The Feasibility, Issues, and Benefits Associated With Expanded Use of Natural Gas at Seaports and Other High Horsepower Applications
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Contract Number: 500-12-008

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ACKNOWLEDGEMENTS

This report was prepared by the clean transportation and energy consulting firm of Gladstein, Neandross & Associates (GNA) in March 2017, as a result of work sponsored by the U.S. Department of Energy and the California Energy Commission, under oversight by the National Renewable Energy Laboratory. The opinions, findings, conclusions, and recommendations found in this report are those of the authors and do not necessarily represent the views of the U.S. Department of Energy, the Energy Commission, or the National Renewable Energy Laboratory. These agencies – and their officers, employees, contractors, and subcontractors – make no warranty, expressed or implied, and assume no legal liability for the information in this report. GNA gratefully acknowledges the essential support of, and content contributions from, these agencies.

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PREFACE

The California Energy Commission’s Energy Research and Development Division manages the Natural Gas Research and Development program, which supports energy-related research, development, and demonstration not adequately provided by competitive and regulated markets. These natural gas research investments spur innovation in energy efficiency, renewable energy and advanced clean generation, energy-related environmental protection, energy transmission and distribution and transportation.

The Energy Research and Development Division conducts this public interest natural gas-related energy research by partnering with RD&D entities, including individuals, businesses, utilities and public and private research institutions. This program promotes greater natural gas reliability, lower costs and increases safety for Californians and is focused in these areas:

- Buildings End-Use Energy Efficiency.
- Industrial, Agriculture and Water Efficiency
- Renewable Energy and Advanced Generation
- Natural Gas Infrastructure Safety and Integrity.
- Energy-Related Environmental Research
- Natural Gas-Related Transportation.

The Feasibility, Issues, and Benefits Associated with Expanded Use of Natural Gas at Seaports and Other High Horsepower Applications is a final report for the Natural Gas Vehicle Research Roadmap project (Contract Number 500-12-008) conducted by the National Renewable Energy Laboratory. The information from this project contributes to Energy Research and Development Division’s Natural Gas-Related Transportation Program.

For more information about the Energy Research and Development Division, please visit the Energy Commission’s website at www.energy.ca.gov/research/ or contact the Energy Commission at 916-327-1551.
ABSTRACT

Using natural gas in high-horsepower port applications, especially high-impact sectors like marine vessels and locomotives can provide strong societal benefits. Natural gas can significantly improve ambient air quality, reduce greenhouse gas emissions (especially renewable natural gas), and help end-user fleets comply with challenging regulatory requirements while also reducing life-cycle costs.

This report focuses on marine vessels and locomotives as key high-horsepower port applications. These two sectors consume significant volumes of fuel, have high associated environmental impacts, and offer the potential to achieve additional environmental benefits beyond those being promulgated through federal regulations. Because marine vessels and locomotives require large onboard energy storage, development and commercialization have been focused on liquefied natural gas fuel systems and technologies. This report analyzes the feasibility, issues, and potential benefits of using liquefied natural gas (LNG) in high-horsepower off-road seaport applications. Compressed natural gas applications are also discussed.

Keywords: natural gas, high horsepower applications, HHP, marine vessels, locomotives, port applications, renewable natural gas, liquefied natural gas, compressed natural gas, seaport

Please use the following citation for this report:

# TABLE OF CONTENTS

ACKNOWLEDGEMENTS ................................................................................................................................. i  
PREFACE ........................................................................................................................................................... ii  
ABSTRACT ....................................................................................................................................................... iii  
TABLE OF CONTENTS ................................................................................................................................. iv  
LIST OF FIGURES ........................................................................................................................................ vi  
LIST OF TABLES .......................................................................................................................................... vii  
EXECUTIVE SUMMARY .............................................................................................................................. 1  
  Introduction .................................................................................................................................................... 1  
  Project Purpose and Process .......................................................................................................................... 1  
  Project Results ............................................................................................................................................... 1  
  Benefits to California ...................................................................................................................................... 3  
CHAPTER 1: Overview of Engine Technology for High Horsepower Port Applications .......... 5  
  1.1 Marine Vessel and Locomotive Engine Technologies and Emissions ............................................. 5  
  1.1.1 Current Emission Standards and Regulations .............................................................................. 6  
  1.1.2 Strategies to Inject and Combust Natural Gas in HHP Engines ................................................... 7  
  1.1.3 Specific Technologies Under Development ................................................................................. 9  
  1.1.4 Emission Control Technologies Related to Natural Gas Engines .............................................. 11  
  1.1.5 Commercial Natural Gas Engine Offerings by HHP Application ............................................. 12  
  1.1.6 Engine Sizes Typical for California Marine and Rail Applications ......................................... 13  
  1.2 Limitations of Current LNG Engine Technologies for Marine and Rail Sectors .......................... 16  
CHAPTER 2: Existing Natural Gas Supply, Infrastructure, and Use for Port Applications .... 18  
  2.1 Large-Scale LNG Facilities Focused on Marine Applications for the West Coast ..................... 18  
  2.2 Smaller LNG Supply Facilities Serving West Coast On-Road Natural Gas Vehicle Markets ...... 20  
  2.3 Current Transportation Uses of Natural Gas at California Ports .................................................. 22  
    2.3.1 On-Road Drayage Trucks and Off-Road Yard Hostlers ......................................................... 22  
    2.3.2 Marine Vessels and Locomotives ............................................................................................... 22  
CHAPTER 3: Opportunities and Challenges for Expanded Use in Key Port Applications .... 24  
  3.1 Overview ............................................................................................................................................... 24
LIST OF FIGURES

Figure 1: Federal Emissions Standards for Marine and Locomotive Engines ........................................ 6
Figure 2: Typical Range of Total Installed Engine Power for Marine Vessels That Call at California Ports ........................................................................................................................................ 13
Figure 3: Available Power Ranges for LNG Marine Engines From Major OEMs ................................ 14
Figure 4: Three Major Types of Locomotives Serving California Port Operations ................................ 14
Figure 5: FortisBC’s Expansion of Tilbury Island LNG Plant to “Meet Growing Market Needs” .......... 18
Figure 6: Clean Energy’s LNG Liquefaction and Storage Facilities at Boron, California .................. 21
Figure 7: Six-Year Trends for LNG-Diesel (left) and CNG-Diesel (right) Price Spreads ................ 25
Figure 8: Actual and Projected Diesel Retail Price for Pacific Region, 2010—2050 ............................. 26
Figure 9: FortisBC’s Target Markets for West Coast LNG Applications .............................................. 28
Figure 10: Likelihood of Individual Marine Vessel Segments Using LNG by 2026 ............................ 30
Figure 11: Interacting Considerations When Making a Business Case for LNG ................................. 33
Figure 12: Mix of Marine Vessel Types Serving California’s Three Major Ports ............................... 34
Figure 13: Estimated Annual Fuel Use Demand for Top Five Fuel-Use Sectors (per-vessel and sectorwide) ....................................................................................................................... 36
Figure 14: Estimated Annual Fuel Demand for Key Port Equipment Sectors at San Pedro Bay Ports ........................................................................................................................................... 40
Figure 15: Leading LNG Bunker Supply Options for Large Mature Markets ..................................... 43
Figure 16: Potential LNG Bunkering Supply Options for San Pedro Bay Ports Complex ................ 44
Figure 17: Construction of North America’s First LNG Bunker Barge ................................................ 45
Figure 18: A “Rack and Tank” Locomotive Fueling Strategy Common to Near-Port Rail Yards .......... 47
Figure 19: A DTL Fueling Process Being Performed at a Designated Location ................................. 47
Figure 20: Natural Gas Volumes Generating Credits in the California LCFS Program, With Percentage Generated by RNG ........................................................................................................ 56
Figure 21: CARB’s “18% Scenario” for Volumes of Transportation Fuels Generating Future LCFS Credits

LIST OF TABLES

Table 1: Key Emission Regulations Affecting Marine and Locomotive Engines in California. 8
Table 2: Leading Dual-Fuel Injection and Combustion Strategies for Marine Vessel and Locomotive Engines .......................................................... 9
Table 3. Examples of Commercial Natural Gas Engine Offerings in Marine and Rail Applications ............................................................................. 12
EXECUTIVE SUMMARY

Introduction
Natural gas use as transportation fuel for high-horsepower seaport-related applications such as marine vessels and rail locomotives has seen increased interest, driven primarily by favorable economics and international and domestic emission regulations. Commercial marine vessels and rail locomotives are projected to be the third and fifth largest sources of nitrogen oxide (NOx) emissions, a precursor to harmful smog formation, in the South Coast Air Basin by 2023. Seventy-two percent of the total NOx emissions from the San Pedro Bay Ports are produced by ocean-going vessels, harbor craft, and locomotives. Natural gas has the potential to displace diesel fuel and reduce NOx emissions from these sources to meet and exceed increasingly stringent emission requirements.

Project Purpose and Process
This study assesses the feasibility, issues, and potential benefits associated with expanding natural gas use in California high-horsepower seaport applications focusing on three of the state’s major ports: Port of Los Angeles, Port of Long Beach, and Port of Oakland. These large seaports act as the anchors of California’s world-class goods movement system. To date, actual natural gas use to power high horsepower locomotives, vessels and equipment at these and other North American ports has essentially been limited to proof-of-concept tests and a few early market commercial uses. Increasingly stringent emission regulations and air quality improvement plans have stimulated new interest in switching to clean-burning natural gas engines for California ports and the United States.

Liquefied natural gas (LNG) fuel systems are receiving the most interest for large high-horsepower applications, however compressed natural gas (CNG) fuel systems may also play a role in niche applications. Renewable natural gas (RNG) can further reduce greenhouse gas (GHG) emissions and maximize climate change benefits.

The research team examined existing engine technology, natural gas supply, and fueling infrastructure before detailing the opportunities and challenges related to using more natural gas in California seaport-related operations. Analysis of potential natural gas adoption scenarios in West Coast ports were also performed to estimate potential fuel demand and associated benefits. Fuel supply scenarios are identified based on the potential fuel demand and California’s current LNG production infrastructure. The team investigated and evaluated the challenges and potential greenhouse gas reduction and economic benefits of using renewable natural gas (RNG) in high-horsepower seaport applications.

Project Results
Estimated demand for existing petroleum fuels from marine vessels (mostly ocean-going vessels) is an order of magnitude larger than the combined fuel demand from locomotives, drayage trucks, and cargo-handling equipment at the San Pedro Bay ports. As a result, marine vessels show huge potential LNG demand even at modest adoption rates. Existing LNG production infrastructure in California will not be sufficient to meet the high fuel demands of ocean-going vessels. There is potential for LNG to be imported from Vancouver, British Colombia or Costa Azul, Mexico to supply ships at California ports. Potential
Locomotive deployment synergies exist due to expected increases of on-dock rail movement and rail infrastructure expansion at California ports.

Although there are significant potential climate change benefits with RNG use in high-horsepower applications, several major challenges make it difficult to estimate the extent of RNG use in high-horsepower applications like marine vessels and locomotives. These challenges include a lack of market supply and demand certainty for biogas feedstock, competing uses for biogas feedstock and/or RNG, requirements for RNG pipeline injection and transmission, and limited applications in high-horsepower sectors that are currently included in Low Carbon Fuel Standard (LCFS) and Renewable Fuel Standard (RFS) markets.

Important technical, policy, institutional, and economic challenges must be addressed before California can realize the major benefits of using natural gas in seaport HHP applications. The team recommended actions to allow fuel switching in marine and locomotive applications serving California seaports. The recommendations generally fall within the jurisdictions of key California state agencies and state funding programs. They also broadly apply to federal and local agencies, industry groups, and academic institutions that seek to reduce criteria pollutant and GHG emissions or both from marine vessels and locomotives.

Specific recommendations to help advance natural gas engines and vessels/locomotives including:

- Conduct research, development and deployment demonstrations to improve the feasibility, emissions, and efficiency of dual-fuel and dedicated natural gas engines designed for marine vessels and locomotives. The focus should be on engine technologies with the best potential to achieve emission levels well below the current cleanest standards. These applications have significant potential to displace conventional marine and rail fuels and reduce emissions.

- Support research, development, and demonstration (RD&D) efforts to use novel fuel injection and ignition strategies for low-NOx large-bore, medium-speed natural gas engines with low methane slip (unburned) and high efficiency, and the option for 100 percent diesel operation.

- Explore the most promising applications for RD&D funding that fall under state and local control, such as switcher and intrastate locomotives, commercial harbor craft, and cargo-handling equipment.

- Review potential for similar locomotive RD&D efforts for intrastate commuter rail and locomotives (for example Amtrak Capitol Corridor, Pacific Surfliner and San Joaquin Valley routes).

- Adapt technologies already commercially used to achieve near-zero-emission levels in on-road heavy-duty natural gas engines to marine and locomotive applications (for example ferries and switcher locomotives). Specific areas of focus include better control of methane slip, improved durability of emission control systems, and increased fuel efficiency. Details will depend on the specific application and engine technology.
• Support activities to help manufacturers reduce the incremental subsystem costs of natural gas marine vessels and locomotives, including fuel storage systems. Once beneficial technologies such as fuel savings and paybacks have been demonstrated, using high-fuel-use natural gas marine vessels and locomotives may not have to depend on additional funding. Incentives designed specifically to help deployments in lower-fuel-use, high-visibility applications like switcher locomotives, ferries/passenger boats, commercial harbor craft, and cargo-handling equipment may help support progress.

• Provide support to promote and accelerate best practices and emerging codes and standards. For example, California agencies can support the ongoing development of federal standards for cars carrying natural gas (tender cars are fuel cars) for locomotives.

To help support and expand fuel production, infrastructure development, and bunker supply chains, recommendations including:

• Identify and facilitate strategic opportunities to develop LNG bunkering projects that specifically serve multiple high-fuel-use applications, including marine, rail, cargo handling equipment, and peak shaving facilities (reducing the high point in electricity demand). For example, the Jacksonville LNG plant in Florida has been designed to serve multiple transportation end uses.

• Develop a standardized LNG specification that ship and rail operators can use when they procure fuel. To reduce potential risks and help streamline fuel purchasing, this specification should be based on a common framework and terminology that describe key LNG fuel composition and condition requirements across the full LNG supply chain.

To specifically help increase in-state RNG production and the related use in high-horsepower port applications such as marine vessels and locomotives, recommendations include:

• Study the potential future dynamics among the supply, demand, and cost/price for RNG as a transportation fuel in California, especially if high-fuel-use applications like ocean-going vessels and interstate freight locomotives are to use RNG instead of fossil natural gas. This study should include evaluating the potential role of removing current exemptions in the LCFS program for RNG used in these applications.

• Evaluate the status of and potential support for facilities and products providing low-cost small-scale biogas liquefaction.

• Develop a broad-based working group among agencies, utilities, and other stakeholders to establish policies and programs that specifically support production and using RNG as a transportation fuel.

• Study the viability and efficacy of producing renewable LNG for transport by rail.

**Benefits to California**
Using natural gas in high-horsepower seaport applications can provide substantial societal benefits, especially in high-impact sectors like marine vessels and locomotives. Transitioning to natural gas use can significantly reduce key harmful air pollutants by displacing diesel. Disadvantaged communities located near California’s largest seaports will benefit from the air quality improvements. By switching to natural gas, high-horsepower end users at California’s seaports have opportunities to simultaneously comply simultaneously with challenging regulatory requirements and plans while potentially reducing life-cycle costs. Moreover, if these fleets can gain affordable access to growing volumes of RNG in California, they will realize solid reductions of GHG emissions.
CHAPTER 1:
Overview of Engine Technology for High Horsepower Port Applications

Using natural gas in high horsepower (HHP) port applications – especially high-impact sectors like marine vessels and locomotives – can provide strong societal benefits. It can significantly improve ambient air quality, reduce greenhouse gases (GHGs) (especially when using renewable natural gas), and help end-user fleets comply with challenging regulatory requirements while also reducing life-cycle costs. To date, actual natural gas use to power marine vessels and locomotives serving California ports has essentially been limited to proof-of-concept tests. However, important commercialization and demonstration efforts are underway internationally and in North America. These activities enable potential major deployments at California ports. This section briefly describes existing technologies, commercialization efforts, and demonstrations that have relevancy to potential wide-scale use at California seaports.

This report focuses on marine vessels and locomotives as key HHP port applications. These two sectors consume large volumes of fuel have significant associated environmental impacts, and offer strong potential to achieve additional environmental benefits beyond those being promulgated through federal regulations. Commercial marine vessels and rail locomotives are also projected to be the third and fifth largest sources of nitrogen oxide (NOx) emissions, a precursor to harmful smog formation, in the South Coast Air Basin by 2023.\(^1\) Seventy-two percent of the total NOx emissions from the San Pedro Bay Ports are produced by ocean-going vessels, harbor craft, and locomotives.\(^2,3\) Because marine vessels and locomotives require large onboard energy storage, development and commercialization activities have been focused on liquefied natural gas (LNG) fuel systems and technologies. However, in certain smaller engine applications that use return-to-base refueling (e.g., harbor craft and switcher locomotives), efforts are underway to demonstrate and commercialize vessels and locomotives fueled by compressed natural gas (CNG). This report focuses on using LNG in HHP off-road seaport applications. CNG applications are also discussed.

### 1.1 Marine Vessel and Locomotive Engine Technologies and Emissions

To understand the potential for wide-scale use of natural gas in marine vessels and locomotives, it is beneficial to review how more stringent federal emission standards and other regulations are helping to define the basic types of engine technologies used in these sectors.

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1.1.1 Current Emission Standards and Regulations

Historically, marine and rail engine emissions have been modestly regulated, to a significantly lesser extent than on-road heavy-duty engines have been. However, since 2000, both sectors have had more stringent regulations that reduce criteria pollutants emissions such as oxides of nitrogen (NOx, a key precursor to photochemical smog) and fine particulate matter (PM2.5). These standards are complex in structure (in particular, for marine diesel engines); a good overview is provided by Dieselnet.com. Figure 1 summarizes the progression of federal NOx emissions standards that have been adopted for the marine and rail sectors over time. As shown in the Figure 1 (upper graph), all 2016 and newer Category 3 (> 30 liters in displacement) “new-build” marine engines powering ships that call at U.S. ports must comply with International Maritime Organization (IMO) Tier III standards. Category 3 engines are very large propulsion units used for ocean-going vessels such as container ships, oil tankers, bulk carriers, and cruise ships. The U.S. Environmental Protection Agency (U.S. EPA) has adopted IMO-equivalent NOx emission standards for new-build Category 3 engines. Although not shown in the graph, Category 1 and 2 marine engines (new-builds or remanufactured) must also meet harmonized IMO and U.S. EPA emissions standards. Category 1 and 2 marine engines (approximately 700 to 1,100 horsepower) typically power much smaller ships like tugboats, supply vessels, fishing vessels, and other commercial harbor craft.

Figure 1: Federal Emissions Standards for Marine and Locomotive Engines

Source: Gladstein, Neandross & Associates

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The lower graph in Figure 1 shows declining NOx emissions standards adopted by the U.S. EPA for switcher and line haul locomotives, culminating in the Tier 4 standard of 1.3 grams per brake horsepow-er-hour (g/bhp-hr) NOx. This Tier 4 standard also applies to a wide range of other off-road vehicles and equipment.

Current emission standards applicable to large marine engines (Category 3) and locomotive engines require 80 to 90 percent NOx reductions, compared to preregulated Tier 0 engines. These emission standards help drive the NOx reduction approaches that manufacturers of marine and locomotive engines decide to use as they certify and commercialize products with progressively lower emissions. Similarly, U.S. EPA’s Tier 4 standards for locomotive engines require PM emission reductions that may drive adoption of new strategies (e.g., addition of diesel particulate filters). Notably, IMO Tier III standards applicable to Category 3 marine engines do not regulate PM emissions.

In addition to these new engine standards, marine vessels and locomotives are subject to numerous other emissions-related regulations from various jurisdictions (international, state and local). Table 1 summarizes key examples. To comply with these various rules and regulations, engine original equipment manufacturers (OEMs) are employing or considering a range of solutions. As outlined in the last column of Table 1, these methods include fuel switching to LNG or a lower-emission petroleum fuel, adopting engine modifications that provide significant NOx reductions from most types of diesel engines such as exhaust gas recirculation (EGR), or an exhaust scrubbers or selective catalytic reduction (SCR), and for locomotives, fully electrifying the drivetrain to eliminate combustion. Identifying the ideal strategy for a given application and engine type entails complex tradeoffs involving technical, logistical, and economic parameters.

1.1.2 Strategies to Inject and Combust Natural Gas in HHP Engines

Several strategies are under development – and in some cases commercialization – to optimally inject and combust natural gas in HHP engines for ships and locomotives. For example, as with small-bore, higher-speed heavy-duty engines used in on-road applications, spark-ignition technology makes it possible to combust 100 percent natural gas in large-bore, medium- and low-speed engines that power ships and locomotives. In fact, some development and commercialization efforts are using that approach. Much of the focus by technology developers for marine and rail applications, however, is on “dual-fuel” compression-ignition engines. Dual-fuel engines combust a mixture of natural gas and diesel in varying percentages. As summarized in Table 2, the volume percentage of natural gas in dual-fuel engines ranges from 50 percent up to 95 percent. Like the spark-ignition approach, each dual-fuel strategy offers “pros” and cons related to cost, required emission controls, levels of emissions that can be achieved, fuel efficiency, and other factors.

The next subsection discusses specific natural gas injection/combustion technologies that are under development for HHP applications and examples of commercial or near-commercial engines that use them. This discussion helps highlight opportunities and challenges for marine and locomotive natural gas engine strategies that can potentially make good focal points for government-industry partnerships that seek to expand commercialization by improving competitiveness versus conventionally fueled engines.
Successful endeavors in this arena can significantly help California meet its aggressive environmental goals by involving high-fuel-use, high-impact marine and rail sectors that serve seaports.

Table 1: Key Emission Regulations Affecting Marine and Locomotive Engines in California

<table>
<thead>
<tr>
<th>Sector</th>
<th>Agency</th>
<th>Status Today</th>
<th>Requirement or Standard</th>
<th>Effective Date(s)</th>
<th>Example Methods to Achieve</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rail</td>
<td>EPA</td>
<td>Tier 4 (newbuilds) NOx: 1.7 g/kWh</td>
<td>Tier 4 (newbuilds) NOx: 1.7 g/kWh</td>
<td>2016</td>
<td>• EGR</td>
</tr>
<tr>
<td></td>
<td>South Coast AQMD</td>
<td>Tier 2 fleet average NOx: 7.4 g/kWh</td>
<td>Tier 2 fleet avg NOx: 7.4 g/kWh</td>
<td>2010</td>
<td>• Engine rebuilds</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>• Dedicated fleet</td>
</tr>
<tr>
<td>Marine</td>
<td>IMO – ECA</td>
<td>NOx: 2-3.4 g/kWh (newbuilds)</td>
<td>NOx: 2-3.4 g/kWh (newbuilds)</td>
<td>2016</td>
<td>• Fuel switching</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Fuel Sulfur: 0.1%</td>
<td>Fuel Sulfur: 0.1%</td>
<td>2015</td>
<td>• Scrubbers + SCR</td>
</tr>
<tr>
<td></td>
<td>IMO - Global</td>
<td>Fuel Sulfur: 3.5%</td>
<td>Fuel Sulfur: 0.5%</td>
<td>2020</td>
<td>• Fuel blending</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>• LNG</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>• Scrubbers</td>
</tr>
<tr>
<td></td>
<td>CARB 2</td>
<td>Fuel Sulfur: 0.1%</td>
<td>Fuel Sulfur: 0.1%</td>
<td>2014</td>
<td>• Fuel switching</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>• SOx Scrubbers</td>
</tr>
<tr>
<td></td>
<td>CARB 3</td>
<td>At-berth Emissions: 50% Reduction</td>
<td>At-berth Emissions: 70% / 80% Reduction</td>
<td>2017 / 2020</td>
<td>• Shore power</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>• LNG</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>• Scrubbers</td>
</tr>
</tbody>
</table>

1. Vessels with engines built prior to 2011 and 2016 must meet Tier I and Tier II standards, respectively. Only new engines installed after 2016 must meet Tier III standards.
2. Applies within 24 nm of California Coast.
3. Limited to frequently calling fleets (25+ times/year for cargo vessels, 5+ times/year for passenger vessels).

Source: Gladstein, Neandross & Associates
1.1.3 Specific Technologies Under Development

Dedicated Spark-Ignition – Dedicated natural gas engines use spark-ignition systems to control combustion. These engines can use either a fumigation or port-injection system; in both cases, combustion pre-chambers and spark plugs are used. Compared to dual-fuel engines, dedicated natural gas engines have reduced fuel handling requirements, because they require only natural gas and not diesel. Spark-ignited HHP natural gas engines will generally reduce “methane slip” (discussed in Section 1.2) compared to dual-fuel technologies, with the exception of high pressure direct injection (HPDI) technology. When used in lean-burn configurations, dedicated natural gas engines can reach efficiencies comparable to diesel engines. However, they may require EGR or SCR systems to meet EPA Tier 4/IMO III NOx emissions limits. Retrofitting existing in-use diesel engines to spark-ignited natural gas engines is not practical. Using dedicated spark-ignited engines is limited to new build engines or complete engine replacements (repowers).

Fumigation – In dual-fuel engines using fumigation systems that injects natural gas into the incoming combustion air stream either before or after the turbocharger, yet is upstream of the engine intake valves. This mixture of natural gas and air is compressed and then ignited using an injection of diesel fuel. The total amount of diesel fuel injected is reduced from the baseline diesel engine configuration to account for the energy contributed by the natural gas. Replacing the diesel fuel with natural gas is referred to as the “substitution rate” and it can reach 50 to 70 percent of the baseline diesel fuel injection rate.

Fumigation systems are low-cost, can be retrofitted onto existing engines, and can be operated with low-pressure natural gas supplies. These engines also retain the ability to operate on 100 percent diesel fuel. Because of valve overlap in diesel engines, methane slip rates tend to be high. The system is also limited in the ability to respond to dynamic load changes, due to delays in the transmission of the gas to the combustion cylinder. This limitation makes the control of combustion quality more difficult, and limiting
substitution rates. Moreover, fuel injected into common intake manifolds limits the ability to independently control the fuel rate to each cylinder. Therefore, knock detection in one cylinder can limit fueling to all cylinders. Fumigation systems typically maintain or marginally improve NOx emissions relative to a comparable diesel engine. They require the addition of an after treatment component such as a diesel oxidation catalyst (DOC) designed to control carbon monoxide (CO) emissions.

**Port Injection** – Similar in operation to fumigation systems, these systems inject natural gas at the intake port of each cylinder. This reduces the fuel path length and enables the control of fueling on a per-cylinder basis, allowing improved control of engine and combustion dynamics. Methane slip or unburned methane can also be reduced by limiting gas injection rates to occur after the exhaust valve has closed. Higher substitution rates of 60 to 80 percent are achievable via port injection compared to most fumigation systems. A port injection system maintains the ability of the engine to operate on 100 percent diesel, but additional gas injectors are required for each cylinder, making the system more expensive and more difficult to retrofit than fumigation systems. Similar to using a fumigation system, NOx emissions are marginally improved by using a port injection system over a comparable diesel engine, although a DOC is required to control CO emissions.

**Diesel Pilot Injection** – Diesel pilot systems are very similar to port injection systems, but they achieve higher substitution rates by using smaller diesel fuel injectors. These smaller injectors improve atomization and combustion performance at low diesel injection rates, but they are not able to provide 100 percent diesel operation. Natural gas substitution rates of 95 percent are possible with this type of system. In addition, the combustion chamber and prechamber may be redesigned to improve overall performance. As with port injection systems, retrofitting an engine with this system is difficult and there are increased costs attributed to the additional natural gas injectors. Note that in some marine engines, the ability of the engine to operate on 100 percent diesel fuel may be retained by installing a separate pilot injector and main diesel fuel injector, or by integrating the pilot and main injectors into a single unit. EPA Tier 4/IMO Tier III NOx emissions levels can be achieved without aftertreatment systems, but a DOC is required to control CO emissions.

**High Pressure Direct Injection (HPDI)** – HPDI systems operate on a traditional diesel cycle, where fuel is injected only at the end of the compression stroke. Natural gas may be injected first, with a subsequent diesel pilot serving to initiate combustion. Or, diesel may be injected first to initiate the reaction, with natural gas injected shortly thereafter to continue the reaction. In either case, both diesel and natural gas must be injected at very high pressures to simultaneously overcome the pressure in the cylinder, deliver enough fuel through the injectors to meet the engine load, and rapidly atomize and disperse the fuel across the cylinder to maintain combustion quality. These requirements for high-pressure injection generally limit HPDI technologies to using LNG rather than CNG because liquids can be pressurized more efficiently than gases can. There are some examples of HPDI strategies using CNG and a booster compressor. Since the fuel is combusted almost immediately after it is injected, HPDI engines have very low methane slip. System costs are high due to the necessity for specialized high-pressure cryogenic pumps and natural gas fuel injectors. Substitution rates are typically at least 95 percent, but the non-premixed combustion process results in higher in-cylinder NOx formation. This requires EGR and/or SCR systems to reduce NOx emissions to EPA Tier 4/IMO Tier III emissions levels.
Although HPDI technology offers numerous advantages (high gas, high substitution, low methane slip), a drawback is that most HPDI engines do not have the ability to operate on 100 percent diesel (as a fallback, if LNG is unavailable). An exception is the MAN ME-GI engine, which can operate on 100 percent diesel; this is a large two-stroke marine engine that is not suitable for smaller applications. Wider availability of high-horsepower HPDI engines that have the capability to operate on 100 percent diesel could help expand natural gas engine markets in port-serving HHP applications. Large-bore, slow-speed engines used in some marine vessels offer greater flexibility and opportunity to employ novel injector designs and gas injection strategies compared to smaller-bore, medium-speed engines. This flexibility offers opportunities for new engine development for large HPDI natural gas engines with high efficiency and low methane slip that allows them to operate on 100 percent diesel, thereby offering fuel flexibility and potentially expanding natural gas use in marine vessel and locomotive markets.

1.1.4 Emission Control Technologies Related to Natural Gas Engines

As described, combusting natural gas in HHP engines may require using specialized emission control strategies to meet existing or emerging standards and regulations. In particular, to control NOx emissions down to EPA Tier 4 levels, dual-fuel engines may require EGR or SCR or both. Whether the engine is conventionally fueled, dual-fueled, or uses dedicated natural gas, OEMs must manage tradeoffs when deciding to employ SCR, EGR, or other emission control strategies. These tradeoffs involve system cost, complexity, durability, and other important factors.

**Exhaust Gas Recirculation** – Most modern heavy-duty engines employ some amount of EGR to control cylinder temperatures and associated NOx emissions. EGR works by capturing a small amount of exhaust gas and recirculating it back into the cylinder during the intake stroke. This exhaust gas displaces some of the fresh air that would otherwise enter the cylinder with exhaust gas composed primarily of inert carbon dioxide and nitrogen. These gases absorb heat from the combustion of the fuel, reducing peak cylinder temperatures responsible for much of the NOx formation in an engine. EGR typically reduces engine efficiency, which creates a tradeoff – increasing levels of EGR provide greater NOx reductions, but at a cost of decreasing fuel efficiency. “High EGR” engines use substantial amounts of gas recirculation to provide greater NOx reductions but require large gas coolers to control the inlet air temperature in the cylinder. These gas coolers can be prone to failure when cooling water flow is interrupted.

**Selective Catalytic Reduction** – SCR systems control NOx emissions through the use of a catalyst and a reducing agent (typically urea). Exhaust gases flow into the SCR reactor where urea is mixed with the exhaust gases. The urea creates a reducing environment within the reactor, allowing the catalyst to convert nitrogen oxide molecules to nitrogen and oxygen. SCR systems can be highly efficient at controlling NOx emissions, commonly achieving reductions greater than 90 percent. Applying SCR to achieve high NOx-control efficiencies allows the OEM to increase fuel efficiency – relative to EGR-only NOx systems – by reducing EGR rates and advancing engine timing. This increases in-cylinder NOx emissions, but SCR aftertreatment greatly reduces them as they pass through the exhaust system. For a given SCR system, NOx reductions are generally proportional to the amount of urea injected – with higher injection rates producing greater NOx reductions. In addition, SCR systems must maintain design operating temperatures to achieve good NOx reduction efficiency. Purchasing, handling, and storing urea adds to engine operating costs, as does periodic maintenance and replacement of the SCR catalyst.
Furthermore, SCR systems can be quickly contaminated by sulfur, making SCR systems generally unsuitable for dual-fuel engines that may operate on high-sulfur distillate fuels.

### 1.1.5 Commercial Natural Gas Engine Offerings by HHP Application

Table 3 provides examples of commercial natural gas engine offerings in marine and rail applications.

#### Table 3: Examples of Commercial Natural Gas Engine Offerings in Marine and Rail Applications

<table>
<thead>
<tr>
<th>Existing Commercial Engine Technologies (may be special order only)</th>
<th>Marine Examples</th>
<th>Rail Examples</th>
<th>Emissions Levels</th>
</tr>
</thead>
<tbody>
<tr>
<td>Marine Distillate or Off-Road Diesel (Compression ignition)</td>
<td>Baseline: most engines and manufacturers</td>
<td>Baseline: most engines and manufacturers</td>
<td>Up to Tier 4 / IMO Tier III with SCR/EGR, SOx control via low sulfur fuels or exhaust scrubbers</td>
</tr>
<tr>
<td>NG-diesel (Low Pressure Fumigation)</td>
<td>CAT 3500 series with Dynamic Gas Blending&lt;sup&gt;6&lt;/sup&gt;</td>
<td>Demo - EMD 710 with Dynamic Gas Blending&lt;sup&gt;6&lt;/sup&gt;</td>
<td>Up to Tier 3 / IMO Tier II with EGR.</td>
</tr>
<tr>
<td>NG-diesel (Low Pressure Port Injection or Low Pressure Diesel Pilot)</td>
<td>MAN DF Series, Wartsila X-DF Series</td>
<td>GE Evolution Tier 2/3 engines with NextFuel</td>
<td>Retrofit: Up to Tier 3 Newbuild: Up to Tier 4 / IMO Tier III with EGR.</td>
</tr>
<tr>
<td>NG-diesel (High Pressure Direct Injection)</td>
<td>MAN ME-GI</td>
<td>None – in development</td>
<td>Up to Tier 3 / IMO Tier II with EGR. EGR/SCR required to achieve Tier 4 / IMO Tier III.</td>
</tr>
<tr>
<td>NG (Spark ignition)</td>
<td>Rolls Royce C26 / B35</td>
<td>CAT G3500 series</td>
<td>Up to Tier 4 / IMO Tier III with EGR.</td>
</tr>
</tbody>
</table>

Source: Gladstein, Neandross & Associates

The natural gas combustion strategy each of these engines uses depends on the specific marine or rail application and the targeted emission levels. While some of these engines are in the early stages of demonstration or precommercial deployment, others have undergone rigorous real-world commercial use. For example, Wartsila dual-fuel engines have been powering three Harvey Gulf marine vessels for about two years, with excellent performance and reliability. Over the next two years Wartsila engines are expected to power many LNG ships, including new-build and conversion vessels on the West Coast for BC Ferries and Seaspan. Worldwide, Wartsila has more than 344 active LNG projects that include merchant ships, cruise ships, ferries, offshore supply vessels, and specialized vessels.<sup>5</sup>

For even the largest marine vessel applications (ocean-going vessels, or OGVs), these types of dual-fuel engines are able to meet IMO Tier 2 or Tier 3 emissions standards when operating on a mixture of natural gas and diesel (last column of Table 3). Comparable diesel marine engines are also able to achieve Tier 3 NOx emission levels. Depending on the type of fuel-injection technology, all these HHP engines may

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require SCR aftertreatment to achieve IMO Tier 3 NOx emission levels. This requirement adds cost and complexity, but inclusion of SCR can allow reduced use of in-cylinder EGR, which improves engine fuel efficiency.

### 1.1.6 Engine Sizes Typical for California Marine and Rail Applications

In the marine and rail sectors, equipment manufacturers employ a range of engine sizes to meet various needs of their customers. Natural gas engines that fit well within those ranges of engine sizes are commercially available or under precommercialization testing.

**Marine Vessels** – The six most-common types of OGVs calling at California ports are listed in Figure 2. OGVs are large vessels designed for deep water navigation, including container ships, tankers, bulk carriers, refrigerated cargo vessels, passenger cruise ships, and “roll-on, roll-off” (Ro-Ro) ships used to transport automobiles. Each year, these types of vessels make nearly 9,000 visits to California ports; most of these are foreign-flagged vessels engaged in international trade. They typically have total installed power ratings that range from 5 to 80 megawatts (MW). These power levels include all installed engines, with most vessels using between one and four engines for main propulsion.

![Figure 2: Typical Range of Total Installed Engine Power for Marine Vessels That Call at California Ports](image)

Figure 2 highlights the available power range of LNG-fueled engines from major marine engine OEMs. As shown, there are LNG engine options covering the full power ranges required by these six vessel types.
These dual-fuel engines can meet IMO Tier III NOx emissions requirements when operating in their dual-fuel mode, with varying levels of natural gas substitution. To meet these low NOx levels while operating solely on fuel oil, these engines typically require complex and expensive aftertreatment systems (SCR).

**Locomotives** – There are three basic types of locomotives that regularly serve California’s ports; these range in power from 1,200 HP to about 4,400 HP (Figure 4). All three types of locomotives are almost exclusively powered by a single diesel engine driving a generator-set, which supplies electrical power to traction motors for propulsion. The largest are line-haul locomotives (typically about 4,400 HP); these are used in “consists” (three to five units) to power large interstate freight trains that can include 100 or more rail cars. A single line-haul locomotive can annually consume 300,000 to 330,000 gallons of diesel fuel annually.

California’s two Class 1 railroads, Union Pacific (UP) and Burlington Northern Santa Fe (BNSF), collectively operate nearly 200 freight trains per day within California. About 65 percent of these train...
trips occur in the South Coast Air Basin, requiring daily use of about 455 line-haul locomotives. To manage these operations, UP and BNSF rely heavily on medium power (2,500—3,200 HP) and switcher (1,200—2,500 HP) locomotives. These smaller units are used to build and move trains within rail yards, between local rail yards, or over local routes. The total freight locomotive fleet that moves goods within the South Coast Air Basin consists of roughly 8,800 medium-power and line haul units and 200 switchers. In addition to the Class 1 railroads, there are also numerous smaller “short-line” operators that move goods within intermodal and industrial facilities, including the ports.

Freight locomotive engine production in the United States is dominated by two manufacturers, GE and EMD (a division of Caterpillar). Both manufacturers are actively developing and demonstrating LNG-fueled engines with BNSF and UP. The primary focus of these demonstrations has been on the EMD 710 and GE EVO engines intended for line-haul service. This is based on the recognition that line haul locomotives consume the most fuel during the associated lifetimes and would provide the greatest fuel cost savings if converted to LNG. Both systems are intended to retrofit existing Tier 2 and Tier 3 locomotives. LNG options for new locomotive engines that must meet Tier 4 emission standards are under development and will likely rely on HPDI or diesel pilot strategies to meet emission standards while providing high substitution rates and maintaining diesel-like efficiency. Class 1 railroads have previously expressed very strong preferences for emission solutions that do not rely on SCR systems. This is because there are significant added costs associated with using urea (supply, distribution, transportation, handling, and onboard storage). Urea is the reducing agent used in SCR systems to control NOx emissions. Both GE and EMD now offer Tier 4-compliant diesel engines without SCR. Thus, LNG-fueled engine offerings must also achieve Tier 4 NOx compliance without SCR aftertreatment.

The two major locomotive engine manufacturers are expected to certify natural gas engines that achieve Tier 4 NOx levels in the near future. Considering the case with on-road natural gas engines, it is reasonable to speculate about whether natural gas locomotive engine technology can offer a viable pathway to go significantly below the Tier 4 NOx level of 1.3 g/bhp-hr. Moreover, these OEMs are not targeting such low NOx levels. Whether it is diesel or natural gas engine technology, OEM efforts to further reduce NOx levels beyond Tier 4 will introduce new tradeoffs with maintaining good fuel efficiency, which is very important to their Class 1 railroad customers. Without regulatory requirements or incentives to reduce NOx beyond the Tier 4 level, the OEMs are unlikely to commit engineering and monetary resources to do so.

Within the smaller switcher class of locomotives, manufacturers have developed “genset” options that combine two or three smaller diesel engines (about 600 to 800 HP) on a locomotive to achieve the same total power output of a single larger engine. The genset design allows greater control over the operating point of each engine, resulting in better fuel efficiency and lower emissions. Additionally, these smaller engines are often certified to lower emission tiers ahead of larger engines. This has allowed some rail operators to deploy genset locomotives certified to Tier 3 or Tier 4 emissions standards before traditional single-engine locomotives meeting these standards became available. Notably, the predominant market

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7 Ibid.
for switcher locomotives is for traditional single engine units. This is likely to remain the case, unless genset locomotive technology can deliver significantly lower life-cycle costs.

There are three OEM natural gas engines commercially available for locomotive applications, as illustrated in Table 3. For switcher applications (around 1,200 HP), there is the dedicated (spark-ignited) Caterpillar G3500 engine. For medium power and line haul applications, the two available engines are the GE Evolution (diesel pilot) and the Caterpillar EMD 710 (dynamic gas blending); both use low-pressure dual-fuel injection systems. No commercialized natural gas locomotive engine has been certified to achieve Tier 4 emissions to date, although some have demonstrated these low levels. At least one small start-up company is pursuing development of a dedicated natural gas genset locomotive targeting the near-zero-emission level of 0.02 g/bhp-hr NOx, which is more than 90 percent lower than current Tier 4 engine standards. This product is still in the development phase, however, and not commercially available.

1.2 Limitations of Current LNG Engine Technologies for Marine and Rail Sectors

Natural gas as a substitute for conventional fuels to power marine and rail applications is a promising fuel-technology pathway to simultaneously achieve major emission reductions of criteria pollutants (especially NOx) and GHGs. The combination of good environmental benefits and payback through fuel cost savings are driving the marine and rail industries to make major investments in LNG engine technologies and fuel systems. Demonstration projects and using early-stage commercial products are well underway. These efforts have helped highlight challenges that must be addressed to fully realize benefits and expand commercialization. A few key challenges are summarized below.

**Methane Slip** – It is very important to minimize methane slip from HHP natural gas engines. Methane slip is the phenomenon when unburnt methane escapes through the engine compartment or tailpipe; it can occur to varying degrees in natural gas engines, depending on the engine technology and application. There are numerous mechanisms for methane slip. These include methane in scavenging air; blow-by of methane from the cylinder into the crankcase; and incomplete fuel combustion within the cylinder that escapes through the tailpipe. These mechanisms are most pronounced on retrofit dual-fuel engines using fumigation or port fuel injection strategies. The high methane slip in these engines occurs because the baseline diesel engine was never designed with the assumption that fuel would be present in the incoming combustion air flow. Consequently, valve timing creates periods where both the intake and exhaust valves are open simultaneously, allowing some fuel to be exhausted without going through the combustion portion of the cycle. Careful control of natural gas fuel injection timing in a port-injected strategy can limit this mechanism of methane slip, but fully addressing this issue typically requires modifying the valve timing of the engine, which can negatively impact the performance of the dual-fuel engine when operating on 100 percent diesel fuel.

**Catalyst Durability** – Hydrocarbon oxidation catalysts that might be used to control methane slip generally employ some amount of precious metals (platinum, palladium and rhodium) as part of the catalytic material. Unfortunately, these metals have well-known susceptibility to deactivation by sulfur compounds, referred to as sulfur contamination. Sulfur present in distillate fuels and lube oils can dramatically reduce catalyst effectiveness over time, particularly on dual-fuel engines that may operate on
20 to 100 percent distillate fuel at any given time. Catalyst regeneration is possible by periodically elevating the operating temperature of the exhaust or catalyst substrate, but this entails increased fuel consumption and the associated cost.

**Near-Zero Emissions** – Using natural gas, manufacturers of on-road engines have demonstrated the ability to achieve ultra-low NOx emissions rates that are more than 90 percent below U.S. EPA 2010 on-road standards and Tier 4 off-road standards. Methane slip rates on these dedicated natural gas engines are low (less than 1 percent). In marine and rail markets, however, no major engine manufacturer appears to be targeting the ultra-low NOx levels already achieved with on-road natural gas engines. In the switcher locomotive market, platforms using multiple engines may provide a path to the use of smaller, dedicated natural gas engines capable of achieving near-zero NOx emissions. In larger rail and marine engines that employ dual-fuel diesel/LNG strategies, more work must be done to demonstrate that near-zero emissions are achievable.
CHAPTER 2: Existing Natural Gas Supply, Infrastructure, and Use for Port Applications

2.1 Large-Scale LNG Facilities Focused on Marine Applications for the West Coast

According to the Federal Energy Regulatory Commission (FERC), “there are more than 110 LNG facilities operating in the U.S.” that perform a variety of services to produce, store, transport, and dispense LNG. Some of these facilities are specifically involved with transportation, while others are focused only on industrial uses. FERC provides maps on its website that depict locations of North America’s existing and proposed LNG export terminals. Those maps indicate that, as of January 2017 there are no existing LNG export terminals on the West Coast of the United States.

On the West Coast of southern Canada, FortisBC has been developing large sea-based LNG infrastructure that can potentially serve California port applications. FortisBC intends to make Vancouver, British Columbia, “one of the top LNG suppliers to the marine shipping industry.” The company is expanding the production capacity of its existing LNG liquefaction facility in Tilbury, British Columbia (Figure 5).

Figure 5: FortisBC’s Expansion of Tilbury Island LNG Plant to “Meet Growing Market Needs”

When completed later in 2017, FortisBC’s expanded Tilbury plant will produce nearly 140 million LNG gallons per year, with 18 million gallons of onsite storage. So far, FortisBC has contracted to supply LNG to nine marine vessels that bunker along the Pacific Northwest coast (TOTE, Seaspan, BC Ferries); the expected annual LNG consumption is 47 million gallons. The long-term plan is for FortisBC to fuel ships
using pipeline-to-jetty bunkering systems wherever feasible. As an interim or “bridge” solution, FortisBC will use truck-to-ship or truck-to-barge systems. Each LNG truck will tow a 16,000-gallon ISO container that can transfer roughly 5,800 cubic meters of LNG per day. Based on the concept developed for TOTE in Jacksonville, Florida, it will take 40 LNG trucks to fill one of Totem Ocean Trailer Express’s (TOTE) LNG-powered ships.8

Pacific Northwest LNG could be used to bunker California marine vessels, however, it must be transported via water. It is nearly 900 road miles from the Vancouver area to the Port of Oakland, and at least another 300 miles to the San Pedro Bay Ports. LNG delivery by truck is only feasible only when the supplying liquefaction plant, which is within a few hundred miles of the bunkering site. In addition to being higher in cost, truck delivery over these distances would result in higher GHG emissions. LNG delivery by truck can work quite well when distances are below about 300 miles, as demonstrated in Southern California by LNG-fueled on-road heavy-duty vehicles. Longer transport distances by truck can lead to excessive LNG boil off.

On a preliminary basis, FortisBC has assessed the business case for using its Vancouver-area LNG facilities and bunkering capabilities to support LNG vessel projects along the California coast. This includes shipping LNG as far south as Los Angeles (approximately 1,200 nautical miles). FortisBC estimates that LNG product could be delivered to Los Angeles via tanker/bunkering service in approximately three days, and the volume of LNG that could be provided is “scalable to meet long term customer needs.” This international service to U.S. ports would not be subject to Jones act restrictions, making this a relatively competitive case (see call-out box).

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**Jones Act:** The Merchant Marine Act of 1920 (aka Jones Act) is a U.S. federal statute that essentially requires vessels operating between U.S. ports to be built in the U.S., owned and crewed by U.S. citizens, and U.S. flagged. Because Jones Act vessels operate primarily between U.S. ports, they are subject to the low-sulfur fuel requirements of the U.S. ECA, for most or all of their operations. Jones Act vessels include container ships that travel between mainland ports and Hawaii, Alaska and Puerto Rico. These “coastwise” (short sea) vessels transport more than one billion cargo tons annually.

**Source:** Maritime Administration, https://www.marad.dot.gov/ships-and-shipping/domestic-shipping/

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This type of LNG bunkering scenario for California ports is in the conceptual stages until FortisBC can firmly establish regular marine vessel demand. The company is now “working with marine logistics service providers” to establish “complete service packages” for end customers. The timeline to actually implement this type of LNG bunkering scenario at California ports “is concurrent with customer plans” to build new LNG vessels or modify existing vessels.9

There are two other existing large, sea-based LNG export terminals that could potentially serve California transportation markets: (1) the Sempra Energy – Shell Costa Azul facility in Baja, Mexico, which can

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9 Ibid.
process up to one billion cubic feet of natural gas per day (approximately 13 million LNG gallons); and (2)
ConocoPhillips' facility located on Alaska's Kenai Peninsula, which is a much smaller facility and appears

Although the company is not yet serving West Coast LNG markets, Eagle LNG Partners is exploring the potential. Eagle LNG is wholly owned by Ferus Natural Gas Fuels (of the Energy Minerals Group). The company’s business plan is to “supply clean burning, competitively priced fuel for the marine, transport trucking, remote power, rail industries, and small-scale export markets.” Eagle LNG has explored the potential to supply LNG for marine and rail markets in California and has demonstrated strong capability that it can actually achieve this. It is developing two facilities in Florida (Jacksonville and Maxville) to supply LNG for Crowley Maritime’s two new-build LNG-powered “ConRo” (combination container) vessels. Crowley’s two LNG ships will operate between the U.S. mainland and Puerto Rico, and are being built to comply with Jones Act requirements. The two LNG facilities in Florida are being constructed with state-of-the-art designs for terminal and shoreside bunker operations, including an LNG processing capacity of 1.5 million LNG gallons per day and on-site LNG storage of 12 million gallons. A local utility will provide Eagle LNG with natural gas feedstock for liquefaction, using existing and expanded natural gas pipelines.\footnote{Eagle LNG Partners, information on website (eaglelng.com) and presented at 2016 Natural Gas High Horsepower Summit by various Eagle LNG representatives.}

Eagle LNG is also working with the railroad industry to advance the potential for using LNG as a major rail fuel. To eventually supply West Coast LNG markets, the company has shown interest in building an LNG liquefaction facility in Tacoma, Washington, and/or the San Francisco Bay Area, or both. To make these projects financially attractive, Eagle LNG would likely require major commitments from marine or rail “anchor tenants” or both.\footnote{Ibid.}

The Port of Oakland could be an early host site to this type of scenario. Several shipping companies, including Horizon Lines and Matson, are considering operating LNG-fueled OGVs that serve San Francisco Bay. Horizon has already committed to converting two vessels to LNG but has not yet indicated which California port will serve as the home base for its LNG vessels. As described, Matson has ordered two LNG-ready containerships. If Matson decides to make the significant additional capital investments necessary to add on-board LNG storage to operate its OGVs on LNG, the Port of Oakland appears to be the most likely port for LNG bunkering.

### 2.2 Smaller LNG Supply Facilities Serving West Coast On-Road Natural Gas Vehicle Markets

There are several smaller land-based LNG liquefaction facilities that focus on supplying natural gas for on-road transportation markets in California and Arizona.

**Clean Energy Fuels** – Clean Energy provides natural gas for on-road transportation markets that serve heavy-duty natural gas vehicles (NGVs) throughout California, including fleet-dedicated and public access CNG, LNG, and liquefied-compressed natural gas (LCNG) stations. In 2008, Clean Energy began production at its LNG Plant in Boron, (Kern County, 140 miles north of the Ports of Los Angeles and Long
Beach). The Boron facility (Figure 6) consists of two LNG production trains, each producing 90,000 gallons of LNG per day for a total of 180,000 gallons per day. The Boron plant has the capability to add a third 90,000-gallon LNG train, for a total capacity of 270,000 LNG gallons per day. The facility currently has onsite storage of 1.8 million LNG gallons. Clean Energy also operates an LNG plant located in Willis, Texas, but this is 1,600 miles from the Los Angeles area. While too far to routinely supply LNG to the San Pedro Bay Ports complex, the Willis plan could provide a potential backup supply of LNG.

Figure 6: Clean Energy’s LNG Liquefaction and Storage Facilities at Boron, California

Applied LNG – Applied LNG is the second largest producer and marketer of LNG for on-road transportation in the United States (after Clean Energy). The producer currently operates an LNG liquefaction facility in Topock, Arizona, about 300 miles east of Los Angeles. Initially developed in 1995 to serve developing heavy-duty fleet markets in Southern California, the Topock facility originally comprised one plant with a capacity of 86,000 LNG gallons per day. A new plant went into production in June of 2014; it is a duplicate of the old plant and employs essentially the same technology. Each small-scale LNG plant produces 86,000 gallons per day, for a combined capacity of 172,000 LNG gallons per day. The Topock facility stores a total of 1.5 million LNG gallons. Reportedly, this LNG facility has significant room for expansion. Applied LNG currently focuses on the on-road NGV markets, using a fleet of 49 LNG trailers to deliver product to fleets in California and Arizona. However, Applied LNG has expressed interest in also serving marine and rail markets in Southern California.

Spectrum LNG – Spectrum LNG owns and operates an LNG liquefaction facility in Ehrenburg, Arizona, which is 250 miles east of Los Angeles. The Ehrenberg plant has a capacity of 60,000 gallons per day, with provisions for expansion and supplies LNG for transportation markets in Arizona and Southern California. However, all of this current LNG production appears to be fully subscribed under a 10-year contract with Clean Energy Fuels.13

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2.3 Current Transportation Uses of Natural Gas at California Ports

2.3.1 On-Road Drayage Trucks and Off-Road Yard Hostlers

The existing LNG supply and delivery infrastructure serving California is focused on trucks, buses, and refuse haulers with limited use of LNG in off-road yard hostlers (vehicle that does short range transfers or switch work at ports). For these smaller-engine applications, actual commercial uses are underway. This includes a large fleet of LNG-fueled on-road drayage trucks (up to 900 trucks at peak) and an ongoing proof-of-concept demonstration of LNG-fueled yard hostlers. Commercialization in 2016 of the near-zero-emission Cummins Westport (CWI) ISL G NZ 8.9-liter engine has provided new impetus for the San Pedro Bay Ports to consider large-scale deployments of drayage trucks and cargo-handling equipment (yard hostlers, top picks, etc.) fueled by natural gas. It is expected that significant deployments of this landmark natural gas engine in heavy-duty trucks will soon follow in and around the port complex.

CWI is also on track to certify a near zero (NZ) version of its 11.9-liter ISX 12G engine, which significantly broadens the number of on-road goods movement applications that can be served by ultra-clean natural gas vehicles. This larger NZ natural gas engine will soon be demonstrated in a fleet of 20 heavy-duty drayage trucks at the San Pedro Bay Ports, with funding from the California Energy Commission and the South Coast Air Quality Management District.

For the off-road side, the Energy Commission has awarded funds to the Los Angeles Harbor Department to deploy 20 new LNG-fueled yard hostlers powered by CWI's 8.9-liter NZ engine at Everport Terminal. All these NZ heavy-duty NGV deployments previously noted will likely use renewable natural gas (RNG, discussed in Chapter 6).

Potential growth in the natural gas infrastructure for these smaller-sized heavy-duty NGVs (drayage trucks and yard hostlers) is unlikely to help drive the major new LNG supplies that would be needed at the ports to fuel LNG-powered marine vessels. The existing LNG station network can support progress toward making the ports ready to add dockside or water-based LNG fueling facilities as business cases emerge for LNG bunkering at California ports. This synergy works both ways: if large-scale LNG supply can be established in the ports to serve marine vessels and locomotives, this may also help enable expansion of drayage truck and yard hostler deployment. LCNG provides an option for supplying CNG vehicles from LNG infrastructure.

2.3.2 Marine Vessels and Locomotives

Current natural gas use in California is essentially nonexistent for marine vessels and locomotives, which are the two major large-engine HHP applications that serve ports. To date, deployments have been limited primarily to small-scale proof-of-concept demonstrations. For example, in 2009 Pacific Harbor Line conducted a nine-month demonstration of a proof-of-concept LNG-fueled switcher locomotive serving rail yards at the Ports of Los Angeles and Long Beach. Natural gas engines are emerging as commercial options to power both marine vessels and locomotives (as described in Chapter 1). Momentum is building for LNG (and possibly CNG) to systematically take on increasing market share as a

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preferred choice to power HHP applications at California seaports. Marine vessels appear poised to lead the way through a combination of emerging environmental drivers and the relatively fast payback on capital investments that can be achieved through the large per-vessel fuel use. These opportunities and associated challenges are discussed in Chapter 3.
CHAPTER 3: Opportunities and Challenges for Expanded Use in Key Port Applications

3.1 Overview

Natural gas can provide major economic and environmental benefits as a large-scale substitute for conventional fuels in off-road HHP applications at California’s seaports. For marine vessels and locomotives, opportunities to expand the use of natural gas tend to center on LNG technologies. However, CNG configurations also have potential to power marine and rail applications; these tend to involve smaller vessels and locomotives that return to the same base for fueling (e.g., harbor craft and switcher locomotives). While the focus of this report is on LNG use in HHP off-road seaport applications, existing or potential CNG applications are also discussed.

Despite favorable potential, the adoption rate has been slow for LNG to become a significant transportation fuel in North American ports. Barriers have included high cost and limited availability of emerging LNG engines and on-board fuel tanks, regulatory uncertainty, lack of end user familiarity, and challenges with fuel supply and distribution. These types of interconnected challenges are inherent to any large-scale attempt to replace a long-entrenched higher-polluting conventional fuel with cleaner alternative fuels, which typically have lower energy density and limited existing fuel production and dispensing infrastructure.

This section discusses opportunities and challenges associated with expanding use of LNG to the two highest fuel use off-road applications, marine vessels and locomotives.

3.2 Major Drivers for Expanded Use and Associated Challenges

Major drivers for marine and rail operations to convert to LNG generally fall within two categories: (1) favorable fuel-cost economics that can save on life-cycle costs and (2) environmental benefits that help comply with regulations or meet organizational sustainability goals or both.

3.2.1 Improving, Favorable Economics

Historically, HHP fleets have explored natural gas as a lower-cost substitute for diesel that can deliver compelling savings on life-cycle costs. Figure 7 depicts the six-year price trends for LNG and CNG compared to diesel; both comparisons are in diesel gallon equivalents (DGE) to provide an energy equivalent basis. Starting in 2010 and through 2014, the price spread for both LNG and CNG versus diesel has ranged from a low of about $1.00 per DGE to highs that exceed $2.00 per DGE. The widest difference in pricing occurred in mid-2012, when retail LNG and CNG were priced less than diesel by about $2.37 and $1.82 per DGE, respectively.
A large price spread is very important because substantial capital investments are needed to switch HHP fleets from diesel to natural gas operation. When there is a large price spread, high-fuel-use applications (marine vessels and locomotives, in particular) can achieve very attractive payback periods on these investments. For example, a 2014 report prepared for America’s Natural Gas Alliance found that simple payback on capital investments to switch to LNG operation can be as short as four years for marine applications and seven years for freight locomotives. In addition to a large fuel price spread and high fuel use, another key to help achieve these favorable economic payback periods for marine vessels and locomotives is due to the long useful lives (20 to 40 years).

Markets for LNG to power both marine vessels and locomotives essentially stalled in 2014, when the price of diesel plummeted. This significantly narrowed the price spread advantage for CNG and LNG, thereby lengthening how long it takes to achieve payback via fuel-cost savings on the required capital investments to switch from petroleum fuel. Thus, under current conditions, the economics of using LNG in the marine and rail sectors are significantly less compelling for end users. Consequently, during the last few years, life-cycle economics have not been a strong driver to switch marine vessels or locomotive fleets to LNG operation. Simply put, a poor price spread discourages decisions by the marine and rail industries to invest in natural gas engines, equipment, and infrastructure.

The price of crude oil began to steadily increase in late 2016 and can be expected to continue to increase. The impact on actual and projected prices of diesel fuel can be seen in Figure 8. According to the U.S. Energy Information Administration (EIA), the price of diesel fuel for the Pacific Region (PADD 5) of the United States reached the bottom point ($2.56 per gallon) in late 2016. EIA projects that the retail price will steadily rise back toward $4 per gallon. Conversely, natural gas prices are expected to stay more stable, around current prices. Thus, economically attractive price spreads for LNG and CNG can be expected to gradually return. If so, this is likely to spark increasing interest among HHP fleet users to

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15 Gladstein, Neandross & Associates, LNG Opportunities for Marine and Rail in the Great Lakes, Gulf of Mexico, and Inland Waterways, prepared for America’s Natural Gas Alliance, October 2014.
explore and adopt natural gas as a substitute fuel. Of course, it remains to be seen if the projected return of a favorable price spread actually comes to fruition, and how markets react.

**Figure 8: Actual and Projected Diesel Retail Price for Pacific Region, 2010—2050**

3.2.2 Environmental Benefits for Compliance and/or Sustainability Initiatives

Despite low oil prices during the last several years, end users have continued to test and deploy natural gas engines in on-road heavy-duty applications. This is largely attributable to the major environmental benefits that can be achieved using LNG or CNG. Natural gas marine vessels and locomotives can also deliver significant reductions of criteria pollutants (especially the ozone-precursor NOx) as well as toxic air contaminants such as diesel particulate matter (DPM). These reductions are necessary in California and the United States. Simultaneously, HHP natural gas engines can deliver significant GHG reductions relative to diesel, as required worldwide to address climate change. The greatest GHG-reduction benefits can be realized when replacing fossil natural gas with very-low-carbon-intensity RNG (Chapter 6).

These benefits (combined with long-term favorable economics) have been significant drivers for marine and rail companies to embark on serious efforts to test and evaluate LNG engines and infrastructure. Additional chapters of this report note some of the major American corporations – including major shipping companies, railroads, and trucking companies – are exploring heavy-duty natural gas engines as foundations of their sustainability policies.

As described, a combination of international, federal, and state regulations are driving manufacturers and end users to reduce marine vessel emissions and making a switch to natural gas provides one compliance strategy. Locomotive emissions are being driven down through federal, state, and local regulations. According to the California Air Resources Board (CARB), efforts to date to reduce ozone-precursor NOx emissions are not sufficient to meet California’s aggressive air quality goals. Consequently, CARB’s 2016
State Implementation Plan (SIP) focuses on aggressively pursuing additional NOx-reduction measures for key HHP off-road sources:

_Overall, NOx emissions from sources that are primarily regulated by the federal government, such as ocean going vessels, aircraft, and locomotives, have not kept pace with reductions in other sectors, and are in aggregate projected to remain fairly constant through 2031. While emissions from locomotives continue to decline, emissions from ocean going vessels and aircraft are projected to increase. Although ARB does not have primary regulatory authority over many of these sources, ARB has nonetheless adopted two major regulations to reduce emissions from ocean-going vessels (OGVs), including the OGV Shore Power Regulation, which reduces emissions from diesel auxiliary engines on container ships, passenger ships and refrigerated-cargo ships at-berth at California ports, and the comprehensive OGV Clean Fuel Regulation, which requires vessel operators to use cleaner distillate fuels in their main engines, auxiliary engines, and auxiliary boilers within 24 nautical miles of the California coastline and islands._16

The revised SIP also describes the importance of achieving greater reductions in cancer-causing emissions such as diesel particulate matter, especially in heavy goods movement applications centered on California ports:

_Although progress has been made over the past decade in reducing exposure to diesel exhaust, diesel PM still poses substantial risks to public health and the environment. Reductions in diesel PM will further reduce statewide cancer risk and non-cancer health effects, especially for residents living near major sources of diesel emissions such as ships, trains, and trucks operating in and around ports, rail yards, and heavily traveled roadways._17

The new draft SIP includes certain potential control measures that, if adopted, would likely increase use of natural gas to fuel marine vessels and/or locomotives. For example, the proposed measure titled “Incentivize Low Emission Efficient Ship Visits” has the specific goal “to achieve early implementation of clean vessel technologies such as liquefied natural gas.”

On the local level, California’s major ports have their own initiatives to reduce emissions of criteria pollutants (NOx, SOx, and PM2.5), air toxics such as DPM, and GHGs. These are additional potential drivers toward increased use of natural gas in HHP port applications. The most comprehensive effort is the newest (draft) joint Clean Air Action Plan (CAAP)18 by the Port of Long Beach and the Port of Los Angeles. The new CAAP will continue efforts since 2007 to aggressively transition to a cleaner, more sustainable goods movement system serving both ports. Certain elements in the proposed CAAP _could_ be supportive of using natural gas in goods movement applications that include cargo handling equipment, marine vessels, and locomotives. The CAAP includes provisions for ordinances, regulations (e.g., shoreside power), green lease agreements, environmental mitigation requirements, and voluntary efforts with incentives (e.g., a clean fuel incentive program to cover the cost differential between dirty heavy fuel

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17 Ibid.
oil and cleaner-burning low-sulfur distillate fuel). However, it remains to be seen if the CAAP can be a significant driver for using natural gas in very-high-fuel-use applications like marine vessels and locomotives. It is more likely that vessel operators using LNG for overall environmental reasons (e.g., Emission Control Area (ECA) compliance) or economic reasons will drive an LNG bunkering project within the twin port complex.

### 3.3 Sector-Specific Opportunities for Marine Vessels and Locomotives

This subsection discusses emerging opportunities to expand deployment of natural gas marine vessels and locomotives that serve California ports, based on public statements made and actions taken by industry insiders and end users. LNG suppliers such as FortisBC are clearly targeting subsectors within these two applications (Figure 9). The actual timeline for commercial deployments will depend on many factors and variables, including the regulatory landscape for the rail and marine sectors, end-user specifics (such as fuel substitution rates, useful life, capital reserves, and technological feasibility of operational routes), broad market factors (fuel availability, technology availability, fuel cost spread), and specific geographies.

**Figure 9: FortisBC’s Target Markets for West Coast LNG Applications**

Credit: FortisBC

#### 3.3.1 Marine Vessels

The emergence of LNG as a marine fuel in North America has largely been led by West Coast vessel operators. Companies including Totem Ocean Trailer Express (TOTE), BC Ferries, and Washington State Ferries (WSF) were the first to announce intent to convert part of their operations to LNG. Actual orders from these companies for new or converted LNG vessels are in various stages of completion, with some deliveries taking place during the next two years.

For perspective on the market size represented by these early adopters, OGVs in short-sea service made about 600 calls to major West Coast ports in 2014. Collectively, these OGVs bunkered roughly 351,000 metric tons of marine fuel. Short-sea vessels are operated on the West Coast by companies including TOTE, Matson, Maersk, APL, Pasha-Horizon, and Alaskan Tanker. An additional 165,000 metric tons of marine fuel were bunkered at West Coast ports in 2014 by ferries and passenger ships (excluding cruise
Total marine fuel use of nearly 516,000 metric tons (MT) heavy fuel oil (HFO) per year (149 million DGE/yr) constitutes about 3 percent of the total marine fuel bunkered at West Coast ports for all applications. Although dwarfed by the overall fuel demand (which is dominated by trans-Pacific OGVs like container ships and tankers), the short-sea shipping market serving West Coast ports could provide sufficiently large LNG demand to justify a good business case for suppliers to build LNG bunkering infrastructure.

In addition to TOTE and WSF, other West Coast ship operators have announced their intentions to deploy LNG-powered marine vessels — or LNG-ready vessels — including Horizon Lines, Matson, American Petroleum Tankers, Crowley, Matson Marine, Seacor Holdings, and Alaska Tankers. Large shipping companies that have expressed interest to use LNG in their operations include Polar Tankers, Pasha, Maersk, and Carnival Cruise Lines.

Despite strong progress, fewer than 150 LNG-fueled ships are either operating today in the worldwide merchant fleet or have been ordered (less than 1 percent). Prospects, however, are promising to increase these numbers over the next two decades, for various related environmental, regulatory, and economic reasons. Perhaps the key driver is the global sulfur cap that will be imposed by IMO starting in 2020. This and a confluence of other factors are stimulating the worldwide marine industry to take new steps toward designing, building, and deploying LNG-fueled ships. The American Bureau of Shipping (ABS) summarized this as follows:

Due to increasingly stricter environmental regulations controlling air pollution from ships implemented through International Maritime Organization (IMO) Annex VI and other local air quality controls, together with the potential for favorable price conditions, the use of LNG as a fuel, instead of conventional residual or distillate marine fuels, is expected to become more widely adopted in the future. In anticipation of this trend, the marine industry is looking for ways to provide flexibility and capability in vessel designs to enable a future conversion to an alternative fuel, such as LNG.

In 2014, ABS queried regional seaports in North America to assess and summarize the general acceptance of LNG in each region and the status of existing or planned LNG bunkering projects. The results showed high interest among West Coast seaports for LNG bunkering projects in the Pacific Northwest and Northern California.

In late 2014, DNV-GL (a leading ship classification and maritime advisory service) noted that:

The number of ships using LNG as fuel is increasing fast and more and more infrastructure projects are planned or proposed along the main shipping lanes. In line with this dynamic development, DNV GL expects LNG to grow even more rapidly over the next five to ten years . . . [reaching] 1,000 non-LNG carrier vessels running on LNG in 2020 or shortly thereafter. At the

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19 These calculations are based on work performed by Gladstein, Neandross & Associates in 2014, using the Sea-Web database from IHS to identify fleet vessels calling at West Coast ports, thereby deriving fuel consumption estimates on a per-vessel and sector basis.
20 DNV-GL, information provided to GNA for various LNG bunkering studies, 2016.
same time, LNG is commercially attractive and available worldwide in quantities able to meet the fuel demand of shipping in the coming decades.\textsuperscript{22}

These various assessments were made before the prolonged drop in crude oil prices that began in 2014. With oil prices still low (albeit, now rising), fuel economics still present a key barrier to expanding use of LNG as a marine fuel in the United States. Other key barriers, which are also rooted in economics, include limited LNG infrastructure at ports and the high capital costs of on-board LNG fuel storage technology.

Fuel economics, however, for LNG are gradually improving (Section 3.2.1). Moreover, the new IMO sulfur cap that takes place in 2020, coupled with other environmental drivers such as establishment of North American ECAs and California’s new SIP (described previously), are stimulating new interest in LNG bunkering among shippers and marine fleets, including those that bunker at California ports. This is because competing pathways for shippers to comply with these stricter emission regulations can also entail higher costs, added complexity, and public complaints. For example, to meet IMO SOx-reduction requirements, some cruise lines have chosen to continue using very-high-sulfur HFO by installing exhaust gas scrubbers instead of using low-sulfur marine fuel or LNG. While scrubbers can have advantages in certain marine vessel applications, they increase fuel cost (about 2 percent),\textsuperscript{23} require sludge cleaning in ports, and can result in unsightly sludge discharges that can be particularly bad for cruise ship applications.

For these reasons, some industry insiders consider bunkering with LNG to be a most-favored compliance option.\textsuperscript{24} New-build orders for LNG ships are now rising, and one recent estimate is that they may increase “exponentially over the next decade.”\textsuperscript{25} In particular, there are certain segments of the marine vessel market that appear most conducive for adopting LNG over the next decade. These tend to be OGV applications that operate on fixed routes (e.g., containers and Ro-Ro) as well as small vessels performing regional trade or ferry operations, especially in ECAs (Figure 10).

\textbf{Figure 10: Likelihood of Individual Marine Vessel Segments Using LNG by 2026}

Source: DNV-GL


\textsuperscript{23} DNV-GL staff, personal communication to Gladstein, Neandross & Associates staff, March 2015.


3.3.2 Locomotives

BNSF and UP have been evaluating LNG as a potential locomotive fuel for decades. The primary driver for their interest has been economics. With a single line-haul locomotive consuming as much as 330,000 diesel gallons per year, switching over to LNG can provide significant fuel cost savings, especially when the fuel price spread exceeds $2.00 per DGE (the 2012 time frame). This can help offset the incremental capital expenses of converting a rail fleet to natural gas, whether accomplished by purchasing new natural gas locomotives or repowering existing locomotives. In addition to costing less on an energy-equivalent basis, natural gas prices have historically been less volatile than diesel prices. This relative cost stability provides another attractive feature for railroads.

Together, a favorable payback period and price stability have compelled UP and BNSF (as well as other Class 1 railroads in North America) to test and evaluate the feasibility of gradually converting their rail operations to LNG. At the peak price differential circa 2012, UP and BNSF were moving rapidly to assess the benefits and costs. Much progress was made by working closely with locomotive and engine manufacturers, cryogenic fuel tank suppliers, and natural gas/LNG suppliers. Not surprisingly, the pace significantly slowed when the price of petroleum fuel dropped to very low levels. Both UP and BNSF continue to explore LNG, but due to collapsing of the price differential their efforts have slowed to test and potentially adopt LNG. UP’s recent public position reflects this current cautiousness: “much research, testing, and analysis” remains to be conducted before UP can “determine whether LNG as a locomotive fuel is reliable and economical.”

Even as a favorable price spread begins to return, there are logistical, technological, and regulatory hurdles that the railroads must overcome before making LNG a mainstream locomotive fuel. The largest hurdles pertain to developing cost-effective, government-approved systems for locomotives to have onboard storage of LNG or CNG with sufficient capacity to meet operational needs. Fortunately, significant progress is being made. Key equipment suppliers have signaled their readiness to supply key components such as LNG tenders and CNG tanks. Essentially, these markets are waiting for oil prices to return to historically higher levels, which can then make the life-cycle economics of LNG rail operations compelling. Meanwhile, small victories are being realized, such as approval by the Federal Railroad Administration (FRA) for Alaska Railroad Corporation to ship about 12 tons of LNG by rail in a 40-foot cryogenic tanker. This will be the first railroad in the United States to win a permit from FRA to transport LNG by rail.

The potential to achieve reductions in criteria pollutants and GHG emissions has also played a role in driving the railroads to explore LNG engines. U.S. EPA Tier 4 emission standards for railroad locomotives, which became effective in 2015, require reductions in NOx and PM emissions by nearly 90 percent compared to the Tier 3 standards. In tandem with these new emission standards, the sulfur content allowable for diesel used in locomotives has been limited to 15 ppm. To reach the Tier 4 standard, locomotive engine manufacturers can apply advanced diesel engine controls (e.g., high EGR levels high-pressure common rail injection systems), or they can develop natural gas locomotive technologies or do

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both. Switching to natural gas in locomotive engines can provide significant reductions of NOx, PM, and GHG emissions. The actual benefits will depend on the relative emission levels of the baseline diesel technology and the replacement natural gas technology, which are dictated by factors such as the specific combustion technologies, types of aftertreatment, and types of emissions certification achieved. As of March 2017, there is no commercially available Tier 4 natural gas freight interstate line-haul locomotive, which is the requirement for new line-haul locomotives since 2015.

Meanwhile, commercially available diesel locomotives now achieve the U.S. EPA’s stringent Tier 4 emission standard. Specific examples include the following:

- General Electric (GE) has introduced its Evolution Series line-haul locomotive that achieves U.S. EPA’s Tier 4 emission levels. This 12-cylinder locomotive engine technology achieves more than a 70 percent reduction in NOx emissions compared to GE’s Tier 3 locomotive technology. GE’s Tier 4 technology does not require SCR or DPF aftertreatment systems to meet standards for NOx and PM, respectively. While GE achieved this initially in part by using credits for going beyond Tier 3 standards, it is now manufacturing and producing locomotives that achieve Tier 4 standards directly. GE reports that it has received thousands of orders for these Tier 4 line-haul locomotives.  

- Electro-Motive Diesel (EMD), owned by Caterpillar through its subsidiary Progress Rail Services Corporation, has introduced its new Tier 4 freight locomotive, the SD70ACe-T4. Like GE, EMD attained Tier 4 NOx emission levels primarily through cooled EGR, without the use of an SCR aftertreatment system.

- Progress Rail’s remanufactured PR 30 locomotives equipped with Caterpillar 3516C-HD diesel engines and Caterpillar’s Clean Emissions modules have been verified by ARB at U.S. EPA Tier 4 emission levels. This verification applies to both four- and six-axle PR30 locomotives that can be used in line-haul applications.  

All of these suggest the emergence of a robust, sustainable market for LNG locomotives must be driven by life-cycle economics or stronger environmental benefits.

3.3.3 Other HHP Port Applications (Drayage and Cargo Handling Equipment)

Class 8 heavy-duty drayage trucks have been a very important “early adopter” application for the use of low-emission natural gas engines, using both LNG and CNG systems. Nearly 900 LNG- and CNG-powered drayage trucks have been deployed to move containers at the twin San Pedro Bay Port complex. To a lesser but growing extent, off-road yard hostlers (the most common type of cargo handling equipment) are also serving as an important early deployment application for clean natural gas engines. Adoption of natural gas engines in these sectors has been driven primarily by the need for the San Pedro Bay Ports to dramatically reduce emissions of NOx and diesel PM in and around the port complex. As


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described in subsequent sections of this report, expanded use of LNG and CNG in these sectors is a strong possibility as the two ports strive to move goods with near-zero-emission or zero-emission fuel-technology platforms. While these other applications won’t drive the LNG infrastructure to enable ocean vessels, they provide experience in the use of LNG at the port. Conversely, the implementation of LNG ocean vessels or locomotives, and the LNG to support them, can enable LNG and CNG drayage and cargo equipment. This offers potential synergy to share increased demand for LNG and CNG with marine vessel and locomotive applications serving California ports.

### 3.4 Potential Growth in Demand for Natural Gas in HHP Off-Road Port Applications

#### 3.4.1 Introduction and General Challenges

Even at a high level, it is challenging to accurately project LNG consumption for future marine and rail deployments. This is partly because end users face uncertainty when making key decisions to enter this emerging market. As depicted in Figure 11, each end user – whether it’s a shipping company or a railroad – must fully evaluate six complex and interacting areas before deriving a good business case for switching to LNG. Doing so requires major investments in engines, on-board fuel storage technologies, fuel infrastructure, training programs, safety systems, and other parameters.\(^{30}\)

![Figure 11: Interacting Considerations When Making a Business Case for LNG](image)

**Input for this figure was provided by the railroad industry, but it is equally applicable for marine fleets.**

**Source:** Gladstein, Neandross & Associates

There are substantial uncertainties associated with this exercise, such as predicting future energy prices and regulatory climates. These uncertainties can lead to hesitation by end users to make the very significant incremental capital commitments associated with switching to LNG. When possible, they may seek to hedge their bets. For example, some marine vessel owners have ordered “LNG-ready” ships,\(^ {31}\)

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\(^{31}\) An LNG ready ship has engines that run on 100 percent conventional fuel, but can also operate in a dual-fuel mode (if and when the shipper is ready). While the ship initially does not have LNG storage tanks, sufficient space and necessary logistics exist to add such storage later.
while deferring the decision to equip those vessels with LNG fuel storage and management components. Such investments can add $20 million to the cost of the vessel (even in the case of a new build). To make such large investments, shippers require a degree of certainty that the payback period will be attractive or that switching to LNG can provide a cost-effective strategy for regulatory compliance or both. A similar situation can occur with railroads considering the switch of diesel locomotives to LNG. All this and more interject significant uncertainty when attempting to project future LNG volumes necessary at California seaports to fuel these applications.

### 3.4.2 Growth Potential for Marine Applications

California is home to three of the five largest port complexes that serve the U.S. West Coast - Port of Los Angeles, the Port of Long Beach, and the Port of Oakland. Five major types of marine vessels dominate vessel populations and fuel use in these ports: (1) bulk carriers, (2) containerships, (3) tankers, (4) tugs and (5) vehicle carriers. The mix of vessels that operate within these ports varies significantly. As shown in Figure 12, the Los Angeles and Long Beach port complexes host large operations for containerships, tankers, bulk carriers, and vehicle carriers, as well as other types of vessels (e.g., cruise ships). The Port of Oakland is dominated by containership operations. The mix of vessels that serve a given port is relevant to the potential for hosting LNG users because each vessel type has typical engine types, sizes, and operational profiles. These types of differences define vessel fuel consumption and fueling logistics that significantly influence fuel demand in each port, how fuel bunkering is typically accomplished, and the degree to which switching to LNG may be operationally or economically feasible or both.

![Figure 12: Mix of Marine Vessel Types Serving California's Three Major Ports](source)

Before the sustained drop in petroleum prices, several entities and studies projected strong growth rates over the next two decades for LNG-fueled marine vessels. Projected adoption rates for the global vessel fleet ranged from 10 to 25 percent; the greatest penetration was assumed for OGVs, which (as shown above) heavily serve the three largest California ports. Some experts projected that thousands of LNG-fueled marine vessels could be deployed worldwide by 2020,\(^\text{32}\) with simultaneous growth in worldwide demand for LNG bunkering.

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These types of projections were based on solid signals from the shipping industry. For example, Lloyd’s Register queried 22 international ports in 2014 using an *LNG Bunkering Infrastructural Survey*. The survey asked these ports – including four in North American ECAs – about their existing or anticipated plans to pursue “wide-scale development” of LNG bunkering. Lloyd’s Register found that more than half of the surveyed ports had developed specific plans for LNG bunkering infrastructure; most planned to implement LNG bunkering before 2020. Reportedly, up to 25 percent of marine vessel bunkers were expected to dispense LNG by 2025. The responding port representatives indicated that the two biggest market pull factors for this expansion of LNG marine vessels were (1) favorable economics (32 percent) and (2) good LNG availability (20 percent).

Based on these projections, it is reasonable to assume a *10 percent* adoption rate for LNG vessels by 2030 for the OGV fleet that regularly serves California’s ports. At a high level, this takes into account two key factors. On the challenge side, the current diesel-LNG price spread continues to be very small (albeit growing). On the opportunity side, IMO’s 2020 global sulfur cap and other environmental drivers make LNG a potentially attractive compliance option. Putting various assumptions together, a plausible *high-level* 2030 LNG demand estimate was derived for marine vessels that make regular calls at California ports. The estimate also assumes California’s marine fleet will not grow during the next 13 years.

Figure 13 summarizes the estimated annual HFO use for the top five vessel sectors that serve West Coast ports (based on 2014 vessel calls). The gray bars provide per-vessel fuel consumption, showing that passenger/cruise ships and containerships have the largest single-unit fuel consumption. The green bars show total fuel use for each of the five sectors, with containerships and bulk carriers being the most-fuel-intensive. Summing the green bars indicates that these five sectors collectively consume an estimated 15.6 million (15,616 thousand) MT of HFO each year. (These five sectors make up about 90 percent of the fuel demand from the entire West Coast marine fleet.)

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34 The Sea-Web database from IHS.

35 These fuel consumption figures do not include fuel use from auxiliary engines or boilers, which means that these HFO volumes represent 80 to 90 percent of the total fuel consumption.
By applying the assumed 10 percent penetration rate for LNG, and assuming that LNG vessels will be powered by engines with a 95 percent diesel substitution rate, the following box provides an illustrative scenario for the total volume of LNG that would be required in 2030 to meet LNG demand for dual-fuel marine vessels of these five types that bunker at the major West Coast ports.

### Estimated LNG Demand for 10% Penetration of Top Five Marine Vessel Types Fueling at West Coast Ports

\[
15.6 \text{ million MT HFO/yr} \times 10\% \text{ penetration by LNG vessels with a } 95\% \text{ LNG substitution rate} = 1.5 \text{ million MT HFO/year displaced} = \sim 740 \text{ million LNG gal/yr}
\]

As indicated, under these assumptions, the annual LNG fuel demand in 2030 from these top five fuel sectors at the major West Coast ports is estimated to be 740 million LNG gallons, or about 2 million gallons per day.

This illustrative case is based on current HFO fuel consumption for all West Coast ports, including Vancouver, Seattle, Tacoma, Oakland, Los Angeles, and Long Beach. California’s three major ports (Los Angeles, Long Beach, and Oakland) consume about half (7.8 million MT) of this HFO (based on volumes dispensed in 2014). It is estimated that California ports would require nearly **370 million LNG gallons per year** in 2030, or **1 million LNG gallons per day**.\(^{36}\)

### Estimated LNG Demand for 10% Penetration of Top Five Marine Vessel Types Fueling at Largest California Ports

\[
7.8 \text{ million MT HFO/yr} \times 10\% \text{ penetration by LNG vessels with a } 95\% \text{ LNG substitution rate} = 0.74 \text{ million MT HFO/year displaced} = \sim 370 \text{ million LNG gal/yr}
\]

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\(^{36}\) These calculations are based on work performed by Gladstein, Neandross & Associates in 2014, using the Sea-Web database from IHS to identify fleet vessels calling at West Coast ports, thereby deriving fuel consumption estimates on a per-vessel and sector basis.
Matson Ocean Services provides a good example for estimating potential LNG demand from a “first mover” shipping company that may gradually switch to LNG and bunker at a California port (Port of Long Beach and/or Oakland). Matson has ordered two LNG-ready Jones Act container vessels (Aloha class) for the California-to-Hawaii/Pacific trade route (a “short-sea shipping” use of OGVs). It has purchased dual-fuel MAN engines for these ships, which are being designed to add LNG storage and fuel piping later. The estimated per-vessel incremental cost for LNG storage and piping is $20.8 million. Each ship would reportedly have on-board capacity to store nearly 790,000 LNG gallons. Matson has estimated that this would be sufficient fuel to sail round-trip from California to Hawaii roughly once per week. Thus, for an OGV making about 52 round trips per year to Hawaii, the LNG demand at the California port would be about 41 million gallons per year. Matson’s decision to actually make the necessary capital investments will depend on (among other factors) its ability to enter into an attractive long-term LNG bunkering contract at a suitable California port (most likely Oakland).³⁷

3.4.3 Rail Applications

EIA estimates that nearly 260 million diesel gallons per year are sold within California for all railroad operations (line haul, switching, passenger, etc.). UP and BNSF collectively consumed about 92 percent (240 million gallons) of this total to operate and support their freight line-haul operations. Based on a recent CARB report, at least half of UP’s and BNSF’s rail operations in California are close to port operations. Thus, using a high-level “top-down” approach, it is reasonable to assume that at least 120 million diesel gallons per year are consumed by California rail operations involved in intermodal goods movement (i.e., closely linked to California ports).³⁸

Similar to the marine vessel case, future LNG demand for rail operations serving California ports can roughly be estimated by applying assumptions for LNG penetration rates combined with other factors (e.g., average substitution rate). For an illustrative rail case, it is assumed there will be a 20 percent penetration rate for LNG by 2030 for locomotives using the same 95 percent substitution rate. Under this scenario, the total demand for LNG in 2030 is estimated below.

<table>
<thead>
<tr>
<th>Estimated LNG Demand for 20% Penetration of Locomotives Serving California Port Activities</th>
</tr>
</thead>
<tbody>
<tr>
<td>120 million diesel gallons X 20% penetration by LNG locomotives with a 95% LNG substitution rate</td>
</tr>
<tr>
<td>= 22.8 million diesel gallons/year displaced = ~40 million LNG gal/yr</td>
</tr>
</tbody>
</table>

As indicated, under these assumptions the annual LNG fuel demand in 2030 from LNG locomotives fueling at California ports is estimated to be around 40 million LNG gallons, or about 110,000 gallons per day.

It is also useful to apply a “bottom-up” approach to estimate potential LNG rail demand for the two San Pedro Bay Ports. Using ARB’s rail yard assessments (2005) – accelerated with estimated rail growth over the last decade, diesel fuel use for all locomotives serving the San Pedro Bay Ports can be approximated. For all locomotive activities, it is estimated 71 million diesel gallons per year are dispensed at or near these two ports. This estimate includes on-dock rail activity, switcher operations, and locomotives

operated at the nearby Watson, LAXT, and ICTF intermodal yards. Under this scenario with a 20 percent penetration rate and 95 percent substitution rate, the total demand for LNG in 2030 is estimated below.

<table>
<thead>
<tr>
<th>Estimated LNG Demand for 20% Penetration of Locomotives Serving the San Pedro Bay Ports</th>
</tr>
</thead>
<tbody>
<tr>
<td>71 million diesel gallons × 20% penetration by LNG locomotives with a 95% LNG substitution rate</td>
</tr>
<tr>
<td>= 13.5 million diesel gallons/year displaced = ~24 million LNG gal/yr</td>
</tr>
</tbody>
</table>

As indicated, under these assumptions the annual LNG fuel demand in 2030 from LNG locomotives fueling at the San Pedro Bay Ports complex is estimated to be about 24 million LNG gallons, or about 65,800 gallons per day. (Section 3.4.2 for comparisons of the total estimated current fuel demand at the San Pedro Bay Ports for marine vessels, locomotives, drayage trucks, and cargo handling equipment).

### 3.4.4 Other Port Applications (Drayage and Cargo Handling Equipment)

For comparison, this section provides estimates of the total diesel fuel usage by (1) on-road drayage trucks and (2) cargo-handling equipment (CHE) that serve the twin San Pedro Bay Ports complex. This is followed by a discussion of the potential synergy with using LNG in the marine and rail sectors.

The following summarizes current combined fuel use at the two San Pedro Bay Ports in drayage and CHE applications:

- Based on ARB’s EMFAC2014 model, drayage trucks (including short-haul near-dock moves) consume roughly 126 million diesel gallons per year (about 9,000 gallons per year, per truck).
- Based on the 2015 emission inventories of both ports, CHE (yard hostlers, top picks, rubber-tiered gantry cranes, forklifts, etc.) collectively consume roughly 16 million diesel gallons per year.

Expanded use of natural gas in these two sectors has potential to provide added market pull for marine and locomotive LNG markets. As described, drayage trucks and yard hostlers have been “ahead of the curve” for natural gas adoption in port applications, especially in drayage trucking. At peak penetration, nearly 900 of the 12,000 Class 8 drayage trucks regularly serving the San Pedro Bay Ports complex were fueled by LNG. Today, the number is about 600. If, for example, 50 percent of the 12,000-truck fleet were to use LNG, this would create new demand for more than 100 million LNG gallons per year.

There is real potential for major penetration of natural gas in these applications. Currently, all drayage trucks serving San Pedro Bay Ports meet the U.S. EPA 2007 or 2010 on-road emissions standards. State regulations require all trucks to meet the 2010 standard by 2023. However, even greater emission reductions are needed for the South Coast Air Basin. Under their joint new CAAP, both ports are drafting a revised Clean Trucks Program that may strongly encourage transition of the drayage truck fleet to zero-emission or near-zero-emission technologies. Natural gas engine technology provides the only certified near-zero-emission platform. Thus, natural gas engines appear poised to capture a larger share of the drayage fleet if the San Pedro Bay ports adopt this type of requirement.

If this type of scenario comes to fruition, drayage trucks will create significant new demand for natural gas fuel at the Ports of Los Angeles and Long Beach. It is more complex, however, to assess how such a scenario might help create LNG demand and infrastructure that is synergistic with LNG bunkering for marine vessels and/or locomotives. Factors that come into play include:
• Industry trends indicate that CNG (rather than LNG) will dominate the fuel systems of natural gas trucks in shorter-haul applications like drayage.

• Drayage trucks fuel at many inland locations away from the ports.

• The working model for current LNG fueling infrastructure used for on-road trucks is to bring in LNG by tanker trucks from one of the existing production facilities in Boron, California, or Topock, Arizona. Expansion of these existing systems would likely be used to meet new LNG demand.

Notably, the fast refueling rates required for a large fleet of CNG drayage trucks could be well served by LCNG stations. For example, Clean Energy’s LNG station near the Port of Long Beach mostly dispenses LNG to drayage trucks, but it also has capability to fuel CNG trucks (or cars) using LCNG dispensing systems. LCNG stations can provide faster fueling rates compared to conventional CNG stations that compress pipeline natural gas. The challenge is that LCNG can be more expensive than CNG, at least when dispensed on a relatively small scale. However, if a large (marine-scale) supply of LNG were to be established at the San Pedro Bay ports, the economy of scale could reduce LCNG costs per gallon. This would create opportunity to fuel large numbers of CNG drayage trucks using a local LNG fuel supply.

3.4.5 Summary: Comparative Fuel Demand at San Pedro Bay Ports by Key Off-Road HHP Sectors

The San Pedro Bay Ports complex (Port of Los Angeles and Port of Long Beach) jointly handle nearly 90 percent of ocean-borne containers entering or leaving California. Given this dominant size, the annual fuel demand for marine vessels, locomotives, drayage trucks, and CHE provides a good indicator of broader port-related diesel activity in California markets. Figure 14 illustrates how current demand for existing petroleum fuels for marine vessels (mostly OGVs) at the two ports is an order of magnitude larger than the combined fuel demand from the other three sectors shown. A 10 percent penetration of LNG for OGVs is roughly equivalent to 100 percent penetration for rail, drayage, and CHE combined.
Figure 14: Estimated Annual Fuel Demand for Key Port Equipment Sectors at San Pedro Bay Ports

Key Assumptions:

**Marine:** based on prior analysis of total marine fuel demand by OGVs calling at West Coast ports. California estimated at 50% of West Coast market and SPBP estimated at 90% of California market.

**Rail:** based on 2005 ARB rail yard assessments and estimated rail growth between 2005 and 2015 for Watson, LAXT, and ICTF intermodal yards near SPBP.

**Drayage:** based on EMFAC2014 fuel use for T7 POLA trucks in California

**CHE:** based on POLA and POLB 2015 Emissions Inventories for yard tractors. Tailpipe GHG emissions converted to diesel gallons based on carbon content in reported fuels (diesel, gasoline, LNG, and propane).

*Fuel oil refers to 1) HFO for marine vessels and 2) diesel for rail, drayage and CHE. These have been normalized to diesel gallon equivalents (DGE).*

Source: Gladstein, Neandross & Associates
CHAPTER 4:  
LNG Infrastructure Needs and Scenarios to Promote Market Growth

4.1 Gaps in Current Infrastructure Needs and Supply Logistics

Currently, there are no LNG-fueled marine vessels or locomotives serving California ports, therefore, there is no immediate need for any new LNG infrastructure to serve those HHP sectors. By contrast, Southern California has a growing fleet of on-road heavy-duty NGVs, which has developed in tandem with robust supply markets for LNG and CNG. On the LNG side, the fuel is produced at a few small-scale, land-based LNG liquefaction facilities. As an example, the existing Clean Energy LNG liquefier in Boron (within 150 miles of Los Angeles) produces up to 180,000 gallons per day; capacity exists to increase this up to 270,000 LNG gallons per day. Onsite storage is for 1.8 million LNG gallons. This and the other land-based LNG production facilities use Class 8 heavy-duty trucks towing cryogenic trailers to deliver LNG to 13 publicly accessible stations in California and Arizona, in addition to various private stations used by heavy-duty vehicle fleets. All three LNG providers have indicated that this system can be expanded to meet additional LNG demand from on-road NGVs.

Significantly larger-scale LNG liquefaction and distribution operations will be required to supply LNG for new markets focused on serving ships and/or locomotives in California. As described, marine vessels (particularly OGVs) are likely to dominate LNG demand at or near California’s three large ports. Even with low initial penetration, LNG volumes needed for OGV applications will likely require large waterside LNG liquefiers with similar production capacities to those now being built in the Pacific Northwest. For example, to meet initial demand for several LNG ships (while planning for expanded deployments), FortisBC is building two liquefiers with capacity of nearly 400,000 gallons per day, and it has installed onsite storage tanks that hold at least 18 million LNG gallons. The new LNG facility being built by Puget Sound Energy in the Port of Tacoma will initially serve two TOTE LNG vessels; it will have a liquefaction capacity of 250,000 gallons per day, with 8 million gallons of storage.

For context and to help understand what would be necessary to serve California marine vessel markets, the FortisBC and Puget Sound Energy LNG liquefaction facilities are compared to the described low and high scenarios for LNG bunkering at California ports:

- **Low-end “Matson” scenario** – A single ship traveling round trip from a California port to Hawaii once a week would require about 112,000 gallons per day; onsite LNG storage similar to that at the Boron facility (1.8 million gallons) might be sufficient.
- **High-end “10 percent” scenario** – To fuel 10 percent of the OGVs that regularly serve California’s three major ports, about 1 million LNG gallons per day would be required; on-site LNG storage at least as large as FortisBC’s 18 million gallons would most likely be required.

Locomotives do not consume as much fuel as marine vessels, yet a single line-haul locomotive can burn as much as 330,000 diesel gallons per year. UP and/or BNSF will require access to fairly large volumes of...
LNG if they decide to convert significant portions of their line-haul operations to natural gas. Identifying specific LNG infrastructure gaps is different for rail applications because fueling logistics (such as where, how, volumes, and constraints) differ greatly from marine vessels (See next section). UP and BNSF are assessing the costs and benefits of potentially switching to LNG. No issue is of greater importance to these railroads than how to safely, efficiently, and affordably accomplish LNG fueling in their systems. Based on public statements to date, the railroads appear to make their own decisions when it comes to obtaining access to LNG fuel supply. However, it is possible that UP or BNSF or both could “piggyback” on efforts by the shipping industry to build LNG bunkering facilities in ports such as Los Angeles, Long Beach, and Oakland. These types of possibilities are discussed in the next section.

4.2 Potential LNG Supply Scenarios

Shipping companies and railroads will likely seek “turn-key” or complete solutions if they switch to LNG. They will want to duplicate current fuel purchasing, supply, and dispensing practices. Unless there are clear advantages to having their own facilities, they will likely enter into third-party agreements to avoid building, owning, and maintaining LNG production facilities. These high-fuel-use fleets have considerable clout with regard to obtaining long-term fuel supply agreements with transparency in pricing, consistency in pricing components, and sharing of amortized development costs.

4.2.1 Marine Vessel LNG Bunkering Strategies

There are four basic LNG bunkering strategies that can potentially be used to fuel marine vessels at California ports: (1) ship to ship, (2) shore to ship, (3) truck to ship, and (4) transferring ISO containers. In startup markets, a truck-to-ship or ISO container strategy can provide a low-cost, easy solution until a permanent strategy can be implemented. Both methods are being explored or actually used in various emerging North American “starter” efforts to bunker LNG vessels. The two most commonly used strategies in mature, high-volume bunker markets are:

- **Shore to ship** – A pipeline network connects bulk storage tanks to shore-side dispensers
- **Ship to ship** – Specialized LNG bunker barges or vessels are used to refuel LNG ships offshore

Figure 15 summarizes the strengths and weaknesses of these two “end-game” bunkering strategies. As the matrix indicates, a ship-to-ship strategy provides geographic and operational flexibility, enables simultaneous bunkering and cargo operations, does not require the bunkering vessel to dock (which takes up valuable space for cargo loading/unloading), and includes other advantages as well. These combine to make ship to ship a relatively low-cost option. The flexibility, relatively minimal developmental requirements, and low cost of ship-to-ship LNG bunkering make it the preferred strategy in many emerging LNG marine vessel deployments, including those in North America. It does, however, require a third-party LNG bunker vessel operator, and it introduces higher risks associated with making ship-to-ship connections.
A shore-to-ship bunkering strategy has advantages, including the potential to achieve high LNG transfer rates. A constraining factor is that shore-to-ship bunkering requires building land-based infrastructure at one or more locations within the port area. Thus, it offers less flexibility and can entail complex permitting and regulatory processes. It also requires the ship being bunkered to dock at the fueling location. This requirement may add costs and time for tugboat/pilotage services, and it takes up valuable docking space in the host port. In the larger context, an advantage of shore to ship (versus ship to ship) is that a land-based LNG bunkering network for marine vessels can potentially also serve nearby LNG rail operations. This is discussed in the next subsection.

In 2014, Lloyd's Register surveyed 22 international ports to assess any preferences for potential “wide-scale development” of LNG bunkering. The findings indicate that responding ports (including the Ports of Los Angeles and Long Beach) may seek “hybrid” versions of these various LNG bunkering strategies, at least for their initial deployments. In the short term, ports generally favor ship-to-ship strategies such as bunker barges or shore-to-ship strategies using truck delivery. Over the longer term, ports and shippers increasingly favor building dedicated LNG liquefaction and storage systems for bunkering, which will be as close to the fueling site as possible. In general, the survey found that ports and shippers will emulate the existing bunkering system for conventional marine fuels; for example, if HFO is delivered by barge today, LNG is likely to be delivered the same way in the future.  

There are no clear movements in California’s three major ports to adopt LNG bunkering strategies, but all three ports (and their shipper customers) are assessing options. These ports are major hubs for international ship traffic. A combination of environmental and economic drivers is anticipated to push many shippers worldwide to gradually start switching to LNG as their primary marine fuel. Shippers that

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serve California ports and start using LNG will require access to LNG bunkering services. In addition to goods movement OGVs using LNG, passenger ships will create LNG demand. The San Pedro Bay Ports complex is one of only a few deep-water ports in the United States capable of receiving large LNG-fueled cruise ships, some of which are under construction.

Assuming this comes to fruition, it’s likely that the big three California ports will employ ship-to-ship LNG bunkering strategies as they implement early market LNG bunkering efforts. Very large volumes of LNG are needed to justify the cost, complexity, and long timeline\(^\text{40}\) associated with building a local LNG liquefier and large volumes of LNG storage. Permitting and construction obstacles include the complex process to assess and address environmental impacts and the significant likelihood that local communities will oppose the project. These factors make a shore-to-ship bunkering strategy less attractive, at least for initial market deployments.

For the two San Pedro Bay ports, it’s possible that shippers such as Horizon, Matson, American Petroleum Tankers, and Carnival Cruise Lines could soon decide to initiate LNG ship deployments using a ship-to-ship strategy. Two potential LNG supply sources are the Sempra-Shell Energia Costa Azul export terminal in Baja, California, and the FortisBC export terminal in British Columbia (Figure 16). These facilities are significant distances from the Los Angeles area, yet they are close enough to make the economics feasible for all parties. The fact that neither export facility is located in the United States adds favorable market dynamics. Ships traveling between these LNG export terminals and the San Pedro Bay ports are engaged in international trade and not subject to the Jones Act. This significantly decreases the capital and operating costs of the vessels.

**Figure 16: Potential LNG Bunkering Supply Options for San Pedro Bay Ports Complex**

\(^{40}\) Any kind of LNG bunkering project would likely take at least two years to complete the California Environmental Quality Act (CEQA) process. Even when a project ultimately offers environmentally beneficial products such as cleaner transportation fuels, the CEQA process can cause major delays or entirely halt the project.
Further, the LNG being supplied from FortisBC is produced at a facility that was constructed using utility ratepayer dollars. This facility was built to provide LNG for peak shaving of utility loads, but a portion of the LNG storage capacity for the facility is available for transportation applications or other merchant uses. When demand for LNG to peak shave is seasonally low, more LNG can be dedicated to merchant sales as long as this is done on an interruptible basis should peak shaving be required. Because this arrangement helps reduces costs to ratepayers, it has been approved by the British Columbia Utilities Commission.\footnote{FortisBC press release, “Tilbury LNG facility expansion and natural gas for transportation boosted by government announcement,” November 13, 2013, https://www.fortisbc.com/MediaCentre/NewsReleases/2013/Pages/Tilbury-LNG-Facility-expansion-and-natural-gas-for-transportation-boosted-by-government-announcement.aspx.}

Under this type of ship-to-ship strategy, LNG bunker barges may be a good choice for delivering the LNG and bunkering LNG ships in the San Pedro Bay Ports. One such barge, the “Clean Jacksonville”, is being built by Applied Cryo Technologies as America’s first vessel of this type to deliver up to 580,000 LNG gallons (Figure 17). This special barge will soon carry LNG from Pivotal LNG to TOTE containerships operating in Jacksonville-to-San Juan (Puerto Rico) service.

![Figure 17: Construction of North America’s First LNG Bunker Barge](source: Pivotal LNG)

Puget Sound Energy’s new LNG facility in the Port of Tacoma could also provide LNG for use at California ports. This facility will be in service by late 2019 with an LNG liquefaction capacity of 250,000 gallons per day and 8 million gallons of storage. It is being constructed to serve TOTE Maritime’s LNG vessels in the Alaska trade while serving as a peaking resource for core natural gas customers. This facility is expected to have additional production capacity for other transportation applications,\footnote{Roger Garratt, Puget Sound Energy, “Tacoma LNG Facility,” presentation to 2016 Natural Gas for High Horsepower Summit, October 2016.} which could include marine and rail applications in California (e.g., Matson in the Port of Oakland). In this case, however, delivery of the LNG would be required using vessels subject to the Jones Act, which will be more expensive than bunker vessels under the Vancouver or Baja California scenarios.

In the long run, one or more world-scale LNG import/export terminals will probably be required to serve the two high-fuel-use HHP applications of marine vessels and locomotives as they move goods through California ports. An existing example in North America is the Sabine Pass LNG Terminal under construction in Louisiana. This large waterside liquefaction facility, owned by Cheniere Energy, will have
the capability to distribute LNG throughout the greater U.S. Gulf Coast region. A “hub-and-spoke” model will be used, featuring large liquefaction capacity and five large storage tanks, with a mix of bunkering strategies that include bunker vessels, tanker trucks, and shore-to-ship loading facilities. As this suggests, it takes very large, guaranteed LNG demand from at least one anchor fleet to justify the major capital investments it takes to design, permit, and build such a large-scale LNG bunkering system.

4.2.2 Potential Synergy with Rail and Locomotive LNG Refueling

As described, California rail operations that are closely linked to California ports consume an estimated 120 million diesel gallons per year. More than 90 percent of this fuel is consumed by the two Class 1 railroads, UP and BNSF. In the San Pedro Bay ports, roughly one-fourth of containerized cargo moves are accomplished using on-dock rail. The Ports of Los Angeles and Long Beach seek to increase on-dock rail movements. This will require additional investments to expand rail infrastructure at existing terminals and provide rail infrastructure at terminals that currently lack it. The two ports are also exploring the concept of “inland ports” connected by short-haul rail. The idea is to move cargo quickly from the seaports to an inland facility, where there is more space and flexibility to distribute cargo using trucks that avoid congested freeways in dense urban areas.

All of this creates an opportunity to potentially develop purpose-built LNG fueling infrastructure for new California rail operations, dependent on railroads like BNSF and UP deciding that LNG is the right choice for their operations. Regardless of the impetus, it is likely that the railroads will plan and build LNG refueling that in many ways emulates the existing model for diesel that has worked for many decades. The Class 1 railroads operate large refueling yards along key freight routes, but they also rely heavily on smaller-scale refueling and maintenance yards, such as those found in congested areas within and surrounding California ports. To dispense their largest diesel volumes, freight railroads use “rack-and-tank” systems (Figure 18). “Direct-to-locomotive” (DTL) fueling is also commonly used, where tanker trucks and wagons are used to dispense diesel directly into locomotives at rail yards and other locations (Figure 19).
For example, BNSF uses DTL services to fuel its locomotives each day at its LAXT rail yard serving the San Pedro Bay Ports. This requires about eight fuel tanker trucks per day.\textsuperscript{43} This same type of DTL service could be used to refuel dual-fuel LNG locomotives. However, it would require roughly 62 percent more truck trips to deliver the same volume of LNG on an energy-equivalent basis (assuming a 95 percent efficiency).

\textsuperscript{43} This information is based on work performed by Gladstein, Neandross & Associates for the natural gas industry.
It remains to be seen whether this could be a practical fueling strategy for LNG locomotives. It seems likely railroads will want to ultimately use rack-and-tank-type systems at dedicated fuel depots to fuel LNG locomotives.
CHAPTER 5:  
Best Practices for LNG Bunkering at Ports

The growing demand for LNG marine fueling operations has compelled U.S. and international organizations (e.g., IMO and the International Standards Organization) to establish standardized infrastructure and operational procedures to help ensure LNG marine fuel transfer operations are conducted safely and uniformly in the global maritime community. Notably, these guidelines are “works in progress” as the maritime industry moves iteratively forward with making LNG a significant marine vessel fuel.

As further described, in U.S. waters the United States Coast Guard (USCG) has jurisdiction for standards, codes, and best practices involving LNG use as a marine fuel. Using LNG is relatively new among U.S. flag and foreign vessels operating in U.S. waters. In some cases, USCG has established regulations that apply to LNG fuel-transfer operations, and U.S. flag vessels powered by LNG are subject to USCG regulations (which are outlined in various subchapters of Title 46 of the Code of Federal Regulations). The specific regulations governing these vessels depend on the type of vessel, such as towing vessel, fishing vessel, tank vessel, or cargo vessel. While the USCG has not established specific regulations for vessels that receive LNG as fuel, it has published guidance for fuel transfer operations and training of personnel work on vessels that use natural gas as fuel and conduct LNG fuel transfers.

The USCG efforts to establish and implement emerging “best practices” for LNG bunkering and use at ports are summarized. These efforts are followed by brief summaries of other U.S. and international agencies that are also providing similar types of guidance and/or regulations.

5.1 U.S. Coast Guard/Department of Homeland Security

The USCG (a division of the Department of Homeland Security) has made concerted efforts to serve as a clearinghouse and common voice to document and promulgate best practices for using LNG at U.S. seaports. There can be important differences in regulations and practices at different ports, and the USCG has helped develop commonality that provides valuable assistance to regulated parties and stakeholders. Toward this end to improve commonality and define best practices for LNG bunkering operations, the USCG has established its Liquefied Gas Carrier National Center of Expertise (LGC NCOE, https://www.uscg.mil/hq/cg5/lgcncoe/).

In developing policies and best practices about LNG bunkering, the USCG has incorporated the maritime industry’s guidance and input. USCG has released several key field notices and policy letters that apply industry input to codify standardized LNG bunkering procedures including:

- Field Notice 01-16, titled “LNG Bunkering Job Aid for Facility to Vessel Operations,” augmented existing policy by providing a recommended checklist that can be used for initial and annual inspections of shore-based LNG bunkering facilities and during transfer monitors of LNG bunkering operations from a facility to a vessel. The information provided in this field notice is to be used as a recommendation to help ensure the safety of marine LNG bunkering operations.
Field Notice 01-15, titled “LNG Bunkering Recommendation,” differentiates LNG bunkering recommendations specific for U.S. flagged vessels from recommendations for all vessels (U.S. and non-U.S. flagged vessels). It also updates previous guidelines by providing recommendations that highlight “best practices and lessons learned” from recent LNG bunkering operations. The information provided in this field notice is to be used as recommendations to help ensure the safety of marine LNG bunkering operations.

Policy Letter 02-15 titled “Guidance Related to Vessels and Waterfront Facilities Conducting Liquefied Natural Gas (LNG) Marine Fuel Transfer (Bunkering) Operations” helps guide owners and operators of vessels and waterfront facilities that operate LNG transfer operations. In addition, this letter guides Coast Guard Captains of the Ports when assessing LNG transfer activities at their ports. Those activities include “bulk liquid transfers conducted from tank vessels (tank ship and barges), waterfront facilities handling LNG in bulk (e.g., storage tanks, mobile tank trucks, and rail cars) and portable tanks containing LNG.” The policy letter does not address licensed LNG deepwater port facilities of certain types, or the design of LNG fuel systems installed on vessels using LNG as fuel (e.g., LNG-powered LNG tankers).44

In January 2016, the USCG published a memorandum describing certain changes to its LNG bunkering recommendations. This LGC NCOE Field Notice augments References 43 and 44 and shares the following recommendations based off best practices and lessons learned observed during recent LNG bunkering operations to prevent future incidents:45

- All vessels engaged in LNG bunkering operations should have procedures for inerting, purging, cooling down, loading, and testing of emergency shutdown devices similar to what are seen in a safety management system before conducting LNG bunkering. For U.S. vessels, these procedures should be reviewed by the USCG prior to any LNG bunkering operation and if initial Inspection for certification of the vessel is not complete, interim procedures should be developed before the first bunkering operation of the vessel (e.g., preceding sea trials). If the vessel does not fall under a safety management system, some alternate procedures should be developed before the vessel’s first bunkering operation.

- U.S. vessels engaged in LNG bunkering operations should have LNG piping drawings/plans that have been approved by the Marine Safety Center, and the local Officer in Charge, Marine Inspection should verify that the as-built arrangements meet these approved plans prior to any LNG bunkering operations.


• All vessels engaged in LNG bunkering operations should ensure their crews have specific familiarity with the LNG fueling system of the vessel in addition to the training requirements noted in the policy letters listed in References 43 and 44.

• If LNG bunkering preparations and operations last longer than eight hours, a duty rotation should be developed to ensure personnel involved received appropriate rest.

• All vessels engaged in LNG bunkering operations should have the ability to produce a historical record of all fueling alarms and valve closure times. These records should be available for inspection.

• A thermal oxidizer, marine flare, or any other equipment that produces an open flame should be placed outside the safety zone if used during LNG bunkering operations.

• Until the Coast Guard provides workforce development for LNG as fuel and LNG bunkering operations to include personnel qualification standards; tactics, techniques, and procedures; and training to properly prepare field inspectors, local marine inspectors should attend LNG as a marine fuel and LNG bunkering Person in Charge courses.

• The LGC NCOE should be involved in initial prebunkering and bunkering to provide LNG expertise for the planning, setup, and the actual operation.

5.2 The American Bureau of Shipping

The American Bureau of Shipping (ABS) has published a guidance document titled “Bunkering of Liquefied Natural Gas-fueled Marine Vessels in North America.” This document provides operators and owners of LNG-powered vessels, LNG bunkering vessels, and LNG-handling waterfront facilities with guidance about key LNG-related requirements and issues. It includes summaries about U.S. and Canadian national regulations, state/provincial requirements, port-specific requirements, and international codes and standards.

In 2015, ABS developed a guidance publication on the technical and operational challenges of LNG bunkering operations. This advisory addresses key issues that include the following:

• General considerations for LNG bunkering.
• Key characteristics of LNG and tank capacity for bunkering.
• Vessel compatibility.
• Operational issues aboard the receiving ship.
• Special equipment requirements aboard the receiving ship.
• LNG storage tanks and systems for monitoring and control of stored LNG.
• Operational and equipment issues from the supplier side.
• Bunker operations.

• Commercial issues and custody transfer.
• Regulatory framework.
• Safety and risk assessments.
• List of guidance documents and suggested references.

Other relevant publications from ABS include Guide for LNG Fuel Ready Vessels (December 2014) and Guide for Propulsion and Auxiliary Systems for Gas Fueled Ships (May 2011).

5.3 The Society of International Gas Tanker and Terminal Operators

The Society of International Gas Tanker and Terminal Operators (SIGTTO) is a shipping industry group that serves as an authority on “the liquefied gas shipping and terminals industry.” SIGTTO’s membership includes about 200 organizations that are stakeholders in using LNG for marine applications. SIGTTO promotes best practices for the liquefied gas shipping and terminal industries and has provided various guidelines applicable to LNG bunkering at marine ports. SIGTTO recently launched a new nongovernmental organization called the Society for Gas as a Marine Fuel to “encourage the safe and responsible operations of vessels using LNG as fuel and all marine activities relating to the supply of LNG used for fuel.”

SIGTTO prepares LNG-related publications that are generally sold for a nominal fee, although some can be downloaded free.47 Examples of key SIGTTO publications involving best practices for LNG marine applications include:

• Ship to Ship Transfer Guide for Petroleum, Chemicals and Liquefied Gases (2013).48 This provides guidelines and advice for relevant parties at marine ports regarding the planning and execution of ship-to-ship fuel transfer operations.

• LNG Operations in Port Areas (2003). This includes guidance on best practices for managing LNG shipping operations within ports. According to SIGTTO, it is “essential guidance to best practice for those involved with the design and operation of new LNG terminals and for existing terminals who wish to re-assess risk due to the dynamic nature of operating environments.” The document includes risk profiles associated with LNG operations and helps outline end users and operators manage such risks in port areas.

• LNG Emergency Release Systems (2017). This publication is a “comprehensive guide” for operators and maintainers of LNG loading arm emergency release systems to ensure the safety of life, protection of the environment, and protection of property during operations. Developed with the input of manufacturers, terminal operators, and LNG shippers, this title has been produced using a risk-based approach and covers the structure, workings, and evolution of emergency release systems as well as recommendations, guidelines, and best practices for their usage. Emergency release system hazards and risk management are also covered in a detailed final section, and two annexes provide competencies and training guides and suggested further reading.


5.4 An Important Need: Standardizing LNG Specifications for HHP Applications

There is no standardized specification that ship and rail operators can use to define LNG fuel composition and condition when they procure fuel. This is a significant gap because engine manufacturers have different fuel composition and conditioning requirements based on the engine type, fuel injection method, and operational profile of the equipment. Equipment operators must engage in a complex process to communicate their specific fuel requirements to LNG suppliers. This reduces the transparency of LNG fuel supply and pricing in the market, exposes the equipment operator to greater risks that they will procure fuel that does not meet their equipment requirements, and increases the equipment operator’s administrative burden to procure fuel. Further, if the equipment operator uses LNG that does not meet an engine manufacturer’s requirements, the engine warranty may be voided. Supporting development of a common framework or terminology to describe key LNG fuel composition and conditioning requirements across the LNG supply chain would reduce potential risks and streamline fuel purchasing.
CHAPTER 6:
Opportunity for Renewable Natural Gas in California Ports / HHP Applications

6.1 Role of Renewable Natural Gas (RNG) to Address Climate Change

RNG provides the lowest carbon intensity of any heavy-duty transportation fuel available on the market today. Consequently, according to CARB, heavy-duty natural gas vehicles burning RNG can deliver “deep GHG emission reductions” while providing ultra-low NOx emissions. RNG is a drop-in substitute for fossil natural gas, which means it can provide major GHG emission reductions when used in either “legacy” (in-use) or new natural gas vehicles and equipment. Production and end use of RNG can significantly reduce emissions of methane, which is a potent GHG that can be emitted during “upstream” production, processing, and delivery segments of the natural gas supply chain. In addition to being categorized as a GHG, methane is considered a short-lived climate pollutant. Short-lived climate pollutants remain in the atmosphere for a shorter period of time than carbon dioxide does, however, the associated global warming potential can be far greater. This higher relative GHG potency makes methane a key target for effective controls.

Methane is naturally formed and emitted during decomposition of organic waste. By capturing waste gases at livestock operations, landfills, and wastewater treatment facilities, the amount of methane that is released into the atmosphere can be greatly reduced. Additional GHG-reduction benefits are realized when this collected “biogas” is cleaned up to RNG, or “biomethane,” and used in transportation applications as a substitute for diesel or fossil natural gas. Recognizing these various benefits, CARB has prioritized greater use of RNG made from organic waste in California’s Short-Lived Climate Pollutant Reduction Strategy. Using these waste gas streams to make RNG for transportation applications becomes a method for reducing methane emissions and generating lucrative monetary credits under California’s Low Carbon Fuel Standard (See below).

Making and using RNG also reduce emissions of black carbon. Black carbon constitutes about 75 percent of the particulates emitted by heavy-duty diesel vehicles and engines. Like methane, black carbon is a short-lived climate pollutant with a global warming potential more powerful than that of carbon dioxide. In addition, black carbon causes major damage to public health, crops, forests, and water quality, and it can disrupt rainfall patterns. According to CARB, black carbon is “a leading environmental risk factor for premature death.” RNG helps reduce black carbon in two key ways. To the extent that RNG is made from biomass that might otherwise burn (e.g., California’s millions of dead trees during forest fires), production of RNG helps reduce black carbon emissions. When RNG is used as an alternative to diesel fuel to power engines and vehicles (especially in sectors lacking state-of-the-art emission controls), black carbon emissions may be avoided.

Deploying advanced natural gas engines using RNG in HHP off-road sectors at ports can accelerate California’s efforts to meet aggressive air quality and climate goals. CARB seeks to transition all the state’s on-road and off-road mobile sources to “zero tailpipe emissions everywhere possible, and near-zero emissions with clean, low carbon renewable fuels everywhere else.” This includes the very-high-fuel-use HHP marine and rail sectors. Similar to on-road heavy-duty vehicles, RNG and renewable diesel are the two major candidate renewable fuels for powering commercially viable HHP off-road engines. Both fuels are already playing key roles in reducing GHG emissions from the on-road heavy-duty vehicle sector. However, only the natural gas engine technology is delivering NOx emissions at the near-zero level of 0.02 g/bhp-hr.

The life-cycle production and use of RNG as a vehicle fuel offer California valuable environmental and economic benefits that go well beyond reducing urban ozone levels and addressing climate change. These include reduced human exposure to harmful diesel PM (especially in disadvantaged communities), enhanced job creation, and improved environmental management of organic waste streams (e.g., at sewage treatment plants and dairy farms). No other commercially available engine-fuel pathway for HHP transportation applications offers such a compelling combination of societal benefits.

As described, RNG is displacing large volumes of diesel in California and helping achieve major GHG and NOx reductions in heavy-duty on-road NGVs. ARB projects good potential to expand in-state RNG production and achieve even greater benefits in California’s on-road heavy-duty sector, although further assessments are necessary and underway. For large off-road applications like marine vessels and locomotives, the GHG- and NOx-reduction benefits of combusting RNG in natural gas engines are not as well characterized, in part because it remains unclear which specific engine technologies are most likely to be fully commercialized and deployed. It’s clear, however, that far greater volumes of RNG will be needed if HHP off-road applications are to use this renewable fuel in meaningful volumes. Thus, it’s difficult to estimate the extent that RNG will fuel HHP off-road applications like marine vessels and locomotives in California over the next decade.

### 6.2 Existing Markets for RNG as an HHP Transportation Fuel

California leads the United States in RNG use as a transportation fuel. Today, nearly 75 million gallons of RNG are annually being consumed annually in California’s on-road heavy-duty vehicle sector. This growing volume of RNG used by California’s heavy-duty NGV fleet is reflected in natural gas usage reported under the state’s Low Carbon Fuel Standard (LCFS) program. The blue line in Figure 20 shows the trend for volumes of total natural gas fuel reported under the LCFS, from inception through the second quarter of 2016. The green bars indicate the growing percentage of RNG that is being used in lieu of fossil natural gas to generate LCFS credits. In Q2 of 2016, 60.4 percent (21.1 million DGE) of the natural gas reported under the LCFS was RNG. At least 19 million DGE of RNG have generated LCFS credits during the last four consecutive quarters.

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This volume continues to increase as additional RNG production is brought online, and heavy-duty natural gas fleets are increasing their use of it. Vendors like Clean Energy and Applied Energy continue to expand availability of RNG to new heavy-duty NGV fleets and to execute new agreements with biogas suppliers to increase their RNG production. Some of this goes toward renewable LNG applications, such as the hundreds of LNG drayage trucks that continue to move containers at the San Pedro Bay Ports. At least one vendor has indicated that obtaining access to additional renewable CNG supply has been challenging, but excess renewable LNG supply is available.

The longer-term trend for RNG is difficult to predict, but it’s expected that there will be significant increases in RNG volumes used in vehicles and reported under the LCFS program. Post-2020, CARB is assessing the potential to increase the carbon intensity reduction target to 18 percent. Figure 21 shows one potential scenario developed by CARB staff for the estimated volumes of transportation fuels that will generate future credits under this proposed new LCFS target. From the “Biomethane” bar (synonymous with RNG), the volume of RNG generating LCFS credits could increase from about 75 million gasoline gallon equivalents (GGE) today to nearly 400 million GGE by 2030. This scenario appears to involve only existing on-road vehicle LCFS markets, excluding potential RNG use for OGVs or interstate locomotives (discussed below).
6.3 Potential RNG Demand Growth From Port/HHP Applications

As long as demand for LNG and CNG increases for HHP applications at California’s ports, there will be potential to substitute RNG for fossil gas to achieve major GHG reductions. In theory, the potential growth demand for RNG in these applications is identical to that of fossil gas. Practically speaking, however, current RNG supplies must be augmented to meet the necessary RNG supply for these high-fuel-use applications. It is also unclear today what specific drivers will compel end users to fuel their marine vessels and locomotives with RNG.

The latter factor is largely a cost issue since it is more expensive to produce RNG compared to fossil gas. In the case of on-road NGVs using RNG, it is the value of California LCFS credits combined with federal Renewable Identification Number values that make using RNG a potentially lucrative endeavor. The rules of these programs are different for marine and rail sector applications. Specifically, under the existing LCFS program:

- OGVS are excluded.
- Commercial and recreational harbor craft are eligible.
- Interstate locomotives are excluded.
- Intrastate locomotives are eligible.

CARB continually seeks to expand and improve its landmark LCFS program. CARB’s proposed 2016 SIP stresses that market demand for clean renewable fuels continues to grow, “with formerly non-regulated entities such as airlines expressing interest” to opt into LCFS markets. ARB notes that this could potentially expand criteria pollutant and GHG emission reduction benefits realized through California
programs “beyond the borders of the State.” CARB’s SIP statement here refers specifically to using renewable jet fuel for the aviation industry, but it is applicable to potentially allowing the shipping and rail industries to opt into LCFS credit-trading markets when using RNG in large marine vessels (OGVs) and interstate locomotives.

Notably, under the federal Renewable Fuel Standard (RFS) program, biofuels used in OGVs are ineligible to generate Renewable Identification Number values. However, biofuels used in other types of marine vessels, as well as in all locomotives, are eligible. Thus, the federal RFS program can help buy down the incremental cost of using RNG in non-OGV marine and rail applications.

### 6.4 Existing Roadblocks to RNG Use in Port / HHP Applications

Cost is the overarching roadblock toward unlocking the full potential of RNG as a major transportation fuel, including use in HHP port applications like marine vessels and locomotives. Producing RNG is significantly more expensive than producing conventional (fossil) natural gas. This cost difference creates market uncertainty making it more difficult to attract investors for RNG-production projects. The monetization of RNG through transactions in California’s LCFS and the federal RFS are important and will need to be sustained. The fact that LCFS credit markets exempt RNG use in OGVs and interstate locomotives is one potential roadblock for replacing fossil gas with RNG in those applications.

Across all existing or potential uses, it is important to reduce the higher costs of producing RNG. That means finding less-costly ways to perform feedstock conversion, upgrade the resulting biogas into RNG that meets pipeline and transportation specifications, inject it into common carrier pipelines, and dispense the fuel. Specific areas for cost reduction appear to focus on biogas cleanup and pipeline interconnection. Another important challenge is to continue reducing upstream methane leakage rates, which is wasteful and costly and remains a significant source of GHG emissions.

In conclusion, while much progress is underway in California and the United States to produce greater volumes of RNG for transportation applications, there are many barriers to overcome to unlock the full potential for RNG as a major transportation fuel. These barriers include:

- Lack of market supply and demand certainty for biogas feedstock.
- Existing or potential competing uses for biogas feedstock or RNG or both.
- Requirements for biomethane pipeline access and transmission.
- General lack of knowledge by policy and decision makers.
- Limited applications in HHP sectors that are currently included in LCFS and RFS markets.

These types of policy and economic barriers limit RNG stakeholder efforts to effecting larger displacement of diesel fuel in California’s on-road heavy-duty vehicle sector. Far greater RNG volumes will be necessary to simultaneously and significantly displace petroleum fuel in marine and locomotive applications. Even if large volumes of biogas can be produced and collected for potential upgrade to RNG,

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52 There are many nuances here, but it appears that ARB can choose to also add OGVs and interstate locomotives as opt-in applications, if and when they start consuming RNG. Based on the current regulation, fossil CNG would also be allowed, but only biomass-based LNG (RLNG) would be allowed.
there will be competition for using the biogas in stationary power generation and other applications. It appears all these issues require further study and support from the State of California if RNG is to become a mainstream fuel in the state’s marine and rail sectors. Early challenges and barriers, however, can be turned into major opportunities for expansion due to the strong market pull that these high-fuel-use sectors can provide.

### 6.5 Key Needs to Promote RNG Growth for California Port HHP Applications

Further study is underway to define the dynamics of RNG supply and demand as it continues to increase market share within California’s transportation fuel markets. Today, RNG is consumed almost entirely in California’s on-road transportation sector, where compelling monetary credits are available through the California LCFS and federal RFS programs. Roughly 400 million DGE per year of RNG will be consumed by California’s on-road sector under a plausible LCFS scenario, and California will be able to obtain its necessary supply through in-state production or importing.

Scenarios for future RNG supply become much more complex and difficult to predict when contemplating the potential for very large volumes to be used in high-fuel-use marine and rail sectors. These applications are exempt from generating LCFS and RFS credits. It’s likely efforts to promote growth of RNG for California port HHP applications will proceed through the same basic process underway to expand use in on-road NGV applications. For off-road sectors like ships and locomotives, it is important to begin making significant deployments of engines that run on natural gas. As this initial challenge is met, a major opportunity can emerge to expand California’s RNG industry because these lasting, high-fuel-use vessels and locomotives can create major new market pull. Strong demand for large volumes of fuel under long-term purchase agreements will send important market signals to existing RNG producers and suppliers.
CHAPTER 7:  
Summary of Key Market/Technology Research Needs and Recommendations

This report highlights emerging opportunities in California to power two specific HHP off-road applications – marine vessels and locomotives – with low-emission natural gas engines. This is especially timely with the predicted return of higher oil prices and recent phasing in of stricter emission regulations. Economic and environmental benefits may persuade end users to consider using HHP marine vessels, locomotives, and equipment with clean-burning natural gas engines. LNG fuel systems are likely to make up the majority of such deployments; however, CNG can also play a role in smaller applications. RNG can displace fossil-based natural gas to maximize the climate change benefits that can be achieved by switching from conventional fuel to natural gas.

Many environmental and economic benefits of switching to natural gas (especially RNG) will accrue at and near large seaports that act as the anchors of California’s world-class goods movement system. To begin realizing these major benefits, however, there are important technical, policy, institutional, and economic challenges that must first be addressed and resolved.

To help advance natural gas engines and vessels/locomotives, recommendations include the following:

- Conduct research, development and demonstrations to improve the feasibility, emissions, and efficiency of dual-fuel and dedicated natural gas engines designed for marine vessels and locomotives. The focus should be on engine technologies with the highest potential to achieve emission levels well below the current cleanest standards. These applications have significant potential to displace conventional marine and rail fuels and reduce emissions.

- Support research, development, and demonstrations to apply novel fuel injection and ignition strategies for large-bore, medium-speed natural gas engines with low methane slip and high efficiency, and the option for 100 percent diesel operation.

- Explore research opportunities for the most promising applications that fall under state and local control, such as switcher and intrastate locomotives, commercial harbor craft, and cargo-handling equipment.

- Review potential for similar locomotive RD&D efforts involving intrastate commuter rail and locomotives (e.g., Amtrak Capitol Corridor, Pacific Surfliner, San Joaquin Valley routes).

- Adapt technologies that are already being commercially used to achieve near-zero-emission levels in on-road heavy-duty natural gas engines to smaller marine and locomotive applications (e.g., ferries and switcher locomotives). Specific areas of focus include better control of methane slip, improved durability of emission control systems, and increased fuel efficiency; details will depend
on the specific application and engine technology.

- Support activities to help manufacturers reduce the incremental subsystem costs of natural gas marine vessels and locomotives, including on-board fuel storage systems. Once beneficial technologies have been demonstrated, HHP deployment may not require more funding support due to the potential to achieve fuel cost savings and compelling payback on investments. Incentives designed specifically to help deployments in lower-fuel-use, high-visibility applications like switcher locomotives, ferries/passenger boats, commercial harbor craft, and cargo-handling equipment may help establish visible progress.

To help support and expand fuel production, infrastructure development, and bunker supply chains, recommendations include these:

- Identify and promote strategic opportunities to develop LNG bunkering projects to serve multiple high-fuel-use applications, including marine, rail, CHE, and peak shaving facilities. For example, the Jacksonville LNG plant has been designed to serve multiple transportation end uses.

- Developing a standardized LNG specification that ship and rail operators can use when they procure fuel. To reduce potential risks and help streamline fuel purchasing, this specification should be based on a common framework and terminology that describe key LNG fuel composition and conditioning requirements across the full LNG supply chain.

To specifically help increase in-state RNG production and the use in HHP port applications such as marine vessels and locomotives, recommendations include the following:

- Study the potential future dynamics among the supply, demand, and cost/price for RNG as a transportation fuel in California, especially if high-fuel-use applications like OGVs and interstate freight locomotives are to use RNG instead of fossil natural gas. This study should include evaluating the potential role of removing current exemptions in the LCFS program of RNG used in these applications.

- Evaluate the status of and potential support for facilities and products providing low-cost small-scale biogas liquefaction.

- Develop a broad-based working group among agencies, utilities, and other stakeholders to establish policies and programs that specifically support production and utilization of RNG as a transportation fuel.

- Study the viability and efficacy of producing renewable LNG for transport by rail.
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<tr>
<th>Term</th>
<th>Definition</th>
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<td>American Bureau of Shipping</td>
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<tr>
<td>bcf/d</td>
<td>billion cubic feet per day</td>
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<td>California Air Resources Board</td>
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<td>g/bhp-hr</td>
<td>grams per brake horsepower-hour</td>
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<td>high horsepower</td>
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<td>natural gas vehicle</td>
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<td>NO(_x)</td>
<td>nitrogen oxides</td>
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<td>NZ</td>
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<tr>
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