

Fall 2015

America's Energy Renaissance

***The Coast Guard prepares for
maritime transportation
system changes***

***The Liquefied Gas Carrier
National Center of Expertise***



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Assistant Commandant's Perspective

by REAR ADMIRAL PAUL F. THOMAS
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Technological advances in energy extraction, such as hydraulic fracturing and directional drilling, have unlocked new production from shale and other unconventional reserves, creating dramatic growth in oil and natural gas production in the U.S. after decades of decline. This dramatic growth, known as America's Energy Renaissance, is being fueled by oil and gas finds in Texas, North and South Dakota, and Pennsylvania, and is predicted to produce enough oil and gas to supply the nation as well as some aspects of the global market for decades to come. As more finds are discovered and recovery rates improve, the total quantity of U.S. reserves will only increase.

The U.S. is already the world's largest producer of oil and natural gas combined, having surpassed Russia to become the world's top natural gas producer in 2009, and is expected to become the world's top oil producer by 2020. This increased production is not only supply-driven; the U.S. Energy Renaissance is meeting the nation's demand for energy dependence, reducing trade imbalances, and, in some cases, providing more environmentally sound energy sources. This presents the need to grow the nation's infrastructure to accommodate this new production.

As such, the Energy Renaissance is reshaping America's marine transportation system (MTS) with an influx of new vessels, new products, new routes, new fuels, and new operations required to transport oil and gas from the inland reserves to coastal facilities and to market. With more than 30 proposed liquefied natural gas (LNG) export facilities, a drastic increase in crude oil transport on our inland rivers, new LNG-fueled vessels and associated bunkering operations, and responses to unconventional petroleum products, these are exciting times with tremendous opportunity.

But there are real challenges here, as well. The most significant challenges speak to the capacity of our ports, waters, shipyards, locks, and terminals, which are stretched, to be sure, as is our capacity to provide qualified, properly experienced, and well-rested mariners. There are challenges in our capacity to respond to incidents, particularly in areas where oil spill response organizations and the rest of the response community may be limited because crude oil was not previously present. Finally, there are challenges in our capacity to provide maritime governance in terms of developing timely, relevant standards as well as people who understand and can help ensure compliance with such standards.

This issue of *Proceedings* provides an in-depth understanding of these new products, their impact on the MTS, and how the U.S. Coast Guard and other government agencies are preparing to address these challenges posed by the U.S. Energy Renaissance.

Champion's Point of View



by CDR JASON SMITH
Detachment Chief, LGC NCOE
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Just a decade ago, America's conventional oil and gas production was facing significant decline. The country was preparing to rely even more heavily on foreign oil and gas, and the industry had spent tens of billions of dollars on new import terminals. Since then, advances in energy production technology, including directional and horizontal drilling, hydraulic fracturing, and new platform and global positioning technology have revolutionized oil and gas production. This has turned a nation once looking abroad for more energy resources into a top oil and gas producer, with production levels continuing to climb. This radical change in the country's oil and gas production has been coined "America's Energy Renaissance," which currently accounts for 8 percent of the U.S. GDP and now significantly impacts our ports and waterways in various ways.

During the American Waterway Operators' 2015 spring convention, the Commandant of the Coast Guard, Admiral Paul Zukunft, said: "The Energy Renaissance in the U.S. is causing tremendous change across our maritime transportation system ... Predictions suggest that domestic energy production will exceed consumption by 2020. This is significant, because much of that oil and gas will move to market on our nation's maritime transportation system."

This impact has already been seen, with new cargoes transported over the water, increased oil tanker and gas carrier transits, and new marine fuels and fueling operations. Even with the drop in global oil prices, we have seen American oil production more than double since 2008, and natural gas production is up about 24 percent. In April 2015, U.S. oil production reached its highest levels since the early 1970s, hitting 9.7 million barrels per day. Analysts predict production will remain at relatively the same level and rise even further once prices rebound.

In addition, the U.S. is positioned to capture a large portion of global liquefied gas demand, which is estimated to grow by more than 5 percent each year over the next ten years, with more than 33 large-scale liquefaction facilities requesting government approval to export.

Using liquefied natural gas as a transportation fuel is another aspect of the gas industry already changing the maritime environment as we know it. The first U.S.-certificated LNG-fueled vessel is in operation, and 11 others are currently under construction in the U.S. There are more than 50 additional vessels under construction internationally, with LNG bunkering operations on the East, West, and Gulf Coasts approved or currently under review. Many predict this trend will continue with more than 1,000 non-LNG carrier oceangoing vessels by 2020.

This edition of *Proceedings* is devoted to how this drastic shift in U.S. energy production is affecting the maritime transportation system. The edition opens with introductions to the new cargoes and operations, and contains separate sections on more detailed aspects of the maritime liquefied gas and petroleum industries. The edition closes with a series of articles on how the Coast Guard is undergoing a servicewide effort to revitalize its marine safety enterprise, retooling existing processes and personnel, and researching other changes and additional resources needed to accommodate the expected maritime growth.

It has been an honor to champion this edition and work with the numerous highly talented authors from various Coast Guard offices, other government agencies, academia, and the oil and gas industry. The unified approach in putting this edition together is a reflection of the cooperation already in place throughout the maritime community to ready our ports for these changes and ensure that, as Admiral Zukunft best put it, "... the Coast Guard facilitates this growth safely, and that we do not impede it."

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The Energy Renaissance

New U.S. energy reserves create a new oil and gas paradigm.

by MR. RICK ELLIOTT

Director, Advanced Supply and Facilities Division
U.S. Department of Energy

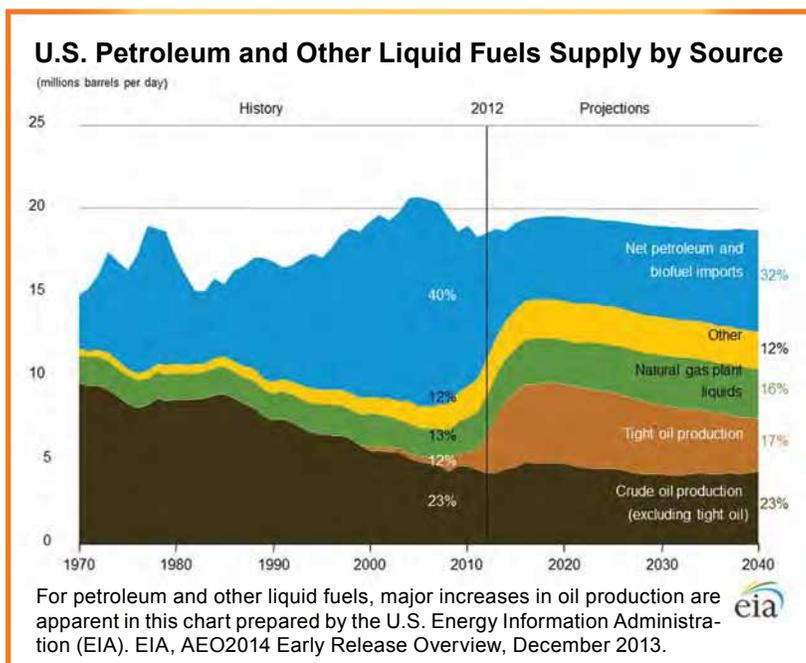
America’s abundant unconventional oil and natural gas (UOG) resources, consisting primarily of natural gas and oil contained in “tight” geological formations with low permeability, have become vital components of our nation’s energy portfolio.¹ As recently as a decade ago, there were widespread predictions the U.S. was running out of recoverable oil, that it was moving toward becoming a net importer of natural gas, and that it would have to depend primarily on coal to generate much of the nation’s electricity for the foreseeable future.

Since then, the successful introduction and widespread implementation of innovative hydraulic fracturing and horizontal drilling techniques have made it economically possible to reach once hard-to-get UOG resources.² The result has been a renaissance or “rebirth” in U.S. crude oil and natural gas production.

Production Increases

The U.S. and Canada are the only major producers of tight oil in the world, and most U.S. tight oil is produced from deposits in Texas and North Dakota. According to the U.S. Energy Information Administration (EIA), U.S. tight oil production averaged 3.22 million barrels per day (MMbbl/d) in the fourth quarter of 2013. This was enough to push overall crude oil production in the U.S. to an average of 7.84 MMbbl/d, or more than 10 percent of total world production. Overall, domestic daily output between 2008 and 2013 grew by 50 percent.

By 2016, the U.S. could be pumping more than 9 million barrels daily, a level not seen since the early 1970s. According to the EIA, the U.S. will surpass both Russia and Saudi Arabia in oil production sometime in 2015. Domestic crude oil production is expected to level off and then slowly decline after 2020.



Energy Information Administration statistics also show a similar story for natural gas, as production from shale gas wells has increased steadily over the last decade. For example, in 2001, shale gas was only about 2 percent of total domestic natural gas production; over the past decade, U.S. shale gas production has increased more than twelvefold, and now accounts for about 27 billion cubic feet per day (bcfd) or 40 percent of total production. The U.S. is now the world’s largest natural gas producer, according to EIA, and is poised to become a net natural gas exporter by 2018.

Transportation Impact

This domestic oil and gas production renaissance presents challenges for the U.S. transportation sector. Pipelines have long been seen as the “preferred” method to move crude oil and other petroleum liquids, and they continue to transport substantially

Hydrocarbon Gas Liquids

The growth in U.S. onshore natural gas and oil production has also led to increased volumes of natural gas plant liquids and liquefied refinery gases, which primarily include propane, butane and ethane, isobutane, and pentanes, among others. To reduce confusion in terminology and improve its data presentation, EIA has developed the term “hydrocarbon gas liquids,” or HGL, to refer to natural gas plant liquids and liquefied refinery gases, while excluding liquefied natural gas and aromatics. Between 2008 and 2014, HGL production from natural gas processing plants increased by 62 percent to 2.9 million barrels per day from 1.8 million barrels per day.

Additionally, increases in oil and natural gas resources are reflected not only in production figures, but also in reserve estimates. As such, EIA estimates of recoverable reserves have been raised to reflect that current technologies allow substantially greater recoveries of oil and natural gas from existing fields.

more crude oil than other methods. However, pipeline construction is an inherently longer-term undertaking, and it has not kept pace with the rapid increases in domestic crude oil production. Currently, crude oil transportation is increasingly multi-modal: Any particular shipment may use various different combinations of trucks, rail cars, pipelines, barges, and tankers. For example, in cases where pipelines are either unavailable or lack suitable capacity, oil is often initially transported by truck to a nearby rail loading facility.

Shale gas transportation has introduced its own challenges. Texas, Pennsylvania, Arkansas, Louisiana, Oklahoma, and West Virginia currently account for the overwhelming majority of shale gas production. This is a change with significant implications for global markets, including portions of the maritime industry that are involved in transporting natural gas overseas, which is primarily achieved by liquefying the gas. As the U.S. has shifted rapidly from being a large liquefied natural gas (LNG) importer to a potential LNG exporter, LNG shipments previously destined for the U.S. have been reallocated to Europe and Asia, where demand for natural gas is growing rapidly and governments are anxious to secure supply to meet rapidly expanding needs.

By volume, domestic shipments of natural gas occur overwhelmingly by pipeline. However, truck, rail, and vessel shipments of compressed natural gas (CNG) are increasing

to serve markets in areas that do not have natural gas pipelines.

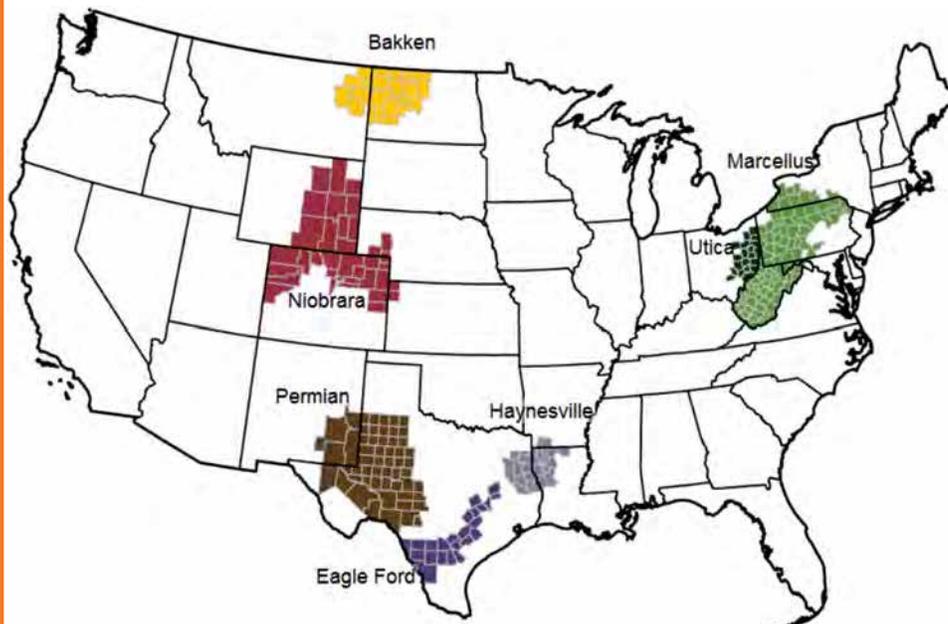
Hydrocarbon gas liquids (HGL) transportation cannot be simply characterized, because there are numerous HGL constituents that can either be shipped together in various types of mixed streams or be separated into pure components prior to shipment. Ethane, propane, and butanes are commonly shipped by pipeline, but can also be shipped by a variety of means in pressurized vessels. Pentanes and other hydrocarbon gas liquids with higher molecular weights are liquid under normal atmospheric conditions, and do not typically require pressurized containment vessels.

Crude by Rail

The EIA tracks U.S. refinery crude oil receipts. Because U.S. law currently prohibits most crude oil exports, essentially all domestic crude oil is destined to be delivered to a U.S. refinery, and consequently refinery receipt information serves as a useful indicator of how crude oil is being transported.

Crude by rail (CBR) transport has quickly filled a void created by a lack of adequate pipeline capacity. Some advantages over pipeline transport are lower capital costs, greater

U.S. Oil Production Growth (95%) and All U.S. Natural Gas Production Growth from 2011–2013



According to the EIA, the seven highlighted regions accounted for 95% of U.S. oil production growth and all U.S. natural gas production growth from 2011–2013.

LNG Exports

While LNG export cost/benefit analysis is complex and subject to debate, EIA recently evaluated the effects of increased levels of LNG exports on U.S. energy markets and reached the following general conclusions:

- ▶ Increased LNG exports will lead to increased natural gas prices.
- ▶ Natural gas markets in the U.S. balance in response to increased LNG exports mainly through increased natural gas production.
- ▶ Supply from higher domestic production is augmented by reductions in natural gas use by domestic end-users, who respond to higher domestic natural gas prices.
- ▶ Increased LNG exports result in higher total primary energy use and energy-related CO₂ emissions. Consumer expenditures for natural gas and electricity increase modestly with added LNG exports.
- ▶ Added U.S. LNG exports result in higher levels of economic output, as measured by real gross domestic product.
- ▶ Added U.S. LNG exports result in higher levels of domestic consumption expenditures for goods and services.

Endnote:

EIA, "Effect of Increased Levels of Liquefied Natural Gas Exports on U.S. Energy Market," October 2014.

flexibility in routing, more supply chain diversification options, faster speed to market, better volume scalability, and shorter-term contracts. CBR can be an effective bridge to pipeline construction in some cases, and offers flexibility in handling rapidly expanding production by transporting crude oil to markets with limited pipeline access.³

However, rail is not in a position to replace pipelines. According to the Energy Information Administration, pipelines

remain the most popular transport option, carrying about two-thirds of U.S. oil and petroleum products. Nevertheless, the EIA reports that the amount of crude oil and refined petroleum products moved by U.S. railroads increased nine percent during the first seven months of this year compared with the same period in 2013.

In July 2014, monthly average oil and petroleum product loadings were near 16,000 carloads per week, according to the Association of American Railroads, which estimates that more than half of the nearly 460,000 carloads tracked in its petroleum and petroleum products category from January through July consisted of crude oil, up from around three percent in 2009. With the average rail tank car holding around 700 barrels of crude oil, about 759,000 barrels of crude oil per day were moved by rail during the first seven months of 2014, equal to eight percent of U.S. oil production.

In addition to Bakken crude oil, which constitutes the largest single portion of U.S. CBR shipments, Canada's heavy crude oils are increasingly being moved by rail. In 1998, Canadian National acquired the Illinois Central railroad, linking the nation's Chicago rail hub with the Gulf Coast and New Orleans, making it the dominant rail provider in Alberta, where Canada's heavy oil sands lie. All told, volumes have increased substantially in recent years, more than doubling since 2012.

Some heavier crude oils are easier to move by rail than by other means. Canadian bitumen cannot be readily transported by pipeline unless it is diluted with lighter petroleum hydrocarbons to reduce its viscosity. While diluted bitumen is moved by rail, rail cars that are equipped with heating coils can transport undiluted bitumen. In some instances, rail cars that would otherwise be empty carry diluent materials on "backhauls" from the U.S. to Canada, increasing the cars' overall utilization. There are other synergies between rail and crude oil production—in addition to transporting

Natural Gas Withdrawals and Production (Millions of Cubic Feet)

	2008	2009	2010	2011	2012	2013	2014
Gross Withdrawals	25,636,257	26,056,893	26,816,085	28,479,026	29,542,313	30,005,254	31,895,427
From Gas Wells	15,134,644	14,414,287	13,247,498	12,291,070	12,504,227	11,255,616	
From Oil Wells	5,609,425	5,674,120	5,834,703	5,907,919	4,965,833	5,427,676	
From Shale Gas Wells	2,869,960	3,958,315	5,817,122	8,500,983	10,532,858	11,896,204	
From Coalbed Wells	2,022,228	2,010,171	1,916,762	1,779,055	1,539,395	1,425,757	
Repressuring	3,638,622	3,522,090	3,431,587	3,365,313	3,277,588	3,331,456	
Vented and Flared	166,909	165,360	165,928	209,439	212,848	260,394	
Nonhydrocarbon Gases Removed	718,674	721,507	836,698	867,922	768,598	722,527	
Marketed Production	21,112,053	21,647,936	22,381,873	24,036,352	25,283,278	25,690,878	27,271,326
Dry Production	20,158,602	20,623,854	21,315,507	22,901,879	24,033,266	24,333,709	25,718,448

Courtesy of EIA, Natural Gas Withdrawals and Production Report, release date 06/30/2015



Gas Transportation

Gas Statistics

- ▶ Raw gas is transported in pipelines to stripping plants, where propane and natural gas plant liquids are extracted to create “pipeline” natural gas, comprised primarily of methane.

Natural Gas

- ▶ Natural gas (methane) is transported in pipelines as a gas or may be liquefied for transportation or compressed for long-term storage.
- ▶ Export LNG facilities are located on the water, where tankers transport it overseas.
- ▶ LNG transport via rail is currently prohibited.
- ▶ Liquefied natural gas truck transport is costly and limited to short distances.
- ▶ There are currently no barges capable of transporting LNG.

Other Gases

- ▶ Other gases are liquefied and/or compressed for storage or truck, rail, barge, or tanker transport, depending on stripping plant location and end use.
- ▶ Rail and truck transport for propane and natural gas liquids is common.

crude oil from producing fields, rail lines can deliver materials such as water, tubular materials, chemicals, and construction consumables oil producers need.

Trucks

Trucks are not generally economical for bulk, long-distance petroleum liquids transportation. However, trucks offer great flexibility and are used extensively in a variety of comparatively short-haul applications. For example, trucks are used in some locations to move crude oil from production wells to storage depots for subsequent transfer to railcars or pipelines. They are used extensively for local distribution of gasoline, diesel fuel, heating oil, liquid propane, and butanes.

Tankers

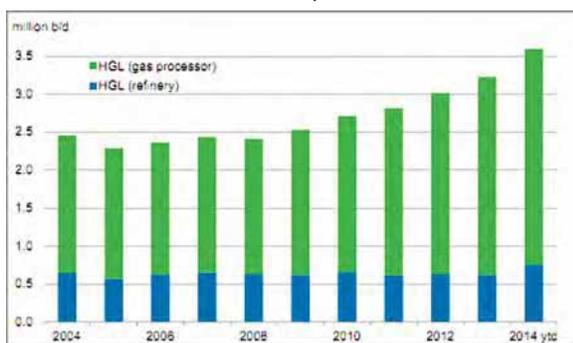
U.S. law does not currently allow crude oil exports, other than by special exception. Consequently, few tankers export crude oil. However, refined petroleum products and HGL can be exported, and such exports have been increasing in recent years. With a surplus of domestic crude oil and export restrictions, it is logical for refiners to export as many refined products as is economically feasible. At the same time, crude oil imports are expected to decline or remain fairly steady.

According to a recent Congressional Research Service report, the U.S. now imports less oil by oceangoing tankers than five years ago, while more oil is moving domestically via river and coastal barges. Additionally, the majority of U.S. refineries are located near navigable waters to take advantage of economical waterborne transport for import and export.

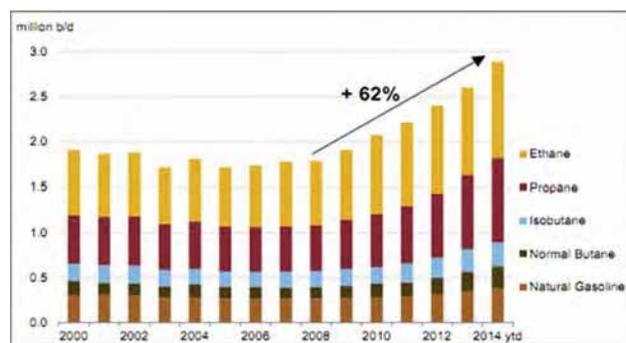
However, refineries wishing to switch from imported crude to domestic crude oil may encounter economic and logistical impediments. The Jones Act (a 1920 law that seeks to protect

U.S. shipyards and U.S. merchant sailors in the interest of national defense) restricts domestic waterborne transport to U.S.-built and -crewed vessels. The purchase price of U.S.-built tankers is reportedly higher than foreign-built tankers, and U.S. crewing costs can be several times those of foreign-flag ships. In addition, the small number of U.S.-built tankers makes it difficult for shippers to charter tankers for a short period or even a single voyage—a shipping pattern that is highly desirable in an oil market with shifting supply.

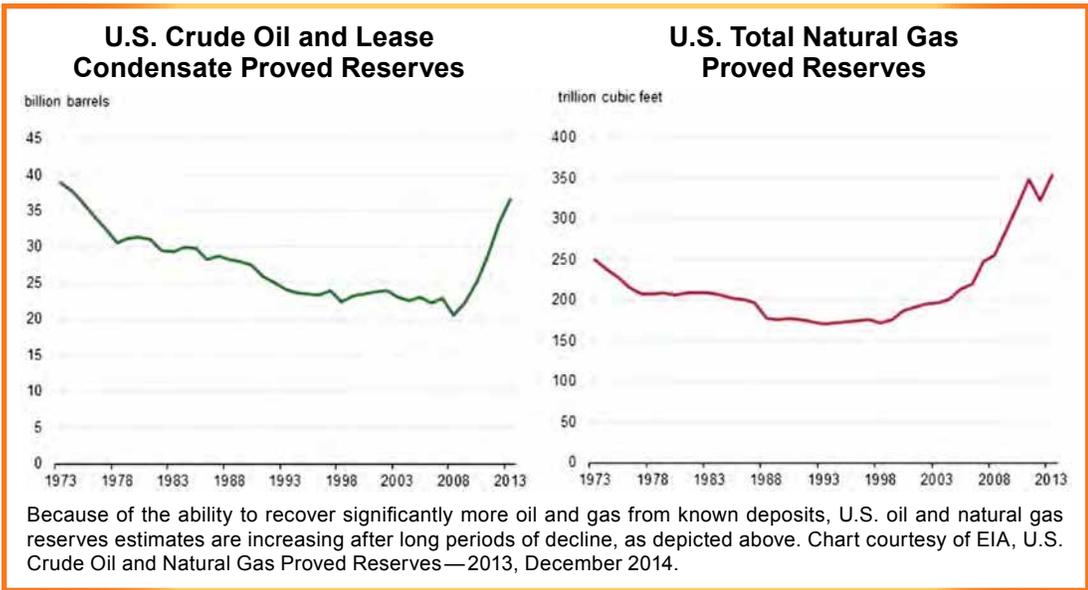
HGL Production from U.S. Gas Processors and Refineries, 2004–2014



HGL Production from U.S. Gas Processors, 2004–2014



The chart on the left shows historic HGL production from all sources, while the chart on the right shows HGL production just from natural gas processing plants. Between 2008 and 2014, HGL production from natural gas processing plants increased by 62 percent to 2.9 million b/d from 1.8 million b/d. Chart data from EIA, Hydrocarbon Gas Liquids (HGL): Recent Market Trends and Issues, November 2014.



This may result in more oil moving by costlier rail transport than otherwise would be the case.

Despite these impediments, there is some interest in domestic tankers. One company spent almost \$1 billion in 2013 to dive into marine transport of crude, acquiring two competitors. Its fleet consists of five medium-range Jones Act-qualified tankers, each with a 330,000-barrel cargo capacity. In addition, the company has four similar tankers under commission for delivery in 2015 and 2016.⁴

Barges

In contrast to domestic tankers, shipping crude by barge is becoming quite popular. U.S. refinery receipts data reflect that deliveries by barge more than doubled from 2005 (164.2 million barrels per year) to 2013 (345 million barrels per year). Crude oil from the Bakken area of North Dakota is delivered to St. Louis either via pipeline or rail and then is barged down the Mississippi River to any one of 19 refineries in Louisiana. Similarly, crude oil is delivered to the Port of Albany, New York, by truck, rail, or pipeline, and is subsequently barged down the Hudson River to reach refineries in Philadelphia. Less than a decade ago, the Mississippi River oil trade barely existed, with fewer than 100 barges, mostly operated by small private companies. Today, one Houston-based corporation alone operates 887 active inland tank barges, 161 active towing vessels, and five fleets. More than 1,500 mariners work for the company.⁵

Barge traffic is less expensive than rail, and in some cases it is less costly than pipeline transport, since pipeline operators typically demand long-term contracts (up to 20 years).

A barge (or rail) operator will sign a one-year contract. That’s a major incentive when producers must concern themselves with the often unpredictable nature of oil wells. All told, moving crude via barge can cost about half the price to move by railcar.

A Look Ahead

Since our nation has very large reserves of crude oil and natural gas, domestic production is unlikely to decline, other than in

response to normal fluctuations in supply and demand. While LNG is not currently exported to any significant degree, LNG and HGL exports are likely to increase substantially in coming years. Concurrently, LNG and crude oil imports are expected to decline.

About the author:

Mr. Rick Elliott, P.E., is the director of the Advanced Supply and Facilities Division within the Office of Fossil Energy – Oil and Natural Gas at the U.S. Department of Energy. His division sponsors research and technology development programs that improve the nation’s natural gas midstream infrastructure operational efficiency.

Endnotes:

- ¹ Natural gas, as it leaves a production well, is a gaseous mixture of hydrocarbons of which the primary one is methane, but which also include ethane, propane, normal butane, isobutene, and natural gasoline. Natural gas is processed downstream of production wells to remove most of the non-methane hydrocarbons by turning them into liquids. In liquid form, they are known as Natural Gas Plant Liquids (NGPLs). Processed (“pipeline-quality”) natural gas is typically 95%–98% methane.
- ² Early research and technology development work sponsored by the U.S. Department of Energy from the late 1970s to the 1990s helped spur private sector investments and industry innovation in these technologies, which led to their eventual commercial success.
- ³ Michelle Thompson, “Right or Wrong,” *Riding the Rails – A Fourth Quarter 2014 Supplement to Oil and Gas Investor*, Hart Energy.
- ⁴ John Fritelli, “Shipping U.S. Crude Oil by Water: Vessel Flag Requirements and Safety Issues,” U.S. Congressional Research Service, April 21, 2014.
- ⁵ Deon Daugherty, “Barging In,” *Riding the Rails – A Fourth Quarter 2014 Supplement to Oil and Gas Investor*, Hart Energy.

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The Global Gas Revolution

America's Energy Renaissance is a game-changer.

by LCDR ANTHONY HILLENBRAND
*National Technical Advisor
U.S. Coast Guard
Liquefied Gas Carrier National Center of Expertise*

The U.S. uses natural gas (methane) and its constituent gases, including ethane, propane, butane, and pentane, for energy production and manufacturing. Until recently, the U.S. was a net energy importer — in addition to oil, the U.S. imported liquefied natural gas (LNG), liquefied petroleum gas (LPG), and others. The shale gas boom has transformed the U.S. from a net importer to a net producer, and in the near future, America will become a net exporter, as America's Energy Renaissance, which also includes crude oil production, is set to position the U.S. as a key player in meeting the global demand for natural gas products.

The Gas Boom

New technologies, including horizontal drilling and hydraulic fracturing, have fueled the shale gas boom. As such, the U.S. Energy Information Administration reported that gas extraction increased 17 percent between January 2009 and January 2014, and, according to the Center for American Progress, U.S. import of natural gas decreased 23 percent in 2012.

However, the current natural gas infrastructure in the U.S. is geared overwhelmingly toward natural gas import. There are 12 LNG import terminals in operation in the U.S. — nine along the East and Gulf Coasts, two located offshore in the northeast, and one in the Gulf of Mexico.

This boost in production coupled with the lack of export facilities in the U.S. has resulted in a surplus of natural gas and its byproducts, also known as natural gas liquids (NGLs). While the U.S. is largely meeting its own consumption needs, there are few options to fully utilize the surplus. The U.S. has only one existing export terminal, located in Alaska, and gas companies have been scrambling to develop gas export capabilities, extensively investing in gas liquefaction plants and marine terminals.

For example, the Federal Energy Regulatory Commission has approved five new export terminals, four of which are

currently under construction, and there are 14 proposed export terminals and two import terminals under review.

LNG Demand

International demand for natural gas continues to grow, particularly in Asia, Southeast Asia, and Latin America. The largest consumer of LNG is Japan, followed by China and South Korea. Recently, there has been relatively no new supply to meet the growing demand, which has pushed prices up, particularly in Asia.

Ernst & Young estimates that global liquefied natural gas capacity will grow by one-third by 2018 and double by 2025 as global projects come online. For example, Australia has seven liquefied natural gas export projects under development, Exxon Mobil recently began operating a new LNG export facility in Papua, New Guinea, and Nigeria is working to expand LNG export capabilities.

As new liquefied natural gas export facilities are being developed worldwide, so are LNG carriers. According to Lloyd's Register, in December 2013 there were 387 LNG ships in service and 114 ships on order, including 16 Arctic-capable LNG carriers. The majority of the vessels are being constructed in South Korea and China.

Market Effects

Meanwhile, the U.S. is estimated to begin to supply global demand for LNG, and U.S. liquefied natural gas export will impact domestic and global prices, global demand, and LNG production. Many academic, government, and market analysts agree that liquefied natural gas export from the U.S. will cause domestic natural gas prices to rise, which will cause a subsequent increase in global LNG prices.

New demand will be stimulated as natural gas becomes more accessible and new LNG sources become available. Demand is already growing for LNG as a fuel for electrical generation worldwide, and new uses are being developed,

continued on page 13



The Basics

Natural gas is a naturally occurring gas mixture, composed mostly of methane, with varying amounts of impurities consisting of ethane, nitrogen, propane, carbon dioxide, butane, pentane, oxygen, sulfur compounds, and water. Natural gas found in gas wells and condensate wells is called non-associated gas, is not formed in conjunction with crude oil, and is in a gaseous or semi-liquid state. Natural gas in oil wells is called associated gas, formed in conjunction with crude oil, and can be separate or dissolved in the crude oil.

Domestic Transportation

Raw natural gas must be purified into pipeline-quality, dry natural gas for transportation. The gas is processed through heaters and scrubbers to remove large particles, such as sand. Further processing removes water, sulfur, carbon dioxide, oil, and natural gas liquids (NGLs) consisting of propane, ethane, butane, and others.

Transmission and distribution pipelines then transport the clean gas to the end user. Interstate pipelines use 24- and 36-inch diameter pipe to transport natural gas at pressures ranging between 200 to 1,500 pounds per square inch. According to the Association of Oil Pipe Lines and the American Petroleum Institute, in the U.S. there are approximately 300,000 miles of interstate and intrastate transmission pipelines and 2.1 million miles of distribution

pipelines that carry gas directly to the consumer.

Global Transport

Natural gas must be cooled and condensed into liquefied natural gas (LNG) to transport it globally by sea, as in its liquid state, LNG takes up 1/600th of the space than does its gaseous form at ambient temperature and pressure. The gas is cooled to -256 degrees F, converting it into a cryogenic liquid. During liquefaction, the natural gas is further purified, resulting in nearly pure methane.

The Gases

Methane: a colorless, odorless gas produced biologically through anaerobic, bacterial decomposition. It can also be produced through technological and synthetic processes. It contains one carbon atom surrounded by four hydrogen atoms. It is nontoxic, but is an asphyxiant at high concentrations.

It can cause frostbite and severe cryogenic burns in its liquid form. The gas is combustible at concentrations between five and 15 percent. Methane is also a greenhouse gas 20 times more potent than carbon dioxide at trapping heat in the atmosphere, accounting for approximately 16 percent of all greenhouse gases. However, it produces fewer greenhouse gases than oil or coal when burned, making it an attractive alternative fuel.

Primary methane sources are not renewable; however, there are some renewable secondary sources, such as manure processing and landfills.

Ethane: a nonrenewable, odorless, and colorless gas composed of two carbon and six hydrogen atoms. It is a clean-burning fuel that is explosive at concentrations between 3.0 and 12.4 percent. It is a byproduct of natural gas purification and crude oil refining.

It is the most abundant of the NGLs and is often blended in LPG to increase energy output. The shale gas boom has increased ethane supplies, reduced the price, and stimulated an interest in exporting the gas. Starting in early 2016, the U.S. will begin exporting 240,000 barrels of ethane a day.

Propane: a nontoxic, colorless, and virtually odorless gas used for heating, cooking, and plastic manufacturing. Propane is a nonrenewable energy source and is made up of three carbon atoms and eight hydrogen atoms.

Propane is produced from crude oil refining, in addition to being a component of natural gas. It is easily liquefied and stored at about 150 pounds per square inch (psi) or at -45 degrees F, and is commonly known as liquefied petroleum gas (LPG). It can cause severe frostbite in its liquid form.

	Lower Explosive Limit	Upper Explosive Limit	Toxicity	Specific Gravity	Color	Odor	Melting Point	Boiling Point
Methane, CH ₄	5%	15%	Nontoxic Asphyxiant	0.56	None	None	-182.5° C	-161.5° C
Ethane, C ₂ H ₆	3%	12.4%	Nontoxic Asphyxiant	1.038	None	None	-182.8° C	-88.6° C
Propane, C ₃ H ₈	2.1%	9.5%	Nontoxic Asphyxiant	1.522	None	None	-188° C	-42.04° C
Butane, C ₄ H ₁₀	1.8%	8.4%	Nontoxic Asphyxiant	2.006	None	None	-138° C	-0.5° C
Pentane, C ₅ H ₁₂	1.5%	7.8%	Irritant Asphyxiant	2.5	None	Gasoline-like	-129.7° C	36.1° C



The explosive limit of propane is between concentrations of 2.1 and 9.5 percent. It is clean-burning and makes an excellent alternative fuel in spark-ignited engines.

Propane accounts for about two percent of energy produced in the U.S. and is used as feedstock for propylene, which is used in plastic production. The U.S. exports about 500,000 barrels per day and Wells Fargo projects U.S. exports to grow 25 percent in the next three years.

Butane: a byproduct of natural gas purification and crude oil refining, it is colorless, odorless, tasteless, and consists of four carbon and 10 hydrogen atoms. It is compressed easily into a clear liquid and is often blended with propane as an additive to LPG.

Butane is a clean-burning fuel most commonly used in cigarette lighters, barbecue grills, and camping stoves. It is feedstock for iso-butane, which is used in refrigerant production and in the crude oil refining processes. Its

explosive range is at concentrations between 1.8 and 8.4 percent. Like propane, butane is not a renewable resource.

Pentane: a colorless liquid that has a smell similar to gasoline. It contains five carbon and 12 hydrogen atoms. It has a boiling point of 97 degrees F and is explosive at concentrations between 1.5 and 7.8 percent. It is a byproduct of natural gas purification and is primarily used as a gasoline additive and in plastic foam manufacture.

such as using LNG as a fuel in shipping and transportation. Already some countries that have historically been liquefied natural gas exporters are now reducing exports to meet domestic consumption needs. Analysts project that the number of countries with import terminals will double by 2020, and global demand will double by 2030. Both higher global and domestic prices as well as greater global demand will stimulate production and export activities in the U.S. and abroad.

About the author:

LCDR Anthony Hillenbrand is the national technical advisor for the U.S. Coast Guard's Liquefied Gas Carrier National Center of Expertise. Previous assignments include chief of investigations at MSU Portland, Oregon; marine investigations at Sector Honolulu; marine inspector at Sector Houston-Galveston; specification writer and type desk manager at Maintenance and Logistics Command, Pacific, Vessel Support Branch; and damage controlman first class aboard the USCGC Decisive. Before joining the Coast Guard and graduating Officer Candidate School in 2003, LCDR Hillenbrand was a hull maintenance technician second class in the Navy. He is a qualified marine inspector and marine investigator and holds a B.S. in business administration (finance and management) as well as an MBA from Hawaii Pacific University.

For more information:

Statistics courtesy of the Liquefied Gas Carrier National Center of Expertise. Visit the website at: www.uscg.mil/hq/cg5/lgcncoe.



The New Crudes

From Bakken to bitumen.

by Ms. DENIESE PALMER-HUGGINS

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U.S. natural gas and crude oil production has grown since the early 2000s in response to high natural gas and oil commodity price signals and due to new production techniques. These “new crudes” are produced in three main areas of the U.S.:

- the Williston basin in North Dakota and Montana,
- the Permian basin in west Texas,
- the Eagle Ford trend in south Texas.

While older, conventional fields still exist in these areas, the newer, unconventional wells and fields have contributed the lion's share of new oil production.

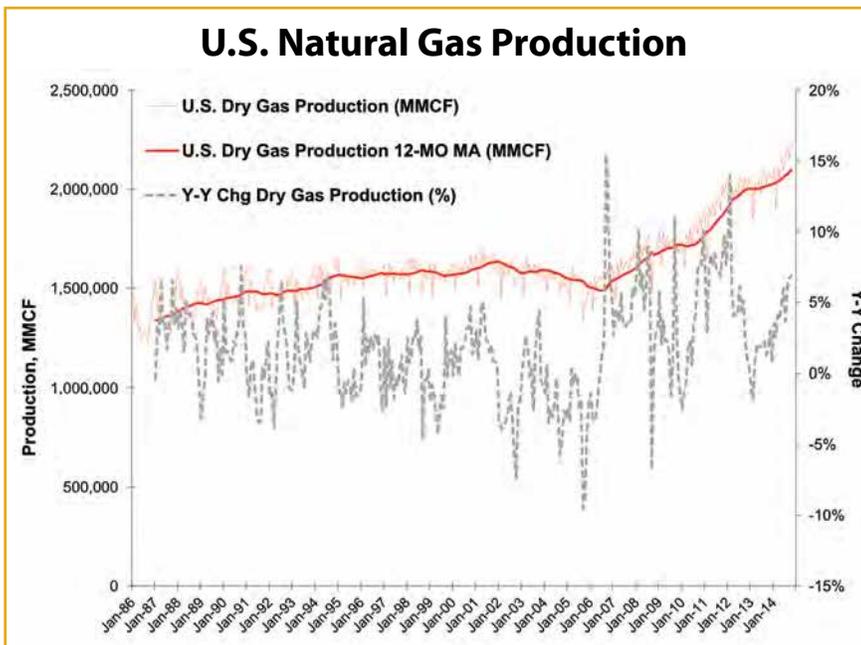
Old Oil

Generally a conventional oil reservoir is porous and permeable enough for operators to produce hydrocarbons without well treatment. Producers drill vertical wells, and fields may undergo multiple stages of development as they age, including:

- “infill” drilling between existing wells,
- water flooding to restore formation pressures,
- enhanced recovery to coax additional remaining oil using carbon dioxide or solvents.

The U.S. industry has excelled in extending the lives of conventional oil reservoirs and fields, providing an important base of oil production for the country, albeit one that inevitably yields less over time as fields continue to mature. The oil most commonly produced from conventional fields in the U.S. is “light, sweet,” meaning it has a low specific gravity relative to water and no (or very low) sulfur content. Traded domestic crude oil—West Texas Intermediate, or WTI—typifies the light, sweet characteristics most customers desire.

The presence of sulfur characterizes crude as “sour,” which means that producers must process the crude to remove it. The higher the sulfur content, the greater the chance of hazards during drilling operations and the more expensive it is to process.



Priced at the main trading point—Henry Hub in south Louisiana. Authors’ analysis based on U.S. Energy Information Administration data.

New Oil

Unconventional oil fields and plays can encompass any progression of tighter, less porous, less permeable rock that requires well treatment to yield hydrocarbons. At one end of the spectrum are the shale oil plays that have been the targets of industry activity.

The most common approach used is to drill a large number of wells with horizontal laterals extending from vertical well bores and employ multiple stages of hydraulic fracturing to expand native fracture zones enough to enable hydrocarbon movement. Because the rock structure is very tight, producers can only coax smaller molecules from the subsurface, usually yielding a much lighter production stream than that of WTI. The Bakken formation in the Williston Basin is a prime example. Elsewhere, and especially in the Eagle Ford trend, shale or mud rock formations can yield “black” oil that more closely resembles WTI.

The Statistics

The U.S. Energy Information Administration recently released its report on the top 100 oil and gas fields in the U.S. Since 2009, approximately 14.2 billion barrels of additional proved oil reserves have been discovered in the U.S. The majority of this comes from the Eagle Ford trend in Texas.¹ In 2013, an estimated 238 million barrels were produced from the Eagle Ford field in the Eagle Ford shale play.²

However, the rapid growth in domestic oil output, especially the lighter “Bakken” type of production, has proved challenging given substantial infrastructure constraints to connect new fields to markets and costs associated with remedies.³

At the other end of the unconventional oil spectrum are the heavy, dense, often high-sulfur oil accumulations frequently extracted using mining techniques. The most important source of heavier unconventional oil for North America is Canada’s oil sands in the far north of Alberta Province, where companies use steam-assisted production that loosens oil from the sandy matrix that allows the oil to flow to well bores for collection. Sulfur must be removed from this heavy “bitumen,” and lighter petroleum products are added. This produces diluted bitumen, or “dilbit,” for pipeline transport.

Light, Medium, Heavy

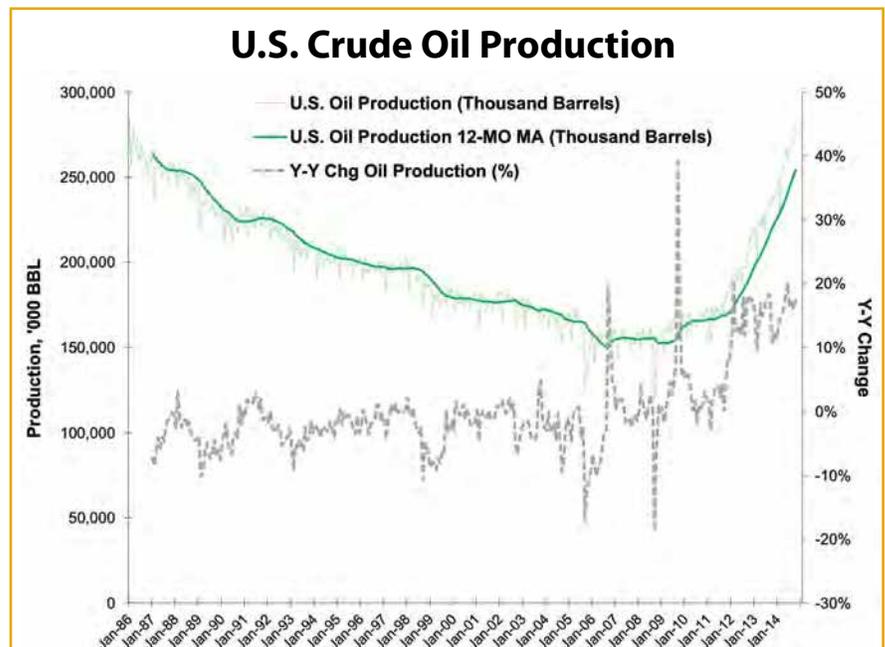
The range of oil, from Bakken to bitumen, is classified according to specific gravity and other features so producers, customers, regulators, and the public can share a common

Degree API for Crude Oil

Degree API	Specific Gravity	Weight	
		(lb/US gal)	(kg/m ³)
8	1.014	8.448	1012
9	1.007	8.388	1005
10	1.000	8.328	998
15	0.966	8.044	964
20	0.934	7.778	932
25	0.904	7.529	902
30	0.876	7.296	874
35	0.850	7.076	848
40	0.825	6.870	823
45	0.802	6.675	800
50	0.780	6.490	778
55	0.759	6.316	757
58	0.747	6.216	745

language. The American Petroleum Institute (API) developed API gravity or “degree API,” which is accepted around the world as the key specific gravity measure. Specifically, degree API is a measure of how heavy or light petroleum is when compared to water (which has a specific gravity of 1). The higher the degree API, the lower the specific gravity of the oil, relative to water.

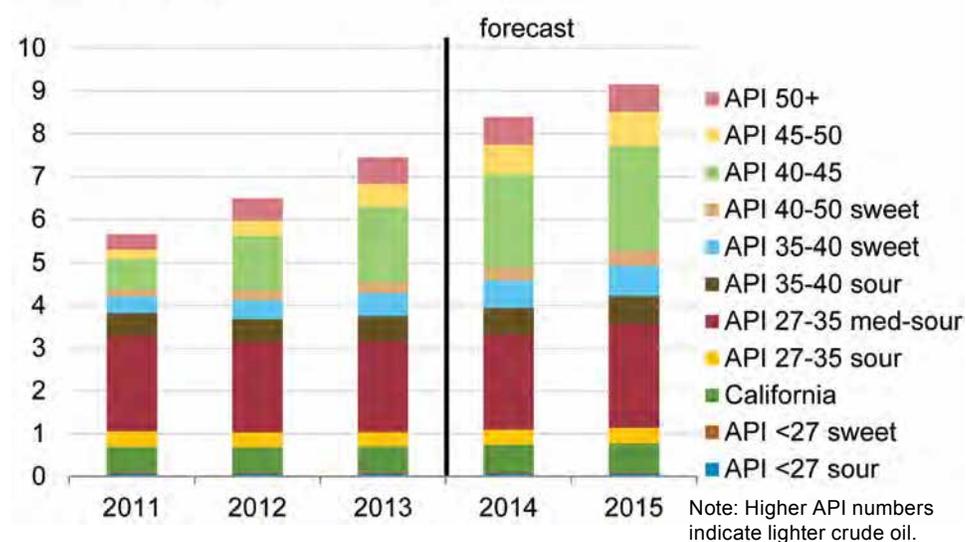
Oil with a high-degree API is lighter than water, and will float. Oil with an API number less than 10 has a high specific



Priced at the main trading point—Cushing, Oklahoma. Authors’ analysis based on U.S. Energy Information Administration data.

U.S. Crude Oil Production by API Type

million barrels per day



A comparison of the yields from various types of crude oil from the U.S. (Bakken, Eagle Ford, WTI, and Louisiana Light Sweet or LLS); U.K. (Forties and Brent); Russia (Urals); Nigeria (Bonny Light); and Mexico (Maya heavy). U.S. Energy Information Administration data.

gravity, so it is heavier than water, and will sink. Most crude oils will measure between 10 and 70 degrees API. Even within crude types, there will be variations, so these characteristics are usually given or quoted as ranges. “Light” crude oil has an API greater than 31 degrees, “medium”-grade crude oil has an API between 22 and 31 degrees, and “heavy” crude oil has an API of less than 22 degrees.⁴

In the U.S., crude oil production has grown by 1.8 million barrels per day from 2011 to 2013, and roughly 96 percent of this is light, sweet-grade oil. These crudes generally have API gravity of 40 or above and sulfur content of 0.3 percent or less.⁵

Market Effect

Crude oil chemical evaluation provides hydrocarbon data for refiners, oil traders, and producers. It can help refineries determine if a crude oil feedstock is compatible for a particular petroleum refinery or if the crude could cause yield, quality, production, environmental, or other problems. Lighter crude oils are valued more in the market, as they do not require technically complex refining facilities for processing and will refine more easily into “light ends,” meaning they can produce a greater quantity of gasoline, diesel, kerosene, and naphtha. Heavier crudes will produce more gasoil, residual fuel oil, and asphalt, which are priced lower and therefore result in lower profit margins for refiners.

To keep feedstock prices low, and because the worldwide trend appeared to be toward producing heavier crude oil, refiners reconfigured facilities to process the heavier, high

sulfur-content crudes. Now, however, the crude oil from Eagle Ford has an API from 38 to 60 degrees and Bakken crude oil from North Dakota ranges from 36 to 44 degrees API. The quality of both are almost identical to WTI, which is 40 degrees API, but it is also the higher API, which indicates that these crudes are more volatile.⁶

The lightest crude oils — condensates — contain natural gas liquids that can come out of solution and form explosive gases, which presents problems during transportation. Pipelines can safely handle the volumes with minimal leakage because the product that is concentrated in field-gathering systems moves to refining locations still contained in the pipeline system. However, when

very light crude oil must be handled outside of pipeline containment, remaining volatile compounds can come out of solution as the production is handled from wells to storage tanks to surface transportation modes to refinery unload.

Transport

A number of incidents have occurred during light crude rail shipment, most notably from Bakken-producing locations, which are remote and not well connected to markets. Transportation for this land-locked crude is primarily via rail, as only one small refinery is located in North Dakota and there is limited pipeline capacity for transport to market hubs. In response, U.S. and Canadian safety regulators have responded with new requirements for rail carriage.⁷

This is not to say there aren’t problems transporting the lighter crudes via pipeline. Lighter crude oil can pose challenges to the gatherers who purchase the crude oil in the field. Most pipelines will require that the crude oil have an API of not greater than 42 degrees, though it will vary by pipeline, and some have a cap of 45 degrees. Midstream pipeline operators must then blend lighter crude oil with heavier crudes to meet pipeline restrictions.

The Global Market

Heavier crudes with an API of 32–28 degrees can be mixed with the lighter crudes of API 50 and above to achieve a medium blend crude oil with a resulting API of 42 degrees or less. This is not a simple process, and it requires facilities located in oil fields near producing wells, pipeline networks, and experienced professionals who understand the

processes involved. A distinct constraint is the availability of heavier crudes to blend with the lighter oil, since light oil production is outpacing the production for heavier crude oils. Canadian oil sands production addresses this need for heavier oil for blending and to facilitate optimal processing of U.S. light crude oil.

Given that U.S. refiners have invested heavily to accommodate heavier crudes, processing only light oil production means inefficient, suboptimal use of these plants. Consequently, blending U.S. light oil with Canadian oil sands product affords benefits across the oil supply system. However, until these efficiencies are achieved, U.S. light oil producers are seeking export approval to debottleneck periodic light oil supply gluts.

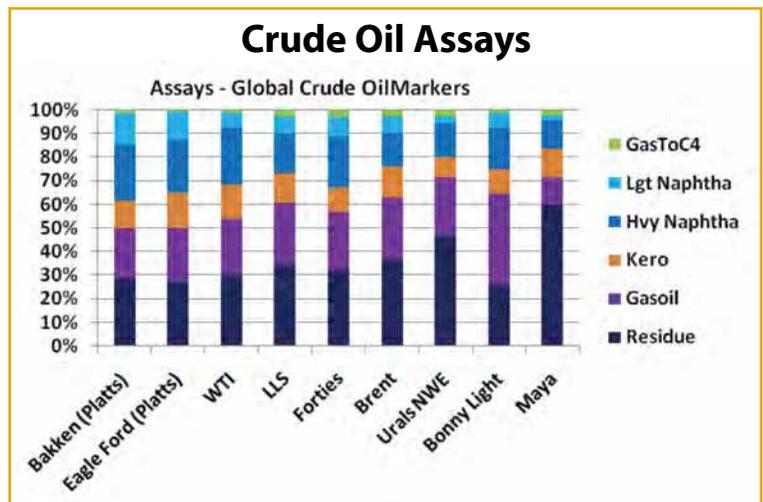
If an integrated U.S./Canadian oil system can be achieved, refiners can take advantage of market conditions as needed to export petroleum products. Since the Gulf Coast hosts the largest concentration of oil storage, processing, and refining capacity with waterway access, coastal transshipment of various crude oil blends and petroleum products—already important components of the oil supply system—could facilitate transfer to other markets.

Future Focus

The U.S. Energy Information Administration forecasts that light, sweet crude production will continue to outpace that of medium and heavy crude through 2015, and more than 60 percent of the EIA's forecasted production growth for 2014 and 2015 consists of sweet grades with API gravity of 40 or above.⁸ Current oil market conditions and lower prices are slowing crude oil production, but production of lighter oil fractions will remain a feature of the U.S. energy landscape for some time.

Midstream infrastructure operators will likely build more storage, processing, and pipeline capacity to handle these lighter crudes, and the downstream segment (refineries) will need access to heavier crude oil sources for blending.

Finally, new carriage safety regulations for lighter, more volatile oil products will influence investment decisions and



Source: EPRINC: A Condensate Primer, Feb. 2015, found at www.eprinc.org.

field operations, as well as field-to-market connections. U.S. policies on exporting crude oil and certifying oil pipelines to carry Canadian oil sands production complicate the outlook.

About the authors:

Ms. Deniese Palmer-Huggins is the senior energy advisor at the Bureau of Economic Geology's Center for Energy Economics, University of Texas at Austin.

Dr. Michelle Michot Foss is the chief energy economist at the Bureau of Economic Geology's Center for Energy Economics, University of Texas at Austin.

Endnotes:

1. The U.S. Energy Information Administration, "Top 100 Oil and Gas Fields," April 2, 2015, found at www.eia.gov/naturalgas/crudeoilreserves/top100/.
2. Ibid.
3. Bakken mainly yields condensates, which are natural gas liquids that are in solution in the production stream and removed in gas processing plants.
4. The U.S. Energy Information Administration, www.eia.gov/analysis/petroleum/crudetypes/pdf/crudetypes.pdf.
5. The U.S. Energy Information Administration, "Today in Energy," June 6, 2014, www.eia.gov/todayinenergy/detail.cfm?id=16591.
6. North Dakota Petroleum Council, www.ndoil.org/resources/bkn/.
7. See www.phmsa.dot.gov/hazmat/regs/ntsb/rail.
8. See www.eia.gov/todayinenergy/detail.cfm.

Energy Renaissance Waterway Impact

Managing the nation’s waterways
as demand increases.

by LCDR JAMIE BIGBIE
U.S. Coast Guard
Office of Waterways and Ocean Policy

The Energy Renaissance is upon us. Thanks to improved technology that has allowed producers to extract oil not previously accessible, the U.S. has become a major crude oil and natural gas producer, and in 2013, the U.S. produced more oil than it imported for the first time in decades.¹ As producers extract more oil, more of that product needs to get from the well to the end user.

Since current law prevents most domestic crude oil export, it must move from the well to U.S. refineries. Natural gas may be exported, but it has to be transported to approved export facilities on the coast, then transferred to ships.

Transportation Challenges

Crude oil and natural gas are predominantly being produced in a just few main areas, called “plays.” Unfortunately, these plays are not located adjacent to the refineries where the product is refined and distributed, nor are they in coastal areas where the product can be loaded directly onto ships for transport to other destinations.

While pipelines are ideal for moving oil from the coastal regions to inland regions, the pipeline infrastructure to move domestic oil from the plays in which they are found to the refineries (many of which are in the Gulf Coast region) is not developed. This crude oil and gas typically moves to the refinery via multiple transportation modes, including maritime conveyance.

For example, movement by barge through the inland river system to coastal refineries is increasing, and as a result, more than 300 tank barges were delivered to end users in 2013, up from 261 in 2012.² This additional barge movement means more traffic on our already busy waterways. Additionally, much of the refined material will be shipped from coastal ports to other ports in and outside of the U.S., increasing traffic and demand on these harbors and shipping lanes.

The growing number of vessels also increases the risk for collisions, allisions, groundings, and security and

The Coast Guard utilizes several tools to ensure the safety and security of the nation’s waterways. While the Coast Guard captain of the port uses various tools to address emergent situations that occur with little to no warning, others are designed to include input from waterway users, and the process for gathering input and evaluating needs may span several months.

PAWSA	<ul style="list-style-type: none"> The ports and waterways safety assessment workshop provides a formal structure for professional waterway users and stakeholders to identify major waterway safety hazards, estimate risk levels, and evaluate additional mitigation measures. The PAWSA process relies on expert opinions and recommendations to inform risk mitigation investments.
WAMS	<ul style="list-style-type: none"> The waterway analysis and management study allows Coast Guard waterways managers to review and improve a particular waterway’s ATON (aids to navigation) system.
PARS	<ul style="list-style-type: none"> The port access route study helps reduce marine casualty risk and increases vessel traffic navigation efficiency in the offshore approaches. Helps to determine if waterways managers should create safety zones, security zones, recommended routes, regulated navigation areas, or other ship routing measures in the offshore approaches to the nation’s ports and harbors.
Limited Access Area	<ul style="list-style-type: none"> The Coast Guard captain of the port establishes limited access areas to control access to and movement within certain areas. Includes long- or short-term safety zones, security zones, and district commanders can establish regulated navigation areas.



environmental incidents within the marine transportation system. So what does this mean for Coast Guard waterway managers?

Evaluating Use and Risk

Fortunately, Coast Guard personnel can rely on several tools to determine how to keep waterways as safe and efficient as possible, including the ports and waterways safety assessment (PAWSA), the waterway analysis and management system study (WAMS), and the port access route study (PARS).³

The ports and waterways safety assessment (PAWSA):

The Coast Guard established the PAWSA process to address waterway user needs and to place a greater emphasis on industry partnerships. The process involves convening a group of waterway users and stakeholders and conducting a structured workshop to elicit their opinions and recommendations. This input then enables the Coast Guard to identify needs such as:

- establishing or relocating aids to navigation,
- adjusting vessel traffic service reporting requirements,
- implementing regulatory changes.

The waterway analysis and management study (WAMS):

Thousands of buoys and beacons on our waterways provide signals to maritime transportation system users. A WAMS study helps Coast Guard waterway managers review and improve a particular waterway's aids to navigation system. Managers evaluate the aids to determine their effectiveness, which can lead to altering the technical aspects of an aid, establishing new aids, or removing ineffective aids. Like the PAWSA, this study incorporates the perspectives of expert and/or frequent waterway users to identify the most effective aid mix while anticipating future demands on a particular waterway.

The port access route study (PARS): To manage the vessel traffic in and out of our nation's ports, Coast Guard waterway managers may designate or adjust fairways and create traffic separation schemes. Through the PARS, Coast Guard managers again consult with a broad array of waterway users and stakeholders to determine present and potential traffic densities, evaluate existing vessel routing measures, and determine if new routing measures are warranted.

Control Measures

While Coast Guard waterway managers typically confer with stakeholders to inform waterway management decisions, they may act autonomously. Should the need arise, the Coast Guard captain of the port (COTP) has the authority to impose requirements on vessels, persons, facilities, or waterways to address specific safety, security, or environmental concerns.

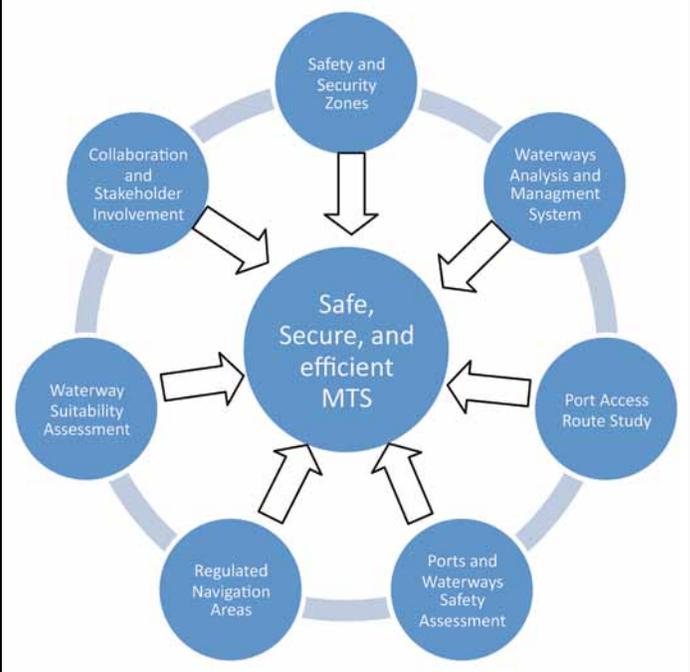
Harbor Safety Committees

Collaboration between the Coast Guard and local waterway users and stakeholders strengthens relationships and improves maritime safety. For example, harbor safety committees are local port coordinating organizations whose responsibilities include recommending actions to improve port or waterway safety and efficiency, and are typically comprised of representatives from federal, state, and local government agencies; maritime labor and industry organizations; environmental groups; and other public interest groups.

The Coast Guard has long recognized the importance of local committees to safe, efficient, and environmentally sound port operations. Harbor safety committees can and do provide valuable input to Coast Guard assessments and studies, and provide a means to address and resolve issues that affect a port, including safety and navigation, port congestion, and overall port and waterway management.

For example, the COTP can establish limited access areas aimed at specific vessels, facilities, or waterways. The captain of the port can also authorize a safety zone to which access is limited to only those the COTP authorizes, such as a fixed zone or a moving zone around a vessel. However, captain of the port authority is not limited to imposing access

The Coast Guard has many options available to address waterways management issues. Collaboration and stakeholder involvement play large roles. Regardless of the process or measure used, the goal is to ensure a safe, secure, and efficient marine transportation system.



restrictions, but may also include imposing requirements for transiting at certain times, requiring vessels to transit only

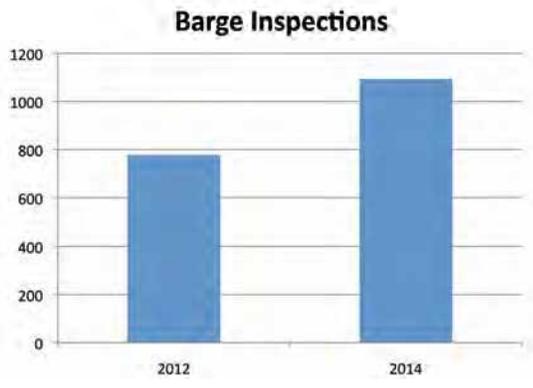
in certain weather conditions, or mandating assist vessels to transit certain areas, to name a few examples.

Waterway Suitability Assessment

A prospective applicant seeking to site, construct, and operate a liquefied natural gas (LNG) waterfront facility must complete a waterway suitability assessment.

The assessment will, among other things, identify additional traffic on the waterway as a result of the new or modified LNG facility, as well as list recommended risk mitigation measures.

Indicative of the increased traffic on the inland waterways, the number of barge inspections per year by Coast Guard marine inspectors at units located in Texas, Louisiana, Tennessee, and Missouri combined for an average increase of more than 40 percent between 2012 and 2014.



Coast Guard Business Intelligence data.

When the situation calls for more extensive, long-term, or even permanent controls, the Coast Guard district commander may establish a regulated navigation area, which is a defined water area within which navigation regulations have been established. Normally a regulated navigation area is established to control vessel operations to preserve adjacent waterfront structures, ensure safe vessel transit, or protect the marine environment.

Future Focus

The nation's waterways have always been a significant part of the overall transportation system of our country by which we move goods between inland and coastal areas. As the Energy Renaissance places even more demand on our waterways, Coast Guard waterways managers fortunately have very broad authority to administer waterway usage, direct vessel movements, and ultimately ensure port and waterway safety.

However, waterways management is a complex endeavor, so the Coast Guard proactively interacts with our port partners to identify and address concerns to ensure our waterways remain safe and efficient for all users.

About the author:

LCDR Jamie Bigbie is assigned to the Office of Waterways Policies and Activities at Coast Guard headquarters. He has served in the Coast Guard for more than 22 years, and his marine safety experience includes port safety and security, waterways management, and vessel inspections. He holds an M.A. in transportation policy, operations, and logistics from George Mason University.

Endnotes:

1. See www.whitehouse.gov/energy/securing-american-energy.
2. Bruce Buls, "Crude oil transport spurs tank-barge construction," WorkBoat.com, 01 April 2014, available at www.workboat.com/newsdetail.aspx?id=23974.
3. For more information on PARS, PAWSA, and WAMS, see *Proceedings of the Marine Safety & Security Council*, Spring 2011, "Collaborating to Mitigate Risk."

Mitigating Risk

America's Energy Renaissance and maritime security.

by LCDR JOHN EGAN
Antiterrorism Division
U.S. Coast Guard

Office of Maritime Security Response Policy

MR. ALAN PEEK
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U.S. Coast Guard

Office of Maritime Security Response Policy

Since the 9/11 attacks, the Coast Guard has developed and implemented risk-informed policy for operational measures to mitigate the various security risks within the marine transportation system (MTS). Using a risk-informed approach ensures that the Coast Guard's constrained resources are used effectively. As conditions change and/or its understanding of risk improves, the Coast Guard periodically reviews and adjusts its policy.

The growth in the maritime industry accompanying America's Energy Renaissance is the latest driver for the Coast Guard to re-evaluate and adjust, if appropriate, its security policy with respect to crude oil and liquefied natural gas (LNG) production and transport. While this re-evaluation is ongoing, initial crude oil transport assessments indicate that risks have not changed appreciably and remain low. Additionally, the risks associated with LNG—while

Maritime Security – the Basics

As the Department of Homeland Security's lead agency for maritime security, the Coast Guard facilitates safe, secure, and lawful trade; travel; recreation; and other MTS uses while preventing and protecting against attacks to infrastructure or marine transportation system use for illegal activities. In partnership with the maritime industry, the public, and other government agencies, the Coast Guard pursues maritime security governance using a three-element strategy:

- maritime security regimes,
- maritime domain awareness,
- maritime security and response operations.

Maritime industry members have the primary responsibility to mitigate the maritime security risks facing their vessels and facilities at all times and in all locations. As the level of maritime security risk increases, or when needed risk-mitigation measures exceed reasonable

expectations of commercial vessel/facility owners, state, local, tribal, and territorial government agencies conduct risk mitigation measures in addition to and in coordination with the maritime industry's measures. At the highest levels of risk, the Coast Guard and other federal agencies add their risk mitigation measures.

Threat, Vulnerability, Consequence

There are three components to maritime security risk: threat, vulnerability, and consequence. Threat is the likelihood that an adversary will attack a maritime target (such as a vessel or facility), largely based on the adversary's capability and intent. Vulnerability is the measure of a vessel's or facility's susceptibility to various attack scenarios. Finally, a successful terrorist attack may have a number of consequences, including injuries and deaths, primary and secondary economic impacts, environmental impacts, and national security impacts.

Risk Assessment

There is not enough capability and capacity across all stakeholders to mitigate all MTS security risks. As a result, maritime security risk stakeholders must use risk-informed approaches to mitigate these risks. For example, the Coast Guard's maritime security and response operations policy is risk-informed. As conditions change and/or risk understanding improves, the Coast Guard re-evaluates and periodically adjusts its maritime security and response operations policy.

The Coast Guard uses the Maritime Security Risk Analysis Model (MSRAM), a terrorism risk-assessment model, to improve its understanding of risk. MSRAM is deployed to field units to help them perform security risk analyses for the MTS, critical infrastructure, and other targets, and the results are used to support a variety of risk management decisions at strategic, operational, and tactical levels.





The Coast Guard provides a security zone for a liquefied natural gas shipment. Art by Nina Buxton, U.S. Coast Guard art program.

not insignificant—are not as great as had been previously perceived. These assessments and any subsequent policy adjustments will incorporate risk-based and risk-informed decision making.

Energy Renaissance and Maritime Growth

Within the past five years, the United States has become the world's largest producer of hydrocarbon liquids and natural gas.¹ Recent advances in deep water and horizontal drilling and hydraulic fracturing have allowed the oil and gas industry to tap into previously inaccessible deposits, launching America's Energy Renaissance. These vast quantities of crude oil and natural gas then must be transported from the exploration sites to refineries and other facilities.

Maritime conveyances are expected to fulfill a significant role, as a substantial portion of America's crude oil storage and refining infrastructure is located in or near commercial ports. Pipelines and rail cars are used to transport crude oil extracted from inland fields to intermodal ports, such as St. Louis or Albany, among others, where the crude oil is transferred to U.S. flag tank barges and/or tank ships for further transport.

Additionally, energy companies are constructing new facilities or modifying existing import facilities to expand LNG export capacity. The future geographical impact can be roughly forecasted using the list of permit requests for liquefied natural gas facilities, which includes projects in New England, the Mid-Atlantic, the Gulf Coast, the Pacific Northwest, and Alaska. According to a recent U.S. Government Accountability Office report, since 2010, the Department of Energy has received 35 applications from companies to

export LNG while the Federal Energy Regulatory Committee (FERC) has received 17 applications to construct LNG export facilities.²

As of January 2015, the FERC has approved five export terminals, four of which are already under construction. Four of the approved applications are for export terminals in Gulf Coast ports. The fifth approved application is for an export terminal in a Mid-Atlantic port.³

Further, the combination of increased availability of low-cost liquefied natural gas and more stringent limits on the main air pollutants in ships' exhaust gas are fostering numerous LNG-fueled vessel construction and/or conversion projects. The prospect of LNG-fueled vessel operations and LNG bunkering operations for these vessels is materializing in numerous U.S. ports.

Crude Oil Risk Mitigation

Crude oil is a mixture of flammable and combustible liquids. The "light end" content (dissolved flammable gases), varies and is generally less than 15 percent by weight or volume. Improper handling and accidental or intentional releases create potential human health and environmental risks. Also, vessels, waterfront facilities, and maritime critical infrastructure and key resources (MCIKR) engaged in transporting, transferring, and storing crude oil are potential targets for numerous maritime attack modes.

The Coast Guard Maritime Security Risk Analysis Model assesses the risks associated with crude oil and other flammable liquids as relatively low. As a result, the maritime security risks associated with them are largely mitigated through the maritime industry's compliance with Maritime Transportation Security Act of 2002 regulations, developing and maintaining maritime domain awareness, and in some cases, aerial, shoreside, and waterside patrols.

Bakken crude oil's "light end" content is comparable to that found in other light crude oils. Likewise, the improper handling, accidental releases, and intentional releases of Bakken crude oil have potential human health and environmental risks.⁴ The perceived risks associated with crude oil, including Bakken crude oil, have not changed appreciably and remain relatively low. As a result, the Coast Guard will likely apply its current risk mitigation approach for crude oil and flammable liquids to Bakken crude.

LNG Risk Mitigation

Liquefied natural gas is generally not flammable unless it is vaporized. It, too, has potential human health and

environmental risks if improperly handled or released. Vessels, waterfront facilities, and maritime LNG infrastructure are also potential targets. Successful attacks against LNG carriers or facilities have potential consequences to the maritime environment extending beyond the loss of the vessel or facility and their personnel. For instance, a 2012 Department of Energy report cautions that the explosive ignition of pooled LNG will likely have an adverse impact on the area surrounding the vessel, waterway, and nearby facilities.⁵ This is particularly the case when the area is densely populated. It is this aspect of liquefied natural gas that has garnered significant media and public attention and that warrants a somewhat different, more sophisticated risk mitigation approach.



LNG tanker escorts are a multi-agency priority. U.S. Coast Guard photo by Petty Officer Kelly Newlin.

Current Coast Guard maritime security and response operations policy calls for escorts of vessels carrying select certain dangerous cargoes (including LNG) in bulk as they transit through or near key port areas. Coast Guard Sector commanders, in collaboration with their area maritime security committees and various offices at the Coast Guard district, area, and headquarters levels identify and assess these key port areas based on population density and MCIKR concentration. Of the two, the proximity to densely populated areas is the more dominant factor.

Where new import, export, and bunkering operations are proposed, Coast Guard sector commanders identify the potential key port areas via the Risk Management Workspace, a tool that allows route pathway analyses for vessels carrying LNG in bulk. This analysis takes into account:

- the likelihood of a successful attack against an LNG vessel;
- amount of liquefied natural gas released;
- weather conditions, and most importantly;
- the impact on nearby populations.

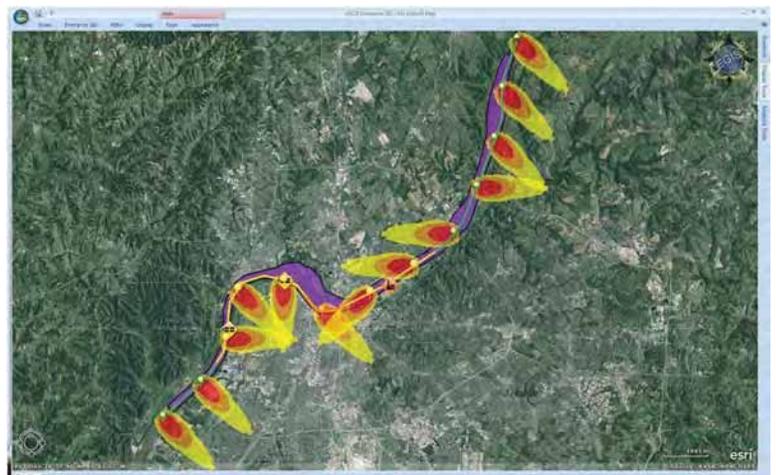
Further, these pathway analyses are broken down graphically into segments of very high, high, medium, low, and very low risk. In some instances, the risk may be low enough to allow the Coast Guard to focus limited resources on only the highest risk segments or on other maritime security activities.

Beyond the key port area pathway analyses, there are other factors to consider when re-evaluating current LNG-related maritime security and response operations policy, including import or export status, source country for imports, receiving country for exports, etc. Considering all of these factors, the ongoing risk-based

re-evaluation may lead to reduced overall LNG vessel escort requirements despite the significant growth in the number of locations with liquefied natural gas operations and the number of LNG vessels plying U.S. waters. However, analysis and possible adjustments to LNG escort policy are not yet complete.

LNG as a Marine Fuel

America's Energy Renaissance presents the Coast Guard with a new security facet to consider. Low cost is one of a number of factors that make liquefied natural gas practical as a marine fuel. LNG-fueled container vessels, passenger/vehicle ferries, and offshore supply vessels are under construction, with some projects now in operation. Bunkering vessels to supply fuel to LNG-fueled vessels are also being designed and constructed.



Notional key port analysis pathway. U.S. Coast Guard image.



U.S. Coast Guard maritime security crews escort a consolidated tug and barge along a channel. U.S. Coast Guard photo by CWO Adam Wine.

Sector commanders can again use the Risk Management Workspace to assess the risks LNG-fueled vessels and liquefied natural gas bunkering operations pose to densely populated areas. The volume of liquefied natural gas involved in these projects is considerably smaller than that being carried in the cargo tanks of LNG carriers. Because of this lesser volume, the risk associated with a liquefied natural gas release from these vessels is considered low. In general, unless the liquefied natural gas carried significantly increases or other factors make them necessary, Coast Guard armed maritime escorts of LNG-fueled vessels and LNG bunkering vessels will likely not be warranted or required. But as construction and design plans change, the Coast Guard will have to continually reassess the potential for increased risks to the marine transportation system.

In Summary

As conditions change and/or the understanding of risk improves, the Coast Guard re-evaluates and periodically adjusts its MSRO policy, and Coast Guard personnel will continue to apply a risk-based and risk-informed framework to manage these maritime security challenges. The risks associated with Bakken crude oil and LNG warrant somewhat different approaches to mitigate them; however, both approaches are risk-informed.

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Endnotes:

- ¹ U.S. Energy Information Administration; International Energy Statistics—Production of Petroleum and Natural Gas—2013 Data; January 23, 2015.
- ² U.S. Government Accountability Office, “Natural Gas: Federal Approval Process for Liquefied Natural Gas Exports,” GAO-14-762, Sept. 2014.
- ³ U.S. Federal Energy Regulatory Commission; North American LNG Import/Export Terminals Approved; Jan. 6, 2015.
- ⁴ From assay data, the “light end” content for Bakken crude is 7.2 percent by volume. “A Survey of Bakken Crude Oil Characteristics Assembled for the U.S. Department of Transportation,” submitted by American Fuel & Petroleum Manufacturers. Prepared by Dangerous Goods Transport Consulting, Inc., May 14, 2014.
- ⁵ U.S. Department of Energy, Liquefied Natural Gas Safety Research Report to Congress, May 2012.

Liquefied Natural Gas Terminals

Review and approval process.

by MR. TERRY L. TURPIN, P.E.
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 Federal Energy Regulatory Commission

More than 130 individual facilities that handle liquefied natural gas (LNG) operate in the U.S. These installations supply natural gas to pipeline systems, store it for peak demand periods, provide LNG for industrial use, serve natural gas as vehicle and vessel fuel, and trade natural gas in foreign commerce. The commercial use and physical location of each installation are factors in determining whether state or federal agencies are responsible for regulating these facilities. The U.S. Department of Transportation (DOT) regulates siting, construction, operation, and maintenance practices for the majority of onshore LNG plants, and the U.S. Coast Guard regulates facilities located in or adjacent to a waterway, including marine transfer area design, construction, operation, and maintenance as well as the waterfront portions of the plant.

Approximately 20 percent of the operational liquefied natural gas plants in the U.S. are also subject to the Natural Gas Act due to their involvement in either interstate or international natural gas transportation.¹ The Federal Energy Regulatory Commission (FERC) determines whether the construction and operation of LNG plants engaged in interstate natural gas transportation by pipeline are in the public interest.

Jurisdiction

The U.S. Department of Energy (DOE) and FERC share Natural Gas Act jurisdiction for onshore and near-shore LNG import or export terminals. DOE reviews applications to import or export natural gas and FERC processes construction and operation applications for specific facilities that will engage in import or export operations. Twenty-four operational plants are under Federal Energy Regulatory Commission jurisdiction: 13 liquefied natural gas facilities engaged in interstate

pipeline transportation and 11 facilities engaged in LNG import or export.

In the early 2000s, there was widespread interest in developing LNG import terminals to supplement the nation's natural gas supply in expectation of dwindling domestic production. Since then, the supply outlook has drastically changed, with increases in domestic natural gas exceeding domestic demand. As a result, the industry is investing billions in developing facilities to export natural gas. Increasing domestic supplies have also prompted investment in developing LNG fueling stations and increased liquefied natural gas transportation via truck, rail, and ship, as noted earlier in this edition.

While terminals within state jurisdictional waters are subject to FERC review under the Natural Gas Act, those located seaward of a coastal state's boundary are subject to the Deepwater Port Act, which requires U.S. Maritime Administration (MARAD) review. Although LNG export terminals, fueling facilities, and container transport would



Operational On-Shore & Near-Shore LNG Facilities. Graphic courtesy of FERC.

mostly be subject to Department of Transportation regulations, and may be subject to Coast Guard oversight, the question of whether FERC jurisdiction applies is frequently raised.

The Natural Gas Act specifically lists several types of facilities that are not subject to Federal Energy Regulatory Commission jurisdiction:

- those that supply natural gas for use exclusively as vehicular fuel;
- those transporting gas within a single state; and
- those engaged in natural gas production, gathering, or local distribution.

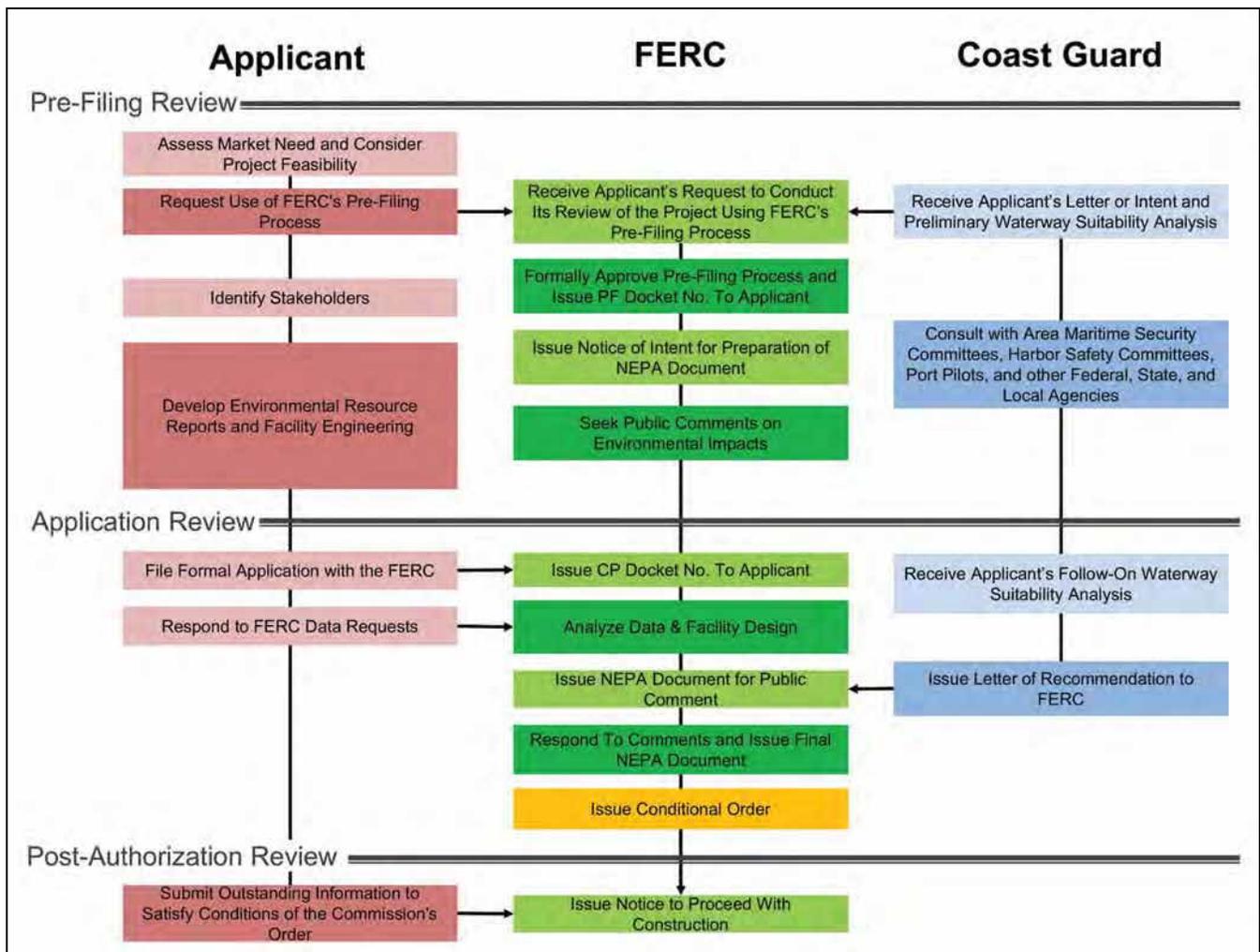
FERC has also generally interpreted its jurisdiction to exclude installations that produce LNG for sale and delivery as an end product (without the liquefied natural gas being vaporized and returned to a pipeline) and those that transport LNG by means other than a pipeline. In 2014, the commission issued four orders addressing its jurisdiction over several facility configurations:

- *Gulf Oil Limited Partnership*, 148 FERC ¶ 61,029 (2014);
- *Shell U.S. Gas & Power, LLC*, 148 FERC ¶ 61,163 (2014);
- *Pivotal LNG, Inc.*, 148 FERC ¶ 61,164 (2014); and
- *Emera CNG, LLC*, 148 FERC ¶ 61,219 (2014).

Jurisdiction determination depends on the specific facts of each case, so while these cases provide some insight into FERC's jurisdictional boundaries, none of these decisions can be extended to apply to facilities with a different configuration. However, for LNG facility export operations, the commission generally found its jurisdiction to be limited to installations that involve direct liquefied natural gas transfer between an oceangoing carrier and an export facility attached to an interstate pipeline.

The commission's process for reviewing liquefied natural gas projects under its jurisdiction consists of three distinct phases:

- pre-filing review,
- application review, and
- post-authorization review.



LNG project review process. Graphic courtesy of FERC.

The pre-filing review and application review involve preparing an environmental assessment or impact statement to satisfy the commission's obligations under the National Environmental Policy Act (NEPA). Although the Federal Energy Regulatory Commission is the lead agency in this effort, NEPA document preparation involves the participation of many other federal agencies in assessing impacts associated with terminal construction and operation. For example, FERC, the Coast Guard, and the DOT signed an interagency agreement in 2004 that outlines the collaborative process that all three agencies use in reviewing LNG terminal proposals.² The DOT and Coast Guard participate in the development of the NEPA document as cooperating agencies, but each remains responsible for enforcing agency-specific regulations covering LNG facility design, construction, and operation.

Pre-filing Review

Applicants for a liquefied natural gas terminal are required to participate in FERC's pre-filing review process for no less than 180 days. During this period, the project owner secures access to the terminal site, develops the preliminary facility design, and drafts the environmental resource reports needed for the FERC application. In addition, the applicant



LNG carrier under tug assist. Photo courtesy of Mr. William Lansinger, Jr., Sempra Energy.

and Federal Energy Regulatory Commission staff members work to identify stakeholders that may be interested in or impacted by the project. The intent is to involve these stakeholders in discussing any project-specific issues that constructing and operating the facility may create. Potential issues can be resolved more easily by engaging these stakeholders before the project design is firmly set.

One of the principal stakeholders that the commission works with during this review phase is the local Coast Guard captain of the port. While FERC does not have any authority to regulate ship transits to LNG terminals, the commission must consider whether the Coast Guard believes the waterway to be safe for these ship transits associated with a terminal.³ Additionally, Coast Guard and FERC regulations require applicants to submit a letter of intent and a Preliminary Waterway Suitability Analysis (WSA) to the Coast Guard at the same time the FERC pre-filing process begins.⁴

While the WSA is under development, the applicant must also create resource report information about the project and the affected environment. During the pre-filing review period, FERC staff members also issue a notice of intent to prepare a NEPA document, which initiates a public scoping period. This notice, which elicits input on potential environmental and safety impact, is sent to all stakeholders, including affected landowners, other federal agencies, state governments, and local entities.



Berthing operations at the Cove Point LNG terminal in the Chesapeake Bay near Lusby, Maryland. Photo courtesy of Mr. Michael Gardner, Dominion Cove Point LNG.

U.S. Coast Guard and MARAD Efforts

by MR. CURTIS BORLAND

Attorney/Advisor

U.S. Coast Guard

Vessel and Facility Operating Standards Division

There are two types of liquefied natural gas terminals over which the Coast Guard exercises regulatory authority:

- traditional shore-side facilities that the Federal Energy Regulatory Commission licenses,
- offshore terminals located beyond state seaward boundaries that are classified as deepwater ports.

Deepwater Ports

The Maritime Administration (MARAD), as the licensing authority, determines if a deepwater port applicant's financial and U.S. citizenship requirements have been met. Additionally, MARAD approves deepwater port construction, operation, and decommissioning.

The Coast Guard is the co-lead federal agency for processing a deepwater port application and leads environmental impact review development for a proposed deepwater port. The Coast Guard also reviews and approves a deepwater port's operations manual, which must describe port operation and include measures to mitigate and monitor any possible adverse environmental impact resulting from port construction and operation.

Since 2002, the Coast Guard and the Maritime Administration have received 18 applications to construct and operate natural gas deepwater ports. There are currently two deepwater ports in operation — one company has received a license to construct and operate a port on the west coast of Florida and one company's application is currently in process.

Waterfront Facility Authority and Actions

The Coast Guard exercises regulatory authority over waterfront LNG facilities and the associated vessel traffic that may affect port areas and navigable waterways safety and security.

The Federal Energy Regulatory Commission has the exclusive authority to approve or deny an application for a liquefied natural gas terminal located onshore or in state waters. As such, FERC is the lead federal agency responsible for preparing the required environmental impact analysis. The Coast Guard is a FERC "cooperating agency" and serves as a subject matter expert on matters relating to maritime safety and security.

An applicant intending to build a new facility handling liquefied natural gas or planning new construction to expand

or modify marine terminal operations at an existing facility must submit a letter of intent and waterway suitability assessment to the Coast Guard captain of the port. The captain of the port then validates the information, typically by convening an *ad hoc* working group of existing committees (such as the harbor safety committee or area maritime security committee) and other stakeholders, including state and local government agencies, first responder organizations, and marine pilot associations. After the validation process is complete, the captain of the port provides the FERC with a letter of recommendation that addresses the project's suitability.

About the author:

Mr. Curtis Borland is a legal advisor in the Coast Guard Office of Operating and Environmental Standards, Vessel and Facility Operating Standards Division. He also served on active duty in the Coast Guard as a judge advocate.

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E.O. 10173

E.O. 13605

The Magnuson Act (50 U.S.C. § 191)

The Ports and Waterways Safety Act of 1972, as amended (33 U.S.C. § 1221 et seq.)

The Maritime Transportation Security Act of 2002 (46 U.S.C. § 701)

42 U.S.C. § 4321 et seq.

33 C.F.R. § 127.007

FERC bases determination of whether an environmental assessment or an impact statement will be developed on the complexity and scope of the proposed project. For example, modifying existing facilities on previously analyzed areas are generally handled through an environmental assessment, where expansions outside of existing facility boundaries typically require an environmental impact statement.

Application Review

After review and FERC comment on draft resource reports, the applicant files the formal Federal Energy Regulatory

Commission application. Commission staff members then provide public notice of the application, review the project sponsor's information and stakeholder comments, and determine whether additional information is needed to address environmental and safety issues. The applicant concurrently submits the Follow-On Waterway Suitability Analysis to the Coast Guard.

At this stage, the information in the waterway suitability analysis should depict the liquefied natural gas terminal, the LNG carrier route, and the port area with enough detail



that any risk mitigation measures and resources necessary to manage the LNG carrier transit can be identified. Coast Guard personnel review this information in consultation with various safety and security working groups, including area maritime security committees; harbor safety committees; port pilots; and other federal, state, and local agencies, and determine if it presents a realistic analysis of the public safety and security implications from LNG marine traffic in the port. Following this review, Coast Guard personnel issue a letter of recommendation to the FERC regarding the suitability of the waterway for LNG marine traffic.

Commission staff members then schedule the National Environmental Policy Act document production. The document contains staff conclusions regarding any impact associated with the proposed liquefied natural gas terminal as well as suggested measures to enhance safety and reduce environmental impact. Staff then issues the NEPA document for public comment and addresses any environmental or safety-related comments received. The FERC considers project effects staff has described as well as any suggested mitigation measures in its decision on whether to authorize the project.

Post-authorization Review

Post-authorization review involves developing detailed facility information. This requires consultation with the DOT and the Coast Guard. During terminal construction, the FERC staff's review ensures the applicant satisfies the safety and environmental measures contained in the commission order. These measures must be satisfied before distinct points of the project's development, such as:

- initial site preparation,
- final design construction, and
- start-up activities.

Prior to each phase, the applicant must submit detailed plans showing how each condition of the commission's order will be met. After review, Federal Energy Regulatory Commission staff will issue a notice to proceed with construction.

Federal Energy Regulatory Commission staff members monitor construction progress during on-site inspections, which occur at least every eight weeks. At these visits, staff members assess the project operator's quality assurance and quality control procedures, review any non-conformance reports, and physically inspect installations for the environmental and safety features required by the commission.

Once the LNG terminal is mechanically complete and in compliance with all FERC requirements, the project operator requests authorization to begin commercial operations. Before the facility is allowed to begin operation, commission staff members consult with the Coast Guard captain of the port to ensure the project operator has developed the required facility security plan and to verify that any needed safety and security measures along the LNG carrier transit routes are in place.

Once in service, each terminal is subject to annual FERC staff inspection for the entire life of the facility, ensuring it continues to be operated and maintained in accordance with the commission's original authorization. The DOT and the Coast Guard also conduct inspections to ensure facility compliance with federal regulations.

About the author:

Mr. Terry L. Turpin is the director of the Division of Gas-Environment and Engineering, which is responsible for conducting environmental and engineering reviews of proposed on shore/near-shore LNG facilities under FERC jurisdiction. The views expressed in this article do not necessarily reflect the policy or views of the Federal Energy Regulatory Commission.

Endnotes:

- ¹ The Natural Gas Act does not apply to any liquefied hazardous gases other than LNG.
- ² "Interagency Agreement among the Federal Energy Regulatory Commission, United States Coast Guard, and Research and Special Programs Administration for the Safety and Security Review of Waterfront Import/Export Liquefied Natural Gas Facilities." February 11, 2004. See www.ferc.gov/industries/gas/indus-act/lng/2004-interagency/2004-interagency.pdf.
- ³ The Coast Guard waterway suitability review process which the FERC relies on is described in "Navigation and Vessel Inspection Circular 01-11, Guidance on Assessing the Suitability of a Waterway for LNG Marine Traffic."
- ⁴ Title 33, Code of Federal Regulations, Part 127 and Title 18, Code of Federal Regulations, § 157.21.

For more information:

Statistics courtesy of the Federal Energy Regulatory Commission. Visit the website at: www.ferc.gov.



Liquefying Natural Gas

Liquefaction uses and advantages.

by Ms. JENNIFER SEITTER
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Throughout history, civilizations have developed technologies to meet the energy demands of an ever-increasing population. By the early 1800s, U.S. energy commodity providers used the railways and steam-powered vessels to transport coal and oil. As the demand for gaseous fuels began to rise in the 20th century, providers introduced pipeline infrastructure, which distributed gas to users over relatively short distances. Today, liquefaction of various gaseous fuels, including natural gas and petroleum gas, allows options for economical transportation and storage.

Gaseous Fuels

Gas is found in naturally occurring pockets of conventional gas, coal bed methane, shale gas, and tight gas, or may also be captured as a byproduct of the oil refining process.

Natural gas is the most common gaseous fuel, and is typically comprised primarily of methane and ethane, with some amounts of heavier hydrocarbons such as propane

and butane. Natural gas remains in its gaseous state when it is transported in pipelines but is liquefied for storage and transport to distant markets.

At the destination, the liquefied natural gas (LNG) is regasified and delivered to users via a pipeline distribution system. More than 110 natural gas liquefaction facilities are operating in the United States alone, which have processed approximately 24 trillion cubic feet of LNG, and U.S. end users consumed more than 26 trillion cubic feet of natural gas in 2013.

Generally heavier petroleum gases such as propane, ethane, and butane are liquefied at the source and stored in their liquefied state until ready for use. Once liquefied, the petroleum gases are then referred to as liquefied petroleum gas or LPG.

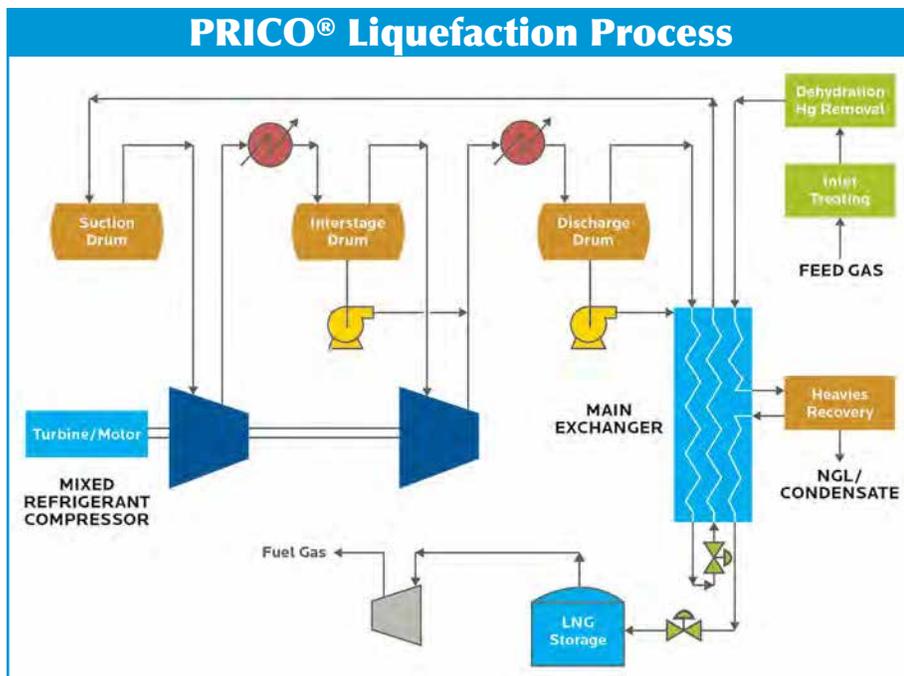
Why Should We Liquefy?

Liquefied fuels occupy only a fraction of the volume required by their gaseous counterparts. This reduction results in significantly smaller storage vessels and allows for affordable transportation. For example, the volume of natural gas is decreased by 600 times when it is condensed into LNG. LNG carriers then transport it cost-effectively to markets around the world.

We can think of this method as a “virtual pipeline” to transport gas from its source to end users. With increasing availability of shale gas in the United States, a large number of liquefaction facilities are being planned as onshore and floating near-shore applications.

Safety

Liquefaction facilities do exhibit some inherent hazards, since all hydrocarbons are flammable, so intentional hydrocarbon



PRICO® liquefaction process diagram. Graphic courtesy of Black & Veatch.

What is Liquefaction?

The liquefaction process is complex but can be simplified into three primary stages:

- pretreatment,
- liquefaction,
- storage and loading.

Pretreatment

Prior to liquefaction, natural gas must be treated to remove all components that will freeze at a liquefaction temperature or may compromise process equipment. These include carbon dioxide, sulfur products, water, mercury, and heavier hydrocarbons like benzene. When purified and liquefied into finished byproducts, the heavy hydrocarbons are referred to as natural gas liquids and include ethane, propane, butane, isobutane, and pentane.

This stage may occur either at the source or at the liquefaction facility. If the pretreatment units are located at the source, further treatment or filtration is necessary at the liquefaction facility before the liquefaction stage.

Liquefaction

During the liquefaction stage, a gas is sub-cooled and liquefied using a process

similar to that used in freezers or air conditioners. Generally, LNG is cooled to -161°C and ethane to -60°C when stored at near atmospheric pressures. Liquefied petroleum gases are stored in pressurized containers, and therefore will be in liquid form at ambient temperatures.

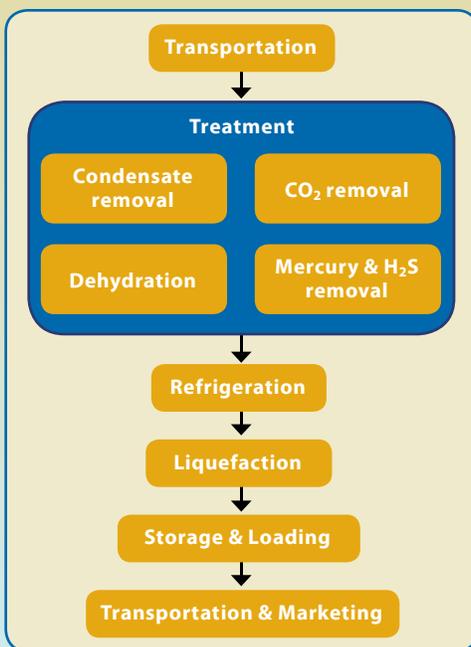
Several liquefaction technologies have been developed to balance the industry

demand for flexibility, facility size, cost, and efficiency, including cascade units, dual mixed refrigerant, and single mixed refrigerant units. Cascade processes were traditionally used in the early days of the industry and used pure hydrocarbon refrigerant loops in series to condense gas. However, these processes were costly and complicated to operate.

Mixed refrigerant processes, true to their name, incorporate a mixture of hydrocarbons as opposed to a pure refrigerant for more efficient heat transfer. Dual mixed refrigerant processes require two refrigerant compression systems to achieve the cooling needed to liquefy the gas and are typically used for large-scale facilities. Single mixed refrigerant processes provide liquefaction capabilities with a smaller footprint, simplified operations and maintenance, and lower overall capital and operating costs.

Storage and Loading

Once the gas is liquefied, it is stored and loaded for transport.



releases are sent to a flare to safely combust. Staff must ensure there are no unintentional leaks, so they place hydrocarbon detectors throughout the facility to monitor for leaks. In addition, as with any type of refining unit, these facilities should be designed to ensure safe operation through adequate relief points, proper operation and maintenance procedures, and personnel safety training.

Typical safety evaluations include proper response to gas dispersion, flare radiation, blast and over-pressurization, controlled depressurization or blow-down, dropped objects, and spill containment.

Looking Ahead

Developing increasingly efficient liquefaction technology and its application to onshore, near-shore, or offshore facilities will continue to create opportunities to tap gas resources once thought unfeasible, so liquefaction will continue to be a key objective for energy companies.

Additionally, as energy demands increase in established and emerging markets, gas resources will continue to demonstrate promise as a fuel source. In turn, liquefaction will most likely become a necessary cog in the world energy market, as through this technology, essential fuel commodities will be accessible to regions of the world that would otherwise go without.

About the authors:

Ms. Jennifer Seitter is a process engineer at Black & Veatch with experience designing natural gas liquefaction facilities and gas processing facilities.

Mr. Javid Talib is a vice president at Black & Veatch and is the floating LNG program manager.

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Accessing Landlocked Natural Gas Reserves

Floating LNG solutions.

by CAPT. STANLEY WENDELEWSKI
Manager, Marine Operations
Excelerate Energy

As demand for natural gas grows, natural gas supply solutions can be challenging. Building a traditional shore-based gas facility requires a large capital investment and undergoing a demanding permitting process. In 2000, industry members explored the concept of floating liquefied natural gas (LNG) regasification vessels to satisfy the energy demand. The concept is simple: Create an LNG vessel capable of taking on LNG cargo and delivering it ashore in its gaseous state.

Floating Storage Regasification Unit

The floating storage regasification unit, or FSRU, stores liquefied natural gas in its cargo containment system, transfers the cargo internally to the vessel's onboard regasification plant, vaporizes the LNG to gas vapor, and delivers the gas vapor under high pressure directly from the vessel into the supply pipeline.

The vessel *Excelsior*, built in 2005, is the industry's first FSRU. *Excelsior* is capable of delivering high-pressure (HP) gas to a shore-based facility via a submerged turret loading buoy in the bow of the vessel or via an outboard high-pressure gas manifold connection.¹ Since *Excelsior's* delivery, floating storage regasification units have featured varied designs. Some FSRUs are new-built vessels, some are existing liquefied natural gas carrier conversions. Some use membrane tank cargo containment systems, some use spherical tank designs.

Many floating storage regasification units can be utilized as traditional LNG carrier vessels when not employed in regas service; some are designed to remain long-term regasification installations. As of November 2014, the FSRU fleet consisted of 20 vessels, with a further eight on order.²

Gas Delivery to Market

Two basic types of technologies support FSRUs:

- a near-shore or offshore regasification terminal,
- a deepwater port regasification buoy.

The near-shore or offshore regasification terminal concept is based on a more traditional dockside design. It consists of a central platform area and mooring dolphins that extend out in either direction to permanently moor the FSRU to the jetty. On the jetty platform area, high-pressure gas arms, designed to connect to the floating storage regasification unit's dedicated high-pressure gas manifolds, receive the gas from the floating storage regasification unit and deliver it directly to the pipeline/shore grid.

The deepwater port buoy concept is an offshore buoy-based configuration with a submerged turret loading buoy anchored to the sea floor and a flexible riser that connects to a subsea pipeline. The floating storage regasification unit



The FSRU vessel *Excelsior*. All graphics courtesy of Excelerate Energy.



An FSRU gas port.



An example of a ship-to-ship transfer.

contains a compartment in its bow that accepts the STL buoy as a permanent moor during regasification operation and provides the HP gas discharge point to the flexible riser and into the subsea pipeline for onward transmission to the shore pipeline.

There are two FSRU ports in the U.S., both located outside the port of Boston. Both utilize the deepwater STL buoy concept.³ Additionally, the Federal Energy Regulatory Commission recently approved a floating storage regasification unit port that utilizes an across-the-dock, hard arm sea island regasification terminal concept.⁴

Ship-to-Ship Transfer Operations

Although commonplace in the oil industry, the world's first commercial full LNG cargo ship-to-ship (STS) transfer occurred in February 2007 in the U.K.⁵ Since then, commercial STS transfer operations are becoming more common, especially since FSRUs require periodic replenishment to allow a continuous supply of natural gas to market.

For example, the ship-to-ship operation may entail transferring a full cargo of liquefied natural gas from a conventional LNG tanker to the floating storage regasification unit. Depending on the facility's design, liquefied natural gas can be transferred between the two vessels via cryogenic flexible hose or hard arm or via a double-banked mooring arrangement or across-the-dock configuration.

As in the oil industry, in double-banked STS operations, LNG vessels are moored side by side and their liquid manifolds connected via flexible cargo transfer hoses. In addition, both the delivering and receiving vessels' vapor manifolds are

connected via flexible hose, which is designed to handle liquefied natural gas. Further, each hose is fitted with an emergency release coupling and each feature purpose-built saddles that provide support and maintain the proper hose bend radius over the vessel rail. Cargo transfer commences after vessel manifold and cargo transfer equipment cool-down. Vapor generated during the STS operation is not vented to the atmosphere, as both vessels consume boil-off gas to properly manage tank pressure.

Floating Liquefaction, Storage, and Offloading Unit

Although a large amount of global natural gas reserves are located in remote areas, continually evolving liquefied natural gas technologies have made these reserves accessible. The FLSO (floating liquefaction, storage, and offloading unit) produces liquefied natural gas and stores it on a floating vessel, which "unlocks" these remote gas fields to bring LNG to the consumer.



An FSRU gateway.



A floating liquefaction, storage, and offloading unit.

Since the FLSO is mobile, the vessel can be stationed in distant locations and moved to multiple reserves. It can also be moored dockside to access shore pipeline-grade gas or offshore to access subsea gas.

Whether dockside or moored offshore, the concept is the same. The gas processing and liquefaction equipment on the vessel's main deck processes the raw natural gas and then the LNG is transferred internally to the vessel's cargo tanks. The stored liquefied natural gas is then offloaded to an arriving liquefied natural gas carrier.

Looking Ahead

With demand for LNG on the rise, the industry continues to bring liquefied natural gas solutions to the global market. In the United States, more than 25 proposed maritime LNG projects have been submitted to relevant regulatory agencies for approval to meet export demand for shale gas that is in surplus to United States domestic requirements.⁶

U.S. import terminals are being converted to export facilities to take advantage of existing storage tanks and marine jetty facilities, new facilities in the U.S. are set to come online in late 2015, and five floating liquefaction projects currently underway are near completion.⁷ Globally, access to significant offshore reserves in areas such as Australia and West Africa are being based on floating liquid natural gas concepts as a lower-cost, fast-track, flexible alternative to a shore-based facility.

Additionally, some vessels are being designed to burn liquefied natural gas for propulsion fuel. As this use becomes

more commonplace, a higher demand for LNG bunker vessels will emerge. As liquefied natural gas projects continue to push boundaries, floating LNG solutions and technologies will continue to evolve.

About the author:

Captain Stanley Wendelewski is Excelerate Energy's manager of Marine Operations. He is a graduate of New York Maritime College at Fort Schuyler. Capt. Wendelewski spent 16 years at sea sailing in licensed capacities, including master and chief officer aboard LNG vessels. Coming ashore in 2006, Capt. Wendelewski has worked in a variety of technical management positions with vessel owner/operators and as director of vetting and audits for a major oil company.

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Liquefied Gas Carriers

Trends, routes, and inspections.

by MR. MICHAEL DAVISON
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LT DALLAS SMITH
Marine Inspector
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The term “liquefied gas carrier” (LGC) covers a broad range of vessel types and includes more than 400 liquefied natural gas (LNG) carriers and more than 1,100 liquefied petroleum gas (LPG) or petrochemical gas carriers operating worldwide.¹

Carrying certain gas cargoes on LGCs in a liquefied state versus a gaseous state reduces the volume immensely. For example, liquefaction of methane gas (LNG) and liquefaction of propane gas (LPG) reduces the volume by factors of 600 and 270, respectively.² However, when liquefied, these cargoes become more challenging to store, due to the low temperature and/or high pressure required to keep the cargo in the liquid state.

Careful vessel design and operation, coupled with international safety codes and strictly enforced industry guidelines, helps to ensure safe liquefied gas shipment. Thus, with increased shale oil and natural gas production, the U.S. is set to become a major liquefied gas exporter.

LPG Carriers

LPG carriers transport heavier hydrocarbon gases, which are typically produced from oil refining processes. Currently, the largest proportion of liquefied petroleum gas is produced in the Arabian Gulf states and shipped to northeastern Asia.³

Large liquefied petroleum gas carriers transport the cargo fully refrigerated at atmospheric pressure, while smaller quantities are transported either under pressure or semi-refrigerated.

LNG Carriers

Large volumes of methane are only carried in the liquefied state. The largest liquefied natural gas producers are currently Qatar, Australia, Malaysia, and Indonesia. The largest consumers (used to

generate power) are Japan, Korea, and China.⁴ The proposed expansion in U.S. LNG export capability will lead to a corresponding ramp-up in U.S. port calls for liquefied natural gas carriers.

Further, the increasing number of U.S. LNG liquefaction facilities either under construction or awaiting approval will create a fourfold increase in the number of liquefied natural gas carrier transits by 2016. By 2020, the Sabine Pass on the Texas/Louisiana border may see hundreds of gas carrier transits per year, marking a major step-change in the volume of world liquefied natural gas exports.⁵

Conditions of Carriage

There are three conditions of carriage for liquefied gas cargoes:

- **Fully refrigerated:** The cargo is carried at or very close to atmospheric pressure.

continued on page 37



An LNG carrier alongside the terminal at Elba Island, Georgia. All photos courtesy of Michael Davison, Project Development Manager, BG Group.

LNG CARRIER CASE STUDY

Let's picture a voyage for a new 174,000 m³ TFDE (tri-fuel diesel electric) liquefied natural gas (LNG) carrier¹ that plans to take on cargo in a U.S. Gulf Coast load port and subsequently discharge in Tokyo Bay.

The Loading Operation

Once the vessel arrives alongside the LNG terminal, the vessel crew connects shore communication systems and emergency shutdown systems to the terminal. Then the crew replaces all of the inert gas in the cargo tanks with cargo vapor from the terminal. This is supplied to the vessel via shore-based hard-arms as LNG, which is vaporized on board.

Once sensors detect methane leaving the cargo tank, the vapor is directed back to the terminal via the vapor return line for reliquefaction. Throughout the loading operation, all vapor displaced from the cargo tanks is also returned ashore to the shore tank.

Once the gassing-up process is completed, the crew cools the cargo tanks before receiving LNG cargo at -163°C. The cool-down process and the loading rates must be carefully controlled, typically lowering system temperatures at 10°C per hour, to avoid excessively rapid cool-down that could damage vessel systems. The vessel is deemed ready to load when the lower part of the cargo tank pipe column reads -130°C. The crew then carefully loads while slowly ramping up the flow rate. This complete process takes around 14 hours.

Conical, fine-mesh stainless steel strainers fitted to the ship's manifolds assure onboard system cleanliness, which is important, because it requires considerable time, effort, and cost to

enter a cargo tank for cleaning once it is under gas vapor.

The Laden Voyage

Once the cargo loading process is complete, the vessel departs on a three-to four-week voyage to deliver LNG to a customer in Tokyo Bay.

From the moment the shore vapor line is closed at the loading terminal, the methane cargo starts to boil off in the tank, and pressure increases. A fully laden 174,000 m³ TFDE vessel with an average boil-off rate of 0.09 percent per laden day will generate approximately 60 to 70 tonnes of boil-off gas per day that needs to be managed to avoid the risk of venting gas to the atmosphere. This is done by sending boil-off gas to the engines as fuel, reliquefying the gas, or consuming gas in the vessel's gas combustion unit.

LNG carriers rarely sit at anchor when laden because of boil-off gas management requirements. As vessel speed and tank pressures are so closely linked, voyage management is critical to maximize ship performance and avoid unnecessary delays.

In the days directly preceding arrival at the terminal, the crew checks the cargo system by operating valves and other safety systems to ensure that everything is in working order. Many LNG terminals see different vessels arrive and depart every day, which requires smooth operations and very high ship reliability so that the end user (such as a power utility) can maintain operating margins on the inventory.

Cargo Discharge

Once the vessel arrives at Tokyo Bay and is alongside the buyer's terminal, qualified cargo surveyors verify the custody transfer and measurement system, and

independent authorities certify the characteristics of the cargo, including volume, vapor pressure, and temperature for customs and contractual purposes before discharge commences. The cargo is discharged via cargo pumps in each tank in about 14 hours.

The Ballast Voyage

Most LNG carriers retain "heel," a small amount of LNG left over from cargo discharge, on board for use as fuel and to keep the tanks cool and ready for loading the next cargo shipment. This is usually about three percent of the vessel's cargo capacity on a long voyage, but varies depending on the fuel strategy employed.

The boil-off rate in the heel voyage is much lower than for the laden voyage. This means that the vessel can operate at a lower speed, if the schedule demands, without creating excess boil-off gas. This is more applicable for spot trading than for liner trades. On liner trades, the voyage schedule is often known a year in advance.

If the vessel arrives at the next loading port with LNG heel, the crew may start to cool down the cargo tanks and handling system prior to arrival. Upon arrival alongside, the cargo surveyor makes custody transfer checks again and the vessel repeats the loading operation.

For spot trading, depending on gas and alternative fuel prices, the strategy for each voyage may be different. For liner trades with long-term sales and purchase agreements, the strategy varies little.

Endnote:

¹ The 174,000 m³ capacity vessels are expected to frequent U.S. ports in the future because their design is optimized for facilities like the Lake Charles LNG terminal. This design also accommodates many other LNG ports in the world and has become popular within the industry.



An LNG carrier transits the Suez Canal at night.



LNG carriers under construction.

- **Semi-refrigerated:** The cargo is carried at an intermediate pressure and temperature.
- **Fully pressurized:** The cargo is carried at ambient temperature.

Design Considerations

The cargo's volume and critical temperature influence cargo containment and handling system design. (Critical temperature is the point above which a gas cannot be liquefied by an increase of pressure alone.) While many LPGs can be liquefied by an increase of pressure that is economical to apply on a ship, methane can only be practically liquefied by refrigeration at -260 degrees F.

The majority of fully pressurized and semi-refrigerated ships are outfitted to carry several types of cargoes. For example, petrochemical gases such as propylene, butadiene, vinyl chloride monomer, and anhydrous ammonia can be carried on liquefied gas carriers, as they have similar characteristics to LPG. However, certain ships are designed only to carry specific cargoes due to temperature constraints (such as ethane and ethylene carriers). Small liquefied gas carriers employ fully pressurized tanks, intermediate-sized vessels are typically semi-refrigerated, and fully refrigerated vessels at near ambient pressure have the largest tanks.

A key consideration for fully refrigerated and semi-refrigerated LGC cargo tank and cargo handling system design is that the cargoes will boil off at varying rates during a voyage due to heat ingress from the surrounding environment. The build-up of this boil-off gas (BOG) is handled in different ways—either by building the tank structure to manage the increased pressure and/or by fitting reliquefaction plants onboard. Pressurized tanks inhibit cargo boil-off.

Cargo Containment Design Requirements

Very cold cargoes can cause brittle fracture of the ship's structure if it is directly exposed to low temperatures, and, as it is not economically feasible to build large LCGs with low temperature-resistant metals, cargo tanks do not share a common boundary with the shell plating.

LGC cargo containment systems vary based on the low-temperature nature of the cargo, ranging from low-temperature mild steel to certain stainless steels and nickel alloys. The tanks fall into two main categories: independent tanks and membrane tanks. Due to the risk of structural damage if very low-temperature cargoes such as LNG come into contact with the ship's hull, ships are fitted with secondary containment systems to capture leakage in the unlikely event that the primary containment system fails. For warmer cargoes, like some LPGs, the secondary barrier can be the ship's hull.

Independent tanks sit within the ship's hull and do not use the ship's structure as a part of the containment system. IMO Type B tanks on LNG carriers are engineered for extremely high reliability, such that, in case of failure, fracture propagation is very slow and leaks are very small. These tanks only require a drip tray below the lowest point to capture any leaks, with gas detection systems fitted.

Membrane containment systems are employed for LNG cargoes and use the ship's structure for support. Such vessels are fitted with two continuous membrane and insulation systems, so that any cargo leakage caused by failure of the inner (primary) membrane will be contained by the secondary membrane.

General Arrangement, Operation, and Safety Systems

The requirements for ship design, construction, and testing vary depending on the product characteristics, including cargo tank type and location, monitoring systems, alarms, and other safety measures. Additionally, due to the low-temperature or high-pressure nature of the cargoes, the vessels are fitted with a number of redundant safety features.

For LNG carriers, all vessels are double-hulled in the way of cargo tanks. LPG carriers typically have double-bottom ballast tanks and the cargo tanks are separated from the side shell. An LGC usually has one to five cargo tanks, depending on the vessel type and capacity. Some vessels may have individual tanks split into port and starboard tanks, but such

tank pairs normally share a vapor space and venting system. LGCs have a separate cargo machinery room which is normally located on the uppermost deck. This room houses gas handling equipment, including liquefaction equipment, vaporizers, and compressors.

Since LNG carriers can burn boil-off gas as fuel, they also incorporate gas-handling equipment in independent spaces within the main machinery spaces, including the gas valve room that controls fuel gas supply to the propulsion system and the gas combustion unit that can burn excess BOG when propulsion demand for gas is low.

Liquefied gas carriers operate on a closed concept. The cargo tanks are initially filled with either vapor, a mix of liquid and vapor, or an inert gas. During cargo loading, liquid gas displaces the original cargo vapor, which the marine facility collects. The reverse occurs during cargo discharge. LPG carriers can operate without vapor return by using an on-board reliquefaction plant.

Crewmembers must control cargo tank pressures during loading and discharging to prevent oxygen being drawn into the tanks or cargo vapor being vented to the atmosphere. Typically the venting system is a set of dual-redundant, pilot-operated pressure vacuum (P/V) relief valves that protect each cargo tank from damage due to under- or over-pressure. These P/V valves are situated between the vapor space and a mast riser for each tank on the deck of the vessel. The tanks also feature multiple-level alarms. Automated control systems will shut down cargo pumps or close valves to prevent overflow, as required.

LNG propulsion systems include steam-turbine, diesel-electric, and two-stroke direct-drive systems that operate on heavy fuel oil (HFO), marine diesel oil (MDO), marine gas oil (MGO), and BOG fuel. Modern, highly efficient liquefied natural gas carriers feature two-stroke gas injection engines (4,400 p.s.i. gas injection pressure) or lower-pressure two-stroke gas induction engines. Liquefied petroleum gas carriers are typically fitted with two-stroke direct-drive engines or diesel-electric systems operating on HFO, MDO, or MGO fuels, but not gas fuels, at present.

Service Life

The accepted industry service life is 40 years for an LNG carrier, and in some cases, 40-year-old vessels are still in good condition and are converted to floating storage. Other older vessels have recently been sold for conversion to regasification vessels or floating LNG production and storage vessels.

There has been a rapid development in LNG carrier design, particularly in the areas of boil-off rate and propulsion

technology. As a result, typical fuel consumption has been reduced by an impressive 50 percent, and vessel capacities have also increased, resulting in a much lower unit freight cost and overall environmental footprint.⁶ LPG carriers typically have a service life of 25 years.

Inspections

The U.S. Coast Guard administers a wide range of maritime safety laws designed to protect merchant seamen and the environment. These laws enforce safety standards for navigation, lifesaving, fire extinguishing equipment, and limited construction standards.

Title 46 U.S.C. 3711 requires foreign vessels carrying cargoes regulated in 46 CFR Subchapter O to have a certificate of compliance authorizing the carriage of those cargoes in U.S. waters. The officer in charge, marine inspections determines if the vessel's required certificates are valid, and examines and assesses the vessel's relevant components, certificates, documents, and safety systems.

Future Focus

After 50 years of LNG shipping activities and more than 79,000 cargoes successfully delivered,⁷ liquefied natural gas shipping has proven itself to be safe and reliable. Its export from the U.S. will increase dramatically in the short term, and Coast Guard involvement will be critical.

About the authors:

Mr. Michael Davison is the project development manager for BG Group's Ship Design and Construction Team based in Houston, Texas. Mr. Davison has been involved in LNG carrier design, construction, inspection, maintenance, and repair for more than 15 years.

LT Dallas Smith is a liquefied gas carrier subject matter expert at the U.S. Coast Guard Liquefied Gas Carrier National Center of Expertise. He has served in the Coast Guard for 15 years, and is a fully qualified marine inspector and casualty investigator with an extensive background in commercial vessel safety and liquefied gas.

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7. SIGTTO (Society of International Gas Tanker and Terminal Operators) website: www.sigtto.org/.

Containment Systems

LNG cargo containment systems are designed for safety.

by MR. AZIZ BAMIK
General Manager
GTT North America, Inc.

Just 50 years ago, William Wood Prince, president of the Chicago Union Stock Yard, developed the world's first liquefied gas carrier, pioneering the safe storage and transport of liquefied gases on the waterways.¹ Now, as the U.S. enters an Energy Renaissance and is positioned to provide large quantities of competitively priced shale gas, the industry is well established with experience, engineering, and standards to ensure the volatile cargo is kept safe in specialized containment systems.

The International Maritime Organization's International Code for the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk (IGC Code) and U.S. 46 Code of Federal Regulations Part 154 are just two internationally recognized regulations that govern gas carriers. According to the IGC code, the entire cargo containment system consists of the following elements:

- primary barrier (cargo tank);
- secondary barrier (if necessary);
- thermal insulation;

- any intervening spaces, and adjacent structure, if necessary, to support these elements.

Tank Types

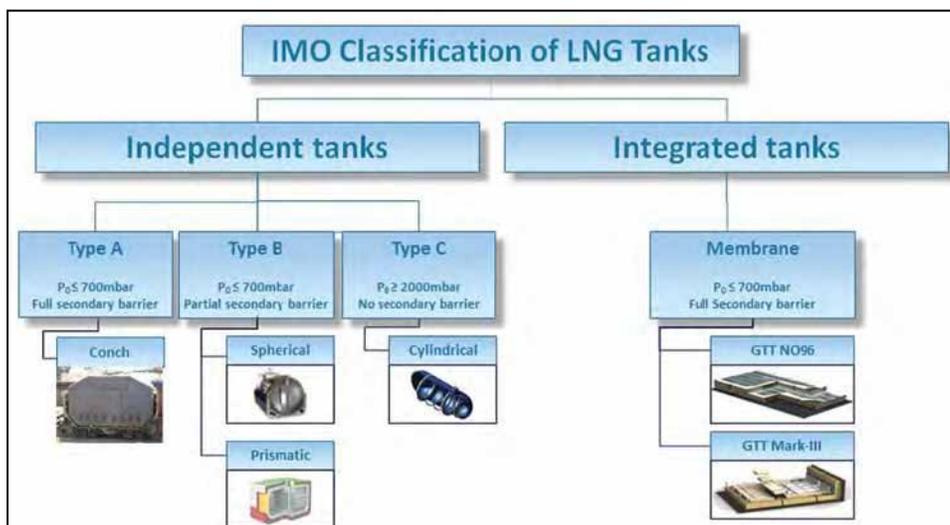
The IGC code differentiates between "independent" tanks and "integrated" tanks. Independent tanks are self-supporting, do not form part of the ship's hull, and are not essential to hull strength.

There are three categories of independent tanks:

- **Independent Type A** tanks are designed primarily using classical procedures for ship structural analysis and are fully insulated, with a complete secondary barrier. The design vapor pressure is 0.7 bar (approximately 10 psi) and they are typically of a prismatic, volumetrically efficient shape.
- **Independent Type B** tanks are designed using model tests and refined analytical tools to determine stress levels, fatigue life, and crack propagation characteristics. This advanced failure-mode analysis means that only a partial secondary barrier is necessary.

These tanks are also fully insulated and have a design vapor pressure of 0.7 bar (approximately 10 psi). Type B tanks take one of two shapes—a spherical tank or a self-supporting prismatic tank.

- **Independent Type C** tanks meet American Society of Mechanical Engineers Section VIII pressure vessel criteria and can accommodate design vapor pressures up to 10 bar (approximately 140 psi). They are fully insulated and require no secondary barrier, but they do require additional space for inspection outside of the tank.

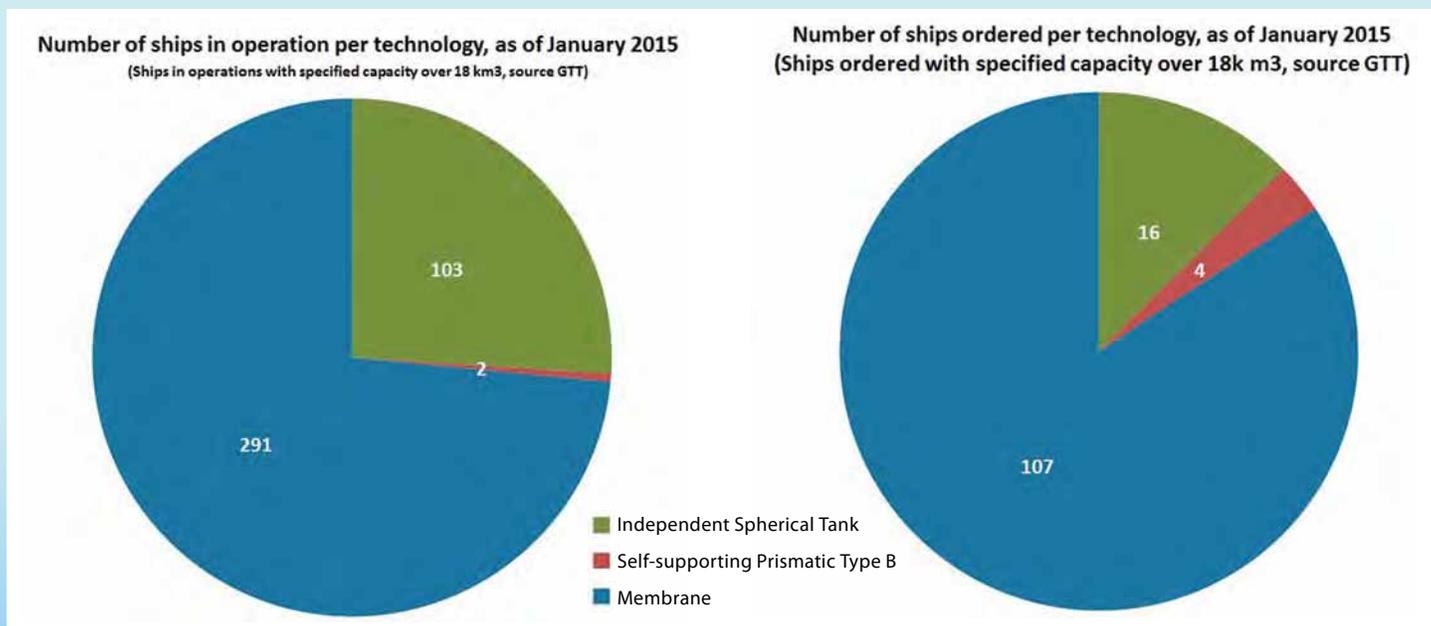


Graphic courtesy of GTT.

Membrane Technologies

The worldwide market for liquefied natural gas (LNG) is growing, and the demand is expected to double within the next 10 years. Additionally, international regulations mandate lower emissions and ship owners are demanding more efficient containment systems with lower boil-off rates (BOR) and more efficient engines.

To meet these customer requirements, GTT membrane technologies offer lower boil-off rate systems: the NO96-GW, NO96-L03, NO96-L03+, and MarkIII Flex, the last two of which offer BOR of less than 0.10 percent per day.



Approximately 75 percent of the global fleet of current LNG carriers and 84 percent of LNG carriers on order contain membrane tanks. Graphic courtesy of GTT.

Membrane tanks (the predominant type of integrated tank) rely on the mechanical strength of the inner hull for support and consist of two relatively thin complete membranes to contain the liquefied gas. These are separated by insulated inter-barrier space layers that transmit the cargo load and any internal pressure to the inner hull. As with Type A and B independent tanks, membrane tanks have a design vapor pressure of approximately 10 psi.

GTT Gaztransport & Technigaz SA is the exclusive provider of the two main types of membrane tank technology:

- the MarkIII system consists of one primary metallic membrane made of corrugated 304L² stainless steel and one triplex composite³ secondary membrane, separated by fiberglass-reinforced polyurethane foam;
- the NO96 system consists of two identical metallic membranes made of invar—a 36 percent nickel/steel alloy. Both insulation layers are made of prefabricated plywood boxes filled with expanded perlite.

The next generation of membrane tanks, MarkV and NO Max, will offer further value to customers and may be ready for ships in operation as soon as 2018.

What's in it For Us?

Regarding North America, abundant resources in shale gas will soon lead the U.S. to become an LNG exporter. Moreover, due to this abundant and affordable domestic natural gas supply and stricter marine emission regulations now in force, LNG-fueled marine vessels and LNG bunker barges/vessels are being and will be increasingly built in the U.S.

In this respect, the U.S. Coast Guard will be crucial for the success of those projects, especially to ensure safety in an industry under rapid expansion.

About the author:

Mr. Aziz Bamik joined GTT in 1999 and is currently general manager of GTT affiliate GTT North America in Houston, Texas. Before assuming this position, he occupied various positions at GTT SA, including research and development engineer, project manager, and director of business development. He received his degree in engineering from Ecole Supérieure de l'Energie et des Matériaux in Orleans, France, in 1998.

Endnotes:

¹ "LNG Shipping at 50—Methane Princess sets the scene," SIGTTO/GIIGNL commemorative publication, 2014.

² This (304L) is the designation of the stainless steel type (18%Ni-10%CR alloy).

³ Triplex is a laminated material which is made of two fiberglass cloths (for the mechanical strength) and an aluminium foil (for the tightness).

The Subchapter O Endorsement

For foreign liquefied gas carriers.

by LT RACHEL BECKMANN
Vessel and Cargo Branch Chief
U.S. Coast Guard Marine Safety Center

The International Gas Code (IGC) provides the international standard for safe liquefied gases carriage in bulk. The corresponding U.S. regulations are found in Title 46 Code of Federal Regulations, Subchapter O, Part 154. As U.S. standards are more stringent than some parts of the international standard, it is important that those who operate foreign liquefied gas carriers in U.S. waters understand the differences in the standards and the process used to enforce those differences.

The Coast Guard verifies compliance using a combination of plan review and physical examination. A successful plan review leads to the Coast Guard developing a “Subchapter O endorsement” (SOE) for carriage of specific cargoes, which is issued after the vessel successfully undergoes a certificate of compliance (COC) exam.



Liquefied natural gas tanker. Image courtesy of Oleksandr Kalinichenko / iStock / Thinkstock.

More Stringent U.S. Standards

The U.S. standards were originally intended to mirror those found in the International Gas Code (IGC). However, there are four areas in which the Coast Guard utilized the regulatory process to establish additional requirements designed to increase liquefied gas carrier safety. These standards focus on areas of the vessel's containment system and hull construction, such as:

- hull material,
- cargo tank pressure and temperature control,
- maximum allowable relief valve settings, and
- ambient design temperatures.

Hull Construction Material

U.S. regulations require that enhanced grades of steel be used along the cargo area for crack-arresting purposes in the event of a cargo spill. This includes the deck stringer, the sheer strake, and the turn of the bilge. The Coast Guard Office of Design and Engineering Standards may approve alternative materials if they are determined to provide an equivalent level of protection.

Cargo Tank Pressure and Temperature Control

The IGC allows a vessel to control cargo pressure and temperature by venting cargo vapors to the atmosphere at sea and in port, if the port's administration allows this. The U.S., however, prohibits the normal cargo vapor venting into the atmosphere in all ports. The U.S. requires that foreign vessels maintain cargo tank pressure below the design vapor pressure indefinitely or for a period of not less than 21 days for liquefied natural gas.

Approved pressure control methods include:

- refrigeration systems,
- burning boil-off gas,
- using boil-off gas as fuel, or
- a combination of methods.

Maximum Allowable Relief Valve Settings

U.S. design requirements for cargo containment systems are based on the American Society of Mechanical Engineers Boiler

and Pressure Vessel Code. Allowable stresses for membrane, semi-membrane, and independent type A tanks are the same in the IGC and U.S. regulations.

For independent type B and C tanks, however, the U.S. uses more conservative (higher) stress factors, which results in lower permissible pressure settings. Therefore, foreign flagged gas carriers are typically approved for two maximum allowable relief valve settings (MARVS) — one for operating in international waters and one for U.S. waters. Prior to entering U.S. waters, foreign vessel crew must set tank relief valves to the lower approved U.S. MARVS.

However, there have been advancements in construction materials, manufacturing, and inspection since original Subchapter O development, so the American Society of Mechanical Engineers has lowered the required stress factors to permit higher design pressures. In 2012, the Coast Guard issued CG-ENG Policy Letter No. 04-12, which notes that international MARVS for independent type B and C tanks on vessels that have been built to IGC 1993 edition standards are acceptable.

Design Temperatures

The International Gas Code provides general standards to evaluate the insulation and hull steel for cargo tanks and secondary barriers for the purpose of design calculations. The ambient design temperatures are 41°F for still air, and 32°F for sea water.

The IGC also states that each administration can dictate higher or lower ambient design temperatures. U.S. regulations specify the following additional ambient design temperatures for vessels required to have a secondary barrier:

- 0°F for 5 knots air, and 32°F for still sea water for any waters in the world, except Alaskan waters; and
- -20°F for 5 knots air, and 28°F for still sea water for Alaskan waters.

The first step in this process is for the operator of a foreign-flagged gas carrier to submit an SOE application to the Coast Guard Marine Safety Center. The application must include a copy of the vessel's flag state or classification society International Maritime Organization Certificate of Fitness (IMO COF), as well as the additional engineering plans and documents listed in 46 CFR 154.22. These documents allow the Marine Safety Center to verify compliance with

the standards that are not found in the IGC and ensure that Coast Guard responders have the necessary drawings on file to respond to a potential gas carrier incident in a U.S. port.

SOE Issuance

After Marine Safety Center personnel verify standards compliance, they generate the Subchapter O endorsement and forward it to the officer in charge, marine inspection at the

vessel's next U.S. port of call. The Subchapter O endorsement contains the following information:

- reference to the applicable International Gas Code,
- vessel maximum allowable relief valve settings,
- tank types,
- minimum cargo temperature,
- list of authorized cargoes,
- general cargo carriage requirements,
- any special restrictions on cargo carriage.

The standard Marine Safety Center turnaround time for an SOE application is 30 days. The SOE application must be approved prior to scheduling a certificate of compliance exam, and local Coast Guard offices must be notified a minimum of seven days prior to the COC exam. Foreign vessel owners should submit their Subchapter O endorsement applications with due consideration for these timelines.

Once the vessel successfully completes a certificate of compliance exam, the operator will receive the Subchapter O endorsement and certificate of compliance.

Updates and Notifications

Subchapter O endorsement updates are only required if there is a change in the cargoes authorized for carriage or

if modifications are made to the cargo containment system. In these cases, the vessel's owner only needs to submit the updated International Maritime Organization Certificate of Fitness and the modified class-approved engineering plans. The local Coast Guard office can handle changes to the vessel name, issuing officer, issue date, and expiration date.

Invalidation

The SOE is considered invalid if the vessel does not have a current IMO COF with annual signatures from the flag state or accepted classification society, if the vessel suffers a marine casualty affecting the cargo containment system, or if a Coast Guard representative considers the vessel unsuitable to carry the authorized cargoes and invalidates the Subchapter O endorsement and/or the certificate of compliance.

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For more information:

Visit: homeport.uscg.mil > Marine Safety Center > Services > Subchapter O Endorsement.



Shifting the Rudder?

Charting LNG export on U.S.-flagged LNG carriers.

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Thus far, the American Energy Renaissance has seen remarkable growth, with encouraging forecasts. Whether spurred by foreign investment or geopolitical pressure, the scramble to export low-cost U.S. liquefied natural gas (LNG) is underway, and a renewed initiative could shift the dynamic on how it is transported downstream in the hopes of similarly buoying U.S. shipping. However, the absence of a qualified U.S.-flagged fleet remains a challenge for the seaborne domestic and international LNG trade.

Market Shift

The American energy crisis of the 1970s prompted LNG import terminal construction, and producers such as Trinidad and Tobago accounted for a majority of American imports as recently as 2013.¹ Today's outlook is much different. As a result of the current domestic shale gas boom and increased domestic natural gas supply, legacy importers are eyeing export potential and have sought approval to build liquefaction facilities to convert domestic gas to its liquid form for transport on ships.

Fortunately, the United States is no stranger to the liquefied natural gas export market. The first transoceanic LNG cargo was shipped from Lake Charles, Louisiana, to the United Kingdom in 1959 on a converted World War II cargo ship.² The first purpose-built LNG export terminal in the United States was commissioned in the late 1960s on the Kenai Peninsula in Nikiski, Alaska. At the time it was the largest plant in the world and the first to serve the Asia-Pacific market, primarily Japan. Following a shuttering in 2011, the plant was brought out of mothballs in 2013 and rejoined the export market with a potential to meet future market demand in the contiguous United States and Hawaii.³

The Maritime Sector

In October of 2014, Coast Guard Commandant Admiral Paul Zukunft noted:

“One development that I’m paying close attention to is the American Energy Renaissance. Just a year

ago... who would have guessed that the United States would be ahead of Saudi Arabia and Russia for oil production today? The United States now produces 14 percent of the world’s hydrocarbon liquids—oil, condensate, and natural gas liquids—and we produce 20 percent of the world’s natural gas. According to estimates, we’re producing roughly 2 million barrels of oil a day more than we were a year ago.”⁴

Mr. Mark Tabbutt of the American Maritime Partnership, a coalition that represents all segments of the domestic marine industry, expressed these sentiments to the U.S. House Subcommittee on Coast Guard and Maritime Transportation: “We have inland shipyards in this country that are building and launching, on average, almost a new barge every single day of the year. New tugs and towing vessels are also being built to handle that increased demand.”⁵

He went on to explain that the largest sector of our domestic marine transportation industry supports the movement of crude oil, refined petroleum products, and other chemicals. He noted that this sector has seen dramatic growth as a result of the shale oil revolution, with new vessel construction orders being taken at a record pace and new vessel order bookings at American shipyards filling fast.⁶

By contrast, U.S. tonnage engaged in international trade has declined. Data from the U.S. Maritime Administration (MARAD) shows that the 1955 U.S. international fleet was comprised of 1,072 merchant ships, which amounted to approximately 25 percent of world tonnage (approximately 13 million deadweight tons). By 2014, MARAD reports a total of 191 U.S. merchant ships, representing approximately 2 percent of the current global maritime shipping tonnage (approximately 9 million deadweight tons).⁷ This comes at a time when the oceangoing U.S. merchant fleet, a key component in civilian commerce and American military readiness, faces a disparity in operating and labor costs when compared with perceived cost-competitive foreign alternatives.⁸

However, LNG exporters warn against increased U.S. construction and operational costs on what is otherwise seen as a low-cost and competitive commodity. These can be substantial factors in a tight market, where shipping costs are largely correlated to the distance between liquefaction and regasification depots and compensating for the geographic proximity of regional competition is essential.

Made in America

Adding to matters is the Merchant Marine Act of 1920. Commonly referred to as the Jones Act, it is the federal statute that regulates coastal domestic maritime commerce between U.S. ports and requires goods and passengers be transported by U.S.-made ships, owned by U.S. citizens, and crewed largely by U.S. citizens. This includes unrestricted coastwise trade between continental U.S. ports, Alaska, Hawaii, and Puerto Rico.⁹

In the early 1970s the U.S. government backed U.S. LNG carrier construction through MARAD Title XI loan guaranties. Ultimately, 16 vessels were built, although three never saw service in the liquefied natural gas trade. The last U.S.-flagged LNG carrier was delivered in 1980. Subsequently, those LNG carriers have all reflagged and registered under other flags such as the Marshall Islands, Bahamas, Norway, and the Isle of Man, with the last leaving the fleet around 2002 (see chart). Today, there are currently no U.S.-flagged LNG carriers, nor are there any planned for construction.

Recent proposals, including the draft legislation “Growing American Shipping Act of 2014,” would promote liquefied natural gas exports on U.S.-flagged vessels. However, there is growing opposition from international organizations who don’t want to see U.S. Jones Act restrictions extended into international trade. Regardless, an alternative legislative provision to study the impact of U.S.-flagged LNG shipping, in favor of a direct “Made in America” clause, has been adopted.¹⁰ Considering the five-year estimate to get

U.S.-built LNG Carriers

Year	Original Name	Shipyard	Containment System	IMO/U.S. O.N. Flag Status (Equasis 12/2014)
1977	LNG AQUARIUS	General Dynamics, Quincy, MA	Moss Spherical Tank Systems	7390181/582506 Indonesia
1977	LNG ARIES	General Dynamics, Quincy, MA	Moss Spherical Tank Systems	7390193/588005 Scrapped 4/2014
1978	LNG GEMINI	General Dynamics, Quincy, MA	Moss Spherical Tank Systems	7390143/595752 Marshall Islands
1978	SOUTHERN	Newport News, VA	TZ Mk1 System	7391197/591902 Scrapped 2/2013
1978	ARZEW	Newport News, VA	TZ Mk1 System	7391202/598727 Scrapped 12/2012
1979	GAMMA	Newport News, VA	TZ Mk1 System	7391214/598730 Norway
1978	LNG CAPRICORN	General Dynamics, Quincy, MA	Moss Spherical Tank Systems	7390208/588006 Marshall Islands
1978	LNG LEO	General Dynamics, Quincy, MA	Moss Spherical Tank Systems	7390155/595753 Marshall Islands
1979	LNG TAURUS	General Dynamics, Quincy, MA	Moss Spherical Tank Systems	7390167/595754 Marshall Islands
1979	LNG VIRGO	General Dynamics, Quincy, MA	Moss Spherical Tank Systems	7390179/595755 Marshall Islands
1979	LNG LIBRA	General Dynamics, Quincy, MA	Moss Spherical Tank Systems	7413232/595756 Marshall Islands
1979	EL PASO SAVANNAH*	Avondale, LA	Conch System	7390727/598731
1979	EL PASO COVE POINT*	Avondale, LA	Conch System	7390739/598729
1979	EL PASO COLUMBIA*	Avondale, LA	Conch System	CG005507
1980	LAKE CHARLES	General Dynamics, Quincy, MA	Moss Spherical Tank Systems	7619587/619531 The Bahamas
1980	LOUISIANA	General Dynamics, Quincy, MA	Moss Spherical Tank Systems	7619575/619532 The Bahamas

* Never saw LNG service. Information from MISLE and Equasis databases.

a conventional LNG tanker built and in service, it does not appear that there is an immediate solution for new construction.

The new construction dilemma does not necessarily preclude reflagging originally U.S.-built LNG carriers and requalifying them for coastwise trade. Nor does it forestall foreign-constructed LNG carriers from reflagging under U.S. registry endorsements for the sole purpose of foreign trade (export) if otherwise qualified. The precedent was established in the America’s Cup Act of 2011, which granted waivers to reissue coastwise endorsements to three previously U.S.-constructed LNG carriers now in a position to reflag, should legislative mandates become a reality or



coastwise domestic demand materialize. Absent either, the current market doesn't necessarily support the demand for U.S. tonnage.

In the interim, speculation has centered on whether would-be U.S. liquefied natural gas shippers would consider diversifying their portfolios to include atypical cargoes such as liquefied petroleum gas (LPG). Currently the global market for LPG is 30 percent larger than the market for LNG, and the U.S. is exporting more than 500,000 barrels of LPG a day.¹¹

U.S.-sourced liquefied petroleum gas is largely the result of the domestic natural gas conditioning process and is a byproduct of oil refining. However, the export share is largely influenced by an international market not necessarily subject to U.S. cabotage laws. In 2013, the Coast Guard experienced a 26 percent increase in foreign LPG vessel certificate of compliance exams. This increase was 15 percent greater than the previous busiest year on record. Current industry forecasts indicate that the 2013 LPG certificate of compliance exam workload could double or triple in 2015 and beyond.¹²

Domestic Challenges

Recognizing the diversity in the U.S. natural gas market, American LNG export presents similar challenges in the domestic trade. This is especially germane as Hawaii and U.S. island territories, such as Puerto Rico, look to lower energy costs and diversify fuel supply, transitioning petroleum energy consumption and primary power generation sources to natural gas. Natural gas appeals as a clean-burning source of energy, which is less carbon-intensive than either coal or oil, to fuel residential, commercial, institutional, industrial, and transportation sectors. Similarly, Alaska is in a position to enter the domestic liquefied natural gas trade to export to the continental U.S. and Hawaii. This also presents challenges when it comes to the lack of available vessels qualified for coastwise LNG trade.

In larger markets, plans include significant infrastructure enhancements, including a floating liquefied natural gas import terminal off the coast of Puerto Rico. Generally, the Puerto Rico Electric Power Authority purchases most of its natural gas from Trinidad and Tobago, transported via foreign-flagged vessels.¹³ The idea of low-cost U.S.-sourced natural gas presents an inviting prospect, albeit complicated by the absence of qualified vessels. U.S. shipping statutes do provide some flexibility under a specific trade provision for LNG movement to Puerto Rico from the U.S. mainland.¹⁴ Despite legislative authorization, U.S.-flagged vessels have not been employed in the Puerto Rico LNG trades because

domestically sourced liquefied natural gas is not yet available for delivery into Puerto Rico due to the regulatory and construction timelines associated with export liquefaction projects.

Bulk liquefied natural gas shipments are not practical in all markets, especially where quantities surpass the capacity and absorption rates of some island economies. In this regard, small-scale LNG imports by way of standardized cryogenic shipping containers may provide an alternative to the costly investment associated with regasification and distribution infrastructure. Further, advances in LNG containment systems may present added possibilities for small-scale bulk liquefied natural gas imports via articulated tug and barge (ATB) combinations.

Envisioned for limited trade in coastal and island markets, advantages include lower construction and operational costs when compared with conventional LNG carriers. This arrangement also conforms to the "drop and swap" method, whereby a laden barge may serve as a storage unit while the tug returns an empty barge for loading. Additionally, the ATB concept could leverage Jones Act shipyards to construct new vessels with LNG containment technologies for qualified coastwise trade.

Liquefied petroleum gas, on the other hand, is transported regularly on specialized tank barges throughout the U.S. western river system. Unlike LNG, LPG does not require complex liquefaction or regasification facilities and can be transported as a liquid in purpose-built pressurized containment or in smaller quantities in International Standards Organization (ISO) containers. On a larger scale, there are currently no U.S.-flagged LPG carriers available for service within the Jones Act trade. However, the new construction dilemma associated with bulk LNG containment technologies may not be as prevalent considering LPG's transportation properties.

On the contrary, there is currently no prohibition to a foreign-constructed liquefied gas carrier receiving a U.S. registry endorsement, if otherwise qualified under U.S. law, while operating in noncoastwise trade. Absent a precondition for U.S. construction, employing modern gas carriers (albeit foreign-constructed) under U.S. registry could be an option in the interim. Nonetheless, a sustainable pool of specially trained and qualified U.S. mariners will be necessary to crew the gas carrier fleet. Developing and maintaining this contingent may present certain challenges in the early stages of fleet development, though access to foreign-flagged gas carriers has provided training and experience opportunities for American mariners.

Open Market Shipping

Capacity aside, the International Chamber of Shipping has voiced concern over a perceived cargo reservation and prioritization for U.S.-flagged vessels as well as a potential incursion of the Jones Act into international trade.¹⁵ Additionally, in what has been largely viewed as a liberalized shipping market accentuated by the connection of major energy and manufacturing companies in principal importing countries, competing national strategies pose an added hurdle for entry in the global market and the ambition to advance a U.S.-flagged LNG carrier fleet. Customarily, the tanker owners have been companies controlled by gas producers as well as importers, which favor long-term contracts. However, as the dynamic shifts and legacy importers realize a greater share of exports, short-term markets may become more commonplace. As the U.S. explores the feasibility of exporting liquefied natural gas on U.S. carriers, the reality is that major U.S. LNG consumers have already angled in favor of their own import interests.

Principally, India and South Korea have maneuvered to impose import registry and construction requirements to boost their respective shipping industries. Under the Indian plan, nine new builds will be chartered, three to be built in Indian shipyards, to import approximately 5.8 million metric tons of U.S. LNG a year for 20 years, starting in 2017.¹⁶ The South Korean strategy similarly imposes carriage requirements by South Korean shippers on six Korean-built LNG carriers to import 2.8 million metric tons per year for 20 years.¹⁷

Prospective

In summary, the growing export potential for American energy presents a certain paradox when correlated with the decline of oceangoing U.S. merchant tonnage. Despite some ancillary factors, there appears to be a global demand for low-cost, U.S.-produced energy such as natural gas. The question is whether or not U.S. shipping can muster sustainable and cost-effective capacity to capitalize on this export growth potential in time.

While foreign energy importers and consumers have already invested in a modern seagoing network with a view of bolstering their national shipyards and fleets, closer to home, domestic shippers grapple with how to bring American natural gas to market without a suitably qualified fleet for

coastwise trade. Understanding these emerging opportunities coupled with an appreciation for the evolving challenges is necessary to implement a comprehensive strategy necessary to leverage a competitive advantage with the collective interests of American energy producers, consumers, and shippers at the forefront. One thing is certain—the market will remain unpredictable and possibly volatile.

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Liquefied Gas Barges

Bunker and cargo considerations.

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Liquefied natural gas (LNG) has arrived on the maritime stage as a viable fuel, due in part to increasing regulatory pressure for cleaner air emissions. For this reason as well as long-term economic benefits and the desire for environmental leadership, the maritime transportation sectors have begun to evaluate LNG as a fuel option.

LNG is a unique cryogenic liquid stored at temperatures of about -162°C . It can't be delivered to many destinations that need it via existing fuel supply networks, so suppliers must develop new infrastructure to form a liquefied natural gas supply network. Further, this new infrastructure must include liquefaction, storage, transportation, and distribution capabilities. As much of the developing infrastructure will be project- and end user- specific, the typical maritime LNG consumer requires an option that can store liquefied natural gas as well as transport and distribute it to vessels.

Options

Three liquefied natural gas bunkering options seem most likely:

- trucks,
- pier-side storage facilities,
- barges.

There are advantages and challenges with each method. For example, trucks can transport LNG to various ports, but they cannot accommodate large quantities, and transfer

rates are relatively slow. Depending on the size of the ship, small loads will require multiple transfer operations. This raises risk, since it increases the number of times personnel interface with the cryogenic cargo. Additionally, trucks travel along roadways, which increases land transportation risk.

Pier-based storage tanks can accommodate large quantities, but they are capital-intensive and lack mobility.

Barges have many desired capabilities, including:

- mobility,
- relatively high loading rates,
- sufficient capacity for most gas-fueled ships.

Barges could potentially bunker liquefied natural gas, shuttle liquefied natural gas cargo along coastal routes, meet deep-draft vessels for ship-to-ship transfer at sea, and deliver LNG cargo to whichever port has the best commercial opportunities.

Tank Design

Today, Coast Guard personnel are frequently in conversation with industry members, barge designers, owners, and investors who ask about what requirements LNG barges must meet to be granted Coast Guard approval. Given LNG's unique properties, designers need comprehensive guidance before they can move forward. LNG bunker barge designers must first decide which containment system will be employed. This will have a wide-ranging impact on many elements of the barge design, including the vessel arrangement, inspection access, and what operating equipment will be required.

Additionally, there are several different types of liquefied natural gas fuel storage tanks. LNG tanks can be independent tanks, which include Type A,



An example of an LNG bunker barge. Image courtesy of GTT North America.

B, and C tanks. LNG tanks can also be non-independent tanks, which include the membrane and semi-membrane types.

Tank Types

The International Code for the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk (IGC Code) defines three categories for independent LNG tanks, which are self-supporting tanks that do not rely on a ship's structure for strength.

Type A independent tanks: are designed primarily using recognized standards of classical ship structural analysis, constructed of a plane surface, and prismatic in shape. The IGC Code, where the minimum design temperature is below -10°C , requires a complete secondary barrier capable of containing the cargo for a period of 15 days in the event of a ruptured or leaking tank.

Type B independent tanks: use model tests and refined tools and analysis methods to determine stress levels, fatigue life, and crack-propagation characteristics. A partial secondary barrier, which can consist of a spray shield and drip pans, is required for independent Type B tanks with minimum design temperatures below -10°C .

Type C independent tanks: are pressure vessels that are designed for pressures greater than two bar¹ and are cylindrical or spherical. Type C tanks can be designed for much higher vapor space pressures than Type A and Type B tanks, and they don't require a secondary barrier.

Membrane, or non-independent tanks: are non-self-supporting tanks that consist of a thin layer (called a membrane) supported through insulation by the adjacent hull structure. This containment system requires a complete secondary barrier capable of containing the cargo for 15 days.

Semi-membrane tanks: are non-self-supporting when loaded. Only parts of the tank are supported (through insulation) by the adjacent hull structure, whereas the rounded parts of this layer connecting the supported parts are designed to also accommodate thermal and other expansion or contraction.

The majority of proposed LNG tank barges utilize either Type C tanks or membrane tanks.²

Another unique challenge for the LNG bunker barge is the large variation among ships the barges plan to serve. Transfer pipes and connections have yet to be standardized, fuel-loading flange access and location may vary greatly, and vapor management systems may also differ for each vessel.³

Regulatory Challenges

The Coast Guard must anticipate quickly advancing technologies in the LNG maritime domain to ensure adequate safety requirements for this valuable product stream. From a regulatory perspective, liquefied natural gas cargo transport has a 50-year history. Classification rules, international regulations, and flag state requirements that support the ship design, construction, and service are mature. However, as a virtually new asset class, LNG bunkering barges face several technical and regulatory challenges, including:

- new vessel specifications and service requirements,
- bunkering practices to transfer the LNG from the barge to gas-fueled ships,
- developing new regulations surrounding LNG transport by barge.

For example, 46 CFR Subchapter D regulations are not suitable for LNG's cryogenic temperatures. While there is guidance for cryogenic cargoes in 46 CFR Subchapter O—Certain Bulk Dangerous Cargoes Part 154, safety standards for self-propelled vessels carrying bulk liquefied gases, they are applicable to self-propelled vessels only, thereby excluding barges.

Although guidance is also available in international maritime standards (the IGC Code applies to liquefied gas carriers), barges differ from liquefied gas carriers (LGCs) in a number of critical areas, including:

- regulatory applicability,
- propulsion,
- size,
- manning and personnel,
- voyage length and routes,
- primary flag state.

LGCs are generally larger than barges and can carry up to 10 times more cargo than a typical barge. LNG carriers' cargo capacities range from 18,800 m³ to 266,000 m³, with a fleet average LNG capacity of 153,000 m³.⁴ By contrast, proposed LNG barge capacities are currently projected to be between 1,000 m³ to 20,000 m³.^{5,6} The only U.S.-flagged LNG barge, the barge *Massachusetts* (no longer in U.S. service), was 5,000 m³.⁷

Another difference between LGCs and barges is their flag and operating zone. Barges are generally domestic vessels, or U.S.-flagged, and are likely to operate in U.S. coastal waterways. This is unlike most LGCs, which are foreign-flagged and travel internationally, triggering IGC applicabilities. As such, the barge community may use current U.S. LNG carrier regulations and the IGC Code as guidance,

continued on page 51



Chemical Transportation Advisory Committee Recommendations

In 2013, the Coast Guard tasked Chemical Transportation Advisory Committee (CTAC) members to provide their recommendations on appropriate LNG barge design standards. To accomplish this, the Chemical Transportation Advisory Committee held seven public meetings, spanning two years, to collect information for their report.

CTAC recommended that 46 CFR Part 154— Safety Standards For Self-Propelled Vessels Carrying Bulk Liquefied Gases— be used as a basis to develop LNG barge standards. The CTAC recommendations are applicable only to barges on domestic routes, unmanned vessels, LNG transport in bulk, vessels dedicated to LNG carriage only, and those that do not supply power or fuel from a barge to towing vessel. In summary, the main areas of focus for the CTAC modifications are:

- materials,
- cargo containment systems,
- electrical requirements,
- firefighting,
- gas detection,
- safety equipment.

All LNG barges must meet requirements in 46 CFR Subchapter D— Tank Barges. The Chemical Transportation Advisory Committee also recommended applying modified versions of 46 CFR 154 subparts C and E to LNG barges. CTAC's recommendations differentiated between unrestricted and restricted, or ocean-going and inland barges, respectively.

Modifications to subchapter D and subpart C and E of 46 CFR 154 are summarized as:

- Barge hull structures should meet requirements in 46 CFR part 154 subpart C, except unrestricted barges may use American Bureau of Shipping (ABS) Rules for Building and Classing Steel Barges and inland barges may use the ABS Rules for Building and Classing Steel Vessels for Service on Rivers and Intracoastal Waterways. Where appropriate, operators should also use applicable portions regarding LNG from the ABS Rules for Building and Classing Steel Vessels. Equivalent rules from other recognized classification societies may be substituted for ABS rules.
- Barges in unrestricted service must meet the requirements for stability and cargo tank location in 46 CFR 154 subpart C; however, restricted barges can use 46 CFR part 172 subpart E.

- Cargo containment systems of all barges are suggested to meet the requirements in 46 CFR part 154 subpart C. Inland barges may use the dynamic load calculations outlined in part §38.05-2, but unrestricted barges are required to meet the dynamic loads in section §154.409.

The following recommended modifications to 46 CFR 154 subchapter O apply to all barges, whether restricted or unrestricted:

- Equipment using liquefied natural gas as fuel on the barge may meet the requirements in 46 CFR part 154.705-709 or CG-521 Policy Letter 01-12 Equivalency Determination— Design Criteria for Natural Gas Fuel Systems.
- The electrical system requirements have been significantly modified to align with the international standards for electrical equipment in hazardous spaces. In particular, hazardous zones have been redrafted. Current hazardous zones under 46 CFR 154 are either “gas safe” or “gas dangerous.” The CTAC recommendations divide the hazardous zones into four categories:
 - Zone 0 is a hazardous location in which an explosive gas or vapor in mixture with air is continuously present or present for long periods.
 - Zone 1 is a hazardous location in which an explosive gas or vapor in mixture with air is likely to occur in normal operating conditions.
 - Zone 2 is a hazardous location in which an explosive gas or vapor in mixture with air is not likely to occur in normal operating conditions, or in which such a mixture, if it does occur, will only exist for a short time.
 - Nonhazardous spaces are gas-safe.
- Unlike subchapter D barges, for which no fixed firefighting is required, LNG barges should have basic firefighting capabilities, including water spray and dry chemical systems.
- Barges should meet the gas detection requirements of 46 CFR 154 subpart C, with some modifications that require the capability to monitor and control cargo tanks and equipment on the barge from remote locations, such as the towing vessel or land-based facility.
- Additionally, barges' essential first response gear should include personal protective and rescue equipment.

but many regulations may not be practical or applicable to barges' specific needs.

To address this void, Coast Guard personnel consulted with the Chemical Transportation Advisory Committee⁸ and members of the public to obtain recommended design standards for barges carrying LNG in bulk, and Coast Guard personnel are preparing a policy letter to guide submitters in LNG barge design. In the meantime, submitters may still provide proposals to the Marine Safety Center, under the existing rules, and request a design basis to clarify detailed design issues or alternative arrangements.

The next generation of LNG barges is coming. The Coast Guard, through industry partnerships, is proactively developing guidelines to ensure safe development for this fuel option. The transition to liquefied natural gas fuel will pose new risks for the maritime community, but it is also a promising new option for our environment and economy. Since the move toward its wide adoption calls for a responsible approach, the goal should be profitable, productive, and innovative use that focuses on safety, responsibility, and protection.

Acknowledgements:

Special thanks to Dr. Cynthia Znati, lead chemical engineer, USCG Hazardous Materials Division, and Mr. Kevin Storm of Global Gas Solutions/the American Bureau of Shipping for their assistance.

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Mr. Roy Bleiberg is the director of U.S. Gas Development for the American Bureau of Shipping, contributing more than 24 years of global marine and offshore systems experience to the position as well as an in-depth knowledge of U.S. federal and state regulatory requirements.

Endnotes:

- ¹ IGC 4.2.4.
- ² TRB AW010(1), New Technologies for the Marine Highway, Jan. 14, 2013.
- ³ Reference to the ISO Technical Specification ISO/TS 18683, "Guidelines for systems and installations for the supply of LNG as a fuel to ships," issued in Jan. 2015, may be helpful.
- ⁴ T. Colton, LNG Carriers in Service or on Order, May 8, 2015. Retrieved July 31, 2015, from Ship Building History: www.shipbuildinghistory.com/history/highvalue-ships/lngactivefleet.htm.
- ⁵ Argent Marine, "Small Scale Distribution of LNG." Retrieved July 31, 2015, from Our Business: www.argentmarine.com/lngsmall.html.
- ⁶ LNG America, "Bunker Barges." Retrieved July 31, 2015, from "Solutions": www.lngamerica.com/lng-barge.
- ⁷ CH-IV International, The LNG Specialists, Feb. 8, 2012. "Safety History of International LNG Operations: CH-IV International Document: TD-02109, Rev. 12." Retrieved July 31, 2015, from www.ch-iv.com/assets/documents/Safety%20History%20of%20International%20LNG%20Operations.pdf?/pdfs/Safety%20History%20of%20International%20LNG%20Operations.pdf.
- ⁸ CTAC serves as an advisory committee to the Coast Guard on matters relating to the safe and secure maritime transportation of hazardous materials activities in so far as they relate to matters within the Coast Guard's jurisdiction. CTAC members represent points of view from chemical manufacturing, marine handling or transportation of hazardous chemicals, vessel design and construction, marine safety or security, and marine environmental protection.



Safe Transport

LNG shipping history.

by MR. ANDREW CLIFTON
General Manager

Society of International Gas Tanker and Terminal Operators Ltd. (SIGTTO)

Shippers first transported liquefied natural gas (LNG) across the Atlantic in 1959. By 1964 the first purpose-built LNG carriers, the 27,400 m³ *Methane Princess* and *Methane Progress*, were in service under a 15-year gas purchase agreement.

In the 50-plus years since their first commercial shipments, LNG carriers have safely delivered more than 80,000 cargoes. These consignments all reached their destination without cargo containment system breach and with no onboard fatalities attributable to the cargo. This is a very

impressive (in fact, unprecedented) safety record for liquid hydrocarbon carriage by sea in bulk.

Safety Record

This exemplary safety record results from a strong, overarching safety philosophy; robust equipment and systems design; good operational and maintenance procedures; operating in excess of the minimum requirements and according to best practice guidelines; and high training standards, coupled with competency verification.

Other factors include the pioneers who developed design standards and operating procedures during the early days of liquefied gas shipping and who helped develop the International Gas Carrier (IGC) Code, based on experiences in the early days of LNG transport, and our industry's ability to share lessons learned and develop universally accepted best practices.

Technology

Although LNG carriers have been involved in grounding incidents, in no case was a cargo containment system breached. This achievement is a legacy of the extra safety margins the LNG shipping industry's founding fathers built into the original rules governing vessel design.



The *Methane Princess* is the first commercial LNG vessel; she entered service in 1964. Photos courtesy of the Society of International Gas Tanker and Terminal Operators Ltd. (SIGTTO).

Moreover, the liquefied natural gas shipping industry continues to expand and introduce new technologies. Larger ships with new types of propulsion systems are now in service, and the fleet continues to grow apace. For example, floating storage and regasification units and floating liquefied natural gas vessels are also now part of the industry.¹

Challenges

Of course, new technology can engender new challenges, including assuring trainers are able to provide the required number of trained and competent shore staff and vessel crews needed in an era of unprecedented growth.

Fortunately, Society of International Gas Tanker and Terminal Operators (SIGTTO) competency standards provide operators with guidance as to the specific competencies each crewmember should possess, with similar competency guidance available for terminal operators and their staff.

Outreach

Additionally, outreach is extremely important, as the public needs to understand that liquefied natural gas carriers are not “floating bombs.” As an example, in a potential fire accident, refrigerated liquefied gas can burn until fuel is consumed, but the tanks are highly unlikely to explode. These vessels are robust ships soundly designed, constructed, and well equipped with safety and emergency systems.

That said, liquefied gas cargo handling procedures can be complex, and the cargo itself is potentially hazardous. For these reasons, personnel operating gas carriers and gas berths require complete ship and shore equipment and cargo property knowledge. They also must follow good operating procedures that include emergency plans.



The floating storage and regasification unit is essential LNG infrastructure.

The industry members must continue to make appropriate use of the robust safety regime that has been established, and it is incumbent upon the shipping industry to adapt it to suit particular circumstances (such as using LNG as a marine fuel) to preserve the exceptional safety record the LNG shipping industry currently enjoys.

About the author:

Mr. Andrew Clifton is the Society of International Gas Tanker and Terminal Operators Ltd. (SIGTTO) general manager and chief operating officer. Previously, he was the SIGTTO panel chairman. He has more than 30 years of experience in the liquefied gas shipping industry, including 19 years at sea, three years at the UK's Marine Accident Investigation Branch, two years in the SIGTTO Secretariat as a technical adviser, and more than five years as LNG shipping operations manager for the BP Tangguh LNG project.

Endnote:

¹ These platforms allow the gas to be regasified on the unit itself.

For more information:

History and statistics courtesy of the Society of International Gas Tanker and Terminal Operators Ltd. Visit the website at www.sigtto.org.



LNG as Fuel

Projects and new design/operating standards.

by MR. TIMOTHY E. MEYERS, P.E.

*General Engineer
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Office of Design and Engineering Standards

MR. SCOTT V. LABURN

*Senior Marine Inspector
U.S. Coast Guard*

Liquefied Gas Carrier National Center of Expertise

Using natural gas instead of oil as a shipboard propulsion fuel is rapidly becoming a leading alternative for meeting domestic and international air emission requirements, including the limits for emission control areas adopted in recent amendments to the International Convention for the Prevention of Pollution from Ships Annex VI.

Current pricing and availability also makes natural gas competitive in comparison to more traditional marine fuels. However, with limited exception, existing U.S. regulations do not address commercial vessel natural gas fuel systems design or installation. Additionally, current Coast Guard regulations do not address the use of natural gas as fuel except as a means of controlling cargo boil-off on liquefied natural gas (LNG) carriers.

International Standards

There are, however, a number of standards (existing and under development) we can look to for guidance. The International Maritime Organization (IMO) is developing a code for gas fueled ships; the International Organization for Standardization (ISO) has guidance documents under development; and several of the major classification societies now have rules or guides for vessels that use natural gas as fuel.

The Coast Guard has taken an active role at the IMO in developing international standards for natural gas-fueled ship design. In June of 2015, the IMO adopted a new International Code of Safety for Ships Using Gases or Other Low-Flashpoint Fuels. Building off previous work published as interim guidelines under IMO Resolution MSC.285(86), this new standard will come into force as a mandatory code under SOLAS in January 2017.

We have also been involved with the ISO in developing new standards for natural gas as a marine fuel. For example, a recently published IMO technical specification provides guidance on bunkering safety for LNG fueling operations, and ISO's Technical Committee on Ships and Marine Technology is working to produce a second standard focusing on bunkering equipment, operational procedures, and fuel quality documentation.

Current Regulatory Landscape

Since using LNG as a marine fuel is relatively new in the U.S., there are no federal regulations to address shipboard gas-fueled systems. Initially, as the Coast Guard began to see design proposals back in 2011, this left such systems to be considered on a case-by-case basis, establishing equivalency to similar requirements under various vessel safety regulations. Eventually, requirements will be developed to cover using liquefied natural gas as fuel, but in the meantime, LNG-fueled vessel approval involves a concept review



Liquefied Gas Carrier NCOE personnel examine a cargo containment system mock-up. U.S. Coast Guard photo.

and developing a design basis that lays out the framework of standards and requirements in the absence of federal regulations. Requirements under this process are project-specific, can be based on a mix of standards, and reviews can tend to be very time-intensive.

In an effort to streamline this process and provide up-front design criteria that the Coast Guard will accept, in early 2012 the Coast Guard Office of Design and Engineering Standards published Commandant Policy Letter 01-12, which provides one avenue to determine an equivalent level of safety to the Code of Federal Regulations (CFR).

The policy uses the IMO interim guidelines as a baseline standard, and provides additional requirements to ensure an equivalent level of safety. It also lays out one set of design criteria for demonstrating equivalency, and is very prescriptive in some areas. We recognize, however, that there may be other means to achieve equivalency, and if a vessel design falls outside the policy's limits, the designer can still apply for concept review and a design basis approval on a case-by-case basis.

The good news is designers can skip the headquarters concept review and go straight to the Coast Guard Marine Safety Center for plan review and approval if they plan to meet the design criteria detailed under the policy letter.

Regulating Fueling Infrastructure

While the industry is still in the early stages of developing the infrastructure necessary to fuel such vessels, there are basically three different methods envisioned for supplying fuel to LNG-powered vessels. These include:

- using a fixed shore-side fueling terminal,
- refueling by tank truck,
- refueling by bunker barge/bunker vessel.

The Coast Guard has regulations in place under 33 CFR to address LNG transfer at shoreside terminals as well as

LNG-Fueled Vessel Projects by Region

Over the past four years, we have seen tremendous interest from industry in using liquefied natural gas as a marine fuel, with more than two dozen vessel projects in the planning, design, or construction phases. The following is a summary of the most active LNG fuel projects by geographic region.

Gulf Coast

In February 2015, a dual-fuel offshore support vessel became the first U.S.-flagged vessel to bunker with liquefied natural gas as well as the first LNG-powered vessel in the U.S. fleet certificated by both the U.S. Coast Guard and the American Bureau of Shipping. Main propulsion for this diesel-electric vessel is supplied by three dual-fuel diesel engines, rated at 7.5MW each. A single vessel storage tank, located amidships under the cargo deck, aft of the accommodations, supplies the engines with methane gas. The vessel is chartered to work in the Gulf of Mexico and will be homeported in Port Fourchon, Louisiana. The operator is also constructing the first U.S. LNG vessel bunkering facility at Port Fourchon, slated to become operational during the second half of 2015.

Also in February 2015, a shipyard in Orange, Texas, was awarded a construction contract to build an LNG bunker barge, which will be the first of its kind in the United States. This single-cargo tank barge will initially operate in the Puget Sound area to provide LNG fuel to two vessels that trade between Tacoma, Washington, and Anchorage, Alaska.

Florida, Puerto Rico

Construction began on the first of two LNG-powered ConRo vessels in January, 2015, at a Pascagoula, Mississippi, shipyard. Expected delivery of the first vessel is the second quarter of 2017. Cargo capacity will be approximately 2,400 TEUs, with space for nearly 400 vehicles in an enclosed roll-on, roll-off garage. Both vessels will trade between Jacksonville, Florida, and San Juan, Puerto Rico.

At a shipyard on the West Coast, construction is well underway on two liquefied natural gas-powered containerships, the first of their kind in the world. These 3,100-TEU vessels will sail between Jacksonville, Florida, and San Juan, Puerto Rico. Main propulsion will consist of a single, slow-speed, dual-fuel diesel engine. The LNG will be stored in two insulated storage tanks located aft of the accommodations and above the main deck.

Pacific Northwest

During the winter of 2015, one industry operator will convert existing roll-on, roll-off vessels to use LNG as fuel. They will feature 12-cylinder, dual-fuel engines and generator sets for the diesel-electric main propulsion system, and will use specialized technology to supply the associated automation and fuel gas-handling systems. The vessels will be fitted with two LNG storage tanks, and they will trade between the ports of Tacoma, Washington, and Anchorage, Alaska.

regulations that cover bunkering traditional liquid fuels. However, there are some gaps with regard to applying these requirements to LNG fuel transfers. Also, existing liquefied natural gas facility and transfer requirements were developed with large-scale cargo terminals in mind, not the smaller-scale fueling facilities expected to support LNG-fueled vessels.



In February 2015, the Office of Operating and Environmental Standards published two policy letters to address operational aspects of using liquefied natural gas as fuel and to provide clear guidance on how existing regulations will apply to LNG fuel transfers.

Since port-specific considerations often come into play, the local Coast Guard captain of the port makes final decisions with regard to facility requirements and bunkering operations. Therefore, anyone considering a vessel or facility project involving LNG fuel should start discussions early on with the Coast Guard sector office that has jurisdiction in their operating area.

Barge Design

The Coast Guard has also received proposals to use LNG barges as bunkering vessels or to transport liquefied natural gas from a source of supply to small-scale LNG fueling terminals. Work was completed in April 2015 on CG-ENG Policy Letter 02-15, Design Standards for U.S. Barges Intending to Carry Liquefied Natural Gas in Bulk.

The Coast Guard's Chemical Transportation Advisory Committee provided valuable input in developing this policy letter, which draws on existing requirements for barges carrying liquefied flammable gases under 46 CFR 38, as well as the self-propelled gas carrier requirements in 46 CFR 154. Designers may use the new policy to gain acceptance on certain LNG barge proposals without undergoing a complete vessel concept review.

Moving Forward

As the relatively new LNG fuel industry continues to mature and grow, the Coast Guard will further refine its policy, continue standards development work within the international community, and likely transition from providing policy guidance to putting into place a more permanent regulatory solution. Ultimately, this could include initiating a rulemaking to incorporate the provisions of the policy letters and international standards regarding designing and operating LNG-fueled vessels and associated LNG fuel bunkering operations. Such a project would build on knowledge gained in developing and implementing the

policies discussed above, close gaps in current regulations to address liquefied natural gas as fuel, and seek where possible to incorporate by reference applicable international standards.

About the authors:

Mr. Tim Meyers is the Coast Guard's lead engineer on regulatory and policy development for the safe design of natural gas-fueled vessel systems and represents the U.S. in developing the International Maritime Organization's International Code of Safety for Ships Using Gases or Other Low-Flashpoint Fuels. Mr. Meyers has more than 24 years of experience in enforcement, interpretation, and development of maritime safety and security regulations. He holds a bachelor's degree in applied science from the U.S. Coast Guard Academy, a master's degree in chemical engineering from the University of Virginia, and is a registered professional engineer.

Mr. Scott LaBurn is the Coast Guard's subject matter expert on vessels using LNG as fuel. He is also the Coast Guard's primary liaison to the Society of Gas as a Marine Fuel. Mr. LaBurn graduated from the U.S. Coast Guard Academy with a bachelor's degree in chemistry and has more than 40 years of maritime experience in shipboard and shoreside environments.

For more information:

History and statistics courtesy of the U.S. Coast Guard Office of Design and Engineering Standards and the U.S. Coast Guard Liquefied Gas Carrier National Center of Expertise.

CG-521 Policy Letter 01-12 is available for download from the Coast Guard Office of Design and Engineering Standards website at www.uscg.mil/hq/cg5/cg521.

OES Policy Letters 01-15 and 02-15 provide guidance on LNG fuel transfer operations, training personnel serving on those vessels, and an overview of existing U.S. regulations applicable to vessels and waterfront facilities conducting LNG marine fuel bunkering operations. The policy letters can be downloaded from CG-OES's website at www.uscg.mil/hq/cg5/cg522/cg5222/PolicyLetters.asp.

A Sea Change

A bright future for gas-fueled shipping.

by MR. MARK BELL
General Manager

The Society for Gas as a Marine Fuel

Gas as a marine fuel has a future, and will assume a significant proportion of the increasing number of marine fuels that are becoming more available to the ship operator. Gone are the days where one fuel fits all, and it is clearly no longer acceptable for the global maritime fleet to be the convenient end user of what is left at the bottom of a barrel of oil. This is neither sustainable nor acceptable in a world with ever-growing environmental concerns.

It is also fair to say that the shipping industry itself is conservative and perhaps slow to change, and rightly so. It has been around for a long time, and although ships themselves have become more efficient, an overnight switch to alternative fuels was never in the cards.

The rate of progress is improving, however—it took a long time to evolve from oars to sail, less time from coal and steam to oil and diesel. It won't be so long for the switch to gas and other alternatives, but at the same time, gas will not suit every application. It is the last natural hydrocarbon fuel available to us, though, and if used correctly, will even reduce CO₂ emissions.¹

So far in this industry, Europe has been driven by subsidy, North America by price and availability. Asia has a mix of both, perhaps, but geography also plays a large part and will certainly continue to do so. Put yourself in the position of the owner or operator deciding on your next asset in shipping. You are there to make a profit, and however you look at it, your fuel bill is going to be in the region of 35 to maybe 65 percent of your operating costs. There are perhaps 10 major factors that are going to change, sometimes quickly and unpredictably—all or any of which will affect your project directly. This

gives some idea as to why the industry appears somewhat slow to embrace gas as a marine fuel. Additionally, as land-based industries have been quick to switch and continue to dominate the global use of gas as a fuel, the ship fuel market has competition for gas and is a relatively small newcomer to the scene.

The Outlook

Toward the end of 2014, changes in the near-term outlook for gas in the marine market have had an adverse effect on new gas-fueled marine sector projects. However, the longer-term outlook remains favorable, as gas is seen as a fuel that can meet all the upcoming regulatory changes.

Further, the dramatic reduction in crude prices since August 2014, with relatively little change in liquefied natural gas (LNG) prices, has tilted the balance in favor of scrubbers, particularly for retrofits. Scrubbing the exhaust gas means literally washing out the sulphurous oxides by forcing the hot exhaust gas through a falling curtain of water. Scrubbers typically fit around the funnel, so space and weight



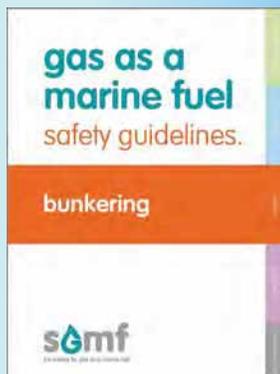
An LNG-powered ship. Photo courtesy of Scott Pittman Photography.

Guidelines

SGMF's technical committee consists of six work groups that are looking at important issues that need to be solved or raised as a priority.

Bunkering

Regarding operational issues between the parties supplying and receiving the fuel, the group has focused on the operation itself by drawing upon the experience gained in the marine gas cargo sector over the last 50 years and applying that to the bunkering operation.



Guidelines published in March 2015 address procedures, situation-specific areas, and examples of industry best practices.

Quality and Quantity Issues

It's crucial to get certain things right from the start, such as looking at all of the issues and best practices surrounding quality and quantity within the gas industry and marine fuel industry and laying down from the outset the best ways to get things right.

Of course, gas has fewer quality concerns when compared to the problems shipping has faced with residual marine fuels over the years, but the gas industry measures by calorific value, whereas the shipping industry has traditionally used volume.

SGMF expects to publish this work for its members by the end of 2015.

are considerations; additionally waste product disposal also needs to be taken into account. This is a convenient but expensive short-term solution, especially for a retrofit, but makes much less sense for a new build, so much so that some of these have been postponed.

However, the practice of dumping sulphur into the oceans rather than the atmosphere or costly removal ashore (though permissible right now) can only be short-term solutions. Energy prices will equilibrate over the longer term, encouraging ship owners to consider LNG as a fuel, especially for new builds.

Factors affecting the decision:

- An immediate need for ship owners to prepare for regulatory compliance as of January 1, 2015, with the change

in emission control area (ECA) sulphur to 0.1%. Owners have decided between using ECA-compliant fuels or installing scrubbers. There appears to be apathy among charterers and owners about the long-term implications, even despite the looming Tier III requirements and the 2020 global sulphur cap.²

- The current lack of LNG bunker supply vessels or equivalent infrastructure makes it look as if fuel supplies will be inconvenient and costly.
- A bewildering mix of codes and regulations, depending on whether you are short sea, deep sea, coastal, harbour, or inland waterways. Likewise, the liaison with land-based regulation does not help the decision process.

Crude Price — Partial Eclipse

Let's be clear that, certainly as far as fossils fuels are concerned, there is no such thing as cheap energy. For the future, gas demand is going to be stronger than that of oil. However, the investment in gas is initially higher, especially for cryogenic distribution.

While the initial pump price can make gas irresistible, the truth is that there's a distribution premium to be paid to get it into your ships' tanks. So, while the price of crude remains low, the differential to gas is high, meaning you may leave your decision to later. However, whatever the reason for the current low crude prices, history tells us prices will go back up, perhaps to never come down again, and when the price does rise, this partial eclipse will be over.

In a cruel twist, making cutbacks now for gas supply in the future could be felt just as global sulphur cap discussion and regulation will be topping the agenda around 2019–2020.³

Distribution

There are approximately 81,000 ships on the planet,⁴ some 52,000 of which are larger than 500[GT]. Our best estimates over the next generation of new builds—let's say seven to 20 years—is that 11 percent of that fleet will run on gas.⁵

Right now, there are approximately 8,000 ports around the world with a coastline or river inland waterway. You can buy oil practically anywhere, but at SGMF, we count 14 ports able to supply LNG now or in the immediate future. While there is a high infrastructure cost involved, there is also a marvelous opportunity to lay out the distribution from scratch and take advantage of providing the fuel in the most efficient places.⁶ When you tie this with natural shipping geographies and new gas transshipment projects, things get very interesting.

What we see right now, however, is short sea trade and back-to-back liner trade, as is found in much of Northern Europe.

As early adopters, distribution is relatively easier there. In North America, the dash for gas is seeing a rapid rise in availability and the first projects in the water during 2015.

Moving Forward

In summary, this has been a period of enlightenment for the maritime industry, and as the partial eclipse of low crude prices passes, the benefits of gas as fuel are illuminated once more. The oil-dependent economy that we have today cannot sustain itself on low prices, as prices will come back, perhaps never to go down again. The oil peak has passed, while the gas peak is yet to come, with hundreds of years' supply still available.⁷

While it has much to gain from using gas as a fuel, shipping has significant competition from other industries. North America has abundant gas supply and will rapidly overtake Europe in its use across all sectors. While the maritime industry is joining the party, there is a job to do to harmonize with standards. Shipping, by its very nature, is an international business, and perhaps it is the international framework that can at last undertake this complicated dance.

About the author:

Mr. Mark Bell is the general manager of the Society for Gas as a Marine Fuel. He is a chartered marine and mechanical engineer and has spent a total of 16 years with the class societies Lloyd's Register and Det Norske Veritas (now DNVGL). He spent three years with the UK Ministry of Defence and also has experience as a ship and engineer surveyor, area manager, business manager, and director. He gained seagoing experience on tankers including gas ships as well as the steam and motor variants.

Endnotes:

- ¹ UASC/Technolog A15,000 TEU new builds over A13 existing vessels 22% CO² reduction; A18,000 TEU over A13 vessels 36% CO² reduction.
- ² Additional NO_x abatement technology will need to be fitted to most vessels to achieve Tier III compliance, typically via a catalytic process based on injecting urea into the exhaust gas.
- ³ Global Marine Fuel Sulphur cap of 0.5% in 2020 or 2025 depending upon low sulphur fuel availability study proposed for 2018 adoption at MEPC 72.
- ⁴ "The World Merchant Fleet in 2013," Equasis, August 2014.
- ⁵ "Global Marine Fuel Trends 2030," Lloyd's Register and UCL Energy Institute, 2015.
- ⁶ Singapore, Suez, Panama, Hong Kong, Gibraltar, and some English Channel entrance or existing ports meet these criteria.
- ⁷ M. King Hubberts' theory that "peak oil" is the period whereby the maximum extraction rate of oil is reached and thereafter forever declines.

For more information:

SGMF was established at the end of 2013 as an industry-based organization to assist with the safe and prosperous use of gas as a marine fuel.

Visit the website at: www.sgmf.info/.



Environmental Response in a New Crude Landscape

Responding to oil sand product spills.

by MR. KURT HANSEN
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Over the past five years, the nation has experienced an increase in unconventional petroleum product transportation. One such product is a fuel known as diluted bitumen or dilbit, which is created by blending the dense and viscous bitumen found in Canadian oil sands with lighter hydrocarbon products known as diluents. This reduces the bitumen's density and viscosity, which allows it to flow in transport, and may add complexity to potential spill response, as compared to more conventional crude oils.

Actual dilbit spill information and lessons learned are limited, since there have only been two major dilbit spills into North American waters, both from pipelines. One of these spills occurred in the brackish water of Burrard Inlet, Burnaby, British Columbia, and resulted in a discharge of about 59,000 gallons. The other occurred near Marshall, Michigan, where more than 840,000 gallons was spilled into a creek that led to the Kalamazoo River.¹



Crews use "stingers" to pump water into the sediment and flush oil to the surface. Photo courtesy of the EPA.

Response Differences and Challenges

In comparing diluted bitumen to conventional crude oil, it is helpful to keep in mind that dilbit is typically mixed with 30 percent lighter components (diluents) whereas conventional crude oil typically contains only seven percent lighter components.² So, there are two primary differences in response to spilled dilbit vs. response to spilled conventional crude oil:

- increased airborne hazards,
- increased probability for sinking.

Airborne Hazards

Spilled diluted bitumen presents a greater airborne hazard for responders than spilled conventional crude oil, due in large part to the greater amounts of diluent. After a dilbit spill, the diluent (composed of the lighter hydrocarbon products) quickly evaporates, which causes elevated levels of airborne combustible gases and small aromatic hydrocarbons such as benzene, toluene, ethylene, and xylene. These airborne hazards present a health and safety risk to responders and, in a large spill, could necessitate evacuating surrounding communities.

Fortunately, responders can mitigate this by using air monitoring and personal protective equipment. In the case of a dilbit spill, air monitoring best practices include:

- ensuring timely public notification,
- establishing appropriate air monitoring thresholds,
- equipping responders with air monitoring equipment and adequate personal protective equipment.

Probability For Sinking

Research suggests that spilled dilbit may have a higher probability of sinking upon release than a more conventional crude oil with a similar specific gravity, especially in fresh water. As the lighter diluent quickly evaporates, the

heavier dilbit components are left behind. Weathering and evaporation increases the spilled dilbit density, increasing the risk of sinking and submergence as time progresses. In addition to weathering and evaporation, sedimentation can also increase the probability of submergence, since the sediment in the water is more likely to adhere to the heavier bitumen component.

This is not to say that all spilled dilbit will sink. There are many factors that influence whether dilbit will sink as it weathers, including:

- its specific chemical composition,
- the water temperature,
- the sediment concentrations in the water body,
- the wind,
- the current.

Indeed, research studies suggest that if environmental conditions are favorable to support floating, dilbit could remain on the surface for up to four days in fresh water and for up to eight days in salt water before sinking.³

Since diluted bitumen may have a higher probability of sinking than other products with similar specific gravities, this reinforces the need to get personnel and equipment on scene quickly. The faster the response, the greater the chance of recovering the spilled dilbit from the water's surface using standard response techniques such as booms and skimmers. Additionally, a dilbit response requires responders to be aware that, over the course of the response, they might also need to deploy submerged oil detection and recovery equipment.

Tools designed to detect and respond to sunken oil include side scan sonar, multi-beam sonar, laser fluorescence, visual and video observations, divers, bottom sampling, sorbent drops, nets and trawls, dredges, pumps and vacuum systems, remotely operated vehicles, and manned submersibles. Responders in the Marshall, Michigan, spill were able to locate submerged oil by disturbing the bottom with poles, but a method to determine the exact volume of submerged oil has not yet been identified.⁴

Response Similarities to Conventional Crudes

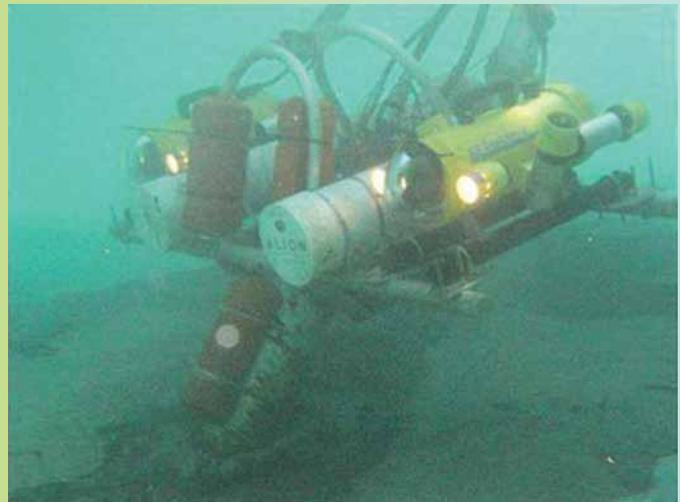
Despite the differences, there are several similarities between diluted bitumen and conventional crudes. For example, both dilbit and conventional crudes follow the same basic weathering progression and can be addressed with some of the same basic response technologies and strategies.

Recent Research and Emerging Technology

The recent growth in transport of unconventional products such as diluted bitumen has inspired government, industry, and academia to conduct numerous dilbit-focused research projects.

The National Academy of Science is currently working on a study that will analyze whether the dilbit properties differ sufficiently from those of commonly transported crude oils to warrant modifications to spill response plans or cleanup regulations. The study should be available in 2016.

The Coast Guard Research and Development Center is also currently engaged in a project to assess the risk of potential dilbit spills as a function of the modes and nodes of transport and to identify appropriate response techniques.



The Coast Guard Research and Development Center tests a remotely operated vehicle. U.S. Coast Guard photo.

These research projects will inform the Coast Guard's understanding of dilbit and help refine response policies and best practices.

In the initial (floating) phase of a dilbit spill response, standard equipment such as containment boom, sorbent boom, various skimmers, and vacuum trucks can be used to conduct the response. Research also suggests that belt, drum, and brush skimmers can be used in the initial stages of the spill and that skimmers designed for more viscous oil would not likely be necessary until several days into the spill.

How the Coast Guard is Increasing Preparedness

Personnel from the Office of Marine Environmental Response Policy are working closely with National Strike Force Coordination Center staffers and the oil spill response industry to increase preparedness for potentially sinking oils such as dilbit. The team is updating the guidelines for the U.S. Coast Guard oil spill removal organization classification program, which will help increase preparedness by more clearly outlining the process to validate commercial oil response capabilities.

For a spill on land, research suggests that low-pressure washing might not be an effective strategy, but that surface washing agents could be useful on oil exposed to the air for up to four days. Additionally, in the later phases of a response, diluted bitumen and conventional crude oils will both experience weathering processes such as oxidation and sedimentation.

About the authors:

Mr. Kurt Hansen has worked at the USCG Research and Development Center since 1993, working on projects dealing with oil spill prevention and response since 1998. He previously served as a sonar engineer and qualified U.S. Navy SCUBA diver at the Naval Undersea Warfare Center. He holds an M.S. in ocean engineering from the University of Rhode Island and a B.S. in mechanical engineering from the University of Delaware.

LT Sara Booth has served in the U.S. Coast Guard for 10 years in many capacities including compliance inspections, environmental response, research project management and design, and industry and interagency stakeholder coordination. LT Booth earned her master's degree in marine affairs from the University of Washington in 2010.

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New Crude Tests Regulatory Flexibility

Bakken crude oil transport challenges.

by LT ANDREW MURPHY
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Historically, the U.S. energy landscape has centered around oil imports, where supertankers transport millions of barrels of crude oil from the Middle East or other OPEC nations to refineries scattered along U.S. coasts. Recently, however, the Energy Renaissance that has focused on the North Dakota Bakken formation is changing this perception and forcing regulatory agencies and their rules to adapt.

Recent high-profile incidents involving trains carrying crude oil from the Bakken formation has led to significant scrutiny of this crude. Much media attention has centered on the fiery aftermath of incidents such as the July 2013 disaster in Canada, in which more than 40 people perished. As a result, many critics and even some experts began to question whether or not this crude oil was too “explosive” to transport.

Unconventional Production and Transport

Part of the problem is that not only is this oil being produced unconventionally through hydraulic fracturing, but it’s also being unconventionally transported. A lack of pipeline infrastructure to transport the oil and the absence of viable waterways within the immediate vicinity of the oil producing region have led to a significant amount of rail transport for this crude.

Furthermore, port areas such as St. Louis and Albany (areas that have historically seen very little in the way of crude oil cargo) have seen large volumes of Bakken crude transported by rail.

To attempt a solution, an enormous amount of attention has been given to the domestic regulations governing the rail transport of crude oil. The regulatory structure in place covering Bakken crude maritime transport may play a big role in the years to come. These regulations, found in Title 46

Code of Federal Regulations Subchapter D, specify safety and construction standards to ensure the safe carriage for flammable and combustible liquid cargoes carried in bulk.

Characteristics

Crude oil is a flammable liquid, which is any liquid that gives off flammable vapors at or below a temperature of 80°F. Flammable liquids are further divided into grades, based on Reid vapor pressure (RVP).¹ Combustible liquids are defined as any liquid having a flashpoint above 80 degrees F and are also further divided into grades (see table below).

Vapor pressure is an important property of all flammable and combustible liquids. It measures the pressure exerted by the vapor of a volatile liquid when the vapor and liquid are in equilibrium. It can also provide a general measure of the volatility of a cargo. The Reid vapor pressure standard, ASTM D323, is incorporated by reference in Title 46 CFR regulations, meaning that it is the required test method used to classify cargo grade. Vapor pressure can also provide an indirect estimate of a volatile liquid’s evaporation rate, where the higher the vapor pressure, the greater the

Cargo Classification Table		
Grade	Flashpoint (°F)	RVP (psia)
A	<80	14 or more
B	<80	above 8.5 but less than 14
C	<80	8.5 or less
D	80 to 150	N/A
E	>150	N/A

The cargo classification table notes the different grades of flammable and combustible liquids. Data from 46 CFR Part 30. All graphics courtesy of author.



evaporation rate. This is especially useful to know when dealing with crude oils, such as Bakken crude, that may contain more dissolved gases.

Classification Schemes Differ Among Agencies

From a regulatory perspective, the Title 46 CFR Subchapter D regulations are somewhat unique in that flammable liquids are defined based on flashpoint and vapor pressure. Most other regulatory bodies and associations only use flashpoint and boiling point to classify flammable liquids.

The International Maritime Organization regulates crude oil carriage in the International Convention for the Prevention of Pollution from Ships Annex I, setting safety and construction standards specifically for carrying oil in bulk. The regulations make no distinction between oils with high or low flashpoints or different vapor pressures. For packaged hazardous materials and other modes of transportation such as rail, flammable liquids are classified as Class 3 hazardous materials.

U.S. domestic definitions for Class 3 flammable liquids are found in the Department of Transportation's hazardous materials regulations in Title 49 CFR parts 171-180, where a Class 3 flammable liquid is defined as a liquid having a flashpoint up to 140 degrees F. Further categorization based on boiling point identifies the fire hazard, with packing group I representing the greatest fire hazard.

The International Maritime Dangerous Goods Code has a similar definition for Class 3 flammable liquids. The Occupational Safety and Health Administration and organizations such as the National Fire Protection Association (NFPA) and the American Petroleum Institute cover storage and handling at shore facilities. NFPA 30, known as the "flammable and combustible liquids code," uses a slightly different classification system than the Department of Transportation. While still using boiling point and flashpoint, NFPA identifies fire hazard risk by assigning flammable liquids as either class IA, IB, or IC, where class IA presents the greatest fire hazard. This differs from the Title 49 classification using packing groups and the Title 46 classification using grades.

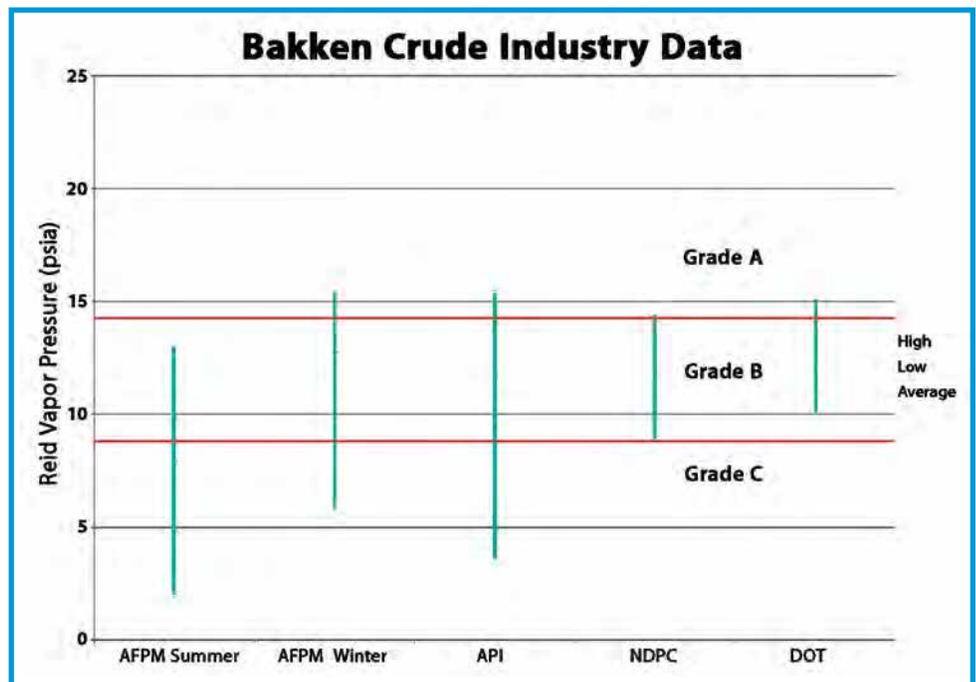
Transport Safety Considerations

For oils such as Bakken crude that use multiple transportation modes, the

differing classifications add complexity, especially for testing to classify cargoes. As such, the safety data sheet has become the standard to determine cargo grade for barge transport. OSHA regulations stipulate that every hazardous cargo is required to have a safety data sheet; however, the safety data sheet only requires the information be specific to a certain hazardous material, such as crude oil, and not the specific cargo being transferred.⁴

A significant amount of recent test data exists for Bakken crude from several different organizations and agencies. For maritime shipping classification, the most important pieces of data are flashpoint and Reid vapor pressure. Industry data indicates that RVP averages somewhere in the Grade B range. A few data points indicate a higher RVP that would result in a classification as a Grade A cargo. Typically, crude oil is carried as a Grade B cargo.

Based on the data, carrying Bakken crude would be no different than traditional crude, other than a few outlying data points. According to the most recent data, "North Dakota Sweet," the trade name for Bakken crude, has RVP values well below some of the most volatile crude oils. However, historical Reid vapor pressure data for North Dakota Sweet shows that samples in 2010 had much higher values of around 9 psi for RVP, making it equivalent to other volatile crudes, such as the Eagle Ford API 57 (see "RVP Comparison" table).



Data from American Fuel and Petrochemical Manufacturers Survey of Bakken Crude Oil Characteristics; American Petroleum Institute Staff Analysis of Crude Oil Samples; North Dakota Petroleum Council Bakken Crude Characterization Task Force Presentation of Preliminary Results; Department of Transportation Operation Safe Delivery Update.

RVP Comparison		
Crude Name	Country	RVP
Brent	U.K.	5.61
Eagle Ford API 57	Texas, U.S.	9.30
Hibernian	Canada	3.18
Light Louisiana Sweet	Louisiana, U.S.	4.52
North Dakota Sweet	North Dakota, U.S.	5.19
Purovsky	Russia	7.74
Saharan Blend	Middle East	6.82
Arabian Extra Light	Saudi Arabia	5.39

Comparison of RVP and other properties among different crude oils.

The reason for the sharp drop is unknown. Furthermore, some uncertainty still exists with regard to understanding Bakken crude properties. One main argument is that not all Bakken crude oil is the same. There may be variations from one well to another, and weather, seasons, and transportation may alter the crude's physical properties. Data from the American Fuel and Petrochemical Manufacturers shows that during the summer months, Bakken crude's Reid vapor pressure decreases significantly. Other properties that have raised concern and could impact transportation are the amount of dissolved gases present in the crude oil as well as the crude's corrosiveness.

Approvals Process

Whether or not Bakken crude is carried as Grade B or lower or as a Grade A cargo, the construction standards for tank vessels, including tank barges, are virtually the same. The Coast Guard's Marine Safety Center personnel review and approve plans to ensure that tank vessels can safely carry a Grade A or Grade B cargo. The plan submitters must request the grade of cargo for which they seek approval, usually before tank vessel construction begins.

Once approved, the tank vessel's certificate of inspection is endorsed with the grade of cargo that the vessel is authorized to carry. Both Grade A and B cargoes require safety relief valves on cargo tanks, double-hull construction, and gauging systems to measure liquid cargo levels. Different structural standards are applied to tank barges once the RVP of the cargo exceeds 25 pounds per square inch (psia).

Liquefied flammable gases, which have even more robust construction and safety requirements, are any flammable gas cargo with a RVP exceeding 40 psia.

In Sum

Current data for Bakken crude suggests that the existing maritime regulations for flammable and combustible liquids are adequate to safely transport on U.S. waterways. Department of Transportation initiatives to emphasize proper classification for rail shipments and American Petroleum Institute recommended best practices for rail crude oil shipment have helped raise awareness of the safety hazards associated with Bakken crude.

These initiatives have benefitted all modes of transportation. The new energy landscape that is being driven in part by Bakken crude has put to test the current regulatory structure for not just the Coast Guard, but the entire federal government. As the collective understanding of Bakken crude properties further evolves, the Coast Guard and partner agencies will continue to evaluate and, if necessary, update existing safety and construction standards to minimize risk to the public and prevent significant disruption of vital maritime resources.

About the author:

LT Andrew Murphy is a staff engineer in the Coast Guard's Hazardous Materials Division. He has served in the U.S. Coast Guard for more than seven years. He holds a chemical engineering master's degree from the University of Rhode Island.

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Marathon Petroleum's Capline Pipeline Unit publishes current crude oil information on hundreds of different crude oils from around the world. See www.caplinepipeline.com/Default.aspx.



Arctic Resources

The lure of energy resources in the frontier.

by LT STEPHEN P. FAINER
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In July 2008, the U.S. Geological Survey estimated that the Arctic contained undiscovered, technically recoverable resources equivalent to 90 billion barrels (Bbbl) of oil, 1,669 trillion cubic feet of natural gas, and 44 Bbbl of natural gas liquids. In total, the Arctic was estimated to account for 22 percent of the world's undiscovered, technically recoverable resources.¹ The study, which took four years to complete, was the largest public hydrocarbon resource appraisal conducted in the Arctic. It solidified the growing consensus that the Arctic was the last great frontier for international oil companies (IOCs) to develop new hydrocarbon resources.²

The History

The study was released amidst a tumultuous time for the oil industry and international economy. While twelve days earlier the international crude oil benchmark, Brent, had peaked at an all-time high of \$147.27 U.S. dollars per barrel, following a four-year bull market, within just five months, Brent would trade at less than \$40 per barrel.³ Just over a month after the report was released, Lehman Brothers announced its bankruptcy, and the global economy entered its worst crisis since the Great Depression.⁴

Despite the incredible churn of the moment, longer-term trends motivated the drive to the Arctic. First, energy demand growth from emerging markets was outpacing supply growth. The period from 2004 to 2014, with the exception of the immediate aftermath of the Great Recession, was marked by tight supply and sustained high oil prices, often in excess of \$100 per barrel.⁵

Second, increased resource nationalism drove IOCs out of premiere oil-producing countries. Unable to compete with state-run national oil companies for the best acreage, IOCs positioned themselves to focus on large, complex, and technically advanced projects.⁶

Lastly, the United States remained in a three-decade-long production decline. In 2008, unconventional natural gas production was just beginning to come online. U.S. oil

production bottomed out at 5 million barrels per day. The combined techniques of horizontal drilling and hydraulic fracturing would later be repurposed for oil production, but would not begin to impact U.S. supply until 2011.

These factors increased the attention on the Beaufort and Chukchi Sea outer continental shelf (OCS) lease sales of 2005, 2007, and 2008. Of the 607 active leases in the Alaska OCS, 599 were leased during these sales.⁷

In February 2008, Lease Sale 193 in the Chukchi Sea resulted in an unprecedented \$2.6 billion in high bids.⁸ Shell Gulf of Mexico, Inc., alone invested more than \$2 billion, acquiring OCS leases, including the single highest bid of \$105 million for a tract in the "Burger" prospect.⁹ These lease sales set the stage for a new round of Arctic exploration, but environmental, economic, and political challenges have significantly slowed progress in the region.

Drilling

These lease sales were not the first in the Chukchi and Beaufort Sea areas. In total, there have been 13 lease sales in the region, dating back to 1979. Thirty-five wells have been drilled, capped, and properly abandoned in the region.

Despite discovering several oil accumulations and the estimated potential for containing undiscovered technically recoverable resources of 23 Bbbl of oil and 106 trillion cubic feet of natural gas,¹⁰ the subset of the U.S. Arctic OCS (the combined Beaufort Sea and Chukchi Sea planning areas) was repeatedly deemed too costly to develop and produce.

Prior to Shell's 2012 exploration program, the last exploration well drilled in the U.S. Arctic outer continental shelf was capped in 2003.¹¹

The exception to this trend is a series of near-shore facilities built on artificial islands in state waters within three nautical miles of Alaska's North Slope coast and near the Trans-Alaska Pipeline System infrastructure. Some of these fields

have produced oil since the 1980s, while others are still not developed.¹²

There are two near-shore discoveries that straddle state and federal waters—the Northstar field, which has been producing oil from an artificial island since 2001, and the Liberty field, for which the Department of Interior’s Bureau of Ocean Energy Management (BOEM) is reviewing a development and production plan.¹³

A decade of sustained high oil prices, lasting roughly from 2004 to 2014, caused stakeholders to reassess the economic feasibility of U.S. Arctic OCS production. With oil frequently trading in excess of \$100 per barrel, international oil companies decided to once again venture further offshore.

Since the 2008 Chukchi Sea OCS lease sale, only Shell has attempted to drill exploration wells from floating rigs in the U.S. Arctic outer continental shelf. The company first submitted a Beaufort Sea exploration plan in 2007 and a Chukchi Sea exploration plan in 2009. However, a combination of legal challenges, the *Deepwater Horizon* incident, the global economic recession, and difficulty meeting all environmental compliance standards resulted in operations in both seas being delayed for several years. In 2012, Shell drilled two exploration wells, one each in the Beaufort Sea and Chukchi Sea planning areas, but was not permitted to drill to depths that would encounter liquid hydrocarbons because the company could not deploy the required Arctic containment system in case of a blowout.¹⁴

Further, during the project’s demobilization phase, the floating rig *Kulluk* in the Beaufort Sea snapped its tow line while transiting from Dutch Harbor, Alaska, to Seattle, Washington, and beached on a small island near Kodiak, Alaska. U.S. Coast Guard Air Station Kodiak MH-60 Jayhawk helicopter crews rescued the rig crewmembers.¹⁵ So, despite years of planning, Shell’s 2012 exploratory program was unable to drill even one exploratory well into a liquid hydrocarbon-bearing zone.

U.S. Arctic Exploration and Production Challenges

The challenges Shell faced in 2012 are characteristic of those for any company operating in the U.S. Arctic OCS. In July, the warmest month of the year, the average daily max temperature is only 47 degrees Fahrenheit. Shore-side supplies must be moved into position during the winter, using the snowy, icy roads before summer’s melted permafrost makes many communities unreachable by truck.¹⁶

Offshore, the ice-free season is less than four months, from July through October, creating a very short operational



The Coast Guard assists a mobile drilling unit. U.S. Coast Guard photo by Petty Officer Sara Francis.

season for offshore drilling rigs.¹⁷ Ice coverage is generally heavier and in place longer east of Point Barrow. However, the wind can blow the pack ice on and off the shore at the beginning and end of the ice-free season.¹⁸

Additionally, the North Slope of Alaska is remote, and lack of infrastructure complicates project management. By road, it is 852 miles from Anchorage, Alaska, to Deadhorse, near Prudhoe Bay, and only one road, which is virtually unpaved for 414 miles, connects the North Slope to the major ports and population centers of the Gulf of Alaska. Cargo delivered by sea to Alaska’s North Slope oil and gas operations must be hauled to Prudhoe Bay by oceangoing tugs and barges that anchor nearly six miles offshore.

Barrow, Alaska, the largest community on the North Slope, has no pier facilities. Cargo bound for Barrow is lightered from barges to landing craft.¹⁹

There are two small ports in the Bering Strait region that can accommodate a limited number and types of vessels engaged in oil and gas operations—one at Nome, with a 175-foot dock and water depth of 21 feet; and the other, a very small port at Kotzebue, where ships must anchor offshore and shallow draft barges must lighter material to shore. The nearest Arctic deepwater port capable of handling a whole drilling operation fleet is located at Dutch Harbor, Alaska, in the Aleutian Islands, more than 1,340 nautical miles from Prudhoe Bay. However, most hydrocarbon supplies and gear depart from Seattle, Washington, 3,072 nautical miles from Prudhoe Bay.²⁰

Offshore oil must be brought ashore by subsea buried pipelines, connected by overland pipelines to the Trans-Alaska

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The Federal Government's Responsibility

The persistent potential of Arctic exploration and production activity has obliged the U.S. government to prepare a regulatory and response framework suited to Arctic conditions, as local, regional, and national interests are only served if U.S. Arctic OCS exploration and production are conducted in a safe, effective, and environmentally responsible manner.

Of a number of federal entities with regulatory and oversight responsibilities, the Bureau of Ocean Energy Management (BOEM), the Bureau of Safety and Environmental Enforcement (BSEE), and the USCG each have significant, but different, roles in the government's regulatory and response efforts, but frequently work together to improve effectiveness and share costs.¹ The Bureau of Ocean Energy Management manages leasing and exploration and development of the nation's outer continental shelf energy and mineral resources, and provides scientific support in leasing process environmental reviews and regulatory review for exploration and development plan processes. The Bureau of Safety and Environmental Enforcement promotes safety and environmental protection in the offshore exploration and production industry through vigorous regulatory oversight and enforcement. The USCG is responsible for vessel safety inspections, maritime search and rescue, and oil and hazardous substance spill preparedness and response in the U.S. coastal zone.

Each agency coordinates with other pertinent members of federal, state, local, and tribal governments; intergovernmental organizations like the International Maritime Organization and the Arctic Council; and other private entities throughout the offshore exploration and production process. BOEM, BSEE, and the USCG are each taking specific steps to prepare for, regulate, and respond to incidents associated with Arctic OCS exploration and production, and to address the special challenges associated with operating in this extreme environment.

The Bureau of Ocean Energy Management

BOEM manages the development of the nation's outer continental shelf energy and mineral resources in an environmentally and economically responsible way.

BOEM uses the best available science and develops, conducts, and oversees world-class scientific research specifically to inform policy decisions regarding OCS energy and mineral resource development. Through its statutory responsibilities, resource stewardship, environmental expertise, and long history in the U.S. Arctic OCS area, BOEM plays an integral role in government preparation for U.S. Arctic OCS energy and mineral development activity.

BOEM's Alaska Region (AKOCSR) in Anchorage, Alaska, is front and center in managing the U.S. Arctic OCS. It implements the five-year OCS oil and gas leasing program, reviews and approves (if appropriate) outer continental shelf exploration and development and production plans, conducts environmental reviews and associated consultations, sponsors environmental studies, conducts resource evaluations, and obtains geophysical and geological data.

The AKOCSR is composed of three main program offices:

- The Office of Resource Evaluation investigates the conventional oil and gas potential of the OCS, ensures the federal government receives fair market value for outer continental shelf leases, and estimates reservoir properties to calculate worst-case scenarios for oil discharges from a blow-out.
- The Office of Environment follows the mandates of the National Environmental Policy Act, the Endangered Species Act, and a host of other statutes to ensure that the best available scientific information and traditional knowledge are employed to inform bureau and departmental decisions.² Its Environmental Studies Program has invested more than \$450 million in Alaska OCS research, the majority of which is Arctic-centric, resulting in more than 1,000 technical reports and publications since 1973.
- The Office of Leasing and Plans ensures that OCS Lands Act requirements and procedures are followed while preparing and conducting competitive lease sales. Once leases are issued, it manages exploration, development, and production plans, certifying that

industry follows lease mitigations and terms of sale when exploring for and developing the oil and gas resources in federal waters.

The Bureau of Safety and Environmental Enforcement

BSEE's two key functions are:

- the Offshore Regulator Program, which develops standards and regulations for exploration and production activity in the U.S. OCS;
- the Oil Spill Planning Division, which develops standards for offshore operators' oil spill response plans.

The BSEE Alaska Region Office in Anchorage, Alaska, manages the Arctic OCS. BSEE regional offices review applications for permits to drill to ensure all applicable safety requirements are met. Second, they conduct drilling rig and production platform inspections using multi-disciplinary inspection teams. Third, BSEE enforces safety and environmental management systems implementation and development for each operator on the U.S. outer continental shelf.

On the international level, the Bureau of Safety and Environmental Enforcement is the lead agency in a partnership developing a database for Arctic oil spill response assets, which will contain detailed information on Arctic-specific equipment, vessels, dispersant stockpiles, and application platforms; *in situ* burn boom, well containment, and cap and flow devices; and other resources owned by or regionally available to all Arctic Council member states. This inventory will support contingency planning and identify gaps in response capabilities. It is also contributing to the draft IMO/Emergency Prevention, Preparedness and Response working group "Guide on Oil Spill Response in Ice and Snow Conditions" and the Arctic Environmental Response Management Application GIS mapping platform, which is designed to assist in oil spill response by providing a common operating picture of all response assets and threatened environmental resources in the region.

BSEE also provides research support through its technology assessment programs and oil spill response research program, and is the principal federal agency

funding oil spill response research. A key component of the program is the Ohmsett National Oil Spill Response Research Facility in Leonardo, New Jersey, which contains the largest outdoor saltwater wave/tow tank in North America, used by a variety of government agencies to test new technologies in a realistic marine environment and to train emergency response personnel.³

BSEE- funded studies include:

- the effects of low temperatures on drilling equipment,
- developing sea ice parameters for offshore structure design,
- testing various response equipment under Arctic conditions, and
- oil recovery in icy waters.⁴

Finally, the Bureau of Safety and Environmental Enforcement works to promote a holistic “culture of safety” in the offshore exploration and production industry.⁵ It formed the Ocean Energy Safety Institute in conjunction with three universities in Texas to facilitate research in the areas of offshore drilling safety and environmental protection.⁶ BSEE also collaborated with the Bureau of Transportation Statistics (BTS) to develop a confidential near-miss reporting system for use on the OCS. BTS will retain the individual confidential reports, but will provide trend analysis and statistical data to BSEE.⁷

The U.S. Coast Guard

As the Arctic Ocean has become more accessible, the Coast Guard has increased its longstanding operational presence in the region, and in May 2013, the USCG released its Arctic Strategy. The strategy’s three strategic objectives for the next decade:

- improve awareness,
- modernize governance, and
- broaden partnerships to ensure safe, secure, and environmentally responsible maritime activity in the Arctic.

The 17th Coast Guard District, headquartered in Juneau, Alaska, oversees Coast Guard regional efforts in the Arctic. In 2012, the Coast Guard annual Arctic Shield operation supported a sustained seasonal presence in the region. Arctic Shield consists of a three-pronged interagency approach consisting of outreach, operations, and capabilities assessment, including research on the effectiveness of various spill detection and skimming systems as well as

exercising government skimming capability that augments the primary response provided by the responsible party.

While the USCG is the primary federal agency for maritime oil spill response in U.S. waters, Coast Guard operational assets are not the first line of defense in spilled oil recovery. USCG preparedness is measured by its ability to manage the response to an oil spill with the cognizant state and the responsible party. The USCG works with the responsible parties, state representatives, and local stakeholders to ensure an effective and timely oil spill response. As the federal on scene coordinator in the coastal zone, the Coast Guard provides oversight and direction over all the responsible party’s response actions.

Further, the Coast Guard has undertaken a port access route study to help reduce the risk of maritime casualties and increase commercial traffic movement efficiency in anticipation of increased human activity in the region. The current proposal is for a voluntary, four-mile-wide, two-way route from the Bering Strait to Unimak Pass, all within U.S. territorial waters. The study recommendations may lead to future rulemaking action or appropriate international agreements. In addition, the USCG facilitated the Arctic Waterway Safety Committee (AWSC) development. Based on successful models used in other critical U.S. maritime regions, the AWSC is a focused nongovernmental committee dedicated to addressing safety, security, subsistence, and environmental issues facing the Arctic. Stakeholders work collaboratively to solve Arctic waterway-related issues without incorporating new regulations.

Interagency Joint Arctic Activities

BOEM, BSEE, and USCG are also active participants in domestic and international interagency working groups and other bilateral activities that focus on Arctic offshore energy and maritime issues. One prime example is involvement in the various working groups and task forces of the Arctic Council. Formally established in 1996, the council serves as a high-level intergovernmental forum that promotes cooperation, coordination, and interaction among the Arctic states and indigenous communities on common Arctic issues, including sustainable resource development

and environmental protection. From 2015 to 2017, the U.S. will assume Arctic Council chairmanship.

The three agencies have helped produce Arctic Council reports, including the “Arctic Offshore Oil and Gas Guidelines,” the “Arctic Marine Shipping Assessment,” “Recommended Practices for Pollution Prevention,” and the “Guide to Oil Spill Response in Snow and Ice Conditions.” The USCG was instrumental in developing the “Agreement on Cooperation on Aeronautical and Maritime Search and Rescue in the Arctic” and, with BSEE, helped develop the “Agreement on Cooperation on Marine Oil Pollution Preparedness and Response in the Arctic.” USCG and BSEE are also members of the current Arctic Council Task Force on Oil Pollution Prevention.

In addition, these three agencies are leaders in implementing the National Strategy for the Arctic Region, including efforts to improve hazardous material spill prevention, containment, and response; promote arctic oil pollution preparedness, prevention, and response internationally; and work in the interagency Committee for the Marine Transportation System, promoting a safe and improved Arctic marine transportation system.

Endnotes:

1. Other federal entities not discussed here are the Environmental Protection Agency, the U.S. Fish and Wildlife Service (Department of the Interior), and the National Marine Fisheries Service (National Oceanic and Atmospheric Administration).
2. A body of evolving practical knowledge based on observations and personal experience of local residents over an extensive, multi-generational time period.
3. Bureau of Safety and Environmental Enforcement, U.S. Department of the Interior, “Ohmsett – National Oil Spill Response Research Facility.”
4. Bureau of Safety and Environmental Enforcement, U.S. Department of the Interior, “TAP Arctic Research.”
5. It defines safety culture as “the core values and behaviors of all members of an organization that reflect a commitment to conducting business in a safe and environmentally responsible manner.”
6. Bureau of Safety and Environmental Enforcement, U.S. Department of the Interior, “Fact Sheet: Ocean Energy Safety Institute.”
7. Bureau of Transportation Statistics, U.S. Department of Transportation, “BTS and BSEE to Develop Confidential Near-Miss Reporting System.”

For more information:

Visit www.boem.gov; www.bsee.gov; www.uscg.mil; and www.arctic-council.org.



Pipeline System, and transported 800 miles to Valdez, Alaska, then loaded onto a tanker for delivery to refineries on the West Coast.²¹

Social Challenges

Beyond the latent physical and environmental challenges, there are a number of political and economic challenges facing production in the Arctic. Most significantly, the Arctic is widely viewed as particularly sensitive and ecologically important. Groups such as the Sierra Club, World Wildlife Foundation, and the Pew Charitable Trust have called for either stricter drilling regulations for the U.S. Arctic OCS, or a ban on drilling altogether. As a result, each new operation comes under intense public scrutiny in a way that drilling activities in other parts of the country simply do not. The U.S. Arctic is also home to thousands of Alaska natives who depend on the marine and coastal environment for their subsistence and way of life. Federal agencies and industry actively collaborate with tribes, local governments, and subsistence groups to ensure good natural resource stewardship and to avoid interference with subsistence activities.²²

Opponents of Arctic offshore drilling have challenged the legality of various aspects of the regulatory and permitting process in court. In 2014, the U.S. Court of Appeals for the Ninth Circuit held that the federal government's reliance on a one-billion-barrel production scenario was arbitrary and caused the agency to underestimate potential environmental impacts. In response, BOEM released a supplemental environmental impact statement on February 12, 2015, based on a 4.3-billion-barrel production scenario. The new analysis included an increased oil spill risk, compared to previous versions. On March 31, 2015, Secretary of the Interior Jewell submitted a record of decision affirming the lease sale in question.²³

Despite this victory for proponents of Arctic drilling, legal challenges are likely to continue. As recently as June 2, 2015, an alliance of environmental and Alaska-based community groups filed a lawsuit in the Ninth Circuit Court of Appeals challenging BOEM's approval of Shell's 2015 summer oil exploration plan for the Chukchi Sea.²⁴

Recognizing the unique challenges the U.S. Arctic presents, BOEM and its sister agency, the Bureau of Safety and Environmental Enforcement (BSEE), released for public comment newly proposed Arctic exploratory drilling regulations on February 24, 2015. Further, both agencies have undertaken extensive environmental and safety reviews of potential oil and gas operations on the U.S. Arctic OCS, which, along with concerns of environmental organizations and Alaska natives, reinforced the bureaus' decision to develop additional measures specifically tailored to the operational and environmental conditions of the U.S. Arctic OCS.²⁵

Various international oil companies have indicated that these regulations will impact final investment decisions; however, the newly proposed Arctic standards (under review as of September 2015) will seek to decrease the uncertainty IOCs face in committing to new exploratory programs.²⁶ Further, the leases in the U.S. Arctic OCS have 10-year terms that are nearing expiration. Shell, Statoil, and ConocoPhillips have submitted letters to BSEE requesting a suspension of operations for their leases, which would extend the lease term period. According to Shell, "... prudent exploration is now severely challenged prior to current lease expiration dates," citing "[previous disruptions], limited rig availability, brief operating windows, and the unusually long lead times required to mobilize activities in Alaska."²⁷

Economic Challenges

The rise of unconventional energy is pressuring the economic feasibility of offshore Arctic oil production, which means that Arctic oil has a very high break-even price point. Industry estimates suggest break-evens for the U.S. Arctic could lie between \$80 and \$110 per barrel. During the last decade, sustained high prices supported Arctic development. However, growth in production from a variety of unconventional sources has created alternatives for capital investments and a structural oversupply that has caused the price of oil to drop 50 percent in the last year.²⁸

North America has led the charge in developing unconventional oil and gas resources. In the U.S., low permeability reservoirs have been accessed using the combined techniques of hydraulic fracturing and horizontal drilling. Deepwater production in the Gulf of Mexico has increased markedly during the same time frame, rising from seven percent of regional offshore production to more than 80 percent in 2012.²⁹ In Alberta, Canada, producers tapped the oil sands deposits, substantially increasing heavy oil production. In Brazil, Petrobras has grown production by reaching ultra deepwater offshore deposits in the "pre-salt" layer. Combined, these three countries increased hydrocarbon liquid production by 8.6 million barrels since 2005. This volume is equivalent to nearly 10 percent of total world production in the third quarter of 2014.³⁰

As a result of the late-2014 collapse in oil prices, oil companies worldwide are slashing exploration budgets, particularly on frontier plays like the Arctic. Financial analysts suggest industry-wide capital expenditures could drop 17 percent in 2015, the third largest decline since 1985.³¹ For example, in December 2014, Chevron announced it was indefinitely suspending plans to drill in Canada's portion of the Beaufort Sea.³² In January 2015, Norway's Statoil announced it would not drill any wells in the Norwegian Arctic despite doing so in the previous two years.³³ Russian National Oil



Consortium Rosneft, which successfully drilled an offshore Arctic well in 2014, announced it would cancel drilling in 2015 due to ongoing international sanctions, and in Greenland, oil companies are relinquishing their leases.³⁴ Meanwhile, some IOCs like Total S.A. have eschewed Arctic oil exploration and production altogether, deeming Arctic operations too environmentally risky.³⁵

ENI, Shell, and Hilcorp are exceptions to this trend. In February 2015, ENI's newest floating production storage and offloading platform *Goliat* began a two-month voyage from South Korea to the northern tip of Norway. When installed (planned for summer 2015), it will become the world's northernmost offshore oil production facility.³⁶ Shell has indicated its intention to drill in the U.S. Arctic OCS in 2015 despite cutting its exploration and production budget by \$15 billion. The company views the U.S. Arctic as a long-term investment and an opportunity to "book" large conventional reserves. While the current oil price reduces available capital for new investments, Shell has already sunk significant investments into its previous ventures in the U.S. Arctic.³⁷

The Outlook

During the next several decades, world oil and natural gas consumption is forecast to continue to grow. Limited access to "easy oil" will drive companies like Shell to seek frontier resources that require significant capital investments and technical expertise. The Arctic's large resource potential will remain a tempting opportunity to "book" new reserves.

While drilling in the U.S. Arctic outer continental shelf is not new, the environmental and logistical challenges remain high. The U.S. federal government, led by BOEM, BSEE, and the USCG, is working to improve its regulatory and response framework to facilitate safe, effective, and environmentally responsible exploitation of U.S. natural resources on behalf of the American people.

About the author:

LT Fainer was the energy and commerce analyst for the Intelligence Coordination Center from 2014 through July 2015. He has served in the Coast Guard for six years, and is completing his M.S. at the National Intelligence University.

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Liquefied natural gas ship. Image courtesy of Alessandro Viganò / iStock / Thinkstock.

Crude Transport

Coast Guard connectivity to the oil and gas supply chain.

by LT BRANDON ATEN
U.S. Coast Guard

Office of Marine Environmental Response Policy

Recent natural disasters, fuel supply disruptions, and unprecedented production increases in shale-based crude oils have highlighted difficulties for federal regulatory and response organizations like the U.S. Coast Guard to institutionalize a system that consistently connects with the dynamic nature of the oil and gas supply chain. After all, there are more than 1,305 petroleum product terminals, 142 refineries, 8,000 independent marketers, 2.1 million miles of natural gas utility distribution and service pipelines, 306,000 miles of high pressure intrastate pipelines, and 192,000 miles of crude oil and petroleum product pipelines.¹ Add onto those numbers ever-increasing barges, oil tankers, liquefied natural gas (LNG) ships, rail cars, and road transportation mechanisms, and you have an incredibly complex and robust system.

Consequently, the Coast Guard can't regulate, prepare, or respond effectively without interagency and industry cooperation. Furthermore, initiating programs that enhance shared interagency and industry information is not an end in itself, but rather a prerequisite for the Coast Guard to establish and maintain active engagement with the multifaceted oil and gas supply chain.

An Expanding Challenge

While the Coast Guard excels in oil spill response, it is important to remember that the challenge is not just the pollution, but also its subsequent ramifications. For example, we must consider how the spill or release impacts the waterway and if there is an impact to the regional or national oil and gas supply chain. We must also factor in which other federal, state, and local agencies have a stake in the spill.

Making the environment even more challenging, the U.S. has become the number one oil producer in the world,² causing a rapid expansion in the oil and gas supply chain infrastructure and growing asset ownership diversification and increasingly complex market structures. Coast Guard expertise can expand as quickly as the industry itself by aligning its prevention and response strategy and doctrine with the energy supply chain structure, its interdependencies, and regulatory framework.

A Specific Crude, A Specific Supply Chain

To garner a comprehensive understanding of the different types of crude oils, like Bakken, Eagle Ford, or Alaskan Northern Slope, our primary focus should be the supply chain and its associated regulatory agencies and trade-based

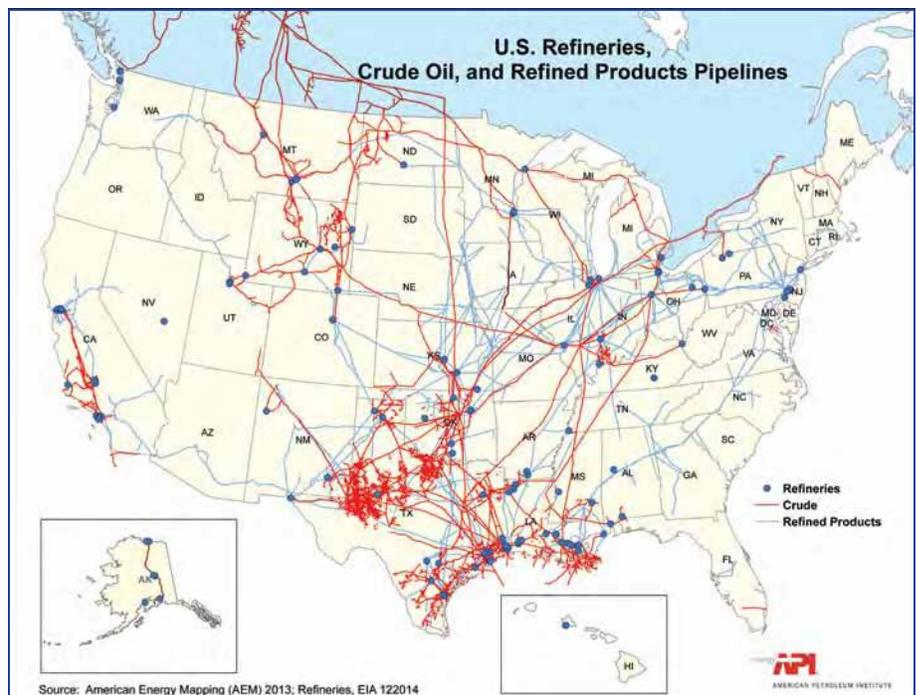
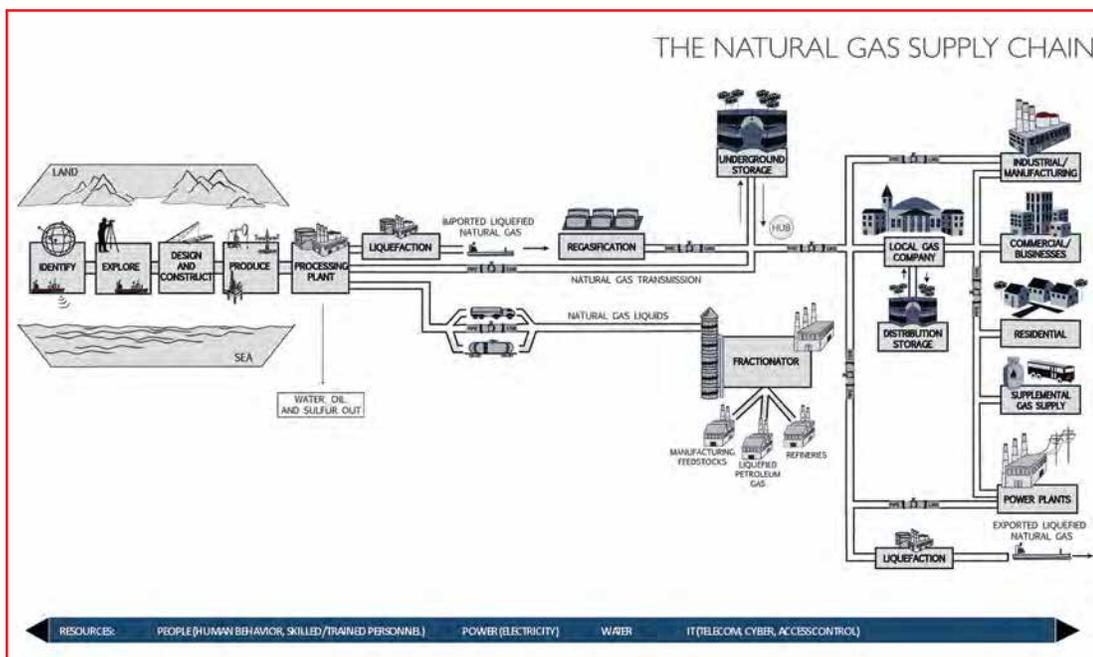


Image courtesy of the American Petroleum Institute.



The natural gas supply chain. Graphic courtesy of the American Petroleum Institute.

with new extraction technologies, the Bakken formation has engendered a sweeping national energy resurgence—a resurgence such upstream-based relationships can help the Coast Guard proactively identify beforehand.

Midstream — Oil and Gas Industry

The midstream sector typically involves crude or refined petroleum product transportation and storage. Tankers, barges, pipelines, and other transport systems move the crude oil from production sites to refineries and deliver the

various refined products to downstream distributors.

- upstream,
- midstream,
- downstream.

Upstream — Oil and Gas Industry

The upstream sector primarily focuses on exploring and producing crude oils and natural gas from underground or underwater formations. For example, the Bakken formation, which produces Bakken crude oil, and the McMurray formation, which produces crude bitumen, are examples of exploration and production locations for oil and gas upstream sector companies. While the upstream sector is arguably the most complex within the oil and gas supply chain, it is also the primary switchboard for midstream and downstream operations.

Upstream Opportunities

While the Coast Guard maintains a strong relationship with upstream-based agencies like the Bureau of Safety and Environmental Enforcement, other important facets of the upstream sector and oriented federal agencies exist that we must also efficiently capitalize. For example, we would do well to utilize United States Geological Survey oil and gas assessments and oil production reports from the Energy Information Administration.

How can these relationships benefit the Coast Guard? First discovered in the 1950s, Bakken crude oil is not a new oil—the ability to extract it was always the challenge. Now,

Midstream by far contains the largest Coast Guard footprint due to existing inspection and response regulatory requirements. However, the focus is not just the maritime industry, but the maritime domain in which various transportation modes pass over, under, and through.

Midstream Opportunities

Recently, the midstream maritime domain has experienced a significant shift to another major midstream entity—the railway. In fact, U.S. freight railroads delivered 435,560 carloads of crude oil in 2013 (roughly equivalent to 300 million barrels), compared to 9,500 carloads in 2008.³

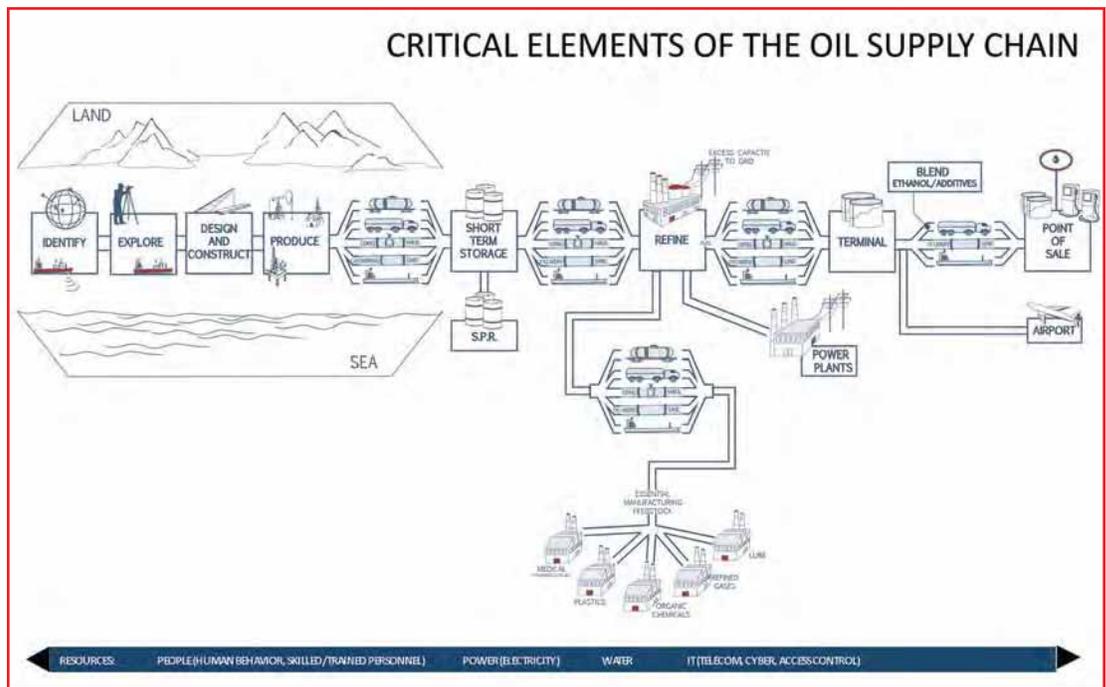
The Association of American Railroads (AAR) primarily represents the major freight rail industry and works on several initiatives, including emergency response, throughout North America. The increase in crude by rail has brought much attention to the rail industry and AAR, as several derailment incidents have reached national media levels.⁴ In response, the American Petroleum Institute and AAR have spearheaded a cross-trade workgroup in which both sides conduct training, trade experiences, and seek incident resolution. Coast Guard integration and information exchanges with such workgroups are paramount to increasing Coast Guard midstream maritime domain awareness and preparedness.

Downstream — Oil and Gas Industry

The downstream sector consists of crude oil and natural gas refining, processing, marketing, and distribution. While all aspects of the downstream sector are vital to the health of

the supply chain, of particular importance to the Coast Guard is the refining segment.

At an oil refinery, the crude oil is processed and refined into functional products like petroleum naphtha, gasoline, diesel fuel, asphalt base, heating oil, kerosene, and liquefied petroleum gas. These types of products serve basic needs like fueling the transportation system, heating homes, and powering the electrical grid.



Critical elements of the oil supply chain. Graphic courtesy of the American Petroleum Institute.

Downstream Opportunities

Particular types of oil are processed at specific types of refineries, depending on chemical composition and functional purpose. For instance, diluted bitumen, a heavy crude oil primarily extracted in Canada, is best suited for refineries in the Gulf Coast, because they are configured to process heavier crudes.

While the Coast Guard’s footprint in the downstream sector is not as significant in comparison to other streams, the consequences of disruptions and the subsequent public impact make the downstream sector a crucial component for Coast Guard inspectors and responders to understand.

Full Coverage

To ensure we maintain a pulse on future developments in the oil and gas sector, the Coast Guard must establish streamlined mission continuity plans within regulatory and response-related Coast Guard offices.

Lacking a clear nexus to the upstream, midstream, or downstream sectors, the Coast Guard will be unable to identify future trends or develop a practical strategy for future marine safety operations. To accomplish this, we should consider facilitating engagements to augment existing inter-agency organizations like the National Response Team, with committees focused on the oil and gas supply chain;

or promulgate federal advisory committees to synergize the interagency and industry for Coast Guard priorities like the Energy Renaissance.

About the author:

LT Brandon Aten has served in the U.S. Coast Guard for seven years in capacities including compliance inspections, environmental response, and naval engineering. LT Aten recently completed marine environmental protection industry training, where he worked with the Oil Spill Preparedness Division at the Bureau of Safety and Environmental Enforcement and the director of Midstream Operations at the American Petroleum Institute.

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Prevention, Preparedness, Response

The U.S. Coast Guard readies for America's Energy Renaissance.

by LCDR MIKE STRUTHERS

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Offshore and inland domestic oil and gas production has hit record levels and may continue to grow. The corresponding increased demand on the U.S. marine transportation system to support the production and transportation of oil and gas, refined products and chemicals, and related manufactured goods will challenge the U.S. Coast Guard's capacity to ensure safety, security, and environmental stewardship in a way that will allow our nation to enjoy the full economic benefit of this American Energy Renaissance.

To address these challenges, Coast Guard leaders collaborated to ensure the U.S. Coast Guard is prepared. Their efforts, which include a strategic communications and engagement plan, a bridging strategy, and an evaluation of necessary resources, provide broad context for strategic, operational, and resource planning to form a scalable action plan to address increased energy production.

The Plans

The strategic communications and engagement plan:

- highlights marine transportation system criticality in domestic energy exploration, exploitation, production, and transportation;
- describes the Energy Renaissance's impact on the marine transportation system;
- illustrates the Coast Guard's role in supporting safety, security, and environmental soundness for these activities.

The plan also describes what the Coast Guard does to facilitate energy-related commerce, including prevention, preparedness, and response efforts to ensure safe, secure, and environmentally responsible maritime activity.

The bridging strategy provides organizational focus to highlight known gaps, outline options to address and mitigate our highest known risks, and recommend courses of action within our resource-constrained environment. Efforts will span the prevention/response spectrum and address such issues as workforce competencies, IT tools, flexibility for operational commanders to address greatest risks, using third-party organizations, engaging industry and inter-agency partners, response guidance for new energy uses and types of oils, and awareness of trends in oil exploration and transportation.

Responding to Evolving Demands

Coast Guard personnel will continue to leverage the multi-mission workforce and operationally flexible assets to mitigate risk by actively patrolling and managing waterways; conducting vessel, cargo, and port facilities inspections for compliance with safety, security, and environmental standards; preparing for and responding to incidents; and conducting investigations.

Working with our interagency and international partners and all stakeholders, the U.S. Coast Guard must ensure that our governance, oversight, and operational approach to prevention, preparedness, and response remain effective, efficient, and relevant to the state of technology and level of activity.

Prevention

The U.S. domestic energy sector's expansion is predicted to have a ripple effect throughout the inland, Great Lakes, coastal, and offshore maritime industry. Given current trends in vessel and facility construction activity, it is likely that a larger, U.S.-flagged coastwise trade tanker and barge

fleet will emerge. These smaller vessels will make more frequent transits in coastal and inland waters, adding marine traffic to already congested waterways.

With a greater number of vessels engaged in shorter-distance, higher-frequency transits, there will be a greater risk of collisions, allisions, and groundings, with increased potential for pollution incidents and greater maritime security risk. Also, in response to stricter requirements to control air emissions from vessels and the availability of relatively inexpensive liquefied natural gas (LNG), there is significant industry interest in building new vessels that use LNG as a marine fuel for propulsion and power generation or converting existing diesel-powered vessels to use LNG.

If significant expansion in LNG-powered vessels occurs, shoreside support infrastructure will likely expand to provide bunkers to fuel these vessels. This could involve liquefied natural gas bunker barges, fuel transfer from shoreside storage tanks, or using tank trucks or rail cars as mobile fueling sources. Much of this activity will occur in the Eighth Coast Guard District, but there will also be evolving energy activity in non-traditional port areas such as Albany, New York, which may present unique challenges during heavy ice years.

In light of the above U.S. Coast Guard leaders will:

- Examine existing regulatory frameworks to position the Coast Guard to address the challenges associated with offshore exploration and production, liquefied hazardous gas (LHG) and LNG bunkering, vessel design, and crew training/certification requirements.
- Continue to support domestic and international standards bodies to develop requirements for LNG-fueled vessel design and LNG vessel bunkering procedures.
- Review existing technical capabilities and seek appropriate remedies to meet the strategic complexities envisioned in the evolving energy sector.
- Review the servicewide personnel training curricula and develop updated personnel qualification standards that establish vessel and facility inspection requirements and provide job aids to marine inspectors.
- Re-assess the risk posed by LNG and LHG to the key port areas it transits and revisit whether such risk warrants armed escorts or can be more appropriately mitigated by other means.
- Develop a new policy and concept of operations to facilitate a safe and secure marine transportation system,



Oil spill response team members force oily water into a skimmer. U.S. Coast Guard photo by Petty Officer Tom Atkeson.

including aids to navigation, waterways management, vessel traffic management, and maritime domain awareness.

- Leverage existing and emerging technology to maximize mariner safety while optimizing the balance between electronic and physical aids to navigation. To attain this balance, Coast Guard personnel will seek stakeholder engagement through aggressive outreach; use updated, data-driven analysis tools; increase marine safety information availability; and promulgate updated vessel carriage requirements.

Preparedness

The Energy Renaissance also requires evaluating current spill contingency plans to ensure that risks resulting from changes in energy production and transport are properly addressed. A renewed emphasis on partnerships and interagency collaboration will also be necessary to develop response strategies to minimize harm to human health and the environment.

Additionally, robust training and exercise programs must adapt to changing risk profiles to ensure that first responders are prepared. Long-term investments in our preparedness capacity will be necessary to develop a robust corps of highly trained and experienced preparedness specialists with the expertise to develop comprehensive response plans and ensure compliance with federal and state environmental laws.

In light of the above, U.S. Coast Guard leaders will:

- Continue to strengthen partnerships with the Environmental Protection Agency as well as the Departments



Chief Warrant Officer Dennis Croyle inspects machinery in the engine room aboard a tankship. U.S. Coast Guard photo by Petty Officer Henry G. Dunphy.

of Commerce, Transportation, Energy, and Interior, in concert with other National Response Team agencies, to facilitate an integrated federal effort in advanced planning for new energy production and transportation.

- Continue to invest in personnel and training to strengthen our cadre of preparedness specialists at all levels of the organization and provide them the tools needed to effectively leverage resources across local, state, and federal government and the private sector; harmonize the diverse family of contingency and response plans; develop preparedness measures; and implement strategies necessary to mitigate the effects of oil spills and hazardous substance releases.
- Evaluate and upgrade the command, control, communications, and sensors necessary for shore-based incident

response to ensure the Coast Guard is technologically prepared to meet the increasing demands of this mission in the 21st century.

- Coordinate with federal agencies, non-governmental organizations, academia, international partners, and the private sector to further advance response-related research and development associated with new forms of energy that may affect U.S. waters to inform preparedness and response activities.
- Continue to engage federal, state, and local stakeholders to review and, if necessary, update existing area contingency plans, area maritime security assessments, area maritime security plans, and preauthorization agreements to reflect new risks associated with increased oil production and new transportation modes.
- Engage with the Department of Commerce and the Department of the Interior to identify sensitive marine environments, identify threatened and endangered species, and ensure compliance with federal consultation laws. Continue to work with these and other partners to integrate other consultation requirements into spill planning and response structures.

Response

Major environmental incidents such as the *Deepwater Horizon* oil spill; Hurricane Sandy; and the Paulsboro, New Jersey, train derailment, which released vinyl chloride into the air; underscore the importance of having well-trained and readily deployable incident management and pollution response professionals. Equally important is a strong regulatory framework that ensures the right private sector resources are available to respond expeditiously, complementing federal, state, and local capacity and ensuring unity of effort.

Small unit sizes, large distances, and limited oil spill removal organization resources along new and emerging transportation corridors, particularly on the western rivers and Great Lakes, present significant response challenges for on-scene coordinators and will require Coast Guard attention to ensure response industry adaptation to changing transportation patterns.

Further exacerbating these shortfalls is the lack of clear regulatory requirements for Group V (sinking) oils, which degrades response plan efficacy and presents an incomplete picture of industry readiness. Moreover, increased domestic energy production and exportation, particularly of LNG, will require additional security resources and innovative means to mitigate risk to ensure the safety and security of the public and maritime response personnel.

In light of the above, Coast Guard personnel will:

- Continue to evaluate incident management, pollution response, and maritime security and response capacities in areas of new oil and gas production and transportation to ensure resources are poised to respond to areas of increased risk.
- Develop new oil spill removal organization classification guidelines for Group V oils to ensure private sector response equipment capability and strengthen government and industry response plans.
- Coordinate with partner agencies, the private sector, and academia to develop a more comprehensive understanding of the fates and effects of new oils [such as Bakken crude and Canadian tar sands (bitumen)] as well as related response technologies to enhance existing environmental response training programs.
- Coordinate with international partners to ensure readiness for transboundary responses resulting from increased international or domestic energy production.
- Coordinate with elements of the marine industry (such as LHG and LNG vessel and facility owners and operators) to ensure private sector response equipment capability and strengthen government and industry response and security plans.

- Enhance response preparedness tools like the Response Resource Inventory and preparedness assessment visits to further align response plans with industry capabilities and provide on-scene coordinators with a common operating picture for response equipment readiness.

In Summary

As marine transportation system demands grow to meet the needs for energy production and transport and to sustain growth in the trade of all goods, demands on the U.S. Coast Guard will grow as well. The Coast Guard action plan establishes a comprehensive response to assess and meet the evolving demands of the energy sector within the offshore, coastal, Great Lakes, and inland zones and focuses our efforts on prevention, preparedness, and response.

These three priority areas will capitalize on the U.S. Coast Guard's authorities, capabilities, competencies, and partnerships while leveraging our stakeholders' knowledge and capabilities to ensure America has safe, secure, and resilient waterways to meet the needs of the 21st century global economy.

About the author:

LCDR Mike Struthers has served in the U.S. Coast Guard for 15 years in a range of capacities, including deck watch officer and helicopter pilot. LCDR Struthers has earned the Coast Guard Medal, two Achievement Medals, and three Meritorious Unit Commendations.



Training the USCG for the Energy Renaissance

Marine inspector qualification and training.

by CDR JIM ROCCO (RETIRED)
Former Chief

U.S. Coast Guard

Outer Continental Shelf National Center of Expertise

MR. ROB HANLEY

Surveyor and Auditor

Prestige Maritime International

MR. MARK J. GANDOLFO

U.S. Coast Guard

Office of Traveling Inspector Staff

The increase in the domestic energy sector's footprint is sure to have an impact on the inland, Great Lakes, coastal, and offshore maritime industry. Additionally, new vessel construction activity makes it more likely that a larger, U.S.-flagged coastwise, tanker, and barge fleet will emerge, creating an influx of smaller vessels transiting coastal and inland waters. Also, in response to stricter air emission requirements and the availability of relatively inexpensive liquefied natural gas (LNG), new vessels that use LNG as a marine fuel for propulsion/power generation will become more and more popular.

Given these new realities, the Coast Guard will most likely:

- Examine its existing regulatory framework to address the challenges associated with offshore exploration and production, new crudes, new liquefied gases, and LNG bunkering from a vessel design, operation, and crew training/certification point of view.
- Continue to support domestic and international standards-making bodies such as the International Maritime Organization.
- Review its technical capabilities and pursue appropriate improvements to meet technological complexities such as drilling for oil/gas deeper and further offshore, transporting products with new characteristics/properties, and bunkering and utilizing new fuels throughout the maritime community.
- Review service-wide workforce accession and development/training programs to ensure the Coast Guard has the capacity to handle the industry's projected growth,

including updating personnel qualification standards; instituting robust tactics, techniques, and procedures; and providing robust job aids (such as electronic performance support systems) for vessel inspectors and facility examiners.

Fortunately, the Liquefied Gas Carrier National Center of Expertise (LGC NCOE) and Outer Continental Shelf National Center of Expertise (OCS NCOE) are fully engaged in adjusting to this Energy Renaissance and the resulting growth within the oil and gas industries.

National Centers of Expertise

The LGC NCOE was established in 2009 as a national repository of expertise and best practices for liquefied gas carrier (LGC) inspection. The OCS NCOE was also established in 2009 to address mobile offshore drilling unit, offshore production installation, and offshore supply/service vessel inspection.

Since the inception of these units, the marine industry has grown exponentially. It is anticipated that the U.S. will experience a significant increase in the number of LGC arrivals. Similarly, the U.S. outer continental shelf is anticipated to continue to experience a steady increase in deepwater offshore activity despite the recent downturn in oil's market value.

Additionally, we have seen a drastic uptick in waterfront and deepwater facility development, numerous novel gas-fueled vessels under design and construction, and a new industry of LNG bunker services. As the Coast Guard's oil

and gas experts, these NCOEs act as the USCG's central location of expertise for the now-broader oil and gas industries.

In response, the LGC NCOE is increasing its expertise with LNG and liquefied petroleum gas (LPG) export operations and facility construction, floating liquefaction, and LNG storage and use as a marine fuel. The OCS NCOE is steadily broadening its understanding of the impact of subsea activities that continue to push boundaries, such as high-temperature, high-pressure wells in water depths greater than 10,000 feet.

Focus on Safety

With Gulf of Mexico production (81 percent of oil and 53 percent of gas in 2014) originating from deep water wells, the need to maintain and enhance a risk-based focus on deep-water operations will challenge the Coast Guard to meet forthcoming safety demands.¹ Additionally, the OCS NCOE is enhancing Coast Guard offshore inspection workforce training by establishing cooperative instructional partnerships with offshore operators and embracing industry-led training.

The national centers of expertise work with their respective industries to cultivate an attitude that encourages moving beyond the traditional prescriptive approach to safety and compliance and facilitate for performance-oriented approaches. In this way, marine and offshore industry representatives actively participate in creating their own policies with which to maintain self-accountability. The NCOEs also continuously seek opportunities to acquire experience with novel marine and offshore-related projects and engage with Coast Guard field units and headquarters policymakers to create practical compliance directives.

As the energy industry advances equipment, processes, and people, the national centers of expertise work to identify and address gaps between those advancements and existing regulation. Looking to provide a greater degree of compliance certainty and consistency, the NCOEs regularly work to assist industry stakeholders in identifying equivalencies to satisfy compliance concerns impacting novel assets and operations.

For example, the LGC NCOE has played an instrumental role in developing key U.S. guidance for the domestic and international liquefied gas industry, such as updates to the International Gas Carrier Code, the International Gas as Fuel Code, and LNG-fueled vessel design and engineering policy letters.

Training

The NCOEs also work closely with the Coast Guard's Office of Commercial Vessel Compliance/Foreign and Offshore



Representatives of the Liquefied Gas Carrier National Center of Expertise (LGC NCOE), the USCG, and a representative of Conrad Shipyard discuss components of a containment system for the first liquefied natural gas bunkering barge in the U.S. being built by the shipyard in Orange, TX. U.S. Coast Guard photo by the LGC NCOE.

Vessel Division, the Traveling Inspector Staff, the Marine Inspector/Investigator Schoolhouse at Training Center Yorktown, and FORCECOM to review and update performance qualification standards (PQS). The LGC NCOE conducted a major overhaul of the foreign gas carrier examiner performance qualification standards, developed a prerequisite guidance document, and drafted the Coast Guard's first industry indoctrination requirements. The OCS NCOE played a primary role in developing the new Foreign Mobile Offshore Drilling Unit Examiner and Offshore Supply Vessel Inspector (OI) PQS along with their associated industry indoctrination requirements. The OI PQS also has two additional addenda for liftboats and anchor handling.

Further, the LGC NCOE has helped develop the weeklong gas carrier inspector course, which has provided training for more than 220 prospective foreign gas carrier examiners, and the OCS NCOE recently established a contract with the Shell Oil training facility to create the Coast Guard's outer continental shelf inspector course. In February 2015, the first class of 20 Coast Guard inspector trainees attended



USCG's Outer Continental Shelf National Center of Expertise graduates its first foreign Mobile Offshore Drilling Units course in Houma, Louisiana. U.S. Coast Guard photo by CDR James Rocco.

this weeklong course, which featured a blend of marine, “downhole,” and certificate of compliance instruction. The Coast Guard will most likely hold this course semiannually to keep pace with offshore operational developments.

The national centers of expertise also remain actively involved in field-level one-on-one training. They conduct on-the-job training for apprentice marine inspectors, coordinate multi-week ship rides and mobile offshore drilling units visits for qualifying inspectors/examiners, support inspectors/examiners throughout their six- and 12-month industry training programs, and facilitate qualification/certification boards.

New Fuels, New Skills

Now that alternative fuels such as liquefied natural gas are becoming more commonplace in the maritime environment, the Coast Guard workforce must evolve technical competencies to oversee vessel and facility design, operations, and emergency response. In response, the NCOE chairs an LNG fuel workforce development committee that includes subject matter experts from the LGC NCOE, marine inspection training officers, and representatives from field units and relevant headquarters program offices.

The committee will determine if a need exists for a formal analysis of current field performance, highlight workforce development gaps, and recommend workforce development improvements necessary to verify regulatory compliance. It will also work to create job aids; tactics, techniques,

and procedures; qualification standards; training; or guidance to ensure national consistency with vessel and facility inspection.

In addition, the Coast Guard continues to bolster competencies related to oil and other liquid bulk commodity transportation, including a crude oil wash/inert gas course for foreign tank vessel examiners and the foreign chemical tanker safety course.

A Look Ahead

Looking forward, the national centers of expertise will continue to enhance the Coast Guard’s technical competency and develop the workforce capacity necessary to account for new and novel vessel designs and anticipated increases in vessels exploring, exploit-

ing, and producing oils and gas on the outer continental shelf.

The NCOEs will also prepare for increasing numbers of foreign-flagged LNG/LPG tankers.

About the authors:

CDR Jim Rocco is the former chief of the Coast Guard’s Outer Continental Shelf National Center of Expertise in Houma, Louisiana. Recently retired with 23 years of experience with the USCG, he served in assignments including commercial vessel inspection, port operations compliance, and staff positions in acquisitions, facility safety and security, and navigation safety. He holds an MBA with a focus in finance from Northern Illinois University and a master of international public policy with a focus in energy resources from Johns Hopkins School of Advanced International Studies.

Mr. Rob Hanley has recently retired from the Coast Guard with 20 years of experience as a USCG marine inspector and Port State Control examiner, and most recently as a Liquefied Gas Carrier National Center of Expertise subject matter expert and training coordinator focusing on foreign gas carrier examiner qualifications, training, and workforce development issues. He currently works for Prestige Maritime International as a surveyor and auditor.

Mr. Mark J. Gandolfo is a retired U.S. Coast Guard officer with 10 years of experience working in the Coast Guard’s training system. He also served in numerous marine inspector billets as a senior marine inspector and currently works for the U.S. Coast Guard Office of Traveling Inspector Staff. His responsibilities include supporting the Liquefied Gas Carrier and Outer Continental Shelf National Centers of Expertise with workforce development initiatives and training curricula.

Endnote:

¹ Bureau of Safety and Environmental Enforcement, “Deepwater Production Summary By Year,” found at www.data.boem.gov/homepg/data_center/production/production/summary.asp.

Mariner Training

Alternative fuel competency.

by MR. DAVIS J. BREYER
Marine Transportation Specialist
Maritime Personnel Qualifications Division
U.S. Coast Guard

MS. MARGARET DOYLE
Chemical Transportation Advisory Committee Chair
LNG Working Group

Most ships today use a petroleum-based fuel. However, due to the environmental benefits and the abundance of alternative fuels like liquefied natural gas (LNG), a new category of ships are being built. In some instances, operators retrofit existing ships to use these fuels. Concurrent with the vessel design or retrofit process, operators must ensure that mariners employed on these ships are properly trained with regard to these low-flashpoint fuels.

In this case, there is currently a training and certification process that can serve as a resource for these new standards. This will help ensure that mariners who serve on LNG carriers that use the boil-off from their cargo as a fuel source receive appropriate training.

Of course, there are differences between ships that carry liquefied natural gas as cargo and vessels that only specifically use gases or low-flashpoint fuels as a fuel source, so any new training standards must ensure mariners can safely handle and operate the specialized and modified equipment involved with alternate fuels. Moreover, by applying the lessons learned from LNG cargo operations and assessing duties and the operational risk, we can develop training tailored to ensure safe and efficient LNG-as-fuel operations.

Training Guidelines

In 2012, the Merchant Marine Personnel Advisory Committee (MERPAC) developed recommendations for training mariners who would sail aboard these ships. Recognizing the similarities and differences between LNG cargo carriers and vessels only using natural gas as a fuel source, MERPAC originally adapted the tankerman liquefied gas training requirements to develop recommended training guidelines to meet International Maritime Organization

(IMO) standards. As discussions expanded to include gases or low-flashpoint fuels as fuel sources, MERPAC amended its recommendations to encompass all fuels cited in the International Code of Safety for Ships using Gases or other Low-flashpoint Fuels (IGF Code), and it continues to develop recommendations as the related domestic and international standards mature.

It is worth noting that other Department of Homeland Security committees as well as the Coast Guard advisory committees were also tasked to address issues related to vessels carrying natural gas or using natural gas as fuel. For example, the Coast Guard's Chemical Transportation Advisory Committee was tasked to identify gaps in current policy and

Course Review

To help schools develop their courses, Coast Guard personnel voluntarily review submitted courses designed to meet the training guidance found in CG-OES Policy Letter 01-15.

Courses that meet this guidance are issued a letter attesting to conformance with the training. It is envisioned that if training regulations are published in the future, institutions that previously submitted courses will be required to re-submit their course materials for approval, in accordance with the appropriate regulations.

For more information, please contact the Coast Guard's National Maritime Center at NMCCOURSES@uscg.mil.



Liquefied Gas Bunkering

There are no mariner qualification changes for those sailing aboard those classes of tank vessels, including liquefied gas carriers, that currently burn their cargo as fuel. As bunkering vessels are considered to be tank ships and tank barges, the training and manning requirements are already in place.

For additional information regarding bunkering vessels using gases and low-flashpoint fuels, consult CG-OES Policy Letter 02-15, available at www.uscg.mil/hq/cg5/cg522/cg5222/PolicyLetters.asp.

regulations regarding vessel design, and to develop acceptable design criteria to fill those gaps.

Also in 2012, the IMO Subcommittee on Bulk Liquids and Gases was in the midst of developing the IGF Code and recognized the need to develop associated training requirements in support of the code, so members requested that the Subcommittee on Standards, Training and Watchkeeping begin work in this area. The ensuing discussions identified a need for mandatory training requirements for crew serving on ships fueled by gas or low-flashpoint fuels.

Furthermore, the subcommittee determined that until such time as mandatory requirements could enter into force, there was a need to develop interim guidance to:

- ensure the safe transition of existing, experienced mariners into the new operations;
- ensure the availability of mariners trained to operate these vessels;
- fill the gap until the Standards of Training, Certification and Watchkeeping (STCW) amendments came into force with the IGF Code.

The United States led the effort to develop the mandatory training requirements as well as the interim guidance, as the MERPAC recommendations became the basis for the U.S. positions at the IMO. The end product from this initiative was a set of amendments to the STCW Convention and Code contained in Chapter V related to the IGF Code.

These amendments were approved in June 2015 and will come into force concurrently with the IGF Code at a future date. Furthermore, interim guidance was approved in November 2014 for immediate implementation until the IGF Code and the above-mentioned training requirements come into force.¹

Current U.S. Training Policy

In February 2015, the Coast Guard published CG-OES Policy Letter No. 01-15, "Guidelines for Liquefied Natural Gas Fuel Transfer Operations and Training of Personnel on Vessels Using Natural Gas as Fuel." Enclosure 3 to this policy letter provides training guidance and recommends the level of competence necessary for the safe operation of ships using gases and low-flashpoint fuels.

Specific training: Mariners employed on these vessels should receive appropriate training on the risks and emergency procedures associated with gases or other low-flashpoint fuels in accordance with their duties and responsibilities. On that basis, the training levels include:

- advanced training for vessels using gases or low-flashpoint fuels. This is applicable to any person with immediate responsibility for the fuel and fuel systems on these vessels. Mariners who are qualified and certified for service on liquefied gas tankers as tankerman PIC (LG) or tankerman engineer (LG) and who have the recommended sea service meet the general training recommendations.
- basic training for vessels using gases or low-flashpoint fuels. This is applicable to mariners with duties associated with using, or in emergency response to, the fuel aboard these vessels. Mariners who are qualified and certified as tankerman PIC (LG), tankerman engineer (LG), or tankerman assistant (LG) meet the general training requirements.

Familiarization training: Mariners on U.S. vessels must comply with the existing requirements in 46 CFR 15.405 (familiarity with vessel characteristics) and 46 CFR 15.1105 (STCW—familiarization and basic training) before assuming their duties. This familiarization is essential, as the specific training described above is general in nature. Mariners and any person aboard vessels using gases or low-flashpoint fuels need job-, ship-, and fuel-specific familiarization training. For the non-mariners, this familiarization should specify any additional information that would affect their onboard safety.

Mariners on foreign-flagged vessels operating in U.S. waters should receive the training contained in the IMO guidance STCW.7/Circ.23 as well as the familiarization training required in STCW Regulations I/14, "Responsibilities of companies."²

Future Considerations

Throughout the policy development process, stakeholders recognized that the ships designed or modified to use these alternative fuels have a great deal in common with vessels that use conventional fuels. The differences lie in the fuel

characteristics, specialized auxiliary equipment, adaptations and/or changes from conventional equipment, and expanded mariner competency requirements.

In the future, gases or low-flashpoint fuels may overtake conventional fuels in marine operations. As the fuel markets mature, the training elements outlined in CG-OES Policy Letter No. 01-15 may be incorporated into mainstream mariner training.

About the authors:

Mr. Davis Breyer has been working in the Maritime Personnel Qualifications Division at U.S. Coast Guard headquarters since 2010. He is a licensed master mariner with more than 20 years aboard LNG carriers. He has also worked as a marine educator and currently serves as a member of the U.S. Delegation to the IMO Subcommittee on Human Element, Training and Watchkeeping.

Ms. Margaret Kaigh Doyle is a senior program manager at the Gas Technology Institute. She has been a long-standing member of the U.S. Coast Guard Chemical Transportation Advisory Committee, chairs its CTAC LNG Working Group, and has participated at IMO on a number of delegations. She currently serves as a member of the U.S. Delegation to the IMO Subcommittee on Human Element, Training and Watchkeeping.

Endnotes:

- ¹ This guidance was promulgated via an IMO circular entitled "Interim guidance on training for mariners on board ships using gases or other low-flashpoint fuels" (STCW.7/Circ.23). This interim guidance is consistent with the mandatory requirements that will be included in Chapter V of the STCW Convention and Code.
- ² Documentary evidence such as course completion certificates, company letters, etc., should be issued indicating that the holder has successfully completed the basic or advanced training. The company letters should include any relevant onboard training that would be recorded as required by 46 CFR 15.1107. This is recommended to ensure that the mariner can demonstrate adequate training for the position held aboard a vessel using gases or low-flashpoint fuels. Additionally, this documentary evidence could help the mariner to obtain any credential endorsements that may eventually be required to sail aboard these vessels.

For more information:

Direct any questions regarding mariner training to CGOES1@uscg.mil.

CG-OES Policy Letter No. 01-15, "Guidelines for Liquefied Natural Gas Fuel Transfer Operations and Training of Personnel on Vessels Using Natural Gas as Fuel," is available at: www.uscg.mil/hq/cg5/cg522/cg5222/PolicyLetters.asp.



Understanding Unslaked Lime

by MR. TOM GLEAVE
Chemical Engineer
Hazardous Materials Division
U.S. Coast Guard

What is it?

Unslaked lime is an inorganic white or grayish-white odorless crystalline solid that is soluble in acid and reacts exothermically with water to form calcium hydroxide. Lime has a wide variety of uses and applications that make it quite valuable, including steel manufacturing, environmental protection, construction, mining, and chemical manufacturing.

In steel manufacturing, it is used as a flux to remove impurities such as silica, phosphorus, and sulfur from molten iron. The fastest-growing and second most common use is in environmental protection, where lime is used to remove sulfur oxides and mercury from power plant emissions. It is also used to treat sewage sludge and animal waste from feeding operations and to adjust pH in industrial waste water discharges.

Why should I care?

Shipping Concerns:

When unslaked lime combines with water, it generates a great amount of heat that may ignite nearby combustible materials, so it should be stored away from paint, vessel stores, or other combustible solids/cargoes.

Health Concerns:

Lime is corrosive to the eyes and mucus membranes. It can also cause serious alkali burns on the skin or internally, if inhaled or swallowed.

Fire or Explosion Concerns:

While lime can generate heat if exposed to moisture, it is not in itself combustible, and therefore presents a low fire risk.

What is the Coast Guard doing about it?

The U.S. Coast Guard ensures compliance with the domestic and international regulations applicable to lime bulk transport in U.S. waters.

About the author:

Mr. Tom Gleave is a chemical engineer in the Hazardous Materials Division at U.S. Coast Guard headquarters. He develops, maintains, and updates domestic and international regulations for solid bulk cargo marine transport. Mr. Gleave earned a B.S. in environmental engineering from Temple University and has more than a decade of experience in environmental engineering and air quality compliance. He also served four years in the U.S. Navy as an aviation electricians' mate.

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Nautical Engineering Queries

Prepared by NMC Engineering
Examination Team



1. What is the function of the autotransformer used with autotransformer starters on some large AC motors?
 - A. provide increased voltage for starting
 - B. provide increased torque for starting
 - C. provide reduced voltage for starting
 - D. provide speed control

2. Regarding the low pressure evaporator steam control orifice in the live steam supply line, the steam at the outlet of the orifice, if not properly conditioned, will be developed as _____.
 - A. desuperheated steam
 - B. superheated steam
 - C. saturated steam
 - D. poor quality steam

3. Injection lag can be caused by _____.
 - A. improper timing of the intake valves
 - B. setting of the pump plunger
 - C. compressibility of the fuel
 - D. position of the needle valve

4. The factor contributing to the greatest effect on the ship's period of roll is the _____.
 - A. length of KB
 - B. vertical weight distribution
 - C. virtual rise in the center of gravity
 - D. moment to trim 1 inch (MT1)

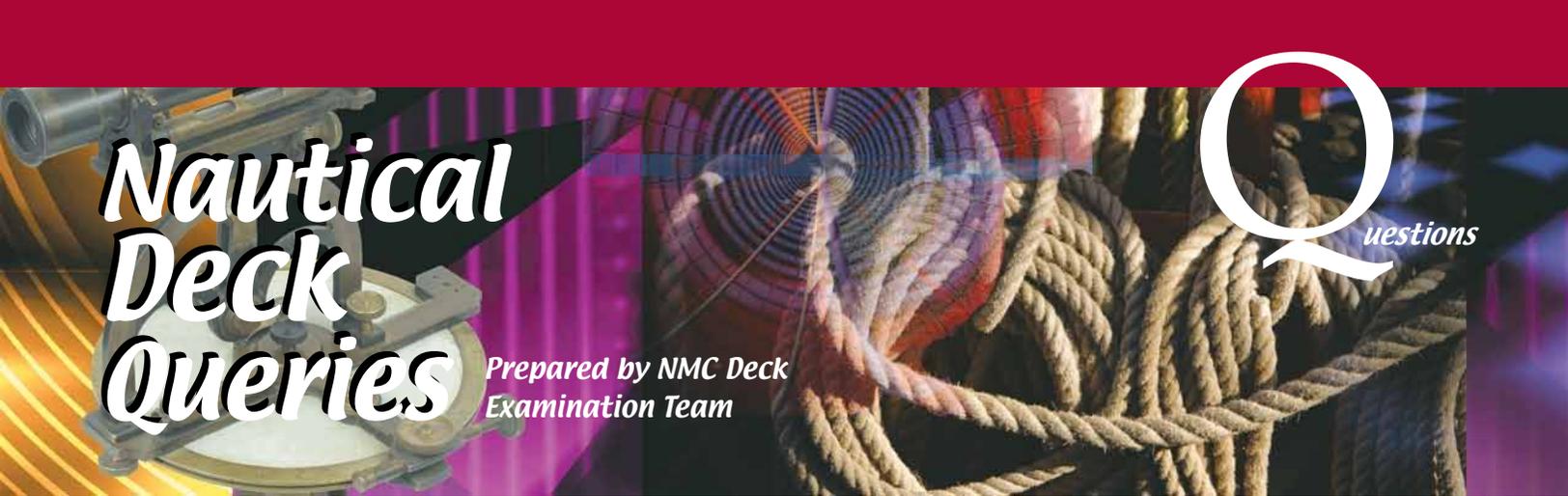


1. *Note: To prevent alternator voltage droop during motor startup, large AC motors usually use some method of reduced voltage starting to reduce motor starting current. One of the commonly used reduced-voltage starting methods used aboard a ship is the autotransformer starter.*
 - A. provide increased voltage for starting Incorrect answer. Autotransformers function to provide decreased voltage for starting, not an increase in voltage.
 - B. provide increased torque for starting Incorrect answer. Although autotransformers function to provide decreased voltage for starting, this results in a decrease in torque for starting, not an increase in torque.
 - C. provide reduced voltage for starting **Correct answer. As explained in the Note above, autotransformers provide reduced voltage for the starting of large AC motors.**
 - D. provide speed control Incorrect answer. Large AC motors may use any of a number of variable speed drive technologies, none of which include the autotransformer type starter.

2. *Note: The steam supply source for an LP evaporator seawater feed heater may be auxiliary exhaust, turbine extraction steam, or "live" steam (steam reduced from boiler pressure). Steam pressure to the evaporator's feed heater is controlled by a regulating valve. An orifice plate downstream of the regulating valve ensures a constant flow of steam to the feed heater. As the supply steam passes through the regulating valve, the steam pressure is reduced, resulting in superheating of the steam. Superheating of the steam is undesirable because the higher steam temperature leads to increased scale formation in the evaporator. To prevent this, the superheated steam is "conditioned" via condensate sprayed through a desuperheater nozzle located between the orifice plate and the inlet to the feed heater.*
 - A. desuperheated steam Incorrect answer. Prior to the steam being conditioned at the outlet of the control orifice, the steam is in a superheated state, not a desuperheated state.
 - B. superheated steam **Correct answer. As explained in the Note above.**
 - C. saturated steam Incorrect answer. Prior to the steam being conditioned at the outlet of the control orifice, the steam is in a superheated state, not a saturated state.
 - D. poor quality steam Incorrect answer. Steam quality is a measure of the proportion of saturated vapor in a saturated vapor-liquid mixture. Since prior to the steam being conditioned at the outlet of the control orifice, the steam is in a superheated state, the steam quality cannot be considered poor.

3. *Note: Injection lag is the time interval between the beginning of the delivery stroke of the fuel injection pump and the beginning of injection at the injector nozzle. It is affected by the length of the high pressure fuel lines, the compressibility of the fuel, and the ability of the system to keep the high pressure fuel lines full of fuel between injection events.*
 - A. improper timing of the intake valves Incorrect answer. Although improper timing of the intake valves may impact the ignition delay period and combustion efficiency, it has no influence on injection lag.
 - B. setting of the pump plunger Incorrect answer. Although the setting of the pump plunger will impact injection timing, it has no influence on injection lag.
 - C. compressibility of the fuel **Correct answer. Even though fuels are virtually incompressible, the small degree of compressibility is one of the factors causing injection lag.**
 - D. position of the needle valve Incorrect answer. The position of the needle valve is determined by the high pressure fuel line pressure. The needle valve is open during injection when the fuel line pressure is high and is closed at all other times. The position of the needle valve has no influence on injection lag.

4. *Note: When external forces act upon the hull of a ship, causing it to roll about its longitudinal axis, the period of roll is the time required to complete one roll cycle. The roll period is primarily determined by the vertical weight distribution (or the length of KG). The higher the center of gravity, the longer the roll period (or slower the roll) will be.*
 - A. length of KB Incorrect answer. The length of KB is determined by the loaded weight of the ship and does not necessarily correlate to the vertical weight distribution.
 - B. vertical weight distribution **Correct answer. As explained in the Note above.**
 - C. virtual rise in the center of gravity Incorrect answer. Although weight shifting transversely as a ship rolls will cause a virtual rise in the center of gravity, and thus have an impact on the roll period, the vertical weight distribution (length of KG) is the primary factor contributing to the ship's roll period.
 - D. moment to trim 1 inch (MT1) Incorrect answer. The moment to change trim one inch (MT1) is associated with movement of weight fore and aft on the ship which impacts longitudinal stability, whereas the ship's period of roll is associated with transverse stability.

The banner features a composite background. On the left, there is a close-up of a sextant. On the right, there are coils of thick, light-colored rope. A large, white, stylized letter 'Q' is positioned in the upper right corner, with the word 'uestions' written in a smaller, white, sans-serif font to its right. The title 'Nautical Deck Queries' is written in a large, white, serif font across the top left.

Nautical Deck Queries

Prepared by NMC Deck Examination Team

Q uestions

1. **INLAND ONLY: While underway and in sight of another power-driven vessel forward of your beam, more than 0.5 mile away, you put your engines full speed astern. Which statement concerning whistle signals is TRUE?**
 - A. You must sound three short blasts on the whistle.
 - B. You must sound one blast if backing to starboard.
 - C. You must sound whistle signals only if the vessels are meeting.
 - D. You need not sound any whistle signals.

2. **How is the annual rate of change for magnetic variation shown on a pilot chart?**
 - A. Gray lines on the uppermost inset chart.
 - B. Red lines on the main body of the chart.
 - C. In parenthesis on the lines of equal magnetic variation.
 - D. Annual rate of change is not shown.

3. **The liquid mud tanks on your vessel measure 30 feet L by 15 feet B by 6 feet D. The vessel's displacement is 968 T and the specific gravity of the mud is 1.8. What is the reduction in GM due to two of these tanks being slack?**
 - A. .19 foot
 - B. .42 foot
 - C. .64 foot
 - D. .87 foot

4. **You are transiting the Straits of Mackinac by way of an improved channel. You have information that indicates that the channel's federal project depth is 28 ft. Which of the following statements is true with regard to this channel?**
 - A. The designed dredging depth of the channel is 28 ft.
 - B. The channel has 28 ft. in the center, but lesser depths may exist in the remainder of the channel.
 - C. The maximum depth which may be expected within the limits of the channel is 28 ft.
 - D. The least depth within the limits of the channel is 28 ft.

1. A. You must sound three short blasts on the whistle. Incorrect answer.
- B. You must sound one blast if backing to starboard. Incorrect answer.
- C. You must sound whistle signals only if the vessels are meeting. Incorrect answer.
- D. You need not sound any whistle signals. **Correct answer.**

Reference: Inland Rule 34

Rule 34(a) states: *"When power-driven vessels are in sight of one another and meeting or crossing at a distance within half a mile of each other, each vessel underway, when maneuvering as authorized or required by these Rules: (i) shall indicate that maneuver by the following signals on her whistle."*

2. A. Gray lines on the uppermost inset chart. **Correct answer.**
- B. Red lines on the main body of the chart. Incorrect answer.
- C. In parenthesis on the lines of equal magnetic variation. Incorrect answer.
- D. Annual rate of change is not shown. Incorrect answer.

Reference: Pub. 106–Atlas of Pilot Charts North Atlantic Ocean (including Gulf of Mexico) 2002, National Geospatial-Intelligence Agency

3. A. .19 foot Incorrect answer.
- B. .42 foot Incorrect answer.
- C. .64 foot Incorrect answer.
- D. .87 foot **Correct answer.**

Reference: Stability and Trim for the Ship's Officer, Fourth Edition, William E. George, p. 167.

Where: GG_0 = reduction per tank

R = ratio of specific gravity of the liquid in the tank to the liquid the vessel is floating in

L = length

B = breadth

$GG_0 = rlb^3 / 420 \times \text{Displacement}$

$GG_0 = (1.8/1.025)(30)(15)^3 / (420)(968) = 0.437$ foot per tank

Total reduction = 2×0.437

Total reduction = 0.87 foot

4. A. The designed dredging depth of the channel is 28 ft. **Correct answer.**
- B. The channel has 28 ft. in the center, but lesser depths may exist in the remainder of the channel. Incorrect answer.
- C. The maximum depth which may be expected within the limits of the channel is 28 ft. Incorrect answer.
- D. The least depth within the limits of the channel is 28 ft. Incorrect answer.

Reference: United States Coast Pilot 6, 2014 Edition, Page 2, *"Federal project depth is the original design dredging depth of a channel planned by the U.S. Army Corps of Engineers and may be deeper than current conditions. For this reason, project depth must not be confused with controlling depth."*

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