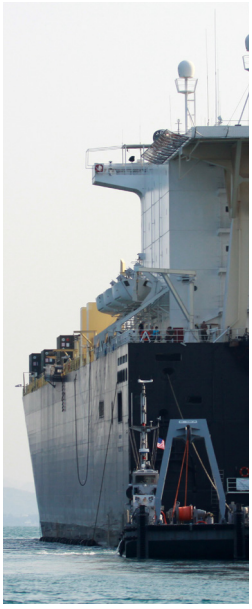
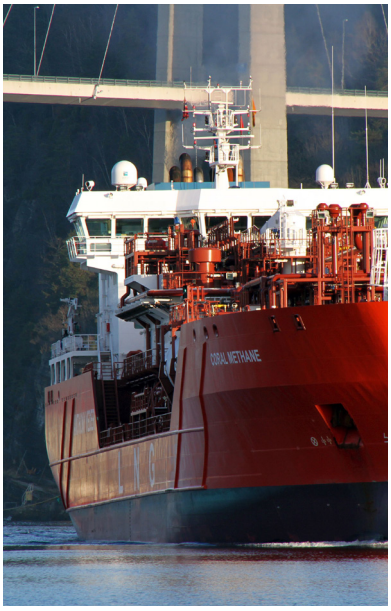
AMERICAN CLEAN SKIES FOUNDATION

# NATURAL GAS FOR MARINE VESSELS

## U.S. MARKET OPPORTUNITIES





APRIL 2012

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AMERICAN CLEAN SKIES FOUNDATION

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# Acknowledgements

This report was prepared for the American Clean Skies Foundation (ACSF) by economists and engineers from M.J. Bradley & Associates LLC (M.J.B. & A) with guidance by ACSF staff. The principal authors were Thomas Balon, Dana Lowell, Tom Curry, Christopher Van Atten, and Lily Hoffman-Andrews of MJB&A.

MJB&A provides strategic consulting services to address energy and environmental issues on land and water for the private, public, and non-profit sectors. Their international client base includes electric and natural gas utilities, major transportation fleet operators, investors, clean technology firms, environmental groups and government agencies.

# About American Clean Skies Foundation

Established in 2007, ACSF seeks to advance America's energy independence and a cleaner, low-carbon environment through expanded use of natural gas, renewables, and efficiency. The Foundation is a not-for-profit organization exempt from federal income taxes under Section 501(c)(3) of the Internal Revenue Code.

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# Foreword

As diesel fuel costs become higher and more volatile, the transportation sector is buzzing about the potential for natural gas to move our goods and services. Most of the talk has focused on fleet vehicles and heavy-duty trucks (i.e., 18 wheelers). However, this winter ACSF commissioned a review of the maritime market opportunities for natural gas. The study offers the first comprehensive look at the challenges and prospects for converting U.S. marine vessels to liquefied natural gas (LNG).

The potential take up of LNG bears consideration. For example, one Great Lakes bulk carrier consumes about as much energy as over 110 tractor trailers or over 4100 cars. Moreover, there is scope for synergy. Like Norwegian shipping fleets (early adopters of LNG in Europe), freighters on the Great Lakes are often birthed near gas pipelines and new areas for shale gas development. Co-locating LNG storage or liquifaction facilities for road and water transport may cut costs for both sectors.

This new ACSF report makes clear, however, that the economics of any specific project will hinge on three factors: vessel fuel use, delivered LNG prices and vessel conversion costs. Regulation will also be a factor as ship owners favoring the status quo must weigh the cost of complying with stricter EPA emissions regulations that will soon require more expensive low sulfur fuels for marine vessels.

In short, as with other transportation sectors, it is time to take a hard look at the alternative fueling options for shipping fleets. The economic and regulatory equations are changing.

Gregory C. Staple

CEO, American Clean Skies Foundation

# 1 Executive Summary

As diesel costs increase, the transportation sector is seeking alternative and cleaner fuels to move goods and provide services. This study offers the first in-depth look at the challenges and prospects of converting U.S. marine vessels to liquefied natural gas (LNG), which is typically viewed as a fuel for long haul trucking.

The authors of this report, economists and engineers led by Thomas Balon and Dana Lowell, are optimistic about the prospects for increased use of natural gas as a marine fuel, both in the U.S. and worldwide. However, natural gas conversion will not be an obvious choice for all vessels due to the high conversion cost. Despite the potential for significant annual fuel cost savings after conversion, this analysis suggests that the payback period for conversion of many vessels could be 10 years or more.

Most marine vessels operate on liquid petroleum fuel – either marine distillate or marine residual oil. Worldwide there are fewer than 50 vessels in-service or on order that operate on natural gas; the majority of these are car and passenger ferries. Virtually all of them operate in Norway or the Baltic or North Sea

In the U.S., natural gas commodity prices are now historically low relative to the price of marine petroleum fuels. Since feedstock gas prices for producing maritime liquefied natural gas (LNG) are uncertain, this study uses an average of the U.S. Energy Information Administration's (EIA) forecast of Henry Hub prices and prices for natural gas delivered to industrial customers, as a conservative proxy.

Based on the current forecasts, natural gas delivered for production of LNG is now at least 70% less expensive on an energy equivalent basis than marine residual fuel and 85% less expensive than marine distillate fuel. EIA currently projects that this relative price advantage will continue, and even increase, through 2035. This has opened up an opportunity for significant annual fuel cost savings when converting marine vessels that use petroleum fuel to natural gas operation. However, to be used as a marine fuel, natural gas must be liquefied to increase its energy density, and there is currently limited LNG infrastructure in many parts of the country, including at marine ports and the Great Lakes.

In addition, conversion of vessels to LNG operation is expensive – it can cost up to $7 million to convert a medium-sized tug to operate on natural gas, almost $11 million to convert a large car and passenger ferry, and up to $24 million to convert a Great Lakes bulk carrier. Approximately one sixth of this cost relates to conversion of the vessel engines and the rest is for installation of LNG storage tanks and related safety systems and ship modifications.

Given the high cost of vessel conversion one key to project success is targeting vessels with very high utilization and annual fuel use relative to vessel size and engine power, to maximize annual fuel cost savings. In terms of U.S.-flagged vessels some good candidates include large

towing tugs and articulated tug-barges (ATB), medium-to-large car and passenger ferries, and Great Lakes bulk carriers. A 150-ton tug can burn more than 400,000 gallons of fuel a year, while a 1,000-ton ferry can burn almost 700,000 gallons, and a Great Lakes bulk carrier can burn 2 million gallons annually.

According to the U.S. Coast Guard, there are currently almost 1,000 U.S.-flagged tugs larger than 100 tons, 65 ferries larger than 500 tons, and 43 Great Lakes bulk carriers. Many of these vessels could potentially be candidates for conversion to LNG operation, but the economics will not work for every project. Despite low natural gas prices, some vessels will not generate high enough annual fuel cost savings to provide a reasonable payback period for the high vessel conversion costs. Each prospective conversion project must be carefully analyzed to evaluate project economics, and must start with a realistic assessment of likely delivered LNG costs given available infrastructure options.

If new LNG production infrastructure is required to support a marine vessel conversion this could double the price of delivered LNG relative to the commodity price of the natural gas being liquefied, thus eroding annual fuel cost savings after vessel conversion to LNG. The economics of any particular marine LNG project will be significantly improved if the project can take advantage of existing LNG import or production capacity within a reasonable distance of the vessel home port, which will reduce the minimum number of vessels required to be converted and/or reduce delivered LNG price, and thus increase annual vessel fuel cost savings.

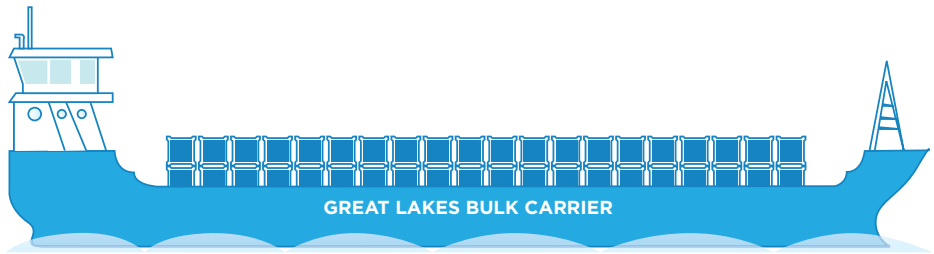
Another issue which will affect the economics of LNG conversion for some vessels is implementation of future U.S. emissions regulations and fuel sulfur restrictions, which will come into effect between 2016 and 2020. In particular, significant reductions in allowable fuel sulfur, for vessels operating in U.S. waters and in the North American and Caribbean Sea Emission Control Areas, will require a switch to more expensive distillate fuel, or installation of expensive emission controls, for vessels that currently burn residual fuel. These vessels include Great Lakes ore carriers, LNG carriers, cruise ships, and cargo vessels. For these vessels, the incremental cost of compliance relative to current fuel costs may significantly improve the economics of conversion to naturally low sulfur LNG.

Successful projects will require both a motivated vessel owner and a motivated LNG supplier. Given significant first-mover disadvantages, initial projects may also require government intervention to offset some of the cost of vessel conversion and/or LNG infrastructure development, in the context of promoting greater use of domestic fuels for transportation. After one or more vessel conversions within a given geographic area, further vessel conversions will become easier to justify on economic grounds.

References for more information:

[RNumber] in subsequent pages corresponds to the numbered reference on page 35.

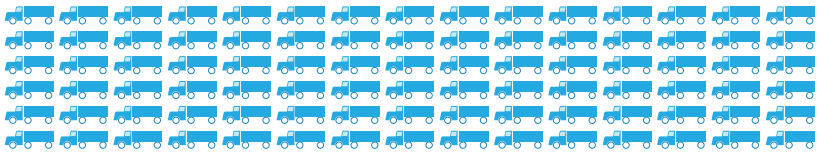
**Figure 1**
Vehicle Energy Consumption



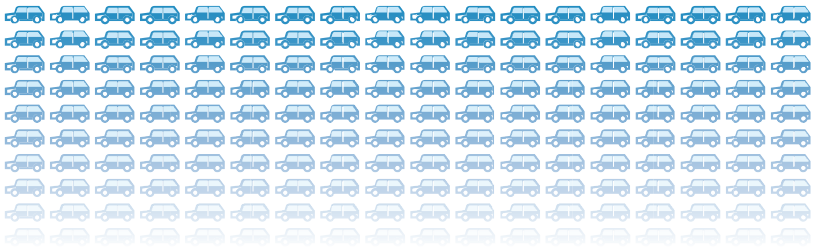

**CONSUMES ABOUT AS MUCH ENERGY AS**

**THREE CAR FERRIES**

**FIVE TUGBOATS**



**113 SEMI TRUCKS* OR**



**4160 COMPACT CARS****

| ANNUAL DEMAND (gallons/vehicle) | ANNUAL ENERGY EQUIVALENT PER VEHICLE (MMBTU) | FUEL TYPE |
|---|---|---|
| 2080064 gal | 312010 MMBTU | RESIDUAL FUEL OIL |
| 678400 gal | 93619 MMBTU | DIESEL |
| 424000 gal | 58512 MMBTU | DIESEL |
| 25000 gal | 2760 MMBTU | DIESEL |
| 600 gal | 75 MMBTU | GASOLINE |

**MMBTU/cu. ft. of Natural Gas**
1.03 MMBTU=1000CF=1 MCF

* Assumes long haul truck traveling 120000 miles per year @ 6 MPG

** Assumes car traveling 15000 miles per year @ 25 MPG average.

**BTU/gallon:**
Gasoline: 125000
Diesel: 138000
Residual Fuel: 149000

From cars to carriers, U.S. vehicles represent an enormous market opportunity for conversion to natural gas.

Sources: American Clean Skies Foundation, M.J. Bradley

# Current U.S. Marine Fuel Use 2

As calculated by the EIA, U.S. domestic and international shipping within U.S. waters consume about 1 quadrillion Btu of fuel oil per year[1]. This is roughly 20% of the energy consumed by the U.S. residential sector in the form of natural gas in 2011 [See Reference 1, page 35].

As shown in Figure 2, EIA projects fuel demand for domestic and international shipping to remain relatively flat after recovering from the recession, increasing on an annualized basis by only about 0.5% and 0.1%, respectively through 2035.[2] About 70% of domestic shipping relies on distillate fuel oil and the remaining 30% relies on residual fuel oil. By contrast, over 90% of international shipping is fueled by residual fuel oil.

Distillate fuel oil is a fuel product derived from petroleum through distillation. While exact specifications can vary by usage, "marine distillate" is essentially the same fuel used in diesel engines installed in trucks and nonroad construction equipment, as well as in boilers for home heating and production of industrial process heat. The most significant difference in the distillate fuel used for various applications (on-road trucks, home heating, marine) is its sulfur level and viscosity. As discussed in section 8.0, until recently marine distillate used in the U.S. was allowed to have much higher sulfur content than on-road diesel fuel.

Residual fuel oil, also called "bunker fuel" or #6 oil, is a heavier fuel oil that is also derived from petroleum through distillation. Residual fuel is what is left over after the lighter constituents have been removed from a barrel of oil to produce gasoline and distillate oil. In comparison to distillate fuel, residual fuel is much more viscous – and is essentially a solid at room temperature. Residual fuel must be heated to keep it in liquid form for transport and storage as a marine fuel. Residual fuel also has significantly higher sulfur content than distillate fuel – 1% sulfur or more – and much higher heavy metal content. As shown in Figure 3, residual fuel is less expensive than distillate fuel.

In its Annual Energy Outlook, EIA projects future delivered fuel prices for broad economic sectors: residential, industrial, electric, and transportation. While domestic and international shipping are included in the transportation sector, the distillate (diesel) fuel price projections for that sector include federal, state, and local taxes associated with on-road vehicles that would not apply to marine vessels. The industrial sector projections for distillate fuel provide a reasonable proxy for the prices paid by the marine sector, and are shown in Figure 3, along with residual fuel oil price projections for the transportation sector, in units of dollars per million Btus ("mmBtu")[3]. Expressed as dollars per gallon, distillate fuel delivered for industrial purposes averaged $3.71 per gallon in 2011 and, according to EIA, is projected to increase an average of 3.2% per year, to $6.51 per gallon by 2035. Residual fuel delivered for transportation purposes averaged $2.25 per gallon in 2010 and is projected to increase an average of 4.8% per year, to $5.06 per gallon by 2035. All values are expressed in nominal dollars.

The natural gas prices shown in Figure 3 reflect the average of the projected price of natural gas at Henry Hub[4] and the projected (higher) price of natural gas delivered to industrial sources via the natural gas distribution system. The two prices are averaged to reflect the expectation that the location of marine fueling stations will be optimized to reduce natural gas delivery costs. This approximation adds an average of 4% to the projected annual Henry Hub price through 2035. As shown, in 2011 natural gas prices calculated using this method averaged $4.48 per mmBtu. Natural gas prices are projected to rise by 3.7% per year, reaching $11.62 per mmBtu in nominal dollars by 2035.

1 Quadrillion Btu equals 1000 Trillion Btu. One gallon of marine distillate fuel contains approximately 137,300 Btu of energy and one gallon of marine residual fuel contains approximately 149,700 Btu of energy. One million Btu is equivalent to approximately 7.3 gallons of marine distillate fuel or 6.7 gallons of marine residual fuel. One gallon of LNG contains approximately 76,000 Btu. One million Btu is equivalent to approximately 13 gallons of LNG. One thousand cubic feet (Mcf) of natural gas contains 1,027,000 Btu of energy. U.S. shipping uses the equivalent of over 7 billion distillate gallons of energy annually, which is equivalent to over one trillion cubic feet of natural gas.

2 According to Assumptions to the Annual Energy Outlook 2011: "Domestic shipping efficiencies are based on the model developed by Argonne National Laboratory. The energy consumption in the international shipping module is a function of the total level of imports and exports. The distribution of domestic and international shipping fuel consumption by fuel type is based on historical data and remains constant throughout the forecast." More info and updates available at: http://www.eia.gov/forecasts/aeo/er/

As shown in Figure 3, natural gas currently costs 70% less per unit of energy than residual fuel oil, and 85% less than distillate fuel oil. EIA currently projects that over the next 25 years natural gas will continue to have a significant price advantage relative to petroleum fuels.

In order to be used as a vehicle fuel, natural gas would have to be compressed or liquefied to increase the energy density of the fuel, which increases its delivered price. See sections 3.0 and 4.0 for further discussion of the costs associated with natural gas compression and liquefaction.

**Figure 2**
EIA Annual Energy Outlook 2012 (Early Release) Fuel Demand Projection for Domestic and International Shipping [R1]

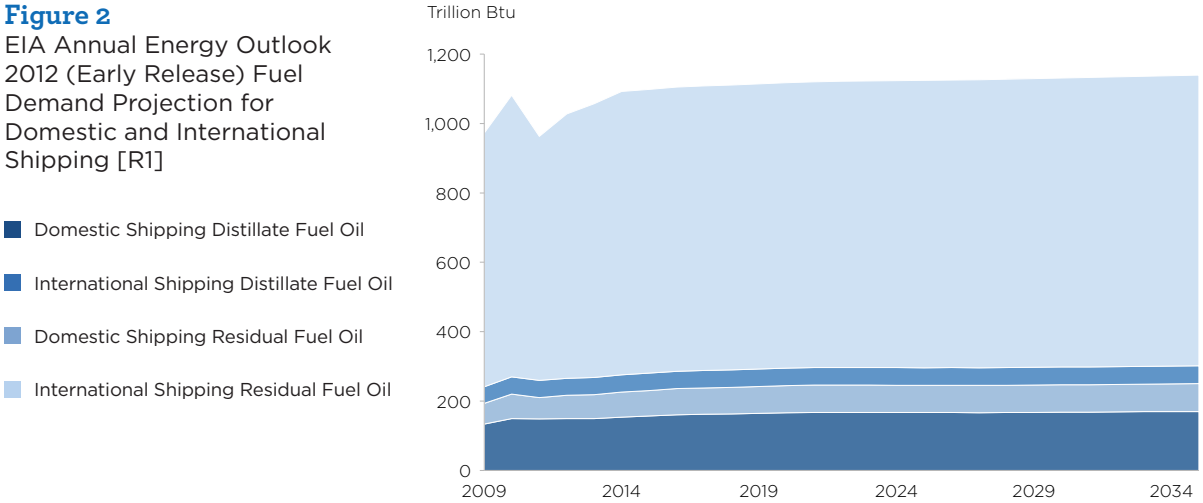
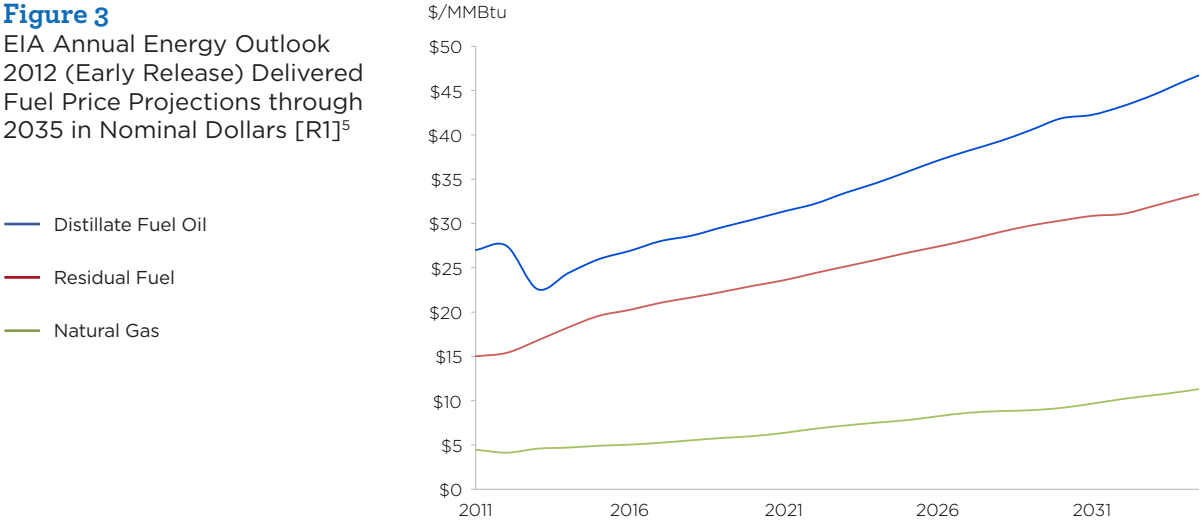



**Figure 3**
EIA Annual Energy Outlook 2012 (Early Release) Delivered Fuel Price Projections through 2035 in Nominal Dollars [R1][5]




3 One gallon of marine distillate fuel contains approximately 137,300 Btu of energy and one gallon of marine residual fuel contains approximately 149,700 Btu of energy. One million Btu is equivalent to approximately 7.3 gallons of marine distillate fuel or 6.7 gallons of marine residual fuel.

4 "The Henry Hub" is the pricing point for natural gas futures contracts traded on the New York Mercantile Exchange (NYMEX). It is a point on the natural gas pipeline system in Erath, Louisiana. Henry Hub pricing could be considered a "wholesale" price potentially available to large users, but it does not include the cost associated with "local" delivery of the gas from Louisiana to the point of actual use.

5 As noted in the text, the distillate fuel oil projections are for fuel delivered to the industrial sector, while the residual fuel projections are for fuel delivered to the transportation sector. Distillate fuel delivered to the transportation sector includes federal and state taxes that do not apply to marine vessels. The natural gas projections are the average of projected Henry Hub and as delivered to the industrial sector, to reflect the expectation that marine fueling stations siting will be optimized to reduce natural gas delivery costs.

# Natural Gas as a Marine Fuel 3

Natural gas is abundant in the U.S. and, as discussed in Section 2.0, is currently priced significantly lower than distillate and residual petroleum fuels. Natural gas also has slightly higher energy density (energy content per pound of fuel) than these marine fuels. However, because it is a gas at ambient temperature and pressure, natural gas is more difficult to transport, handle, and store on board a vessel than a liquid fuel and has a lower energy content per volume than diesel fuel. For any mobile piece of equipment, including marine vessels, natural gas can be stored on board as a high pressure compressed gas (CNG) or as a cryogenic liquid (LNG).

CNG is produced by compressing natural gas from a utility pipeline - which typically has a pressure of 100 – 500 pounds per square inch ("psi") – to a much higher pressure using a compressor, thus reducing its volume per unit of energy by a factor of ten or more. The gas is compressed into high-pressure storage tank(s) on the vessel. In the U.S., CNG vehicles typically have tanks designed to store their fuel at 3000 psi or 3600 psi.[6] The energy required to compress natural gas to produce CNG varies from 2 -5% of the energy content of the gas being compressed, depending on starting pipeline pressure, size of the compressor station, and rate of vehicle filling [R1].

When the temperature of natural gas is reduced to approximately -260°F (-162 °C), at atmospheric pressure, it condenses to a liquid (LNG). The energy required to produce LNG varies from 10 – 20% of the energy content of the natural gas liquefied, depending on composition of the input gas, liquefaction technology, and plant size [R2].

A given weight of natural gas stored as LNG takes up only about 40% of the volume of the same weight of natural gas stored as CNG at 3600 psi. LNG can be transported, pumped, and stored like other liquid fuels, but its temperature must be maintained below -260°F at all times or it will gasify and "boil off"; LNG is stored in specially-designed insulated containers. Depending on their design, LNG storage vessels can maintain LNG temperatures for days, weeks, or months but, if LNG is stored for longer periods without drawing off any of the vapor from the tank (for example to power an engine), some amount of gas venting is required to maintain tank temperature and relieve internal pressure. For large storage systems re-liquefaction of vented gas is possible to prevent ultimate release to the atmosphere.

Production, transport, and handling of LNG can be more complex and expensive than handling of CNG. Per unit volume, LNG storage systems are also typically more expensive than CNG systems, but they hold more fuel; therefore long haul trucks, for example, may cost less to purchase from the dealer with LNG storage systems, than with CNG storage systems that provide the same driving range.

For mobile applications the choice of using CNG or LNG involves a trade-off between cost and operational considerations such as practical onboard fuel storage volume and practical re-fueling intervals. For example, in practical terms, due to space constraints, most trucks and buses can only store enough CNG on board to operate for fewer than 250 miles between fill ups, but they can store enough LNG to drive more than 600 miles before refueling. Therefore, most transit buses operating on natural gas store the fuel as CNG – they typically drive fewer than 150 miles per day, and they return to the same location every day, which makes daily fueling practical. On the other hand, long-haul tractor-trailers that can drive 500 miles or more per day and which do not necessarily return to the same location each night would need to store their natural gas fuel as LNG.

6 Older vehicles may be at 3000 psi, but current industry standards for new vehicles are 3600 psi.

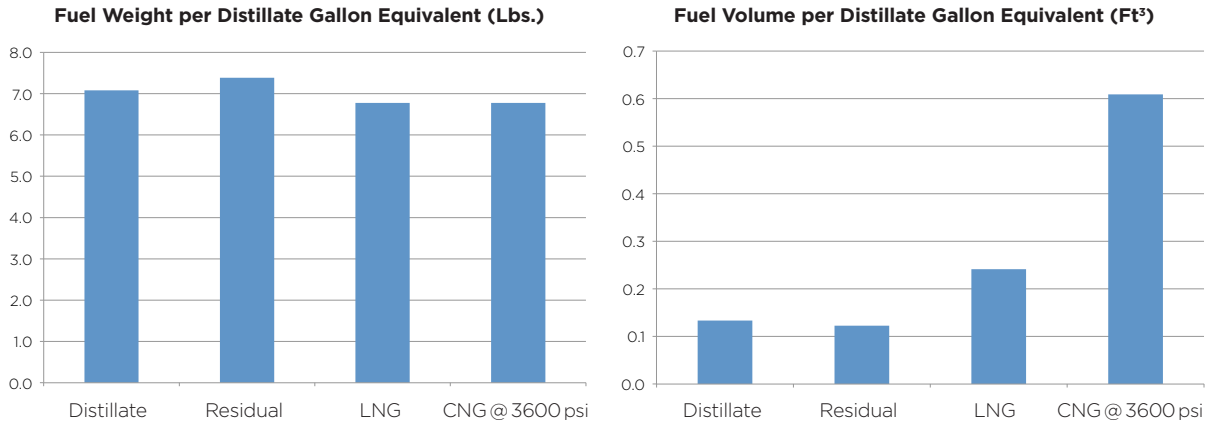
Figure 4 compares the weight and volume required to store 137,300 Btu of energy as marine distillate fuel, marine residual fuel, LNG, or CNG at 3600 psi. This is the amount of energy in one gallon of marine distillate fuel (distillate gallon equivalent). As shown, whether stored as CNG or LNG, a distillate gallon equivalent of natural gas would weigh slightly less than an equivalent amount of liquid petroleum fuel.[7] However, if stored as LNG the fuel would take up twice as much space as the liquid fuel, and if stored as CNG it would take up five times as much space.

Table 1 shows the daily fuel use and on board fuel storage volume required for three "typical" marine vessels: a towing tug, a 100-car ferry, and a Great Lakes ore carrier.[8] This table also shows the volume required for onboard fuel storage for each vessel if the fuel is carried as a liquid petroleum fuel, as LNG, or as CNG. Most marine vessels use a significant amount of fuel daily, and for many it is not practical to refuel every day. As such, it is likely that for most marine vessels it would not be practical to store natural gas fuel on board as CNG. Most marine vessels newly constructed or converted to operate on natural gas fuel will have to store the fuel as LNG.

Given current LNG tank technology, the total volume of an LNG fuel storage and delivery system for a marine vessel is approximately 2.5 – 3.0 times the volume of a system to store and deliver an equal amount (energy content) of liquid petroleum fuel. It is expected that future implementation of prismatic membrane tanks for LNG storage will reduce this ratio to two to one [R2].

## Figure 4

Weight and Volume of One Distillate Gallon Equivalent of Different Fuels




## Table 1

Fuel Usage and Fuel Storage Volumes for Typical Marine Vessels

| Vessel | Fuel Type | HP | Daily Fuel Use | Typical Minimum On-board Fuel Storage | | Volume of On-board Fuel Storage | | |
|---|---|---|---|---|---|---|---|---|
| | | | | | | Dist. or Residual | LNG | CNG |
| | | | [gal] | [days] | [gal] | [ft3] | [ft3] | [ft3] |
| Towing Tug | Distillate | 3,000 | 1,417 | 14 | 20,000 | 2,674 | 4,830 | 12,178 |
| 100-car Ferry | Distillate | 6,000 | 2,268 | 7 | 16,000 | 2,139 | 3,864 | 9,742 |
| Great Lakes Ore Carrier | Residual | 10,000 | 6,934 | 21 | 145,000 | 19,385 | 38,183 | 96,264 |

7 This figure shows the weight of the fuel only. CNG and LNG storage vessels are heavier than liquid fuel tanks. The total weight of a CNG or LNG fuel system, including the fuel and the storage vessels, is typically greater than the weight of a liquid fuel system that can store the same amount of energy. In general, CNG storage systems are heavier than LNG storage systems for a given weight of natural gas being stored.

8 Data shown is representative only, based on the author's experience. Within any class of vessel there will be a range of vessel sizes and operating conditions that would affect daily and annual fuel use. This table assumes a 68% engine load factor for all vessels, and 12 hours or daily operation for the ferry, 15 hours for the tug, and 24 hours for the ore carrier. All of these vessels are assumed to operate for approximately 300 days per year.

# LNG Production 4

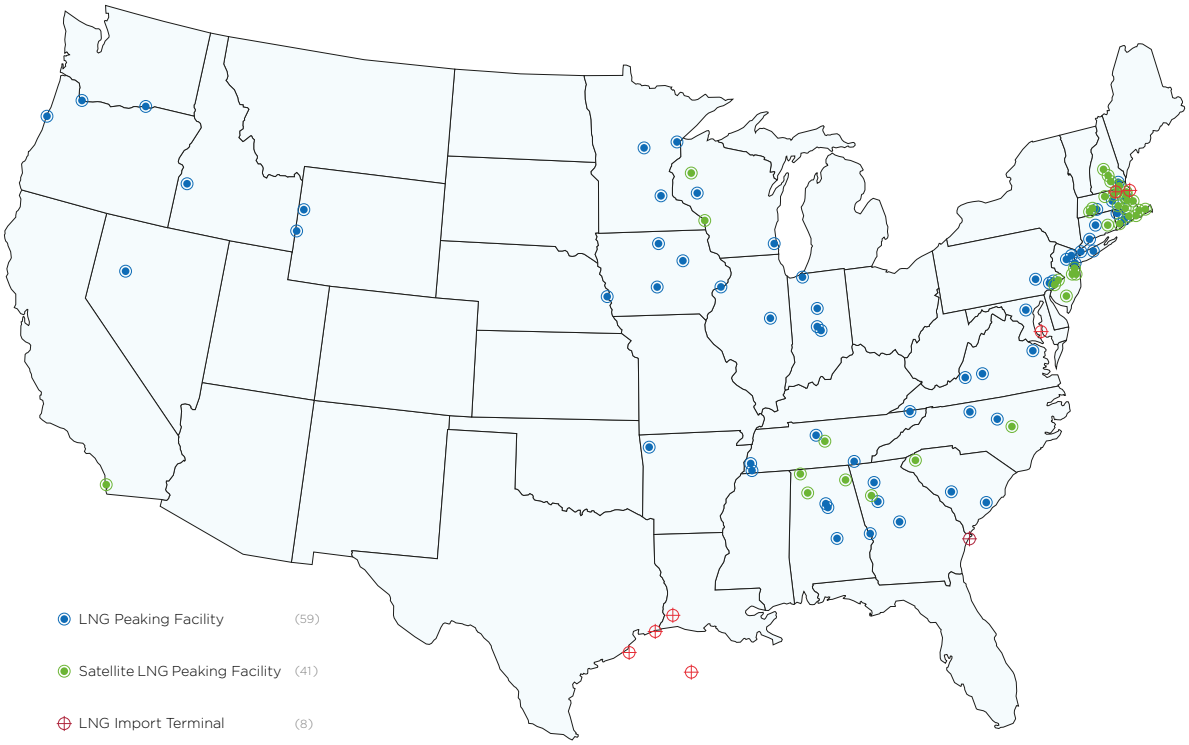
As discussed in section 2.0, the economics of natural gas relative to residual and distillate fuel make conversion to LNG a potentially attractive option for marine vessels. However, availability of the fuel is a challenge – particularly for first movers. Ferries, tugboats, and bulk carriers have established fuel supply chains and bunkering capability. While natural gas is widely available in the U.S., it is stored as LNG only at select locations (see Figure 5).

LNG locations include import terminals, LNG peaking facilities with liquefaction capabilities, and satellite LNG peaking facilities that store LNG but do not liquefy it. Natural gas LNG peaking locations are the most prevalent source of LNG in the U.S. These locations store natural gas as LNG for use during peak demand periods. During a cold snap when natural gas consumption for heat increases, the operators of storage locations will gasify the LNG as a way to supplement supply. Liquefaction and storage of LNG can also help reduce pipeline capacity commitments that are only used during peak periods [R4]. The fact that LNG is present at the locations shown in Figure 5 does not necessarily ensure its availability for sale to customers.

In addition to the locations shown in Figure 5, LNG is also available at select refueling stations (focused on heavy-duty onroad vehicle applications). For example, Clean Energy has LNG facilities in Texas and California that produce LNG for vehicle use [R6].

To provide LNG at a marine port, suppliers could transport LNG to the port via barge or tanker truck from existing production facilities, or suppliers could construct new production facilities shore-side to service marine customers. Table 2 highlights some of the pros and cons of building a shore-side LNG production facility and three potential options for alternative sources of LNG.

**Figure 5**
U.S. LNG Peaking Shaving and Import Facilities, 2008 [R5]




Note: Satelite LNG facilities have no liquefaction facilities. All supplies are transported to the site via tanker truck.
Source: Energy Information Administration, Office of Oil & Gas, Natural Gas Division Gas, Gas Transportation Information System, December 2008.

**Table 2**
LNG Supply Options for Marine Vessels

| Option | Pros | Cons |
|---|---|---|
| Build shore-side LNG production facility | Secure, local fuel source; scales to potential demand | Economics require scale and sufficient demand; location could limit use of LNG for other purposes (e.g., long haul trucks) |
| Transport LNG (via barge) from new LNG production facility | LNG facility could be strategically located to serve both marine and road transportation markets and could be located near existing natural gas pipelines to reduce infrastructure needs | Fuel not produced on site; no dedicated source of LNG |
| Transport LNG (via barge) from existing LNG import terminal | Potentially valuable interim solution; takes advantage of existing infrastructure | Fuel not produced on site; no dedicated source of LNG |
| Transport LNG from existing LNG peak storage location (via barge or tanker truck) | Potentially valuable interim solution; takes advantage of existing infrastructure | Fuel not produced on site; no dedicated source of LNG; opportunities may be limited depending on proximity of storage locations to ports; volumes of LNG available for marine sale may be limited; tanker truck transport is expensive due to necessary volumes |

As a way of considering the economics of LNG relative to distillate and residual fuel, MJB&A modeled the LNG price implications of a purpose-built LNG production facility. The analysis is designed to be conservative and suggests an upper bound to the potential cost of delivering LNG to marine vessels. Other alternatives, such as those that take advantage of existing LNG production infrastructure would likely have lower costs for delivered LNG, particularly if the initial demand for LNG is small and a purpose-built LNG production facility did not run at design rates. As an alternative to building a production facility that only services marine vessels, an LNG producer could construct a facility with an eye toward other customers, as a way of reducing the upfront risk of not having enough vessels to meet optimal production levels.

The economics of constructing an LNG production facility shore-side depend on the size of the facility, its percent utilization, and details of financing requirements. Based on publicly available information and discussions with industry experts, MJB&A estimates that an LNG production facility sized to produce 100,000 gallons per day (gpd) of LNG, with 500,000 gallon on-site storage capacity, would require about $50 million of capital to construct.[9] For this modeling exercise we assumed a facility design utilization rate of 80% (equivalent to continuous operation 292 days a year). Other assumptions are summarized in Table 3, including an annual fixed operation and maintenance (O&M) cost of 2%, a variable O&M cost of 15% of the price of natural gas liquefied[10], a rate of return on investment of 11%, and a 10-year investment horizon.

**Table 3**
Model LNG Production Facility Assumptions [R7]

| Variable | Value |
|---|---|
| Target IRR | 11.0% |
| Term (years) | 10 |
| Capital cost ($) | $50,000,000 |
| Liquefaction capacity (gpd) | 100,000 |
| Energy content (btu/gal) | 76,000 |
| Fixed O&M (% of capital costs) | 2% |
| Variable O&M (% of fuel price) | 15% |
| Availability (%/year) | 80% |

9 This figure is in 2011 dollars and represents the total cost for facility development, including land acquisition and permitting.

10 Based on an energy penalty of about 10-20% to convert natural gas to LNG.

Given the assumptions in Table 3, MJB&A estimates that the modeled LNG production facility would have an annual revenue requirement averaging $11.1 million per year for the 10-year investment period. Figure 6 shows the implied price of delivered LNG ($/therm[11]) from the model facility in nominal dollars, in order to meet this revenue requirement. The delivered price is made of two components: (1) the model facility LNG production cost, assuming 80% utilization; and (2) the EIA AEO 2012 (Early Release) projected natural gas input price (as calculated in Section 2.0). As shown, producing LNG shore-side with the modeled facility roughly doubles the delivered price of the fuel relative to the commodity price of delivered pipeline natural gas.

Despite LNG production almost doubling the price of delivered natural gas, the fuel is still attractive relative to EIA's projected prices for residual and distillate fuel oil as shown in Figure 7. Over the next ten years, delivered LNG for marine use is projected to cost at least 41% less than residual fuel and 57% less than distillate fuel per unit of energy delivered.

The price of delivered LNG is sensitive to changes in any of the variables in Table 3 but particularly to the percent utilization of any purpose-built LNG production facility. Figure 8 shows the relationship between facility utilization and delivered LNG price. The prices shown in Figure 7 are for 2012 and assume a natural gas commodity price of $0.41 per therm. Below 35% plant utilization, LNG would have to be priced above the 2012 price of residual fuel oil to make the plant economically viable.

The relationship of production facility utilization to LNG delivered price highlights the challenge of developing an LNG production facility in the absence of a sufficiently sized LNG market. Until a sufficient demand exists, it may be appropriate to look for interim or alternative sources of LNG such as those highlighted in Table 2.

To evaluate what LNG sourced in one of these ways might cost, MJB&A reviewed landed prices for short-term imports of LNG, as tracked by DOE's Office of Fossil Energy Natural Gas Regulatory Program. As of April 2011, short-term LNG imports averaged $0.49 per therm ($4.91 per mmBtu) [R8]. Landed prices include the commodity price plus transportation to, and off loading at, a U.S. terminal; they do not include costs for re-gasification. Short term imports are defined as those imported under supply contracts with terms of under two years [R8].

Table 4 compares the average landed price for short-term imports of LNG to the average price for pipeline natural gas delivered for industrial use, as reported in EIA AEO 2011. As shown, the landed price of LNG is very competitive with the average delivered pipeline price of natural gas. While the landed price of LNG does not include the cost of transporting the LNG from an import terminal location to a marine port for fueling vessels, the price difference suggests the potential for alternative sources of LNG that are less expensive than those from a purpose-built facility.

**Table 4**
Landed Price of LNG Imports Compared to Pipeline Natural Gas Delivered Price

| Year | Average Landed Price for Short-term Imports of LNG ($/Therm) [R9] | Average Price for Pipeline Natural Gas Delivered for Industrial Use ($/Therm) [R10] | Difference |
|---|---|---|---|
| 2008 | $1.07 | $0.90 | $0.17 |
| 2009 | $0.54 | $0.53 | $0.01 |
| 2010 | $0.48 | $0.48 | $0.00 |
| 2011 | $0.49 | $0.50 | -$0.01 |

11 One therm is 100,000 Btu. The energy content of LNG is approximately 76,000 Btu/gallon, so one therm of LNG is 1.32 gallons.

**Figure 6**
Implied LNG Price from Purpose-Built Model Facility, Assuming 80% Utilization (Nominal Dollars)

- EIA AEO 2012 Natural Gas Price
- Model Facility LNG Production Cost

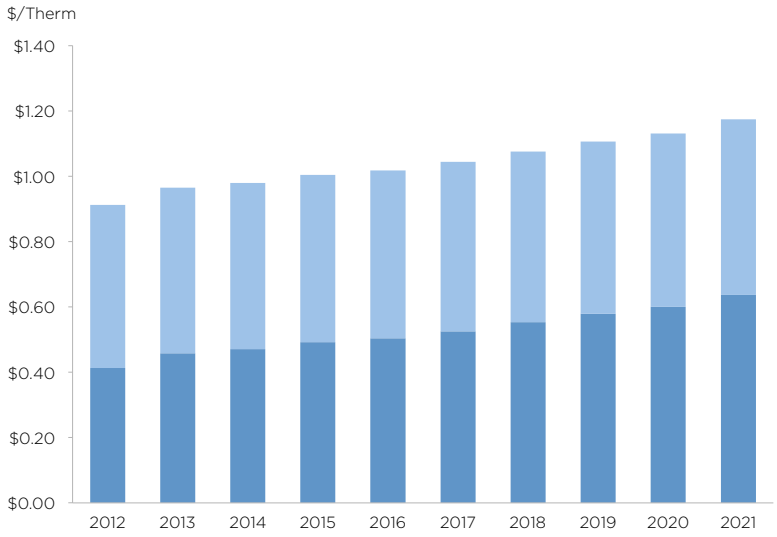



**Figure 7**
Model Facility LNG Price Relative to Projected Distillate and Residual Fuel Oil Prices (Nominal Dollars)

- EIA AEO 2012 (Early Release) Distillate Fuel Oil Price
- EIA AEO 2012 (Early Release) Residual Fuel Oil Price
- Model Facility LNG Delivered Price

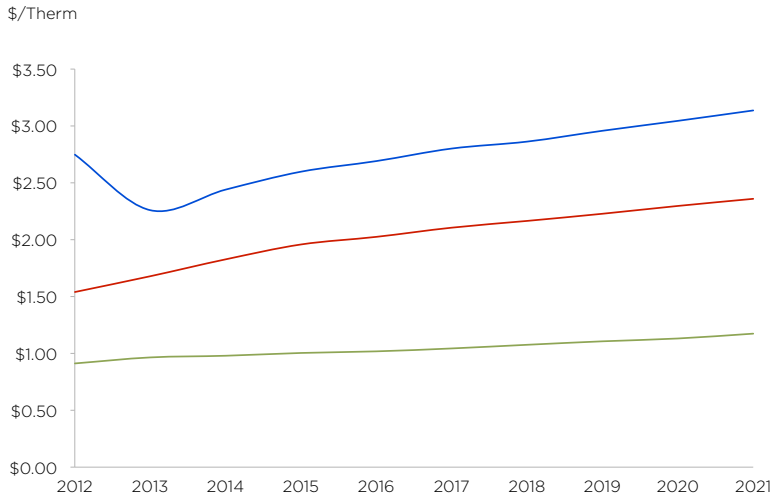
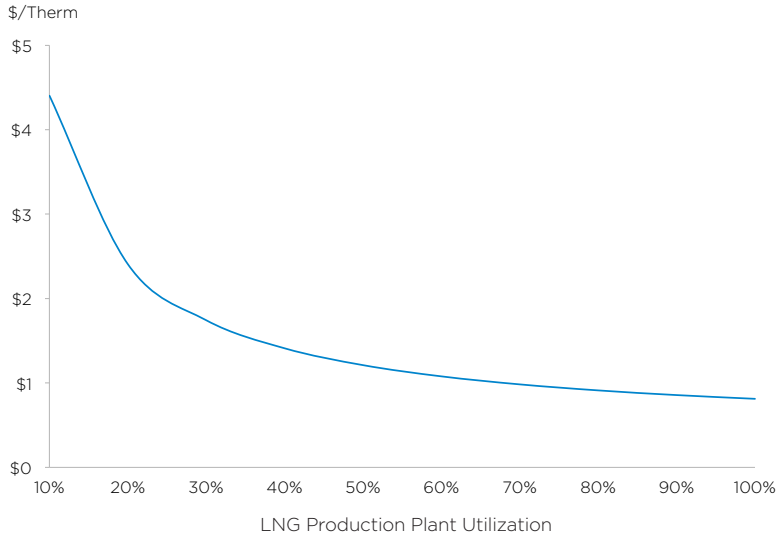



**Figure 8**
Impact of Shifts in Utilization on Implied Delivered LNG Price, Based on Projected 2012 Prices



# Current Worldwide NG Use in Marine Vessels 5

LNG bulk carriers have used the "boil off" gas from their LNG cargo to provide ship propulsion since the first ship was put in production in 1964 – these vessels have typically used the natural gas to power steam turbines [R11]. Other than these vessels, prior to 2000, only a handful of relatively small vessels – small ferries, canal boats, and tourist boats – used natural gas for propulsion. Most of these vessels used dual-fuel diesel/natural gas engines and carried their fuel as CNG while operating in Canada, the Netherlands, and Russia [R11].

The first modern vessel built to operate exclusively on LNG fuel was the *Glutra,* a 100 car/300 passenger ferry that went into operation in Molde on the west coast of Norway in February 2000 [R11]. Since then an additional 28 LNG vessels have been put into service worldwide, and another 12 are on order [R12, R13]; these vessels are summarized in Table 5.

The majority of current LNG vessels in service or on order (20) are car and passenger ferries and virtually all of these operate in Norway; there are also three Norwegian coast guard vessels that operate on LNG. The second largest group of LNG vessels in service or on order (11) is offshore supply/service vessels operating in the North Sea and Baltic Sea. In addition to these relatively small vessels there are currently two larger vessels in service and another three on order (roll-on/roll-off vessels, bulk carriers, and tankers).

**Table 5**
Current LNG Vessels in Service and On Order Worldwide
*Source: Marintek*

| VESSEL TYPE | In Service | On Order | TOTAL |
|---|---|---|---|
| Car/Passenger Ferry | 16 | 4 | 20 |
| Off-shore Supply/Service Vessel | 6 | 5 | 11 |
| Patrol Vessel | 3 | 0 | 3 |
| LNG Tanker | 2 | 0 | 2 |
| Roll-on/Roll-off (Ro-Ro) Ship | 1 | 2 | 3 |
| Bulk Ship | 0 | 1 | 1 |
| Chemical Tanker | 1 | 0 | 1 |
| **TOTAL** | **29** | **12** | **41** |

**Figure 9**
LNG Powered Vessels

**Ferry *Glutra***
Photo Credit: Mikkel, shipspotting.com

**LNG Tanker *Coral Methane***
Photo Credit: Tomas Østberg-Jacobsen

# Marine NG Engine Conversion 6

There are currently three natural gas engine technologies used for large marine vessels: (1) spark-ignited lean-burn, (2) dual-fuel diesel pilot ignition with low-pressure gas injection, and (3) dual-fuel diesel pilot ignition with high-pressure gas injection. Spark-ignited engines operate exclusively on natural gas, while diesel pilot ignition engines can operate on a range of fuels, including natural gas, marine distillate, and marine residual fuels. Besides fuel flexibility there are other trade-offs between the various technologies, including NOx and GHG emissions, efficiency, and sensitivity to natural gas quality (methane content) [R13].

There are currently three manufacturers in this market: Wärtsila, Rolls-Royce, and Mitsubishi Heavy Industries – of the 41 LNG powered vessels in service or on order 42% have Rolls-Royce engines, 33% have Mitsubishi engines, and 25% have Wärtsila engines [R13]. Each of these manufacturers also produces a range of large marine engines that operate on liquid petroleum fuels. There are several other manufacturers that might enter the market by adapting their existing stationary gas engines to marine applications if there is sufficient demonstrated demand.

As an example, the Rolls-Royce marine gas engine line encompasses two engine series with between six and 20 cylinders per engine, and power ratings between 1500 and 9000 kW (2000 – 12000 HP). The Rolls-Royce marine gas engines use spark-ignited, lean burn technology, and they are certified to meet IMO Tier 3 NOx limits; in comparison to new marine diesel engines operating on residual fuel, these gas engines emit 86% less NOx, 98% less PM, and 30% less $CO_2$ [R2]. They also emit virtually no $SO_2$. These gas engines would comply with the most stringent emission and fuel sulfur restrictions currently in place in the U.S. and Europe (see Section 8.0).

In some cases, existing diesel engines can be converted to dual-fuel diesel-gas operation, generally in conjunction with a scheduled engine overhaul; Wärtsila offers kits for some engines to make the conversion. Otherwise, to use a Rolls-Royce dedicated natural gas engine, the existing engine would need to be replaced.

In general, the equipment cost of conversion is similar to the cost of a new engine, though installation may be easier and less expensive when converting an existing engine. When converting a vessel from diesel to natural gas, the biggest expense is the cost of installing LNG fuel storage containers, piping, and related safety systems/vessel modifications; these costs can be five times or more the cost of the engine conversion or replacement. Table 6 presents an order-of-magnitude estimate of the costs involved in converting "typical" tug, ferry, and Great Lakes bulk carriers to LNG operation. The costs shown are illustrative only – there will be significant variability in actual costs based on vessel size and configuration.

When building new vessels it will always be more expensive to equip them to operate on LNG than to operate on liquid petroleum fuels, due to the increased size, complexity, and cost of the LNG fuel storage system. However, the incremental cost for new vessels will be less than the cost to convert a similar existing vessel.

Given the significant capital expense involved, the decision to convert an existing vessel to LNG will depend on the potential fuel cost savings associated with substituting LNG for distillate or residual fuel oil. MJB&A used the projected fuel prices shown in Figure 6 (section 4.0), vessel conversion cost data in Table 6, and the vessel fuel use characteristics in Table 7 to calculate the present value of ten years of fuel savings after conversion, assuming a discount rate of 7%.

As shown in Table 7, over a ten-year period a "typical" tug could be expected to save almost $7 million in fuel costs after conversion to LNG, while a medium-sized ferry could save about $11 million, and a Great Lakes bulk carrier could save over $20 million. These savings are significant; however, they fall short of paying back the investment for vessel conversion in all but the case of the modeled ferry. The payback period for conversion of the modeled tug would be just over ten years, and the payback period for conversion of the modeled Great Lakes ore carrier would be approximately 12 years.

The economics of any specific project would hinge on three factors: (1) annual vessel utilization and its fuel use, (2) delivered LNG price, and (3) vessel conversion costs. Factors which would make a specific project more economically attractive include higher than average annual vessel utilization/fuel use, lower LNG costs based on high LNG production utilization and/or use of imported LNG or excess production capacity in an existing LNG facility, and lower vessel conversion costs. Net costs for vessel conversion will be lower for vessels which require major engine work or replacement, because much of the cost of the new natural gas engines would be required for engine overhaul or replacement anyway. The incremental cost of a new vessel built to operate on LNG would also be lower than that shown in Table 7.

The above analysis does not account for the fact that marine emission regulations will drive up future fuel costs for some vessels that use marine residual fuel (see Section 8.0). Future emission compliance costs may change the economics in favor or LNG conversion, compared to other compliance options, for some of these vessels.

### Table 6
Order of Magnitude Costs to Convert Typical Marine Vessels to LNG Operation

| Type | Size (tons) | Engines | Engine Cost | Fuel System Cost | TOTAL CONVERSION COST |
|---|---|---|---|---|---|
| Tug | 150 | 2 x 1500 HP | $1.2 million | $6.0 million | $7.2 million |
| Ferry | 1000 | 2 x 3000 HP | $1.8 million | $9.0 million | $10.8 million |
| Great Lakes Bulk Carrier | 19000 | 2 x 5000 HP | $4.0 million | $20 million | $24 million |

### Table 7
Fuel Usage of Model Vessels

| Type | Fuel | Annual Demand (gal) | Annual Equivalent LNG Demand (gal) | Annual Energy Demand (Therm) | Present Value 10-year Fuel Savings (7% Discount Rate) | Net Present Value of the Project |
|---|---|---|---|---|---|---|
| Tug | Distillate | 424,000 | 768,221 | 583,848 | $6.9 million | -$0.28 million |
| Ferry | Distillate | 678,400 | 1,229,154 | 934,157 | $11.1 million | $0.27 million |
| Great Lakes Bulk Carrier | Residual | 2,080,064 | 4,097,179 | 3,113,856 | $20.6 million | -$3.4 million |

# U.S. Marine Vessel Inventories 7

## United States-Flagged Vessels

Vessels that have potential for natural gas conversion include towboats (push boats, tugboats, and ATBs) and ferries. The U.S.-flagged marine vessels in these categories, their size, and their geographic location are summarized in Table 8. These counts are taken from a U.S. Army Corps of Engineers publication [R14]. However, this publication may slightly underestimate the number of vessels; for instance, a list of inland and gulf coast waterways vessels assembled by The Waterways Journal lists over 3,300 towboats and over 470 tugs [R15].

Virtually all of these vessels burn marine distillate fuel; on average, tugs, articulated tug-barges (ATBs), push boats, and ferries use 23 to 32 gallons of fuel per hour for every 1000 engine horsepower.[12] These vessels also tend to get used 5 – 7 days per week and 12 – 18 hours per day. A medium-sized tugboat (150 tons) could use more than 400,000 gallons of fuel per year. This is equivalent to the amount of fuel used by 40 transit buses or 20 long-haul tractor-trailers annually.[13] A large car ferry (1000 tons) could use as much as 650,000 gallons of fuel per year. This is equivalent to the amount of fuel used by 65 transit buses or 33 long-haul tractor-trailers annually.

Great Lakes-bound vessels, known as lakers, are another opportunity for natural gas conversion. There are 55 such vessels, which are largely used for shipping bulk commodities such as iron ore. Table 9 summarizes these vessels and their characteristics [R17].

Some of these vessels are propelled by diesel engines while some use steam engines. Three quarters of these vessels burn distillate oil; most of the remainder burn residual oil, while one steam ship still burns coal.

On average each of the 43 dry-bulk ore carriers burn approximately 290 gallons of fuel per hour, and as much as 2 million gallons of fuel per year.[14] One of these vessels uses as much fuel annually as 200 transit buses, 100 long-haul tractor-trailers, or about 2% of the amount of fuel a 500-MW natural gas combined cycle unit operating at 50% capacity.

## International Vessels

Liquefied natural gas carriers, none of which are currently U.S.-flagged but many of which do deliver LNG to the United States, represent a unique opportunity for LNG conversion due to the fuel already being carried onboard. As of 2011, there were 347 LNG tankers in the worldwide fleet, with 26 new ships on order [R18]. Some of these vessels are powered by diesel engines and some are powered by steam engines. As discussed in section 5.0, since 1964 some LNG carriers have used "boil-off gas" from their cargo to supply some of their propulsion fuel needs, but only two of these vessels currently use LNG exclusively or propulsion. The remainder primarily burn residual oil.

12 This assumes 50 – 70% average load factor and 40% average engine efficiency.

13 US transit buses typically drive approximately 30,000 miles per year and average about 3 MPG. Long haul tractor-trailers can travel more than 100,000 miles per year and average about 5 MPG.

14 This assumes 68% engine load factor, 40% engine efficiency, and operation 24 hours per day 300 days per year.

## Table 8

U.S.-Flagged Tugboats, Push Boats, and Ferries [R16]

### Tugboats

| Size (tons) | Number | Average Horsepower for Size Class |
|---|---|---|
| 0-25 | 390 | 453 |
| 26-50 | 369 | 885 |
| 51-100 | 832 | 1765 |
| 101-200 | 889 | 3664 |
| 201+ | 100 | 5020 |
| No weight listed | 26 | 1595 |
| **Total** | **2606** | |

| Location | Count |
|---|---|
| East Coast | 590 |
| West Coast | 379 |
| Great Lakes | 243 |
| AK/HI/Territories | 139 |
| Gulf | 949 |
| Inland | 155 |
| Not Listed | 151 |

### Pushboats

| Size (tons) | Number | Average Horsepower for Size Class |
|---|---|---|
| 0-25 | 323 | 417 |
| 26-50 | 468 | 683 |
| 51-100 | 950 | 1133 |
| 101-200 | 545 | 2043 |
| 201+ | 516 | 4807 |
| No weight listed | 29 | 556 |
| **Total** | **2831** | |

| Location | Count |
|---|---|
| East Coast | 181 |
| West Coast | 81 |
| Great Lakes | 378 |
| AK/HI/Territories | 11 |
| Gulf | 1363 |
| Inland | 757 |
| Not Listed | 60 |

### Ferries

| Size (tons) | Number | Average Horsepower for Size Class |
|---|---|---|
| 0-25 | 59 | 269 |
| 26-50 | 97 | 966 |
| 51-75 | 198 | 2083 |
| 76-100 | 39 | 2445 |
| 101-500 | 67 | 1683 |
| 501-2000 | 52 | 4775 |
| 2000+ | 13 | 9972 |
| No weight listed | 54 | 1532 |
| **Total** | **579** | |

| Location | Count |
|---|---|
| East Coast | 246 |
| West Coast | 97 |
| Great Lakes | 83 |
| AK/HI/Territories | 55 |
| Gulf | 63 |
| Inland | 35 |
| Not Listed | 0 |

## Table 9

Summary of Great Lakes Bound Vessels

| Vessel type | | Count | Average size (tons) | Average horsepower |
|---|---|---|---|---|
| Dry-bulk carriers | Self-propelled | 43 | 19,248 | 9,546 |
| | Tug-barge | 7 | 12,316 | 6,626 |
| Cement carriers | Self-propelled | 2 | 7,493 | 3,750 |
| | Tug-barge | 3 | 7,179 | 6,267 |
| Supply boat | | 1 | 53 | 190 |
| Car ferry | | 1 | 4,244 | 7,000 |

| Fuel Type | Count |
|---|---|
| Distillate Oil | 41 |
| Residual Oil | 13 |
| Coal | 1 |

# Marine Emission Regulations 8

Under the Clean Air Act, the U.S. Environmental Protection Agency (EPA) regulates exhaust emissions from all new gasoline and diesel engines that enter commerce in the U.S., by setting standards for allowable mass emissions of four different pollutants: carbon monoxide (CO), hydrocarbons (HC), nitrogen oxides (NOx) and particulate matter (PM). Carbon dioxide ($CO_2$) and other greenhouse gas (GHG) emissions are currently unregulated. The fuel economy (MPG) of cars and light trucks has been regulated by the Department of Transportation under the Corporate Average Fuel Economy (CAFE) program since 1975,[15] and EPA has recently adopted rules to begin directly regulating $CO_2$ and other GHG emissions from cars and light trucks beginning with the 2012 model year, and from heavy-duty onroad trucks and engines beginning with the 2014 model year. EPA currently has no plans to regulate GHG emissions from nonroad or stationary engines or equipment such as marine engines and vessels. The International Maritime Organization (IMO) is in the process of implementing efficiency standards (Energy Efficiency Design Index (EEDI) for new vessels only.

For heavy-duty nonroad applications, including marine vessels, the engine alone is regulated by EPA, not the vehicle. For these engines, emission standards are expressed as allowable mass per unit of work output (grams per brake horsepower-hour, g/bhp-hr, or grams per kilowatt-hour, g/kWh).

EPA marine engine emission standards only apply to engines installed in U.S-flagged vessels. For the most part these vessels are coastal vessels that operate full-time within the U.S. Exclusive Economic Zone (EEZ) – tugs, barges, ferries, and other work vessels; these vessels typically have Category 1 or Category 2 engines[16] (per EPA designations). Most large ocean-going vessels (cruise ships, container ships, tankers, and bulk carriers) have Category 3 engines[17]. These vessels are also usually foreign-flagged, and may or may not be subject to emission regulations imposed by the flag country. However, when operating in U.S. waters, these vessels are subject to emission standards negotiated under the auspices of the International Maritime Organization (IMO) and adopted by EPA. They are also subject to limitations on the sulfur content of the fuel they use.

EPA first imposed emission limits on cars and light trucks beginning in the 1970s. Emissions from diesel engines used in heavy-duty trucks were not regulated until the 1988 model year, and diesel engines used in marine applications were not regulated until the early 2000's (see Figure 10).

For nonroad applications EPA standards are typically labeled in "tier levels." The least stringent level of regulation for new engines is Tier 1, and the most stringent level currently proposed is Tier 4. EPA marine engine emission standards generally only apply to new engines, when the engine is manufactured. However, the most recent EPA standards for marine engines, codified in 40 CFR 1042,[18] also introduced a requirement that Category 1 and Category 2 engines larger than 600 kW (800 HP) that were built after 1973 be upgraded to reduce PM emissions by 25% when rebuilt or remanufactured. These previously unregulated engines are typically referred to "Tier 0" engines[19]. EPA and IMO standards applicable to Category 3 marine engines may also require upgrade of certain engines to reduce NOx emissions when the vessel or engine is overhauled.

15 $CO_2$ emissions (g/mi) from cars and trucks are proportional to fuel use (gal/mi), so that fuel economy regulations are, in effect, CO2 regulations.

16 Category 1 engines have power ratings less than 3700 kW (4933 HP) and displacement of less than 7 liters per cylinder; these engines are similar to engines used in large construction equipment. Category 2 engines generally have displacement of between 7 and 30 liters per cylinder; these engines are similar to engines used in locomotives.

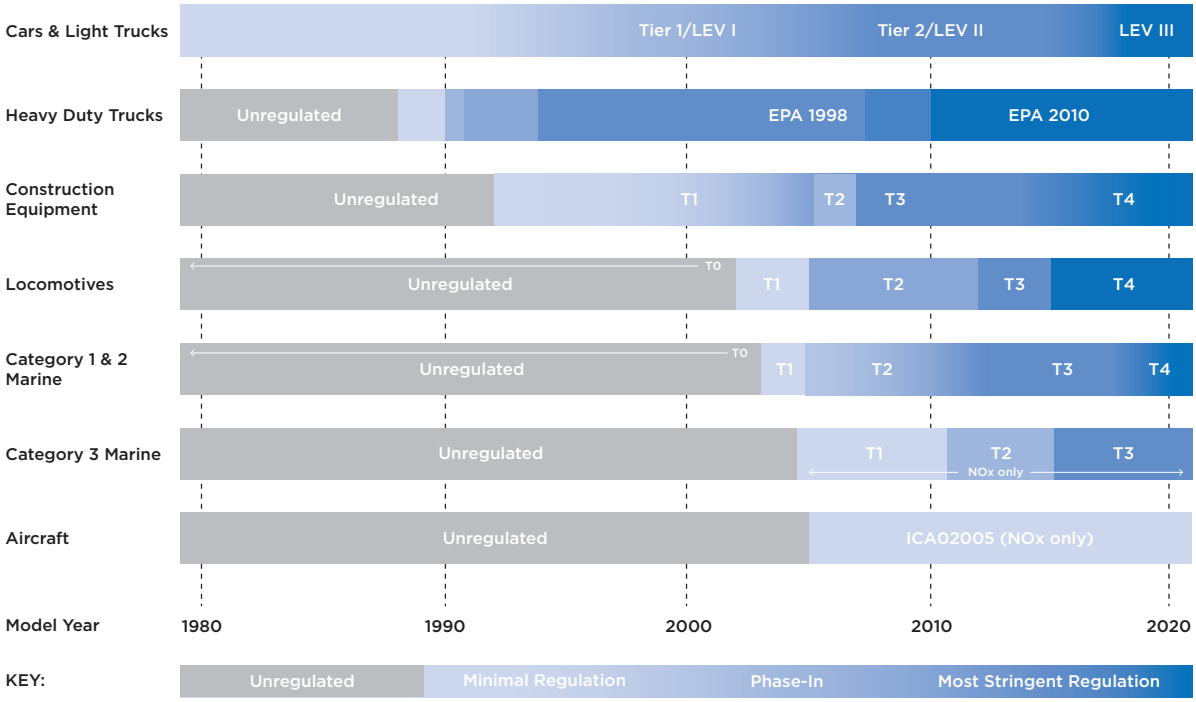
17 Category 3 engines have displacement greater than 30 liters per cylinder. These are slow- to medium-speed engines and are unique to marine vessels. These engines typically burn residual, not distillate, fuel.

18 Code of Federal Regulations, Title 40, section 1042

19 Some people refer to all engines built prior to the imposition of EPA regulation for new engines as Tier 0 engines, but this is not technically correct.

## Figure 10

Time Frame for Imposition of EPA Emission Regulations for Mobile Sources




Notes:
EPA Tier 2 and California LEV II light-duty standards were phased in over several model years based on fleet average requirements.

Construction equipment and Category 1 & 2 marine engine standards were phased in over several model years based on engine size.

Category 3 marine engines are very large slow- to medium-speed engines used mostly in ocean-going vessels; these engines currently burn residual fuel. EPA T1-T3 standards only apply to U.S.-flagged vessels.

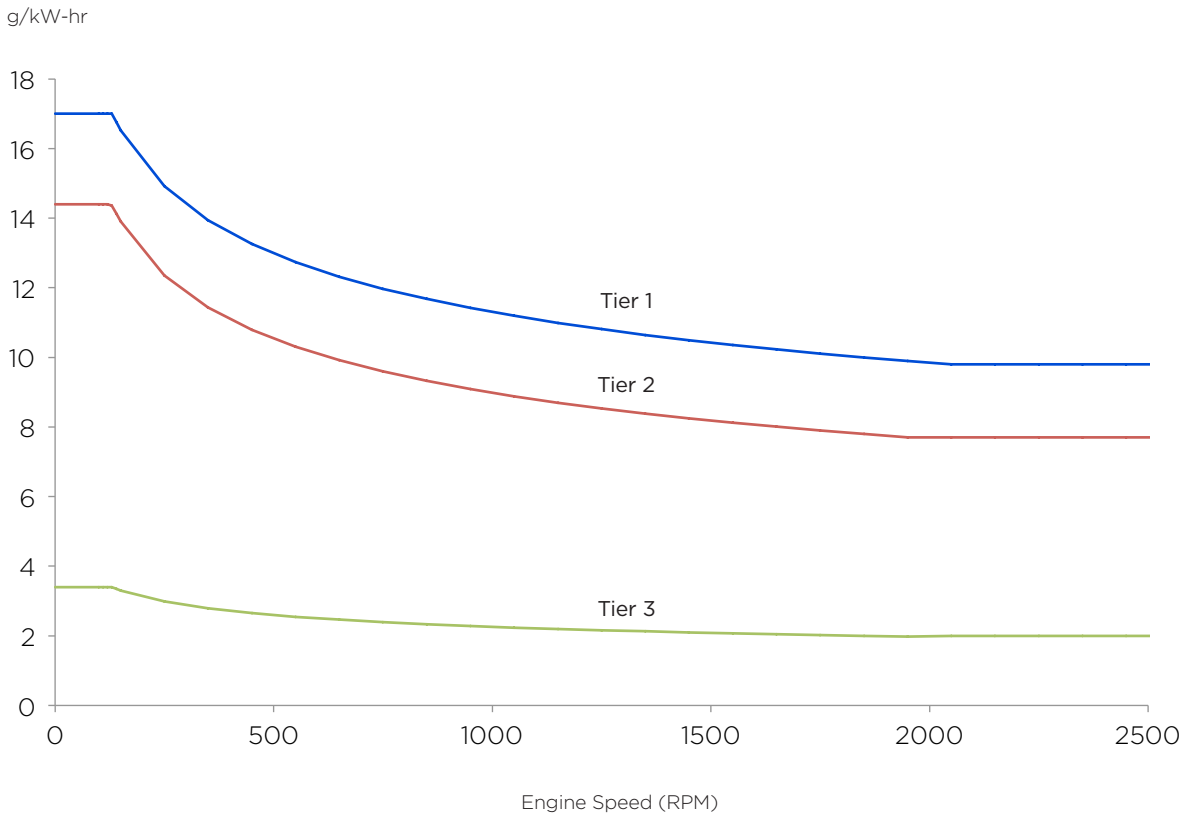
Beginning in calendar year 2000, Tier 0 locomotive standards apply retroactively to locomotive engines built from 1973 – 2001, when the engine is rebuilt or remanufactured, and they require 25% PM reduction.

Beginning in calendar year 2008, Tier 0 marine standards apply retroactively to Category 1 & 2 marine engines larger than 600 kW built from 1973 – 2004, when the engine is rebuilt or remanufactured, and they require a 25% PM reduction.

The vast majority of in-use marine engines around the world are currently unregulated. As shown in Figure 10, new U.S. marine engines being manufactured today are regulated at the Tier 2 level. More stringent Tier 3 regulations will phase in between the 2012 and 2016 model years, depending on engine type and size. This level of regulation is not as stringent as regulations that are currently applied to new onroad diesel engines. New Category 1 and 2 marine diesel engines will not be regulated as stringently as onroad diesel engines until Tier 4 standards are applied beginning in the 2018 time frame.

EPA standards applicable to the Category 3 engines used in ocean-going vessels are equivalent to the IMO regulations applicable to these engines. These standards only limit NOx, CO, and HC emissions, and do not regulate PM. EPA/IMO Tier 3 NOx limits applicable to some Type 3 engines after 2016 have similar stringency to EPA Tier 4 NOx limits applicable to Category 1 and 2 engines built after 2018. See Figure 11.

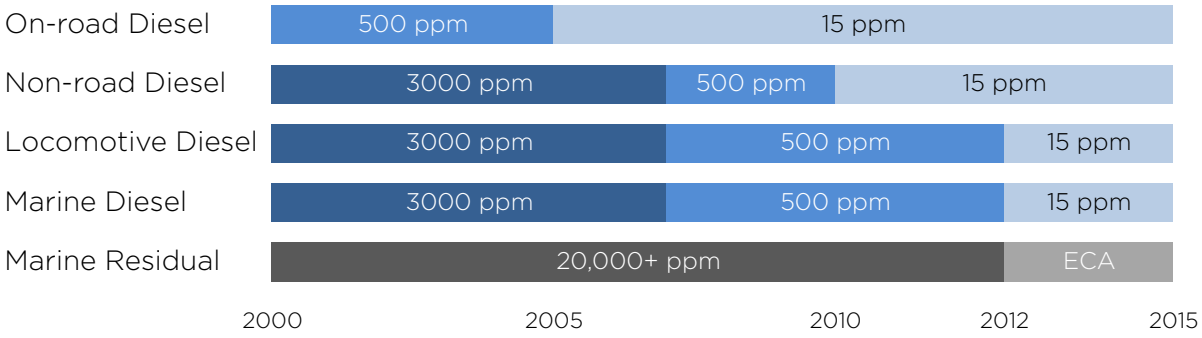
**Figure 11**
EPA/IMO NOx Limits Applicable to Category 3 Marine Engines




In addition to regulating emissions from new engines, EPA sets standards for allowable sulfur content of various fuels. Beginning with onroad vehicles in 2005, EPA mandated significant reductions in the allowable sulfur level of diesel fuel (see Figure 12); currently the diesel fuel used in onroad cars and trucks and nonroad construction equipment must be "ultra-low sulfur diesel" (ULSD) with no more than 15 parts per million (ppm) sulfur – a reduction of 97% compared to allowable levels prior to 2005. Beginning in June 2012[20] distillate fuel used by locomotives and marine vessels will also have to be ULSD. Marine residual fuel, used mostly by ocean-going vessels, is still allowed to have much higher sulfur levels; however, beginning in 2012 vessels operating within a designated "Emission Control Area" near the U.S. coastline will have to burn lower sulfur fuels under rules set by IMO and adopted by EPA (see below).

20 Refineries must begin producing ULSD marine fuel in June 2012. Due to inventory turnover, higher-sulfur fuel can continue to be used in vessels until December 2012 in most of the country. Mid-western refineries are given more time to comply.

**Figure 12**
Allowable Sulfur Content of U.S. Diesel Fuel



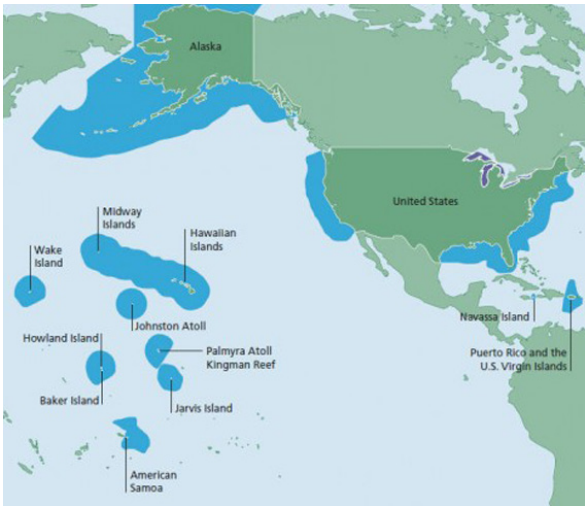

Under its most recent marine rule-making (40 CFR 1043), EPA adopted the IMO NOx emission standards and fuel sulfur limits codified under IMO MARPOL Annex VI. Under these rules, all U.S.-flagged vessels greater than 400 gross tons are required to have an International Air Pollution Prevention Certificate (IAPP Certificate), which is issued by the U.S. Coast Guard. One of the requirements for the Coast Guard to issue an IAPP Certificate to a vessel is that the operator must provide a valid Engine International Air Pollution Prevention (EIAPP) Certificate for each installed engine larger than 130 kW (175 HP), which indicates compliance with IMO NOx emission limits. Subject vessels must have been certified and received an IAPP certificate at the first scheduled dry docking that occurs after January 8, 2009, but no later than January 9, 2012.

While vessels smaller than 400 gross tons do not require an IAPP Certificate, they must still have valid EIAPP Certificates for their installed engines.

Engines installed in vessels flagged by a country which is a party to MARPOL Annex VI (Party Vessels) must have a valid EIAPP Certificate to operate in U.S. waters. Vessels flagged in a country that is not a party to MARPOL Annex VI (non-Party Vessels) do not need to have an EIAPP certificate, but in order to operate in U.S. waters the operator must have evidence that the engines conform to the NOx emission limits of Annex VI, Regulation 13. Such evidence must be provided by the government of a country that is a party to Annex VI, or by a "recognized classification society" which is a participating member of the International Association of Classification Societies (IACS).

In terms of this requirement, "operation in U.S. waters" means operation within the U.S. Exclusive Economic Zone (EEZ). In general, the U.S. EEZ extends from the U.S. coastline out 200 nautical miles into the ocean. The exception is where the U.S. EEZ under this definition would overlap with the EEZ of another country (i.e., Canada, Mexico, or Caribbean nations off the coast of Florida); in this case the marine boundary of the EEZ is as negotiated between the U.S. and the relevant nation. The United States' EEZ encompasses marine areas adjacent to the Atlantic, Pacific, and Gulf of Mexico coast lines of the continental United States, as well as areas within the Caribbean Sea, Pacific Ocean and Arctic Ocean adjacent to the Hawaiian and Alaskan coasts and the coastlines of the Commonwealth of Puerto Rico, Guam, American Samoa, U.S. Virgin Islands, Commonwealth of the Northern Mariana Islands, and any other territory or possession over which the United States exercises sovereignty. See Figure 13.

**Figure 13**
Source: NOAA



U.S.-flagged vessels which "operate only domestically", and which do not contain any engines with displacement at or above 30 liters per cylinder, are exempt from the requirements of 40 CFR 1043; they do not need an EIAPP Certificate to operate in U.S. waters. However, the engines in these vessels are subject to EPA regulation under 40 CFR 94 and 40 CFR 1042, and the emission limits under these regulations are generally more stringent than the limits in Regulation 13 of MARPOL Annex VI. U.S.-flagged marine vessels are considered to operate only domestically if they "do not enter waters subject to the jurisdiction or control of any foreign country, except the Canadian portions of the Great Lakes."

MARPOL Annex VI, Regulation 13, as implemented by 40 CFR 1043, imposes limits on NOx emissions from marine engines – other pollutants such as PM, HC, CO, and $CO_2$ are unregulated.[21] There are three levels of regulation: Tier 1, Tier 2, and Tier 3; implementation dates for each Tier level are shown in Table 10. For each Tier, the numerical limits vary depending on engine speed (RPM) – see Figure 10.

As shown in Table 10, Tier 1 and Tier 2 apply to vessels/engines operating anywhere in the U.S. EEZ, while Tier 3 limits only apply to vessels/engines operating in an Emission Control Area (ECA) and "ECA associated areas".

### Table 10

Implementation Dates for 40 CFR 1043 NOx Limits

| Tier | Area of Applicability | Model Year |
|---|---|---|
| Tier 1 | All U.S. navigable waters and EEZ | 2004 - 2010 |
| Tier 2 | All U.S. navigable waters and EEZ | 2011 - 2015 |
| | All U.S. navigable waters and EEZ, excluding ECA and ECA associated areas | 2016 and later |
| Tier 3 | ECA and ECA associated areas | 2016 and later |

An ECA is an area off the coast of a country, which is designated by the International Maritime Organization as a zone in which stringent international emission controls may be applied to ocean-going ships. To be eligible to submit an application to designate a new ECA, an interested country must have ratified, and thus become a Party to, MARPOL Annex VI, and an application for an ECA must be approved by the Parties to MARPOL Annex VI. The U.S. deposited its Instrument of Ratification with the IMO on October 8, 2008, and Annex VI entered into force for the U.S. on January 8, 2009. In March 2009 the U.S. and Canada jointly proposed a North American ECA (NAECA) which extends 200 nautical miles off the coasts of the U.S. and Canada, including the southern coast of Alaska. It also extends 200 nautical miles off the coast of the major Islands of Hawaii, but does not include waters around the U.S. territories of Puerto Rico, the U.S. Virgin Islands, the Pacific U.S. territories, the smaller Hawaiian Islands, or Western Alaska. In March 2010 the NAECA was approved by the IMO and is enforceable as of August 2012.

The NAECA is contiguous with the portions of the U.S. EEZ off the Atlantic, Pacific, and Gulf of Mexico coasts of the continental U.S., as well as the portion of the EEZ off the coasts of the major islands of Hawaii. The NAECA does not include the portions of the EEZ off the western and northern coasts of Alaska, or the coasts of U.S. commonwealths and territories in the Caribbean and the Pacific Ocean - see Figure 14. ECA associated areas are U.S. internal waters that are navigable from the ECA.

In July 2011, IMO adopted a proposal by the U.S. to designate a Caribbean Sea Emission Control Area (CSECA), off of the Atlantic and Caribbean coasts of Puerto Rico and the U.S. Virgin Islands. Vessel emission and fuel sulfur limits within the CSECA are similar to those within the NAECA, in order to control NOx, PM, and $SO_2$ emissions from ships; the CSECA will enter into force in January 2013, but will not be enforced until January 2014.

21 Emissions from shipboard systems other than marine engines are regulated by Annex VI. Regulation 12 addresses emission of ozone-depleting substances (primarily refrigerants such as hydro-chlorofluorocarbons) and Regulation 15 addresses Volatile Organic Compound (VOC) emissions from the cargo (primarily crude oil and refined oil products) carried on tankers.

Vessels built after 2016 which operate within the NAECA, CSECA or ECA associated areas must comply with Tier 3 NOx emission limits, while vessels built after 2016 which operate in other parts of the U.S. EEZ, but not the NAECA or CSECA (for example off the western coast of Alaska) will only have to comply with Tier 2 NOx emission limits.

40 CFR 1043 was effective as of July 1, 2010; Tier 1 NOx limits apply for applicable vessels and their installed engines built after January 1, 2000, even though the engines were originally manufactured with no emissions limit. If the engine cannot meet the NOx emissions limit as designed, the engine can receive an EIAPP Certificate based on application of a certified "Approved Method." An Approved Method is a retrofit procedure that will reduce NOx emissions to the applicable Tier 1 standard on a specific engine or engine family.

40 CFR 1043 also implements limits on the sulfur content of marine fuels used in U.S. navigable waters, the U.S. EEZ, and the NAECA and CSECA, which are consistent with the fuel sulfur limits of MARPOL Annex VI. These limits are shown in Table 11.

Vessels subject to 40 CFR 1043 may use higher sulfur fuels if they apply a certified "equivalent control method" to their engines which will achieve PM and $SO_2$ emission levels equivalent to those achieved when using compliant fuel.

The fuel sulfur limits of 40 CFR 1043 only really affect marine residual fuels – as discussed above, as of 2012 U.S. marine distillate fuels are required to have no more than 15 ppm sulfur (0.0015%) and therefore easily meet the requirements of 40 CFR 1043, even within an ECA. Currently, marine residual fuels often have 4% sulfur or more – significant reductions will be required to meet the requirements of 40 CFR 1043, especially while ships are operating within an ECA.

EPA may exempt historic steamships from the fuel sulfur requirements under 40 CFR 1043 – through 2020 - if they operate in U.S. internal waters. Operators of such vessels must request an exemption from EPA. EPA may also exempt steamships operating exclusively on the Great Lakes from the fuel sulfur requirements of 40 CFR 1043 based on documented "serious economic hardship."

IMO has also adopted Sulfur Emission Control Areas (SECA) in the Baltic Sea (in force since May 2005) and the North Sea and English Channel (in force since August 2007). Within these SECA there are limits on fuel sulfur levels, but no specific limits on NOx emissions from ships.

**Figure 14**
North American ECA

**Table 11**
Fuel Sulfur Limits in 40 CFR 1043

| Calendar Years | Fuel Sulfur Limit (%) | |
|---|---|---|
| | U.S. navigable waters and EEZ | ECA and ECA associated areas |
| 2010-2011 | 4.50% | 1.00%[1] |
| 2012-2015 | 3.50% | 1.00%[1] |
| 2016-2019 | 3.50% | 0.10% |
| 2020 and later | 0.50% | 0.10% |

[1] Requirements specific to the North American ECA are not enforceable until August 2012, based on the ECA approval date by IMO.

# U.S. Marine NG Market Opportunities 9

There are two main drivers of the potential for LNG to be used as a marine fuel in the U.S.:

1 historically low natural gas prices (coupled with rising oil prices) have opened up a significant price gap between LNG and traditional marine fuels, which results in vessel fuel cost savings after conversion to LNG operation; and

2 the need to reduce NOx, PM, and SOx emissions from marine vessels, particularly within the North American and Caribbean Sea ECAs. These issues are related since future fuel sulfur limits within the ECAs are expected to require in the coming months substitution of more expensive, low-sulfur distillate fuel for current high-sulfur residual fuel for some vessels. Technology such as scrubbers could be used in lieu of lower sulfur fuel, but this would also add capital and operating costs. Since LNG is naturally low in sulfur, it can be used to comply with fuel sulfur restrictions.

The two largest impediments to conversion of marine vessels to LNG operation are:

1 the high capital cost of vessel conversion and
2 lack of LNG infrastructure in many parts of the country, particularly at marine ports.

Again, these two issues are linked in that the need to develop new LNG infrastructure will significantly increase the cost of delivered LNG as a marine fuel, thus reducing annual fuel cost savings required to pay back the upfront cost of vessel conversion.

Given the high cost of vessel conversion, one key to project success is targeting vessels with very high utilization and annual fuel use relative to vessel size/engine power, to maximize annual fuel cost savings. Some good candidates among U.S. flagged vessels include large towing tugs and ATBs, medium-to-large car and passenger ferries, and Great Lakes bulk carriers. Both tugs and ferries tend to have high annual utilization, and both generally burn distillate fuel oil. Some Great Lakes bulk carriers currently burn distillate fuel and some burn lower-cost residual fuel. In the short term, project economics for LNG conversion will be significantly better for vessels that use distillate fuel.

However, as discussed in section 8.0, fuel sulfur limits that take effect in 2016 will likely require a switch to low sulfur distillate fuel – or the addition of emission controls – for the vessels that currently burn residual fuel, unless they are given an exemption by EPA based on economic hardship.

All tugs, ferries, and some Great Lakes bulk carriers currently use diesel engines – when converted to LNG operation they will have roughly the same engine efficiency. Some Great Lakes bulk carriers currently have steam engines, which are less efficient than diesel and LNG engines; after conversion to LNG operation these vessels would benefit from both a lower fuel price and lower fuel use due to greater engine efficiency. The conversion in these cases may increase annual fuel cost savings and enhance project economics.

Another key to the success of any marine vessel conversion to LNG operation is to ensure the lowest possible cost of LNG fuel to maximize annual fuel cost savings. As discussed in section 2.0, in the U.S. natural gas delivered to industrial customers is now 61% less expensive on an energy basis than marine residual fuel and 75% less expensive than marine distillate fuel.

However, as discussed in section 4.0, conversion can have costs. The need to develop new LNG production infrastructure to support marine vessel conversions could double the price of delivered LNG relative to the commodity price of the natural gas being liquefied, thus eroding annual fuel cost savings after vessel conversion to LNG. In addition, the LNG delivered price is highly dependent on both the size and utilization rate of the LNG plant.

MJB&A estimates that the practical minimum size for cost-effective LNG production would be a plant sized for 100,000 gallons of LNG per day operated at an average utilization of at least 80%. Such a plant, if dedicated to the marine market, would need a client base of approximately seven Great Lakes bulk carriers, 24 ferries, or 38 tugs to be economically viable.

The economics of any particular marine LNG project will be significantly improved if the project can take advantage of existing LNG import or

production capacity within a reasonable distance of the vessel home port, which will reduce the minimum number of vessels required to be converted and/or reduce delivered LNG price, and thus increase annual vessel fuel cost savings.

As shown in Figure 4 (section 4.0) there are several LNG liquefaction/storage facilities located near the Great Lakes that could potentially be used to support LNG conversions there. In addition to the Great Lakes bulk carriers (55 vessels) the USCG vessel inventory indicates that there are 243 tugs and 83 ferries that operate in and around the Great Lakes – though not all of these vessels would be good candidates for LNG conversion.

There are also a number of LNG liquefaction/storage facilities located close to the central Atlantic coast that could potentially support conversion of tugs (590 vessels) and ferries (246 vessels) operating in the New York/New Jersey region.

On the northwest Pacific coast there is an LNG liquefaction/storage facility that could potentially support conversion of ferries there – particularly the Washington State Ferry system and international ferries operating between the U.S. and British Columbia (97 vessels), as well as, potentially, cruise vessels operating between Seattle and Alaska (11 vessels).[22]

Finally, there are several LNG import terminals on the Gulf coast that could potentially be used to support conversions of vessels operating in the lower Mississippi River and in the Gulf coast ports of Louisiana and Texas (949 tugs, 63 ferries).

The authors of this report are optimistic about the prospects for increased use of natural gas as a marine fuel. However, LNG conversion will not be an obvious choice for all vessels. As discussed in section 6.0, despite historically low natural gas prices relative to marine distillate and residual fuel, for many vessels annual fuel cost savings after conversion to LNG may not be large enough to provide a reasonable payback period for the high vessel conversion costs. Each prospective conversion project must be carefully analyzed to evaluate project economics, and must start with a realistic assessment of likely delivered LNG costs given available infrastructure options.

Successful projects will require both a motivated vessel owner and a motivated LNG supplier. Given significant first-mover disadvantages, initial projects may also require government intervention to offset some of the cost of vessel conversion and/or LNG infrastructure development in the context of promoting greater use of domestic fuels for transportation. After one or more vessel conversions within a given geographic area, further vessel conversions will become easier to implement.

In addition to the U.S.-flagged vessels discussed above, other obvious candidates for conversion to LNG operation include the internationally-flagged LNG bulk carriers used to carry LNG around the world, including those which supply U.S. LNG import terminals. These vessels obviously have easier access to inexpensive LNG fuel than most other vessels. Unlike most U.S.-flagged vessels, these LNG carriers currently burn less-expensive residual fuel. However, as discussed in section 8.0, as of 2016 these vessels will be required to burn low-sulfur distillate fuel, or install emission controls, when operating in the North American ECA. These future fuel sulfur restrictions will make the economics of LNG conversion more favorable for these vessels.

22 According to the Port of Seattle 2012 cruise sailing schedule, there are eleven cruise ships from seven different companies that regularly operate between Seattle and Alaska from May through September; as many as 10 vessels are scheduled to leave Seattle per week, during that time period, for seven- or fourteen-day cruises to Alaska. One impediment to conversion of these vessels to LNG operation, however, is the fact that from October to April these same vessels operate from different West coast ports, for cruises to Hawaii, Mexico, South America, and the South Pacific. In order to convert these vessels to LNG operation the fuel would have to also be available in the ports where they operate during the winter months.

# Glossary

**Compressed Natural Gas (CNG)** - Natural gas that has been compressed to high pressure to reduce its volume for storage. In the U.S. onroad heavy-duty vehicles which operate on natural gas fuels often carry their fuel on board as CNG; their mobile CNG fuel systems typically operate at a maximum gas pressure of 3600 pound per square inch.

**Distillate Fuel** – A non-volatile liquid fuel created via distillation of petroleum, and generally composed of alkanes with 12 or more carbon atoms. Distillate has a boiling point range of approximately 450 to 650 degrees Fahrenheit.

**EIAPP Certificate** - A certificate issued to a marine vessel to certify initial compliance with Regulation 13 of MARPOL Annex VI. EIAPP stands for Engine International Air Pollution Prevention.

**Emission Control Area (ECA)** - An area off the coast of a country designated by the International Maritime Organization as a zone in which stringent international emission controls may be applied to ocean-going ships. To be eligible to submit an application to designate a new ECA, an interested country must have ratified, and thus become a Party to, MARPOL Annex VI, and an application for an ECA must be approved by the Parties to MARPOL Annex VI. The U.S. deposited its Instrument of Ratification with the IMO on October 8, 2008, and Annex VI entered into force for the U.S. on January 8, 2009. In March 2009 the U.S. and Canada jointly proposed a North American ECA which extends 200 nautical miles off the coasts of the U.S. and Canada, including the southern coast of Alaska. It also extends 200 nautical miles off the coast of the major Islands of Hawaii, but does not include waters around the U.S. territories of Puerto Rico, the U.S. Virgin Islands, the Pacific U.S. territories, the smaller Hawaiian Islands, or Western Alaska. In March 2010 the North American ECA was approved by the IMO and is enforceable as of August 2012.

**Exclusive Economic Zone (EEZ)** - Under the law of the sea, an exclusive economic zone (EEZ) is a sea zone over which a state has special rights over the exploration and use of marine resources. In general, the U.S. exclusive economic zone extends from the U.S. coastline out 200 nautical miles into the ocean. The exception is where the U.S. EEZ under this definition would overlap with the EEZ of another country (i.e. Canada, Mexico, or Caribbean nations off the coast of Florida). In this case the marine boundary of the EEZ is as negotiated between the U.S. and the relevant nation. The United States' EEZ encompasses marine areas adjacent to the Atlantic, Pacific, and Gulf of Mexico coast lines of the continental United States, as well as areas within the Caribbean Sea, Pacific Ocean and Arctic Ocean adjacent to the Hawaiian and Alaskan coasts and the coastlines of the Commonwealth of Puerto Rico, Guam, American Samoa, U.S. Virgin Islands, Commonwealth of the Northern Mariana Islands, and any other territory or possession over which the United States exercises sovereignty.

**Foreign-flagged Vessel** - A marine vessel of foreign (non-U.S.) registry or a vessel operated under the authority of a country other than the United States.

**International Maritime Organization (IMO)** - The United Nations specialized agency with responsibility for the safety and security of shipping and the prevention of marine pollution by ships.

**Liquefied Natural Gas (LNG)** – Natural gas that has been cooled below -260 °F (-162 °C), until it condenses into a liquid. In this state it can be transported and stored like other liquid fuels. The volumetric energy density (energy per unit volume) of LNG is more than 600 times greater than that of natural gas at atmospheric pressure and approximately 2.5 times greater than CNG stored at 3600 psi pressure.

**Laker** – A marine vessel captive to the U.S./Canadian Great Lakes. There are 55 of these vessels; the vast majority of them are bulk carriers used to transport iron ore and other bulk commodities. Most of these vessels are large – greater than 19,000 tons capacity. The Great Lakes encompass all the streams, rivers, lakes, and other bodies of water that are within the drainage basin of the St. Lawrence River, west of Anticosti Island (U.S. EPA definition).

**MARPOL Annex VI** – Annex VI to the Marpol Convention adopted by the International Maritime Organization in 1997. Annex VI contains regulations for the prevention of air pollution from ships.

**Residual Fuel** – A non-volatile fuel created via distillation of petroleum, generally composed of multi-ring compounds with greater than 70 carbon atoms. Residual fuel has a boiling point greater than 1000 degrees Fahrenheit, and is a solid at room temperature.

**Ultra-low Sulfur Diesel Fuel (ULSD)** - Distillate petroleum fuel with less than 15 parts per million sulfur content. This fuel has been mandated for onroad trucks since 2007 and as of 2012 will be mandated for locomotives and US-flagged marine vessels.

**U.S.-Flagged Vessel** - A marine vessel with United States registry or a vessel operated under the authority of the United States.

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16. Table 8 does not include cruise ships because they are internationally flagged. While they are potential targets for LNG, it is important to note that cruise ships that operate along the West Coast to Alaska typically only do that in the summer months – during the winter they go other, warmer, places. A similar thing happens on the East Coast – the same vessels that go from NYC to the Caribbean in the winter go from NYC to the Maritimes in Canada during the summer. Therefore, even if there was LNG available on the West Coast, a vessel might not be able to convert because there might not be LNG available at the other locations it sails to in the winter.
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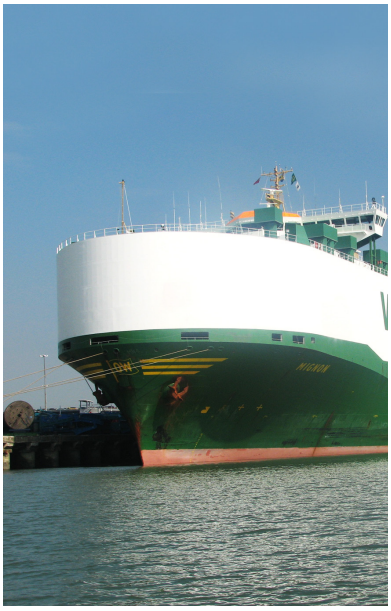

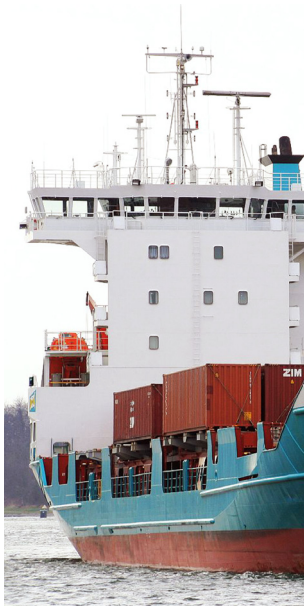
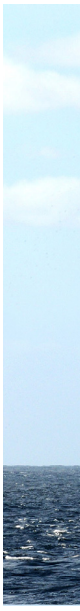

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