.0723	72.1	68.5
Lignite	26.30	MMTC/10^{15} Btu; kg C/MMBtu	Table 6-2, EIA, 2007; Table B-1, EPA, 2008b; Table 12.1, TCR, 2008.	0.1015	0.0964	96.2	91.4
LPG	16.99	MMTC/10^{15} Btu	Table 6-1, EIA, 2007	0.0656	0.0623	62.2	59.0
	17.23	Kg C/MMBtu	Table B-1, EPA, 2008b; Table 12.1, TCR, 2008.	0.0665	0.0632	63.0	59.9
Butane (normal)	17.71	MMTC/10^{15} Btu	Table 1-5, EIA, 2007	0.0684	0.0649	64.8	61.5
	17.72	Tg C/10^{15} Btu	Table A-40, EPA, 2008; Table 12.1, TCR, 2008.	0.0684	0.0650	64.8	61.6

Table -4-3. CO_2 Combustion Emission Factors (Fuel Basis) for Common Industry Fuel Types (continued)

Fuel	Carbon Emission Factor from Original Source Document			CO_2 Emission Factor[a, b], US Units		CO_2 Emission Factor[a, b], SI Units	
	Emission Factor		Source	tonnes /10^6 Btu (LHV)	tonnes /10^6 Btu (HHV)	tonnes /10^{12} J (LHV)	tonnes /10^{12} J (HHV)
Ethane	16.25	MMTC/10^{15} Btu; Tg C/10^{15} Btu	Table 1-5, EIA, 2007; Table A-40, EPA, 2008; Table 12.1, TCR, 2008.	0.0627	0.0596	59.4	56.5
Isobutane	17.75	MMTC/10^{15} Btu; Tg C/10^{15} Btu	Table 1-5, EIA, 2007; Table A-40, EPA, 2008	0.0685	0.0651	64.9	61.7
Propane	17.20	MMTC/10^{15} Btu; Tg C/10^{15} Btu	Table 1-5, EIA, 2007; Table A-40, EPA, 2008; Table 12.1, TCR, 2008.	0.0664	0.0631	62.9	59.8
Miscellaneous Product[d,e]	20.33	MMTC/10^{15} Btu	Table 6-1, EIA, 2007	0.0785	0.0745	74.4	70.7
Motor Gasoline (Petrol)	19.33	MMTC/10^{15} Btu; Tg C/10^{15} Btu	Table 6-1, EIA, 2007; Table A-32, EPA, 2008; Table 12.1, TCR, 2008.	0.0746	0.0709	70.7	67.2
Naphtha (<401°F)	18.14	Tg C/10^{15} Btu	Table A-29, EPA, 2008; Table 12.1, TCR, 2008.	0.0700	0.0665	66.4	63.0
Nat. Gas Liquids	17.5	kg C/10^9 J (LHV)	Table 1.3, IPCC, 2007	0.0677	0.0643	64.2	61.0
Natural Gas (Pipeline)[f]	14.47	MMTC/10^{15} Btu; kg C/MMBtu	Table 6-1, EIA, 2007; Table B-1, EPA, 2008b; Table 12.1, TCR, 2008.	0.0590	0.0531	55.9	50.3
Natural Gas (Flared)	14.92	MMTC/10^{15} Btu	Table 6-1, EIA, 2007	0.0608	0.0547	57.6	51.8
Other Bituminous Coal	25.8	kg C/10^9 J (LHV)	Table 1.3, IPCC, 2007	0.0998	0.0948	94.6	89.9
Other Oil (>401°F)	19.95	Tg C/10^{15} Btu	Table A-29, EPA, 2008; Table 12.1, TCR, 2008.	0.0770	0.0732	73.0	69.3
Pentanes Plus	18.24	Tg C/10^{15} Btu	Table A-29, EPA, 2008; Table 12.1, TCR, 2008.	0.0704	0.0669	66.7	63.4
Petroleum Coke[g]	27.85	MMTC/10^{15} Btu; Tg C/10^{15} Btu	Table 6-1, EIA, 2007; Table A-32, EPA, 2008; Table 12.1, TCR, 2008.	0.1075	0.1021	101.9	96.8
Refinery Gas	15.7	kg C/10^9 J (LHV)	Table 1.3, IPCC, 2007	0.0607	0.0577	57.6	54.7
Residual Oil #5	46.9	lb C/10^6 Btu	Derived from fuel property data in Table 3-8	0.0821	0.0780	77.8	73.9
Residual Oil #6	21.49	MMTC/10^{15} Btu or Tg C/10^{15} Btu	Table 6-1, EIA, 2007 Table A-32, EPA, 2008; Table 12.1, TCR, 2008.	0.0829	0.0788	78.6	74.7

Table 4-3. CO_2 Combustion Emission Factors (Fuel Basis) for Common Industry Fuel Types (continued)

Fuel	Carbon Emission Factor from Original Source Document			CO_2 Emission Factor[a, b], US Units		CO_2 Emission Factor[a, b], SI Units	
	Emission Factor		Source	tonnes /10^6 Btu (LHV)	tonnes /10^6 Btu (HHV)	tonnes /10^{12} J (LHV)	tonnes /10^{12} J (HHV)
Special Naphtha	19.86	Tg C/10^{15} Btu	Table A-29, EPA, 2008; Table 12.1, TCR, 2008.	0.0767	0.0728	72.7	69.0
Still Gas	17.51	Tg C/10^{15} Btu	Table A-29, EPA, 2008; Table 12.1, TCR, 2008.	0.0713	0.0642	67.6	60.9
Sub-bituminous Coal	26.48	MMTC/10^{15} Btu; Tg C/10^{15} Btu	Table 6-2, EIA, 2007; Table A-33, EPA, 2008; Table 12.1, TCR, 2008.	0.1022	0.0971	96.9	92.0
Unfinished Oils[d,e]	20.33	MMTC/10^{15} Btu; Tg C/10^{15} Btu	Table 6-1, EIA, 2007; Table A-33, EPA, 2008; Table 12.1, TCR, 2008.	0.0785	0.0745	74.4	70.7

Sources:

Energy Information Administration (EIA). *Documentation for Emissions of Greenhouse Gases in the United States 2005*, DOE/EIA-0638(2005), October 2007.

Environmental Protection Agency (EPA). *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2006,* Annexes. EPA 430-R-08-005, April 15, 2008.

Environmental Protection Agency (EPA), Climate Leaders. *Greenhouse Gas Inventory Protocol Core Module Guidance: Direct Emissions from Stationary Combustion Sources*. EPA 430-K-08-003, May 2008 (2008b).

Intergovernmental Panel on Climate Change (IPCC). *2006 IPCC Guidelines for National Greenhouse Gas Inventories*, Volume 2, Chapter 1, 2006 Revised April 2007.

The Climate Registry (TCR). *General Reporting Protocol,* Version 1.0, March 2008.

[a] CO_2 emission factors shown are based on the default *Compendium* assumption of 100% oxidation.
[b] To convert between higher and lower heating value emission factors, the assumed conversion for gaseous fuels is: (EF, HHV) = (0.9) × (EF, LHV), and for solids or liquids the assumed conversion is (EF, HHV) = (0.95) × (EF, LHV).

[c] Theoretical number. Under international GHG accounting methods developed by the IPCC, biogenic carbon is considered to be part of the natural carbon balance and does not add to atmospheric concentrations of CO_2.

[d] Term is defined in the Glossary.

[e] Carbon content assumed to be the same as for Crude Oil (EIA, 2007).

[f] Natual gas carbon coefficient is based on a weighted U.S. national average.

[g] Note that catalyst coke is not the same as petroleum coke/marketable coke. Catalyst coke refers to coke formed on catalysts while petroleum/marketable coke is coke that is the "final product of thermal decomposition in the condensation process in cracking" (EIA, 2007b). Carbon dioxide emissions from catalyst coke are discussed in Section 5.

[h] Values are for Residual Fuel, which is defined in the text of the reference document as No. 6 fuel oil.

Table 4-4. CH_4 and N_2O Combustion Emission Factors (Fuel Basis) for Common Industry Fuel Types

Fuel	CH_4 Emission Factor[a], US Units		CH_4 Emission Factor[a], US Units		N_2O Emission Factor[a], US Units		N_2O Emission Factor[a], SI Units	
	tonnes /10^6 Btu (LHV)	tonnes /10^6 Btu (HHV)	tonnes /10^{12} J (LHV)	tonnes /10^{12} J (HHV)	tonnes /10^6 Btu (LHV)	tonnes /10^6 Btu (HHV)	tonnes /10^{12} J (LHV)	tonnes /10^{12} J (HHV)
Aviation Gasoline/Jet Gasoline	3.17E-06	3.01E-06	3.00E-03	2.85E-03	6.33E-07	6.01E-07	6.68E-13	5.70E-04
Biogasoline	3.17E-06	3.01E-06	3.00E-03	2.85E-03	6.33E-07	6.01E-07	6.68E-13	5.70E-04
Biodiesels	3.17E-06	3.01E-06	3.00E-03	2.85E-03	6.33E-07	6.01E-07	6.68E-13	5.70E-04
Bitumen	3.17E-06	3.01E-06	3.00E-03	2.85E-03	6.33E-07	6.01E-07	6.68E-13	5.70E-04
Coke Oven and Lignite Coke	1.06E-06	1.00E-06	1.00E-03	9.50E-04	1.58E-06	1.50E-06	1.67E-12	1.42E-03
Crude Oil	3.17E-06	3.01E-06	3.00E-03	2.85E-03	6.33E-07	6.01E-07	6.68E-13	5.70E-04
Ethane	1.06E-06	1.00E-06	1.00E-03	9.50E-04	6.33E-07	6.01E-07	6.68E-13	5.70E-04
Gas Coke	1.06E-06	1.00E-06	1.00E-03	9.50E-04	1.06E-07	1.00E-07	1.11E-13	9.50E-05
Gas/Diesel Oil	3.17E-06	3.01E-06	3.00E-03	2.85E-03	6.33E-07	6.01E-07	6.68E-13	5.70E-04
Jet Gasoline	3.17E-06	3.01E-06	3.00E-03	2.85E-03	6.33E-07	6.01E-07	6.68E-13	5.70E-04
Jet Kerosene	3.17E-06	3.01E-06	3.00E-03	2.85E-03	6.33E-07	6.01E-07	6.68E-13	5.70E-04
Lignite	1.06E-06	1.00E-06	1.00E-03	9.50E-04	1.58E-06	1.50E-06	1.67E-12	1.42E-03
Liquified Petroleum Gases	1.06E-06	1.00E-06	1.00E-03	9.50E-04	6.33E-07	6.01E-07	6.68E-13	5.70E-04
Motor Gasoline	3.17E-06	3.01E-06	3.00E-03	2.85E-03	6.33E-07	6.01E-07	6.68E-13	5.70E-04
Naphtha	3.17E-06	3.01E-06	3.00E-03	2.85E-03	6.33E-07	6.01E-07	6.68E-13	5.70E-04
Natural Gas	1.06E-06	9.50E-07	1.00E-03	9.00E-04	1.06E-07	9.50E-08	1.11E-13	9.00E-05
Natural Gas Liquids	3.17E-06	3.01E-06	3.00E-03	2.85E-03	6.33E-07	6.01E-07	6.68E-13	5.70E-04
Other Biogas	1.06E-06	9.50E-07	1.00E-03	9.00E-04	1.06E-07	9.50E-08	1.11E-13	9.00E-05
Other Kerosene	3.17E-06	3.01E-06	3.00E-03	2.85E-03	6.33E-07	6.01E-07	6.68E-13	5.70E-04
Other Liquid Biofuels	3.17E-06	3.01E-06	3.00E-03	2.85E-03	6.33E-07	6.01E-07	6.68E-13	5.70E-04
Other Petroleum Products	3.17E-06	3.01E-06	3.00E-03	2.85E-03	6.33E-07	6.01E-07	6.68E-13	5.70E-04
Other Primary Biomass	3.17E-05	3.01E-05	3.00E-02	2.85E-02	4.22E-06	4.01E-06	4.45E-12	3.80E-03
Paraffin Waxes	3.17E-06	3.01E-06	3.00E-03	2.85E-03	6.33E-07	6.01E-07	6.68E-13	5.70E-04
Petroleum Coke	3.17E-06	3.01E-06	3.00E-03	2.85E-03	6.33E-07	6.01E-07	6.68E-13	5.70E-04
Residual Fuel Oil	3.17E-06	3.01E-06	3.00E-03	2.85E-03	6.33E-07	6.01E-07	6.68E-13	5.70E-04
Sub-Bituminous Coal	1.06E-06	1.00E-06	1.00E-03	9.50E-04	1.58E-06	1.50E-06	1.67E-12	1.42E-03
Wood/Wood Waste	3.17E-05	3.01E-05	3.00E-02	2.85E-02	4.22E-06	4.01E-06	4.45E-12	3.80E-03

[a] Converted from original units of kg/TJ (LHV). To convert between higher and lower heating value emission factors, the assumed conversion for gaseous fuels is: (EF, HHV) = (0.9) × (EF, LHV), and for solids or liquids the assumed conversion is (EF, HHV) = (0.95) × (EF, LHV). Intergovernmental Panel on Climate Change (IPCC). *2006 IPCC Guidelines for National Greenhouse Gas Inventories*, Volume 2, Chapter 1, 2006 Revised April 2007.

Appendix D

Redacted Version

Appendix D
Sensitivity Analysis of Net Present Value under Various Scenarios (2015 USD)

Scenario No.	Scenario Description*	Calculation from Data Request Reponse (151663-UG PSE Resp WUTC DR 005 Attach A (HC)): Incremental Costs of the Tacoma LNG Facility Including Benefits of TOTE and Non-Regulated Sales	Calculation from Data Request Reponse (151663-UG PSE Resp WUTC DR 005 Attach A (HC)): Incremental Pipeline Costs (Includes PSE Core Customers, TOTE, and Other Diverted Gas)	PSE Core Gas Customer's Allocated Costs for Tacoma LNG (Including Distribution): 25 Years	PSE Core Gas Customer's Allocated Costs for Tacoma LNG (Including Distribution): 40 Years	PSE Pipeline Alternative Cost (Assumed 85,273 Dth/Day in 2021): 25 Years	PSE Pipeline Alternative Cost (Assumed 85,273 Dth/Day in 2021): 40 Years
1	As Filed (Updated Capital Costs)	$ 164,048,151	$ 372,656,174	$ 244,036,815	$ 268,833,098	$ 372,656,174	$ 451,257,905
2	$[redacted] Westcoast/$[redacted] NWP (0% Pipeline Rate Inflation)	$ 205,605,875	$ 306,507,970	$ 244,036,815	$ 268,833,098	$ 306,507,970	$ 356,029,831
3	$[redacted] Westcoast/$[redacted] NWP (0% Pipeline Rate Inflation)	$ 213,517,619	$ 268,559,365	$ 244,036,815	$ 268,833,098	$ 268,559,365	$ 311,949,947
4	$[redacted] Westcoast/$[redacted] NWP (250k Expansion, Extra Capacity Remarketed at Full Rate, 0% Pipeline Rate Inflation)	$ 216,560,597	$ 253,963,747	$ 244,036,815	$ 268,833,098	$ 253,963,747	$ 294,996,145
5	$[redacted] Westcoast/$[redacted] NWP (250k Expansion, Limited Ability to Sell Excess Capacity, 0% Pipeline Rate Inflation)	< Scenario 4	> Scenario 4	$ 244,036,815	$ 268,833,098	> Scenario 4	> Scenario 4
6	BWMQ Modifications, As Filed Rates	$ 126,457,692	$ 375,552,267	$ 214,417,353	$ 231,769,629	$ 375,552,267	$ 455,718,619
7	BWMQ Modifications, $[redacted] Westcoast/$[redacted] NWP (0% Pipeline Rate Inflation)	$ 168,943,486	$ 308,791,224	$ 214,417,353	$ 231,769,629	$ 308,791,224	$ 359,292,510
8	BWMQ Modifications, $[redacted] Westcoast/$[redacted] NWP (0% Pipeline Rate Inflation)	$ 177,025,194	$ 270,559,930	$ 214,417,353	$ 231,769,629	$ 270,559,930	$ 314,808,675
9	BWMQ Modifications, $[redacted] Westcoast/$[redacted] NWP (250k Expansion, Ability to Sell Excess Capacity at Cost, 0% rate inf	$ 180,133,543	$ 255,855,586	$ 214,417,353	$ 231,769,629	$ 255,855,586	$ 297,699,508
10	BWMQ Modifications, $[redacted] Westcoast/$[redacted] NWP (250k Expansion, Limited or NoAbility to Sell Excess Capacity, 0% r	< Scenario 9	> Scenario 9	$ 214,417,353	$ 231,769,629	> Scenario 9	> Scenario 9
11	Scenario 9 with Initial Unsubscribed Capacity 100% Subscribed	$ 176,638,584	$ 255,855,586	$ 210,922,393	$ 228,274,669	$ 255,855,586	$ 297,699,508
12	Scenario 9 with Initial Unsubscribed Capacity 0% Subscribed	$ 193,385,685	$ 255,855,586	$ 223,052,018	$ 243,427,429	$ 255,855,586	$ 297,699,508
13	Diverted Gas Cost/Benefit: As described in report (e.g., 1.4 million gallon tank used for 19,237 Dth/day Diverted Gas)			$ 24,701,219		$ 57,057,648	

*Unless otherwise stated, scenarios utilize "Management Forecast" on Unsubscribed Capacity Utilization.