Assessment of Fuel Cell Technologies at Ports

United States
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Assessment of Fuel Cell Technologies at Ports

Transportation and Climate Division
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EPA OVERVIEW – ASSESSMENT OF FUEL CELL TECHNOLOGIES AT U.S. PORTS

Ports in the United States are gateways for trade and critical to the economy. While future growth in global trade and goods movement at ports is expected, it is critical to be cognizant of environmental protection. The Environmental Protection Agency's (EPA) Office of Transportation and Air Quality (OTAQ) recognizes the air quality, environmental justice, and economic significance of the U.S. port sector and established the EPA Ports Initiative. EPA's Ports Initiative supports efforts to improve efficiency, enhance energy security, save costs, and reduce harmful health impacts by advancing next-generation, cleaner technologies, and practices at ports. Fuel cells, in addition to other technologies, have the potential to replace diesel engines across a variety of sectors and thus significantly reduce emissions at ports. To better inform port stakeholders, EPA contracted Eastern Research Group (ERG) to research and develop a report characterizing different fuel cell technologies and how they might be utilized at ports.

The predominate equipment power source at ports are diesel engines, however, diesel engines are often a significant source of air pollutant emissions. While there are a variety of technologies used to address emissions at ports, this report specifically examines fuel cell technologies compared to traditional diesel applications in order to gain a better understanding of this particular technology.

The *Assessment of Fuel Cell Technologies at Ports* report characterizes fuel cell systems, their history, and their potential utilization at ports. The report consists of four main components: 1) fuel cell background information, 2) current fuel cell applications at ports, 3) emission analysis of fuel cell technologies, and 4) economics and impacts of using fuel cells. This report illustrates that fuel cell technologies have the potential to replace diesel engines across a variety of sectors and thus significantly reduce diesel emissions at ports.

Important Findings & Points Regarding the Assessment of Fuel Cell Technologies at Ports Report

- Fuel cell equipment and fuel cell power generation options are currently commercially available in certain applications (e.g. forklifts). Fuel cells generate electricity to power equipment much like a battery supplies electricity to power equipment. However, fuel cells use a fuel such as hydrogen l rather than recharge from the electric grid. Fuel cell electric technologies produce only water vapor and warm air. Consequently, fuel cell electric and battery electric are common terms that distinguish these two zero emission technologies as both are types of electric, clean technologies.
- This report focuses on fuel cell electric applications compared to the traditional diesel applications at ports to learn more about the technology and its various applications. Other technologies, such as battery electric applications, are not examined in this report. Information on how fuel cells compare to battery electric applications is available from other sources, including a 2009 Department of Energy report titled "Fuel Cell and Battery Electric Vehicles Compared"[1] by Dr. C.E. Sandy Thomas at H$_2$Gen Innovations, Inc. Also, more information on alternative fuels and advanced vehicles can be found at https://afdc.energy.gov/fuels/. [More information provided on the footnote below[2].]
- Different sources of hydrogen are currently available, but the environmental benefits vary.

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[1] https://www.energy.gov/sites/default/files/2014/03/f9/thomas_fcev_vs_battery_evs.pdf

[2] https://innovation.luskin.ucla.edu/wp-content/uploads/2019/10/Zero_Emission_Drayage_Trucks.pdf https://kentico.portoflosangeles.org/getmedia/31d5e97c-37f9-4519-953d-dc149968a7dc/zero-emissions-roadmap-technical-report, https://kentico.portoflosangeles.org/getmedia/f5183c7e-3731-4cd6-a4d0-346955a17e3a/Zero_Emmissions_White_Paper_DRAFT, https://cleanairactionplan.org/documents/final-cargo-handling-equipment-che-feasibility-assessment.pdf/

- While some fuel cell equipment is currently cost competitive with diesel equipment, for other equipment applications the incremental capital and operating costs will need to decrease over the next decade to achieve parity with diesel equipment.
- EPA recognizes that demonstrating long term durability of the various applications fuel cells is critical to fully capturing the benefits of the technology. Additional research will be critical to fully understand the complexities of fuel cell technologies beyond the demonstration phase.

For more information about this Assessment of Fuel Cell Technologies at Ports

Web: https://www.epa.gov/ports-initiative

Email: TalkAboutPorts@epa.gov

Table of Contents

Appendix A – Summary of Recent Fuel Cell Equipment Demonstrations and Deployments at U.S. Ports

List of Tables

List of Figures

Glossary of Terms

Alkaline fuel cell (AFC) – a type of fuel cell that uses an aqueous electrolyte solution of sodium hydroxide or potassium hydroxide and reacts pure hydrogen with oxygen to produce electric current.

Ammonia cracking – a thermal catalytic cracking process using temperatures above 400°C.

Anode – the electrode of a fuel cell in which electrochemical oxidation occurs.

Biomass- An energy resource derived from organic matter. These include wood, agricultural waste, and other living-cell material that can be burned to produce heat energy[3]. They also include algae, sewage, and other organic substances that may be used to make energy through chemical processes.

Biomass feedstocks- include dedicated energy crops, agricultural crop residues, forestry residues, algae, wood processing residues, municipal waste, and wet waste (crop wastes, forest residues, purpose-grown grasses, woody energy crops, algae, industrial wastes, sorted municipal solid waste [MSW], urban wood waste, and food waste).[1]

Biomass-to-liquids (BTL) Pro a multi-step thermochemical process for producing synthetic hydrocarbon fuels made from biomass feedstocks.

Boil-off – the vaporization and release of liquid hydrogen while stored over time.

Capital payback – the economic recovery of an initial capital investment over time. Payback can be measured in dollar value, percent or time (e.g., years).

Carbon capture and sequestration (CCS) – a set of technologies involving the capture, transport, and underground injection or geological sequestration (storage) of carbon dioxide (CO_2) emissions.

Cascade storage system – a subsystem used in hydrogen refueling stations, cascade storage is comprised of high-pressure storage cylinders typically arranged in three or more banks manifolded together. Hydrogen compressors pressurize the banks as needed to maintain pressure levels. A cascade control system or fuel dispenser supplies high pressure gas preferentially from each bank to the equipment requiring refueling based on the pressure level of the equipment's storage system and the final desired delivered pressure.

Cathode – the electrode of a fuel cell in which electrochemical reduction occurs.

Centralized hydrogen delivery pathway – the process of producing pure hydrogen at large scale plants (50,000 to 500,000 kg/day) followed by hydrogen transport via pipeline, truck, or rail to serve regional or national end-use markets.

Combined heat and power (CHP) – also known as cogeneration, CHP is a type of energy recovery technology that involves the simultaneous production of electricity and recovery of heat from plant waste

Cryo-compressed hydrogen storage – the process of storing hydrogen gas at cryogenic temperatures but within a pressure capable vessel.

Cryogenic liquid – a liquid stored at extremely low temperatures.

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[3] According to DOE's EERE Bioenergy Technologies Office, https://www.energy.gov/eere/bioenergy/glossary.

Diesel gallon equivalent – an amount of fuel equivalent to a gallon of diesel fuel on an energy basis.

Distributed hydrogen delivery pathway – the process of producing hydrogen in small scale plants (typically less than 1,500 kg/day) at or near hydrogen end-use locations using hydrogen carrier feedstocks such as natural gas or hydrocarbon fuels that have been transported via pipeline or truck to the plant.

Economic equilibrium point – a quantity measurement at which product demand and supply prices are equivalent.

Economic hydrogen demand potential – a subset of technical hydrogen demand potential in which hydrogen is less expensive than other options that can supply the end-use.

Electrochemical reaction – a reaction produced by or accompanied with electricity involving the transfer of electrons between two substances.

Electrolysis – the process of splitting water into hydrogen and oxygen when applying an electric power source.

Electrolyte – a substance that produces an electrically conducting solution when dissolved in a polar solvent, such as water.

Ethanol steam reformation (ESR) – a process for producing hydrogen that uses ethanol as the feedstock.

Flammability range – the range in which a fuel in the presence of air is flammable, usually expressed as volume of fuel in air.

Flash point – the lowest temperature at which a flammable liquid gives off enough vapors to form an ignitable mixture with air.

Fuel cell stack – multiple individual fuel cells of the same type stacked in a series.

Fuel cycle – under total energy analysis methodology, the fuel cycle encompasses all energy and emissions - related processes and activities of fuel feedstock extraction, fuel production, fuel product transport, distribution, dispensing, and fuel usage by end-use vehicles and equipment.

Gasification – the process whereby the reaction of coal or biomass feedstocks with oxygen and steam at high pressures and temperatures produces synthesis gas consisting of carbon monoxide (CO), hydrogen and impurities. The impurities are removed from the synthesis gas, which then undergoes the water-gas shift reaction to produce CO_2 and additional hydrogen.

Fiber reinforced polymer (FRP) – a recently emerging, advanced material under development as a cheaper alternative to steel used in pipeline materials.

Hydrogen kilogram equivalent (kg-e) – an amount of fuel equivalent to a kilogram of hydrogen on an energy basis.

Hydrogen storage module (HSM) – refillable storage devices used to supply hydrogen to various applications. Storage volumes vary, but HSMs can be substituted for refilled units once depleted in the field.

Inland port – term sometimes used to describe a port that is not located on a coast (e.g., Great Lakes or Mississippi River ports) or an area with large intermodal freight facilities that is not near navigable water (e.g., landlocked intermodal rail and truck facilities).[4]

Internal reforming – the ability of some types of fuel cells to convert natural gas or other hydrocarbon fuels directly into hydrogen at the anode of the fuel cell, thereby eliminating the need for an external fuel processor for performing the same function.

Liquefaction – the process of converting gases into liquids at very low temperatures.

Microbial biomass conversion – a fermentation process in which biomass feedstock is broken down by selective microbes to produce hydrogen gas. The process is referred to as "dark fermentation" since it does not involve light or photosynthetic activity.

Molten carbonate fuel cells (MCFC) – a type of fuel cell that uses a molten carbonate salt in a porous, chemically inert matrix as an electrolyte and reacts pure hydrogen or hydrocarbon fuels with oxygen to produce electric current.

Phosphoric acid fuel cell (PAFC) – a type of fuel cell that reacts pure hydrogen or hydrogen carbon fuels and oxygen, while also using an electrolyte consisting of phosphoric acid soaked in a porous matrix or imbibed polymer membrane to produce electric current.

Partial oxidation – a process involving the reaction of natural gas or other feedstocks with less than stoichiometric levels of oxygen (usually from air), resulting in a synthesis gas stream of hydrogen, CO, nitrogen (if air is used as a reactant rather than oxygen), and a small amount of CO_2 and other trace products.

Polymer electrolyte membrane fuel cells (PEMFC) – a type of fuel cell that reacts pure hydrogen and oxygen and uses a polymer electrolyte membrane to produce electric current.

Port – generally refers to places alongside navigable water (e.g., oceans, rivers, or lakes) with facilities for the loading and unloading of passengers or cargo from ships, ferries, and other commercial vessels. These facilities may be operated by different entities including state or local public port authorities, private terminal operators, and federal agencies. Activities associated with ports include operation of vessels, cargo handling equipment, locomotives, trucks, vehicles, and storage and warehousing facilities related to the transportation of cargo or passengers as well as the development and maintenance of supporting infrastructure (also see inland ports).[2]

Pump-to-Wheels (PTW) – under total energy analysis methodology, PTW refers to the portion of the Fuel Cycle that covers the delivery to and use of the fuel source by the end-user equipment application.

Semi-centralized hydrogen delivery pathway – the process of producing pure hydrogen at facilities between 1,501 and 49,999 kg/day for transport by pipeline, truck, or rail to directly serve municipal or multiple municipal markets.

Steam methane reformation (SMR) – a hydrogen production process in which natural gas is reacted with high temperature steam over a catalyst to produce synthesis gas containing hydrogen, CO, and a small amount of CO_2. The CO and steam are then reacted to produce CO_2 and additional hydrogen, commonly referred to as the

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[4] According to EPA's Ports Primer for Communities Glossary, https://www.epa.gov/community-port-collaboration/ports-primer-a3-glossary.

water-gas shift reaction. In a final pressure swing adsorption step, the CO_2 and impurities are removed, resulting in highly pure hydrogen gas.

Solid oxide fuel cells (SOFCs) – a type of fuel cell that reacts pure hydrogen or hydrocarbon fuels with oxygen and uses non-porous ceramic compounds or metal as an electrolyte to produce electric current.

Technical potential hydrogen demand – the market and resource potential of hydrogen, which is determined by existing end-uses, real-world geography and system performance, as opposed to economic indicators.

Tube trailer – a type of gaseous hydrogen transport involving the use of high-pressure cylinders mounted on a mobile trailer.

Vaporizer – a device used in hydrogen liquefaction plants and equipment refueling stations. Vaporizers serve as heat exchangers to convert liquid hydrogen to gaseous hydrogen at pressure using ambient air or warm water.

Vehicle/equipment cycle – under total energy analysis methodology, the vehicle/equipment cycle includes the energy and emissions -related processes and activities of raw material extraction and transport, component production and assembly, vehicle and equipment transport to end-use, and vehicle/equipment post-life disposal and/or recycling.

Well-to-Pump (WTP) – under total energy analysis methodology, WTP refers to the portion of the Fuel Cycle that covers production and collection of fuel feedstock, fuel production, and transport of the fuel source to the refueling station or end-use site.

Well-to-Wheels (WTW) – under total energy analysis methodology, WTW represents the full Fuel Cycle covering feedstock collection, fuel production, fuel transport and fuel dispensing, and usage by the end-user equipment application.

Executive Summary

Port facilities play a critical role in the nation's economy. Marine port operations and activities include the marshalling of freight into and out of the country, often operating older diesel engines and equipment. As such, their continued operation can contribute significantly to local and regional emission inventories and mitigation objectives. The EPA recognizes the economic and environmental significance of the U.S. port industry sector and has established the EPA Ports Initiative to identify and advance technologies and strategies that reduce emissions. Fuel cell technology promises significant advantages over current diesel-fueled port equipment for a broad array of port applications, including lower criteria pollutants, greenhouse gas, and noise emissions, higher energy efficiency and lower petroleum use, diverse fueling capability, and potentially lower maintenance requirements. In this report, ERG provides insight for EPA into the opportunities, impacts, and challenges associated with current and future fuel cell applications at ports.

How a Fuel Cell Works

Fuel cells generate electricity through chemical reactions that take place at the fuel cell electrodes, the anode (negative electrode) and cathode (positive electrode). The anode and cathode are separated by electrolyte material. In typical fuel cells, hydrogen-rich fuel is fed continuously to the anode, and an oxidant (typically oxygen in air) is fed to the cathode. The anode breaks down the hydrogen molecules into free electrons, which are routed through an external circuit to the cathode, producing direct current electricity output and charged particles that are conducted internally through the electrolyte material to the cathode. At the cathode, the charged particles combine with the incoming oxygen and free electrons to produce water and heat. Additional information can be found at:

https://www.energy.gov/eere/fuelcells/fuel-cells
https://afdc.energy.gov/vehicles/fuel_cell.html
https://www.epa.gov/greenvehicles/hydrogen-fuel-cell-vehicles

The key findings presented in this report include the following:

- **For ports, a number of fuel cell-powered equipment are currently available or under development.** Commercial fuel cells are currently available for forklifts and stationary power applications. Pre-commercial fuel cell platforms have been demonstrated and continue to be further developed for drayage trucks, yard tractors, cargo handlers, switcher locomotives, and marine vessels, and harbor craft.
- **In examining lifecycle emissions, hydrogen fuel cell-powered equipment in various port applications achieve significant lifecycle emission reductions for air pollutants examined.** However, higher SO_2 emissions were seen for many gaseous hydrogen fuel pathways within the feedstock collection, production, transport (for centralized pathways), and dispensing processes. Higher CH_4 and N_2O emissions were seen for some hydrogen pathways as well.
- **Gaseous hydrogen fuel pathways with lower fossil energy resource inputs exhibited the lowest criteria pollutants and GHG emissions.** Note, liquid hydrogen fuel pathways have higher energy use requirements, which is generally correlated with higher GHG and criteria pollutant emissions, than gaseous hydrogen pathways.
- **Upstream emissions results associated with distributed grid-based electrolysis are highly dependent on the sources of electricity.** Grid-based electrolysis using high fossil energy and low renewable energy resources require high energy use and produce higher emissions than grid-based electrolysis using low fossil energy and high renewable energy resources. Thus, distributed grid-based electrolysis in areas of the country served by electrical grids with high renewable energy input will have better lifecycle emissions than those with high fossil energy inputs.
- **Due to its early stage of development, higher hydrogen fuel prices, lower volume production, and current delivery options, port fuel cell-powered equipment currently costs more to operate relative to comparable diesel-fueled equipment counterparts.** However, in the future there is the opportunity for ports to realize significant benefits from the increased use of fuel cell equipment over time. Costs can be

further reduced due to economies of scale that support lower hydrogen fuel prices, with greater availability, and increasing production levels for fuel-cell powered forklifts, yard tractors, cargo handlers, harbor craft, and power generators. Hopefully, these savings will be sufficient to make port related fuel cell equipment competitive with available alternatives from a cost standpoint.

- **Durability and reliability across fuel cell-powered applications have improved considerably, including port equipment.** Fuel cell systems are expected to meet durability targets (of 5,000 hours for mobile applications and 80,000 hours for stationary applications) within the next two to four years.
- **Current annual hydrogen production in the U.S. is about 10 million metric tons, but recent research suggests a hypothetical hydrogen demand potential of about 166 million metric tons by year 2050.** Currently, the primary hydrogen markets are the petroleum refining (68 percent) and fertilizer production (about 21 percent) industries. Steam methane reforming using natural gas feedstock makes up about 95 percent of hydrogen supplies today. There are a variety of other hydrogen production processes already commercially available or under development including gasification of biomass or coal, and water electrolysis.
- **There are two likely pathways for near-term hydrogen delivery: centralized and distributed pathways.** Centralized pathways involve large-scale hydrogen production (50,000–500,000 kg/day) for serving regional or national markets via pipeline, truck, or rail. Distributed pathways involve local or onsite hydrogen production (less than 1,500 kg/day) fed by hydrogen product carriers like natural gas or water. Semi-centralized plants (between the 1,500 and 50,000 kg/day) may also arise for meeting regional hydrogen markets. In addition to hydrogen, other fuel sources can be used directly by some types of fuel cells. These fuels include natural gas, ammonia, and methanol.

Port Fuel Cell Equipment Applications

There are five primary types of commercial fuel cells defined according to their electrolyte type: 1) Polymer Electrolyte Membrane Fuel Cells (PEMFCs), 2) Alkaline Fuel Cells (AFCs), 3) Phosphoric Acid Fuel Cells (PAFCs), 4) Molten Carbonate Fuel Cells (MCFCs), and 5) Solid Oxide Fuel Cells (SOFCs). Worldwide fuel cell markets include both stationary power and transportation applications (primarily on-highway applications and material handling equipment). The most prominent fuel cell types in the marketplace include PEMFCs and SOFCs. In 2020, PEMFCs accounted for about 64 percent of total worldwide fuel cell shipments, while SOFC shipments contributed to about 30 percent (E4etch, 2020). On a total megawatt shipped basis, PEMFCs accounted for about 77 percent and SOFCs comprised about 11 percent of the new fuel cell market in 2020. The market dominance of PEMFCs likely results from their high efficiency, low temperature operation (allowing for quick start-up and higher durability), high power density, and low weight and volume relative to other fuel cell types. SOFC technology has found a strong market niche in the stationary power sector due to their fuel flexibility (ability to operate on a variety of hydrogen containing fuels), high efficiency (especially when coupled with combined heat and power systems), and high tolerance to fuel impurities.

For port managers and stakeholders, fuel cell technology offers a potentially significant new approach to improving port air quality and reducing petroleum fuel use. However, several challenges exist as fuel cell technology continues to evolve in the marketplace as a replacement for traditionally diesel-fueled applications. Table 1 provides a summary of the benefits and challenges associated with the use of fuel cell equipment at port facilities. The remainder of this Executive Summary discusses these elements in greater detail.

Table 1. Primary Benefits and Remaining Challenges for Fuel Cell Technology Applications at Port Facilities

Parameter	Benefits	Remaining Challenges
Port Fuel Cell Equipment		
Availability ***[See Sections: 2.3, 3.0, 7.1, 7.3]***	Available for many on-road, nonroad and stationary power port applications.	Pre-commercial status for many port applications but expected to become commercial in the near-term, including heavy forklifts, yard tractors, and cargo handlers.
Fuel Efficiency ***[See Sections: 2.3, 3.0]***	Up to 2.5 times more efficient than diesel for some applications.	Additional R&D for improving fuel cell system efficiency and equipment platform effectiveness for meeting specific equipment duty cycles is necessary.
Exhaust and Lifecycle Emissions ***[See Section: 6.0]***	Zero fuel cell equipment exhaust pollutants, only water vapor and heat. Significant lifecycle emission reductions.	Continued improvements in hydrogen fuel pathways (production, transport, and dispensing) along with greater long-term use of renewable energy sources will increase lifecycle emission benefits. Primary challenges include SO_2, CH_4, and N_2O emissions for some hydrogen fuel cell pathways.
Performance ***[See Sections: 2.3, 3.0, 7.1,7.3]***	Comparable to diesel equipment in many applications, although pre-commercial systems still lacking in some applications with challenging duty cycles.	In many applications, systems are still under development for meeting the demanding port equipment operational environment. Research on hybrid fuel cell/battery platforms for meeting peak power and operational range requirements continues.
Durability ***[See Sections: 2.2, 2.3, 7.1.2]***	Comparable to diesel for many applications.	Additional long-term testing and implementation experience necessary for some applications.
Capital Costs ***[See Sections: 2.3, 3.0, 5.3, 7.1.1]***	Projected future capital costs comparable to diesel following further system development and high-volume production.	Current capital costs are higher than comparable port-related diesel equipment, ranging significantly (e.g., 24-212% higher) across applications depending on their commercial status.
Maintenance Costs ***[See Sections: 2,3, 5.2, 5.3, 7.1.5]***	Projected maintenance costs likely to be lower than diesel.	Currently maintenance costs are equivalent or higher than diesel depending on the application.
Hydrogen Fuel Supply		
Fuel Availability ***[See Sections: 4.0, 7.3]***	Hydrogen currently produced for range of end-use sectors.	Currently regionally based production but projected to expand with rising demand.
Supply Infrastructure ***[See Sections: 4.0, 7.2]***	Large, centralized plant production and small onsite port (distributed) production.	Currently limited pipeline capacity, mostly truck transport and delivery.
Onsite Infrastructure ***[See Section: 4.0]***	Fuel dispensing equipment available for both gaseous and liquid hydrogen product.	Lower energy content of hydrogen requires larger storage footprint than diesel fuel. Dispensing and storage equipment costs are higher than diesel fuel.
Fuel Price ***[See Sections: 5.1, 5.3, 7.1.6]***	Long-term; forecasted to be lower than diesel price based on energy and efficiency equivalent basis.	Currently priced significantly higher than diesel based on energy and efficiency equivalent basis.
Fuel Safety ***[See Section: 4.1.3.5]***	Gaseous fuel that dissipates quickly without need for environmental clean-up.	Significant additional site/facility safety requirements, procedures, and special equipment due to hydrogen fuel property differences.

Current port applications for fuel cell technology cover on-highway vehicles, nonroad vehicles and equipment, rail, marine, and stationary power applications. In this study, the following port-related equipment applications were selected for further analysis based on EPA's interest, their use across port facility types and locations (including typical annual utilization and fuel use), and overall criticality for port operations: forklifts, yard tractors, cargo handlers (e.g., top loaders), switcher locomotives, marine propulsion and auxiliary power, and stationary power generation. This report does not focus on heavy duty drayage trucks; however, there are a number of ongoing port demonstrations as discussed in Section 2.3.2.3 and Appendix A of this report.[5] As noted in Table 2, PEMFCs are the primary technology used in the port-related equipment listed.

Table 2. Typical Diesel-Fueled Equipment Used at Port Facilities and Common Fuel Cell Replacement Characteristics

Diesel Equipment Type	Common Fuel Cell Types	Estimated Fuel Cell Equipment Commercial Status*	Application Summary
Forklift	PEMFC	TRL 7 Class IV, V and higher	Commercially available for Classes I, II and III; pre-commercial demonstration for Classes IV, V and higher.
Yard Tractor	PEMFC	TRL 7	Pre-commercial demonstrations.
Cargo Handlers	PEMFC	TRL 7	Pre-commercial demonstrations.
Switcher Locomotives	PEMFC	TRL 6-7	Pre-commercial switcher and line-haul demonstration; recent domestic and international pre-commercial passenger train demonstrations could benefit future switcher.
Harbor Craft			Both domestic and international pre-commercial demonstrations for propulsion and onboard power.
Propulsion	PEMFC	TRL 7	
Auxiliary	PEMFC, SOFC	TRL 7	
Power Generator	PEMFC, AFC, PAFC, MCFC, SOFC	TRL 9	Commercially available in 5 kilowatt (kW) - 10 megawatt (MW) capacities for stationary, back-up, and portable power applications.

*Based on the U.S. Department of Energy (DOE) Technology Readiness Level (TRL) Scale

Hydrogen Fuel Production, Supply and Dispensing

Current annual U.S. hydrogen production is about 10 million metric tons, which has increased over the last several decades to meet the primary hydrogen market demand for petroleum refining and fertilizer production. The significant expansion of existing production, storage and distribution infrastructure will be necessary to meet future hydrogen demand for widescale fuel cell equipment use, including port users.

Hydrogen production to end-use delivery will follow two pathways: centralized or distributed pathways. Centralized pathways involve large-scale hydrogen production (50,000–500,000 kilograms per day (kg/day)) and serve regional or national end-use markets (depending on plant location). In these cases, hydrogen product can be transported via pipeline (in pressurized gas form), truck (in pressurized gas or cryogenic liquid), or rail (in pressurized gas or cryogenic liquid form) to end-use markets. Hydrogen transport mode is contingent on a variety of factors, including transport distance, capital investments and permitting restrictions. Pipelines represent the most economically viable method of transport of large quantities of hydrogen over about 1,000 miles. At present, 1,600 miles of hydrogen pipelines exist in the U.S.; California, Louisiana, and Texas account for the majority of existing pipeline, with the primary purpose of supporting the petroleum refining industry.

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[5] Numerous research and development projects are underway by original engine manufacturer's and others around the world related to fuel cell powered heavy duty truck application. DOE has recently launched two consortia to advance fuel cell tuck and electrolyzer research and development. Information on this than can be found at, https://www.energy.gov/eere/articles/doe-launches-two-consortia-advance-fuel-cell-truck-and-electrolyzer-rd.

Additional hydrogen pipeline implementation may evolve over time as hydrogen demand increases and markets expand.

Regarding distributed pathways, hydrogen is produced locally or onsite to support local or regional end-users such as ports. For example, hydrogen carriers (e.g., natural gas or water) are transported to the end-use site to be used as feedstock in small scale (less than 1,500 kg/day) hydrogen production processes. The choice of centralized versus distributed hydrogen pathway delivery depends on the availability of, and proximity to, feedstocks and process energy sources; the size of regional or local markets; the degree of efficiency and costs associated with hydrogen production processes; and the market, environmental and socioeconomic impacts of hydrogen production. While it is convenient to define centralized and distributed production plants according to size, especially in terms of near-term market conditions, it should be noted that facilities may also produce between 1,500 and 50,000 kg/day for meeting larger local or regional hydrogen markets (U.S. Drive Partnership, November 2017). These so-called semi-central facilities may evolve and grow into centralized plants serving broader geographical regions.

Currently available or emerging hydrogen production processes include steam methane reformation (SMR), gasification of biomass or coal feedstocks, water electrolysis using electricity, biomass-to-liquids (ethanol) followed by reformation, microbial biomass conversion (or dark fermentation), and ammonia cracking. Natural gas SMR is the leading hydrogen production process and produces about 95 percent of hydrogen supplies (Ogden, 2018). Refinery and chemical processing by-products (including hydrocracking plants and chlorine production plants) as well as small-scale water electrolysis, account for the remaining 5 percent of current hydrogen production supplies. Table 3 lists the hydrogen production processes according to their application in centralized or distributed pathways. Note that only natural gas SMR and grid-based electrolysis are currently for sale and available for purchase. Hydrogen by-product production from hydrocracking and chlorine production plants can also be considered as commercially available, although these processes are more likely to serve in market support roles than as full-scale centralized plants. For this reason, they are not included in Table 3 as centralized plants specifically established for purposes of hydrogen product.

Table 3. Centralized and Distributed Hydrogen Pathway Production Processes and Characteristics

Hydrogen Pathway	Hydrogen Production Process	Commercial Status[6]	Process Water Use
Centralized	Natural Gas SMR	Current	Moderate
	Biomass Gasification	Mid-term	High
	Coal Gasification	Mid-term	Low
	Electrolysis - Renewable Energy	Mid-term	Moderate
	High Temperature Electrolysis	Long-term	Low
Distributed	Natural Gas SMR	Current	Moderate
	Grid-based Electrolysis	Current	Moderate
	Electrolysis - Renewable Energy	Current	Moderate
	Bio-derived Liquids Reforming	Mid-term	Moderate
	Microbial Biomass Conversion	Long-term	High

Several other processes may offer significant potential for commercialization in the coming decade(s), mid-term (2030-2040) and long-term (2040+). Additionally, many of the hydrogen production processes are associated with significant water use requirements, an important consideration for plant siting, especially in locations with water resource limitations and/or use restrictions. Further, while each of the centralized

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[6] As characterized by DOE's Hydrogen and Fuel Cell Technologies Office, https://www.energy.gov/eere/fuelcells/hydrogen-production-pathways

pathway production processes provides opportunities for serving national hydrogen markets, many of these processes may be more regionally significant due to feedstock, energy resource, and transportation distance constraints.

In terms of distributed pathways, the existing natural gas pipeline system can support the use of natural gas as a viable hydrogen carrier source for onsite hydrogen production given that small-scale SMR plants are already commercially available across the country. Similarly, small-scale water electrolysis plants are commercially available, the water distribution system in the U.S. is ubiquitous, and port locations are therefore well-served.

For biomass-derived liquids reforming, biomass-derived ethanol is already mass produced across the country, and ethanol is transported widely because of its use in chemical markets and as a gasoline additive. Although commercially unavailable at present, ethanol steam reforming (ESR) plants are similar to SMR in terms of operating temperatures, hydrogen yields, energy efficiency and production costs.

Once hydrogen is produced onsite or arrives as pressurized gaseous or cryogenic liquid product, the hydrogen can be stored locally until ready for use. Stationary power fuel cell applications can typically be fed gaseous hydrogen directly. For mobile fuel cell equipment, gaseous hydrogen is typically boosted in pressure before dispensing to increase the stored hydrogen energy density onboard the equipment. For liquid hydrogen dispensing systems, a cryogenic pump increases the liquid hydrogen pressure before a heat exchanger (vaporizer) converts the liquid hydrogen to required gaseous hydrogen pressures. A gaseous hydrogen dispenser then delivers product to the fuel cell equipment at required equipment onboard storage pressures, typically at either 350 bar (5,000 pounds per square inch (psi)) or 700 bar (10,000 psi).

Additional safety considerations remain for the storage, handling and dispensing of hydrogen fuel product due to differences in hydrogen fuel properties relative to diesel fuel. At ambient conditions, diesel fuel is a low volatility fuel, while hydrogen is a gas with wider flammability limits. It can readily mix with air and burns almost invisibly when ignited. Enclosed facilities that store or maintain hydrogen fuel cell equipment must be properly designed to account for hydrogen gas releases and leaks. Liquid hydrogen product should be handled with care to prevent exposure to fuel spills or uninsulated dispensing equipment, which could result in severe frost bite upon skin contact. Notably, however, hydrogen gas is lighter than air and thus disburses quickly in open areas. Hydrogen leaks (either as a gaseous or liquid product) do not require extensive clean-up like diesel fuel, and hydrogen is non-toxic, unlike diesel fuel.

While hydrogen fuel presents significant potential for fuel cells, there are non-hydrogen fuels such as natural gas, ammonia, and methanol that can be considered. Section 4.3 discusses these fuels in greater detail. Natural gas, widely availability in the U.S., currently is a key fuel source for supporting onsite production of hydrogen under distributed hydrogen pathways, but it can also be used directly as a fuel in some types of fuel cells such as MCFCs and SOFCs. MCFCs and SOFCs are generally relegated to stationary power applications, so natural gas could be delivered via pipeline directly to these onsite applications. Methanol, or methyl alcohol, is another fuel for potential direct use in certain types of fuel cells. As a liquid fuel, methanol's energy content is higher than natural gas but lower than gasoline. Methanol is currently used extensively in the U.S. chemical market and is available widely. Methanol can be used in direct methanol fuel cells (DMFCs), which is a specialized form of a PEMFC. Currently, DMFCs are used in small portable power applications for cell phones and laptop computers but could be adaptable to other power applications. Lastly, ammonia is extensively used in the U.S. for serving agriculture, pharmaceutical, and other industries, and thus is supported by an extensive supply infrastructure. Ammonia has comparable energy density to methanol and can be utilized directly in some fuel cell types. These include AFCs, AMFCs, and SOFCs but further research is needed before commercialization.

Hydrogen Fuel Cell Lifecycle Emissions

Based on a Well-to-Wheels (WTW) construct that comprised Well-to-Pump (WTP) and Pump-to-Wheels (PTW) components, lifecycle emissions analyses were conducted to represent fuel cell equipment usage and hydrogen production, distribution and delivery routes at U.S. ports. The WTP component includes hydrogen feedstock collection and transport, hydrogen fuel production, and hydrogen fuel storage, transport, and dispensing at the end-use site. As presented in Section 6, a comparison of WTP energy, water use and emissions from various hydrogen fuel pathways was conducted. The analysis used the 2019 Argonne National Laboratory's (ANL) Greenhouse Gases, Regulated Emissions, and Energy use in Transportation (GREET) model and default model assumptions. Assumptions covered hydrogen production feedstocks and process efficiencies, gaseous hydrogen transport modes, and gaseous hydrogen transport distances. WTP results for year 2020 are listed in Table 4 for low sulfur (15 ppm) diesel fuel and various centralized and distributed hydrogen fuel pathways, including both gaseous and liquid hydrogen.

Note that the low sulfur diesel pathway results are presented on a per gallon basis, while the hydrogen fuel pathway results are listed on a per kg basis. In general, the WTP results for most hydrogen production pathways are more energy and water use intensive than diesel fuel production on a per unit fuel production basis. Natural gas SMR and solar-based electrolysis displayed the lowest water consumption rates among the hydrogen pathways and are roughly on par with diesel fuel. Hydrogen production pathways with lower fossil energy exhibited the lowest criteria pollutants and GHG emissions in general, with pathways using natural gas having significant CO_2 emissions. Compared with gaseous hydrogen, liquid hydrogen pathways have higher energy use requirements, and as a result typically produce higher criteria pollutant and GHG emissions. (It should be noted that in the case of liquid hydrogen produced from centralized biomass gasification, biomass-generated electricty was assumed for the liquefaction process resulting in lower net CO_2 emissions. For liquid hydrogen produced from centralized solar-based electrolysis, solar-based electricity generation was assumed for the liquefaction process resulting in significantly lower emissions compared with gaseous hydrogen produced from centralized solar-based electrolysi.) For additional consideration, one gallon of low sulfur diesel fuel produces approximately 10% more total energy than one kg of hydrogen.[7]

Table 4. WTP Emissions Characteristics for Hydrogen Fuel and Diesel Fuel Pathways for Year 2020

Hydrogen WTP Pathway	Total Energy (BTU)	Fossil Energy Fraction	Water Use (gal)	Pollutant Emissions (grams)						
				VOC	CO	NO_x	PM_{10}	$PM_{2.5}$	SO_x	CO_2
Diesel Fuel Production [per Gallon]										
Low Sulfur Diesel	23,149	0.99	2.9	0.97	1.54	2.61	0.20	0.16	0.88	1,640.00
(Centralized Hydrogen Production (Gaseous Product) [per kg]										
Natural Gas SMR	63,511	0.96	5.6	1.37	2.71	3.35	0.54	0.38	3.36	10,550.00
Biomass Gasification	174,888	0.15	7.6	0.92	2.79	3.64	0.55	0.33	7.54	3,170.00
Electrolysis Solar	69,375	0.12	5.7	0.21	0.93	1.04	0.22	0.08	1.86	1,750.00
Distributed Hydrogen Production (Gaseous Product) [per kg]										
On-site Natural Gas SMR	79,618	0.97	5.4	1.94	6.29	7.43	0.43	0.29	3.34	11,470.00
On-site Electrolysis Solar	62,663	0.00	14.2	0.00	0.00	0.00	0.00	0.00	0.00	0.00
On-site Electrolysis Grid (US Average)	207,958	0.77	38.2	2.28	10.11	11.41	2.43	0.84	20.29	19,070.00

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[7] https://afdc.energy.gov/files/u/publication/fuel_comparison_chart.pdf

Hydrogen WTP Pathway	Total Energy (BTU)	Fossil Energy Fraction	Water Use (gal)	Pollutant Emissions (grams)						
				VOC	CO	NO_x	PM_{10}	$PM_{2.5}$	SO_x	CO_2
On-site Electrolysis Grid (High Coal/Low Renewable)	341,742	0.98	35.8	3.28	2.54	10.75	4.39	1.03	75.30	44,060.00
On-site Electrolysis Grid (Low Coal/High Renewable)	91,501	0.01	148.3	0.35	10.68	2.76	3.50	1.04	1.55	200.00
Centralized Hydrogen Production (Liquid Product) [per kg]										
Natural Gas SMR	110,666	0.92	9.9	1.71	4.21	5.23	0.89	0.51	6.22	13,360.00
Biomass Gasification[1]	257,339	0.07	5.3	1.94	3.37	5.22	0.74	0.50	21.88	1,770.00
Electrolysis Solar[2]	86,760	0.00	4.5	0.02	0.07	0.26	0.01	0.01	0.00	46.86
Distributed Hydrogen Production (Liquid Product) [per kg]										
On-site Natural Gas SMR	151,994	0.92	12.2	2.45	8.57	10.00	0.98	0.48	7.89	15,760.00
On-site Electrolysis Solar	94,841	0.00	15.3	0.00	0.00	0.00	0.00	0.00	0.00	0.00
On-site Electrolysis Grid (US Average)	265,628	0.77	42.3	2.69	11.92	13.45	2.87	0.99	23.92	22,490.00
On-site Electrolysis Grid (High Coal/Low Renewable)	423,312	0.98	40.8	3.86	2.99	12.67	5.18	1.22	88.77	51,940.00
On-site Electrolysis Grid (Low Coal/High Renewable)	128,200	0.01	174.4	0.42	12.59	3.25	4.12	1.22	1.82	240.00
[1] Pathway includes hydrogen liquefaction process supported by electricity generated from switchgrass integrated gasification combined cycle (IGCC) power plant.										
[2] Pathway includes hydrogen liquefaction process supported by electricity generated from solar power.										

Results for distributed, grid-based electrolysis vary significantly depending on electricity grid generation mix. For instance, coal-based electricity generation in the U.S. varies from zero to over 90 percent (U.S. Energy Information Administration, 2020). For this reason, three grid-based electrolysis scenarios are shown: 1) U.S. Average Generation Mix 2) High Coal and Low Renewable Generation Mix and 3) Low Coal and High Renewables Mix. The U.S. Average Mix results are based on the U.S. Energy Information Administration's (EIA) Annual Energy Outlook 2020, which estimates coal-fired generation at 22 percent (U.S. Energy Information Administration, 2020). In comparison, the High Coal/Low Renewables and Low Coal/High Renewables scenarios assume 92 percent and 0 percent coal-based electricity generation, respectively.

The PTW component for ports covers the use of port equipment onsite. Based on average port equipment power levels and EPA-approved emission factors, PTW emission estimates were derived for low sulfur diesel-fueled port equipment, as shown in Table 5 (U.S. EPA, 2019) (U.S. Energy Information Administration, 2020) (U.S. EPA, Office of Transportation and Air Quality, 2019) (U.S. EPA, Office of Transportation and Air Quality, 2016) (U.S. EPA, Office of Transportation and Air Quality, 2018).There are no PTW emissions for comparable hydrogen fuel cell port equipment since hydrogen fuel cells emit only water vapor and heat. It is a zero-emission tailpipe technology.

Table 5. PTW Emission Characteristics for Diesel-Fueled Port Equipment

Diesel Port Equipment Type	Typical Propulsion Power (hp)	Pollutant Emissions (grams/gallon)						
		VOC	CO	NO_x	PM_{10}	$PM_{2.5}$	SO_2	CO_2
Forklift	100	5.10	70.40	63.26	0.57	0.56	0.09	10,023
Yard Tractor	200	2.84	1.47	22.03	0.22	0.22	0.07	10,029
Cargo Handler	310	2.84	1.68	26.32	0.24	0.23	0.07	10,029
Assist Tug	1,908	3.81	35.25	138.17	3.64	3.53	0.09	9,729

Diesel Port Equipment Type	Typical Propulsion Power (hp)	Pollutant Emissions (grams/gallon)						
		VOC	CO	NO_x	PM_{10}	$PM_{2.5}$	SO_2	CO_2
Ferry	1,718	2.82	70.50	98.70	2.43	2.35	0.09	9,729
Harbor Tug	711	2.82	70.50	98.70	2.43	2.35	0.09	9,729
Switcher Locomotive	2,000	11.06	27.82	187.0	4.10	3.98	0.09	10,208
Generator	135	21.18	70.50	56.40	4.23	4.10	0.09	10,210

Combining WTP and PTW emission results provided full WTW emissions estimates for the port applications considered. Table 6 lists the efficiency adjusted mass of WTW emission reduction results[8] on a per hydrogen kg equivalent basis for fuel cell equipment types versus comparable diesel equipment for various gaseous hydrogen fuel delivery pathways. Note that the results captured in Table 6 account for the increased fuel efficiency of hydrogen fuel cells compared with their diesel engine-powered counterparts. For each port equipment application, fuel cell equipment energy efficiencies were estimated based on assumed PEMFC fuel cell stack and drivetrain efficiencies relative to their diesel counterparts. Based on these estimates, port fuel cell equipment was estimated to be up to 2.5 times more efficient than comparable diesel equipment. Table 6 values that are shown in green are positive emission reductions, indicating that hydrogen fuel cell equipment WTW emissions are lower than those of diesel equipment per hydrogen kg equivalent consumed, while values shown in red are emission increases signifying higher hydrogen fuel cell WTW emissions than diesel. Note that in general hydrogen fuel cells primarily provide WTW emission reductions (i.e., primarily 'green' Figures in Table 6) relative to diesel equipment. And criteria air pollutants, such as nitrogen oxides and particulate matter, for hydrogen pathways are not being emitted in port areas, so their human exposure and health impacts are far less significant than diesel equipment tailpipe emissions that occur at or near ports.

Based on these results, hydrogen fuel cell-powered equipment in various port applications can achieve significant WTW emission reductions. Volatile organic compound (VOC) and nitrogen oxide (NO_x) emissions reductions were achieved across all port equipment types for each of the hydrogen fuel delivery pathways. Carbon monoxide (CO) emissions were generally lower for the majority of fuel cell equipment and hydrogen pathways. Similarly, lower particulate matter 10-micron (PM_{10}) emissions were determined for fuel cell equipment applications and hydrogen fuel pathways, except for yard tractors, forklifts, and cargo handlers under some grid electrolysis pathways. The higher PM_{10} emissions for this equipment can be attributed to higher WTP emissions for grid electricity generation, especially for those generation mixes with high coal and/or high biomass resources. In fact, biomass-based electricity generation may produce more PM_{10} emissions than coal-based generation dependent on the feedstock. Thus, PM_{10} emissions with grid electrolysis from the low coal/high renewables electricity generation mix was higher than the U.S. Average mix because it assumed over three times more biomass-based generation. Particulate matter 2.5-micron ($PM_{2.5}$) emissions, however, were lower for all hydrogen pathways except for yard tractors and cargo handlers under some grid-based electrolysis pathways.

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[8] Port equipment emission reductions for various hydrogen fuel pathways are compared to diesel fuel pathways. NG SMR and Electrolysis Solar hydrogen pathways are highlighted here because NR SMR is a common source of hydrogen production and electrolysis solar is the cleaner hydrogen production pathway. For a more detailed summary of port equipment emissions reductions on a hp-hr basis across additional pathways, please see Section 6, Table 39.

Table 6. WTW Emission Reductions for Fuel Cell Equipment and Four Gaseous Hydrogen Fuel Pathways Relative to Comparable Diesel-Fueled Equipment

Fuel Cell Equipment Type	Hydrogen Fuel Pathway	WTW Emission Reductions Relative to Diesel-Fueled Equipment (g/hp-hr) [Efficiency Adjusted]								
		VOC	CO	NO$_x$	PM$_{10}$	PM$_{2.5}$	SO$_2$	CO$_2$	CH$_4$	N$_2$O
Yard Tractor	Centralized NG SMR	0.063	0.035	0.458	0.004	0.004	-0.011	136.668	0.045	0.000
	Centralized Electrolysis Solar	0.073	0.051	0.479	0.006	0.007	0.002	215.402	0.250	0.000
	Distributed NG SMR	0.058	0.003	0.421	0.005	0.005	-0.011	128.437	-0.078	-0.002
	Distributed Electrolysis Solar	0.075	0.060	0.488	0.008	0.007	0.019	231.060	0.283	0.001
Forklift	Centralized NG SMR	0.108	1.400	1.274	0.011	0.011	-0.011	136.549	0.047	0.000
	Centralized Electrolysis Solar	0.118	1.416	1.295	0.013	0.014	0.003	215.283	0.252	0.000
	Distributed NG SMR	0.103	1.368	1.238	0.011	0.012	-0.011	128.318	-0.076	-0.002
	Distributed Electrolysis Solar	0.120	1.425	1.304	0.015	0.014	0.019	230.940	0.285	0.001
Cargo Handler (Top Loader)	Centralized NG SMR	0.063	0.040	0.543	0.004	0.004	-0.011	136.668	0.045	0.000
	Centralized Electrolysis Solar	0.073	0.055	0.563	0.007	0.007	0.002	215.402	0.250	0.000
	Distributed NG SMR	0.058	0.008	0.506	0.005	0.005	-0.011	128.437	-0.078	-0.002
	Distributed Electrolysis Solar	0.075	0.064	0.573	0.009	0.008	0.019	231.060	0.283	0.001
Assist Tugboat	Centralized NG SMR	0.072	0.683	2.732	0.067	0.067	-0.037	48.922	-0.164	0.008
	Centralized Electrolysis Solar	0.091	0.713	2.770	0.072	0.072	-0.012	195.892	0.219	0.009
	Distributed NG SMR	0.062	0.623	2.664	0.069	0.068	-0.037	33.557	-0.392	0.005
	Distributed Electrolysis Solar	0.095	0.728	2.788	0.076	0.073	0.019	225.119	0.281	0.009
Ferry	Centralized NG SMR	0.052	1.381	1.950	0.043	0.043	-0.037	48.922	-0.164	0.008
	Centralized Electrolysis Solar	0.072	1.411	1.989	0.048	0.048	-0.012	195.892	0.219	0.009
	Distributed NG SMR	0.043	1.321	1.882	0.045	0.045	-0.037	33.557	-0.392	0.005
	Distributed Electrolysis Solar	0.075	1.426	2.006	0.052	0.050	0.019	225.119	0.281	0.009
Harbor Tugboat	Centralized NG SMR	0.052	1.381	1.950	0.043	0.043	-0.037	48.922	-0.164	0.008
	Centralized Electrolysis Solar	0.072	1.411	1.989	0.048	0.048	-0.012	195.892	0.219	0.009
	Distributed NG SMR	0.043	1.321	1.882	0.045	0.045	-0.037	33.557	-0.392	0.005
	Distributed Electrolysis Solar	0.075	1.426	2.006	0.052	0.050	0.019	225.119	0.281	0.009
Switcher Locomotive	Centralized NG SMR	0.221	0.547	3.712	0.078	0.077	-0.024	100.225	-0.061	0.000
	Centralized Electrolysis Solar	0.235	0.569	3.741	0.082	0.081	-0.004	212.321	0.231	0.000
	Distributed NG SMR	0.213	0.501	3.660	0.080	0.078	-0.023	88.506	-0.235	-0.003
	Distributed Electrolysis Solar	0.238	0.581	3.755	0.085	0.082	0.019	234.612	0.278	0.001
Stationary Generator	Centralized NG SMR	0.424	1.397	1.131	0.082	0.080	-0.018	118.051	-0.008	0.001
	Centralized Electrolysis Solar	0.436	1.416	1.157	0.085	0.084	-0.001	215.311	0.245	0.002
	Distributed NG SMR	0.417	1.357	1.086	0.083	0.081	-0.018	107.883	-0.159	-0.001
	Distributed Electrolysis Solar	0.439	1.426	1.168	0.088	0.084	0.019	234.652	0.286	0.002

In the case of sulfur dioxide (SO_2) emissions, higher WTW emissions for all hydrogen fuel pathways were estimated except for distributed solar-based electrolysis, and in some equipment cases, centralized solar-based electrolysis and low coal/high renewables generation grid-based electrolysis. Higher SO_2 emissions are produced with all high coal resource pathways (grid electrolysis with U.S. Average and High Coal/Low Renewables generation mixes) and natural gas SMR-based pathways (both centralized and distributed) compared with diesel. The SO_2 emission increases for centralized biomass gasification can be attributed to higher overall energy requirements, biomass feedstock (corn stover) collection and processing, the biomass gasification process, and the U.S. average electricity grid mix (higher coal) supporting this hydrogen pathway. Similarly, SO_2 emission increases for natural gas SMR hydrogen pathways result from the SMR process and the U.S. average electricity grid supporting the process. Higher SO_2 levels with the distributed grid-based electrolysis using U.S. Average and High Coal/Low Renewables can be attributed to the much higher energy requirements for these electrolytic processes and their supporting grid electricity comprised of high fossil energy resources, especially in the case of the High Coal/Low Renewables pathway. As the U.S. electricity generation mix evolves to higher levels of renewable energy-based generation in the future, reductions in SO_2 emissions produced from SMR, biomass gasification, and grid electrolysis can be expected.

Finally, WTW carbon dioxide (CO_2) emissions were significantly lower across all hydrogen equipment and fuel pathways, except for High Coal/Low Renewables generation grid-based electrolysis and in some limited cases, U.S. Average generation grid-based electrolysis. The lower CO_2 emissions result primarily from much higher energy efficiencies and elimination of fuel cell equipment PTW CO_2 emissions relative to comparable diesel equipment.

Regarding individual pathways, all hydrogen fuel pathways provided significant emission reductions for most port equipment applications although, as noted above, higher SO_2 emissions were seen for many pathways. In general, the solar-based electrolysis pathway emerged as the best performing hydrogen fuel pathway for both centralized and distributed cases. While solar-based electrolysis shows promising results for emission reductions, it should be noted that this technology requires implementation of supporting solar arrays and energy storage to provide power to the electrolysis process, significantly increasing capital investments and requiring additional site space considerations. The analysis also revealed that the performance of distributed grid-based electrolysis is highly dependent on the electricity generation mix. Regions of the country with high coal and low renewable resource generation can be expected to produce significantly less favorable grid-based electrolysis pathway WTW emission results as compared to regions with low coal and high renewable resource generation mixes. A future electricity grid mix with higher renewable resource generation should also result in lower PM_{10} and SO_2 emissions for the hydrogen pathways supported by the grid.

The WTW emission results presented here represent specific assumptions for both WTP and PTW estimates. WTW results may vary depending on hydrogen production scenarios, feedstock and fuel transport modes, and port equipment types and sizes. As such, local and regional analysis can facilitate emissions assessments associated with hydrogen fuel cell equipment use at specific port locations.

Port Fuel and Fuel Cell Equipment Costs

The dispensed hydrogen per kilogram cost ($/kg) to the end-user should account for all production and delivery pathway factors. In the case of centralized hydrogen production pathways, this includes amortized costs for production, transport to the site, and dispensing station capital cost recovery and operations. Currently, most of the hydrogen sold for vehicle or equipment usage is produced by industrial gas suppliers at low volumes and thus higher costs. There are limited dedicated regional hydrogen pipelines in various regions of the country, and most of the available hydrogen is delivered via truck at higher cost and dispensed through low volume stations. For comparison, dispensed hydrogen market prices are roughly $13-16/kg in most areas of the country (Satyapal, 2018).

Additional research is being conducted and industry development is occurring to improve hydrogen production and transport technologies, lower refueling station capital costs, and increase station efficiency and outputs. In addition, as hydrogen demand increases, economies of scale can be achieved by boosting production and transportation and lowering fuel prices for the consumer. In fact, the DOE has projected a future high-volume hydrogen price of about $5-10/kg by 2025, and a long-term mature market price of less than $4/kg (Satyapal, 2018).

As discussed in Section 5, capital and operating cost estimates were derived for port fuel cell equipment and their diesel equipment counterparts, including forklifts, yard tractors, cargo handlers, switcher locomotives, marine vessels, and power generators. Incremental costing between fuel cell and comparable diesel-fueled equipment was based on available cost information, typical equipment operating characteristics and anticipated lifetimes. Notably, many of the current fuel cell equipment costs were estimated for pre-commercial systems. Future costs for this equipment were estimated based on DOE cost projections for fuel cell systems (Satyapal, 2018) and assumed an annual inflationary rate of two percent. Annual operating costs (fuel and maintenance costs) were also estimated for each type of equipment. Diesel fuel price projections were determined based on EIA Figures. Hydrogen fuel prices were calculated based on the aforementioned DOE hydrogen price projections.

Table 7 lists the capital and operating cost comparison for port fuel cell and diesel equipment. Capital cost estimates assumed two percent annual inflation for both fuel cell and diesel equipment costs. In 2020, the estimated capital costs for the port fuel cell equipment were higher than the comparable diesel equipment. In 2030 and 2045, assuming lower cost fuel cell systems and equipment platforms and increased production volumes based on DOE estimates, fuel cell equipment costs had greater parity with comparable diesel equipment. Similarly, annual operating costs were lower for many of the port equipment types due primarily to the lower projected hydrogen fuel prices starting in 2030 and continuing through 2045.

Based on these results, simple capital payback was assessed for each type of fuel cell equipment using the incremental capital and annual operating costs. As shown in Table 7, none of the fuel cell equipment provided capital payback potential in 2020 due to their high incremental capital costs and low operational savings. However, in 2030, reasonable capital payback values were derived for fuel cell equipment types, except for switcher locomotives and ferryboat applications. In 2045, very favorable paybacks were derived for all fuel cell equipment analyzed except for switchers and ferryboats which still must overcome high incremental capital costs.   However, based on recent developments the future costs may be reduced such that a favorable payback could come within the tine periods projected. These results suggest that port fuel cell equipment economic benefits will increase in the long-term as equipment capital costs decrease and the hydrogen fuel market matures.

Table 7. Summary of Fuel Cell Equipment Capital and Operating Cost Results

	Forklift		Yard Tractor		Cargo Handler		Switcher Locomotive		Ferryboat		Generator	
Parameter	**Diesel**	**Fuel Cell**	**Diesel**	**Fuel Cell**	**Diesel**	**Fuel Cell**	**Diesel**	**Fuel Cell**	**Diesel**	**Fuel Cell**	**Diesel**	**Fuel Cell**
Lifetime	10		12		12		20		20		10	
Year 2020												
Capital Cost ($)	45,000	84,194	110,000	225,000	584,500	727,078	1,544,000	3,466,543	11,600,000	17,166,000	100,000	312,000
Operating Costs($)	11,242	19,736	22,981	38,464	77,717	131,534	188,439	504,700	1,713,086	6,751,790	31,553	64,528
Payback (Yr)	None		None		None		None		None		None	
Year 2030												
Capital Cost ($)	54,855	71,068	134,089	182,704	712,502	789,997	1,882,127	3,804,663	14,140,335	15,258,100	121,899	174,124
Operating Costs($)	12,996	10,768	26,314	17,799	88,302	54,498	220,955	274,120	1,971,870	2,858,896	36,118	29,279
Payback (Yr)	7.3		5.7		2.3		None		None		7.6	
Year 2045												
Capital Cost ($)	73,827	74,256	180,467	189,556	958,934	975,157	2,533,096	3,094,292	19,031,030	19,281,258	164,061	180,688
Operating Costs($)	15,059	9,352	29,577	16,376	90,813	40,851	267,335	267,162	2,254,365	2,622,602	40,563	25,711
Payback (Yr)	0.1		0.7		0.3		None		None		1.1	

*Operating Cost includes annual maintenance costs and fuel costs

**Lifetime estimate assumes switcher locomotive was previously used for 20 years of line haul duty.

*** Year 2020 [Diesel Fuel Price $3.33/gal, H2 Dispensed Price $13.00/kg]; Year 2030 [Diesel Fuel Price $3.76/gal, H2 Dispensed Price $4.00/kg]; Year 2045 [Diesel Fuel Price $4.05/gal, H2 Dispensed Price $4.00 kg; Switcher Diesel Year 2020 $2.07/gal, Year 2030 $2.34, Year 2045 $2.52/gal; Ferryboat Liquid Hydrogen Year 2020 $11.64/kg, Year 2030 $4.40/kg, Year 2045 $4.00/kg

Future Hydrogen and Fuel Cell Market Penetration

A variety of factors may impact future fuel cell market viability for ports and other sector applications. These factors include:

- **Equipment capital cost** – Current fuel cell system costs are much higher than comparable diesel powerplants. Much of this cost variance is due to differences in production capacities resulting from economies of scale. Research and development efforts have resulted in dramatic reductions in fuel cell system costs over the last decade and are expected to continue reducing costs. For example, the DOE anticipates forklift and stationary genset fuel system costs to decrease by 61 and 37 percent, respectively, as the market transitions from low production to high-volume production scales (Satyapal, 2018).

- **Required emission reductions** – Replacing diesel-fueled equipment with hydrogen fuel cell equipment provides opportunities for significant emission reductions for port applications, especially with hydrogen produced with renewable energy sources. For those ports with high future emission reduction targets for greenhouse gas and criteria pollutant emissions, fuel cell equipment can help ports meet their emission inventory goals. As state renewable portfolio standards, declining costs of renewable energy technology, and other factors continue to drive increasing shares of renewable electricity generation and reductions in average grid emissions, the emissions benefits associated with grid electrolysis-based hydrogen production pathways will likely increase over time.

- **Equipment durability/reliability** – Fuel cell durability and reliability across equipment applications, including port equipment, have improved considerably. Advancements in catalysts and fuel processing capabilities have improved fuel cell resistance to fuel and air impurities. Significant progress has been achieved in voltage degradation, operational durability, start-up times and cold weather performance. Additional progress with system voltage degradation is necessary for some transportation applications, but the DOE supports research and development to meet targets within the next two to four years.

- **Equipment power/duty cycle performance** – Some port equipment applications present challenging duty cycle and operational conditions (e.g., cargo handlers). The general scalability of fuel cells should allow fuel cell systems to meet maximum power requirements for even the most challenging duty cycles. The current development of hybrid fuel cell/battery platforms for achieving high power and long operational ranges also provides manufacturers with greater flexibility in meeting these challenging applications.

- **Equipment operational hours/range** – For port applications such as forklifts, yard tractors and cargo handlers, operational capacity or driving range is essential to maximizing port operational efficiency and productivity. For most port equipment, operational ranges for fuel cell-powered equipment are like those of diesel-fueled equipment. For some port equipment such as cargo handlers and marine propulsion, hybrid fuel cell battery systems and improved hydrogen storage systems are under development to assist in meeting equipment operational capacity requirements.

- **Equipment maintenance/serviceability** – While scheduled maintenance for fuel cell systems is generally less frequent than comparable diesel equipment, pre-commercial systems have exhibited higher rates of downtime due to unscheduled maintenance. Some fuel cell stack and balance of plant issues have been experienced in pre-commercial systems, along with non-fuel cell related maintenance for hybrid fuel cell systems. As pre-commercial fuel cell systems continue to develop, these unscheduled maintenance-related issues are expected to diminish.
- **Hydrogen fuel price** – Fuel price is currently a limiting factor for fuel cell equipment market growth. As noted earlier, dispensed hydrogen market prices are roughly $13-16/kg (or about $7.55-9.30/diesel gallon equivalent (DGE) when adjusted for the energy content and typical higher fuel efficiency of hydrogen). Through additional research and higher volume production, DOE targets hydrogen fuel costs to decrease to about $2.91-5.81/DGE efficiency adjusted in 2025, and to less than $2.32/DGE efficiency adjusted in the long-term (Satyapal, 2018). These future hydrogen fuel costs compare favorably with EIA diesel fuel price forecasts of $3.76/gallon in 2030 and $4.05/gallon in 2045.

- DOE's Energy Earthshots Initiative aims to accelerate breakthroughs of more abundant, affordable, and reliable clean energy solutions. The first Energy Earthshot was Hydrogen Shot, launched June 7, 2021, seeks to reduce the cost of clean hydrogen by 80% to $1 per 1 kilogram in 1 decade ("1 1 1")[9]**.**

Future hydrogen supply should benefit from the flexibility of hydrogen production across a variety of feedstocks and processes, extensive networks of natural gas pipelines, electricity transmission and distribution infrastructure, projected low long-term prices of natural gas and electricity, and anticipated growth in renewable energy electricity generation. Natural gas steam reforming production can increase in the near-term, but low-cost electrolysis coupled with renewable energy sources holds significant promise with regards to long-term sustainable hydrogen production and reductions in emissions. In both cases, higher volume hydrogen production should lead to economy-of-scale pricing, making fuel cell equipment economically competitive with traditional diesel equipment.

Market penetration estimates for port fuel cell equipment applications were estimated between 2020 and 2050 based on future market assumptions and by employing an S-curve market penetration methodology. Results are illustrated in Figure 1 for the following port equipment: forklifts, yard tractors, cargo handlers, switcher locomotives, marine propulsion and auxiliary power, and stationary power generators. The highest fuel cell generator market share was estimated at about 62 percent among port equipment applications in 2050, given their commercial status over a range of power levels, as well as assumed limited market competition (except for diesel engines). Conversely, fuel cell switcher market penetration was at its lowest (about 15 percent) in 2050 given that little development has occurred over the last decade. However more recently work has been completed on diesel hybrid platforms and fuel cell platforms for switcher and line haul locomotives which could increase penetration. In the case of forklifts (about 50 percent) and yard tractors/cargo handlers (about 24 percent), recent market entries in lighter forklift classes and prototype demonstrations across a variety of yard tractor and cargo handler applications indicate relatively strong market penetration over time. Similarly, recent prototype demonstrations of fuel cell harbor craft both domestically and internationally, such as passenger cruise boats, ferry boats, tugboats and push boats, project

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[9] https://www.energy.gov/eere/fuelcells/hydrogen-shot

to about 23 percent of the new vessel market by 2050. Note that these projections could increase significantly if breakthroughs or other incentives come to into being that are not included in this analysis.

Higher fuel cell equipment market penetration in the long-term correlates with higher equipment manufacturing volumes and associated high volume fuel demand, both of which would dramatically lower fuel cell equipment costs and dispensed fuel prices.

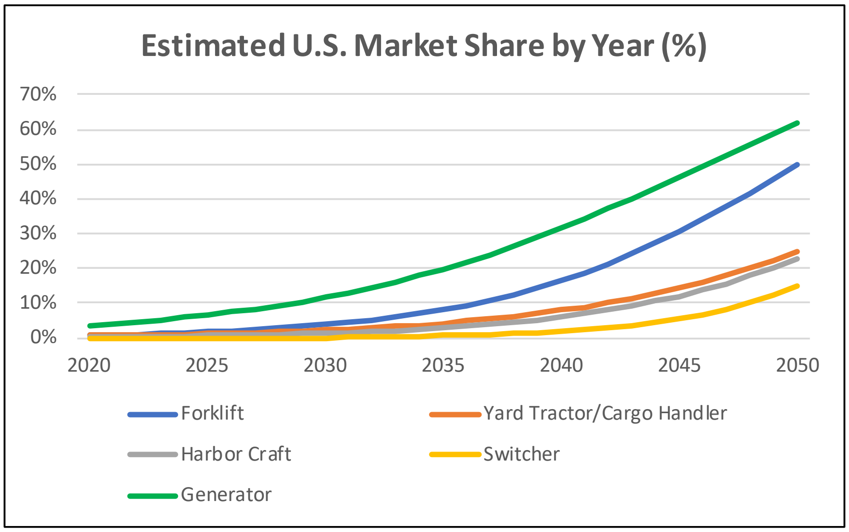

Figure 1. Estimated Port Fuel Cell Equipment Market Penetration (2020-2050)

Key Stakeholder Considerations for Current Port Fuel Cell Equipment Implementation

While fuel cells may prove instrumental in supporting current and future port equipment applications, port stakeholders should consider the following factors before implementing the technology:

1. **Significant Fuel Savings** – Significant fuel use reductions can be achieved for most applications, as fuel efficiency with fuel cell equipment is approximately two to three times higher than comparable diesel equipment, depending on the operational duty cycle of the equipment application. These fuel use reductions will translate directly into lower fuel expenditures.
2. **Lifecycle Emission Reductions** – Hydrogen fuel cell equipment implementation will typically provide significant reductions in criteria pollutant, greenhouse gas emissions, and toxic air pollutants relative to comparable diesel equipment at most port locations.. Hydrogen produced using renewable feedstocks and/or energy sources will provide the most favorable emissions.
3. **Lower Noise Emissions** – Fuel cell equipment produces significantly lower noise levels than diesel engine-powered equipment. Ports located in proximity to residential neighborhoods or other sensitive populations should note that noise reduction efforts are integral to meeting noise level targets at port facilities.
4. **Pre-commercial Status of Fuel Cell Port Equipment Applications** – While some applications such as fuel cell stationary power generators and small forklifts are available as commercial product, many fuel cell port equipment types are in pre-commercial stages of development. This may impact the availability of certain fuel cell equipment, especially for ports with aggressive fuel cell equipment implementation schedules. The pre-commercial status of equipment also renders direct comparisons with mature market diesel equipment unclear, given that fuel cell equipment evolves into commercial products over time.

Further, pre-commercial fuel cell equipment downtime may be impacted by spare part and replacement system availability from manufacturers.

5. **High Equipment Capital Costs and Hydrogen Fuel Prices** – Port operators should expect higher upfront costs for many fuel cell equipment types since many systems are still in pre-commercial stages of development or are early market entries. Like vehicle battery technologies over the last decade, prices for fuel cell systems should continue to decrease in the future as system designs improve, production increases and economies of scale are achieved. In the near-term, hydrogen fuel prices for port and other applications will remain high until hydrogen market demand significantly increases and centralized hydrogen production volumes grow to meet demand. External grant funding will likely be needed to support significant near-term investment in fuel cell equipment.
6. **Considerations for Centralized Versus Distributed Production and Gaseous Versus Liquid Hydrogen** – Ports will need to assess hydrogen fuel supply options to implement fuel cell equipment. Ports must decide whether to obtain fuel supplies from centralized hydrogen production versus onsite production using natural gas SMR or water electrolysis, making sure to consider available feedstocks, water restrictions, upfront capital costs, and lifecycle operating and maintenance costs, among others. For centralized hydrogen fuel supplies, ports must consider whether gaseous or liquid product is most favorable for operations. A gaseous product is generally less costly to store and dispense on site, while a liquid product has higher energy density and requires less frequent re-supplies when serving high volume consuming equipment applications. Of course, local/regional hydrogen product availability will also dictate near-term port decisions regarding hydrogen supplies and onsite storage and use.
7. **Hydrogen Fuel Properties and Operational and Safety Considerations** – As a gaseous fuel under ambient conditions, hydrogen has significantly different properties than diesel fuel which requires additional requirements for safely handling, transporting, and storing. Differences in fuel properties should be addressed and managed through preparation, necessary operational changes, and staff training at ports. Benefits of hydrogen include its lower toxicity compared with diesel fuel and it does not require environmental clean-up for leaks or spills.

1. Introduction

1.1 Study Purpose, Objectives, and Approach

Marine port facilities and operations are important to the nation’s current and future economic well-being. Port facilities serve as key gateways for importing and exporting commercial products, and thus constitute critical economic activities at the national, regional, and local level. Ports often become hubs of commercial and operational activities, for example, facilitating the movement of equipment (e.g., freight) in and out of their harbors. Due to their extensive concentration of heavy equipment for operations, including cargo handling equipment, ships, and locomotives, ports often contribute to a large component of local and regional emission inventories. Through programs such as the Ports Initiative, the U.S. Environmental Protection Agency (EPA) aims to better understand and characterize the emission contributions of port facilities and operations, in addition to identifying and supporting emission reduction strategies and emerging advanced technologies. With this report, EPA was interested in learning more about fuel cell technologies and the opportunities they offer to reduce pollution by replacing diesel-powered equipment at port locations. As such, the EPA seeks a comprehensive analysis of the technical, environmental, economic, and safety aspects of fuel cell technology applications for marine port facilities and operations.[10]

Under contract, Eastern Research Group (ERG) was tasked with completing a comprehensive study of fuel cell technology for marine port equipment applications.

The key objectives of this effort include the following:

- Define the various types of fuel cell technologies and their current market status, as well as ongoing research at the federal, state, and private levels to address fuel cell performance and costs.
- Define potential fuel cell technology applications for U.S. marine ports, analyzing their critical operational, cost, maintenance and lifetime pros and cons relative to traditional diesel-fueled equipment.
- Assess potential fuel sources and required infrastructure for supporting port fuel cell applications, including both centralized and distributed production and transportation solutions.
- Assess the lifecycle emission benefits for fuel cell technologies relative to diesel-fueled equipment in port applications, including criteria pollutants, mobile source air toxics (MSATs), and greenhouse gases.
- Assess the economics of using fuel cell technology in port applications, including the future business case for such applications.
- Assess the current commercial viability of fuel cell technology, and forecast its market penetration for port applications, including performance, cost, and infrastructure challenges for the technology, as well as its competitiveness in the future near and long -term marketplaces.

ERG’s approach for meeting these objectives included the completion of the following prescribed task research activities:

- Task 1 – Background Information
- Task 2 –Applications of Fuel Cells at Ports
- Task 3 – Emissions Analysis
- Task 4 – Economic Analysis

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[10] Note: This reported is intended to examine fuel cell technologies compared to existing, conventional diesel engines. It does not incorporate other advanced clean technologies as a comparison.

- Task 5 – Future Projections

Each of these tasks incorporated comprehensive research and analysis based on publicly available information and data obtained from both government and private sources. Each task activity culminated in the development of a standalone task summary report, which documented ERG's results and facilitated the EPA's review of those results.

This report contains the following primary sections:

1. Introduction;
2. Fuel Cell Technology and Market Status;
3. Fuel Cell Applications and Characteristics for Ports;
4. Fuel Cell Fuel Supply Infrastructure;
5. Fuel Cell Equipment, Infrastructure, and Fuel Costs;
6. Hydrogen Fuel Cell Equipment Lifecycle Emissions;
7. Future Hydrogen and Fuel Cell Market Penetration; and
8. Summary and Conclusions.

2. Fuel Cell Technology and Market Status

2.1 Fuel Cells Explained

Fuel cell technology has evolved from its conceptual development in the early 19th century to its viable application in commercial products across multiple market sectors. A fuel cell is an electrochemical device for converting the chemical energy of a fuel into electrical energy. Since the process of energy conversion is electrochemical as opposed to thermochemical, as in the case of fuel combustion, fuel cells do not produce any undesirable post-conversion products. Fuel cells are also simple devices with minimal moving parts and mechanisms, and thus produce minimal noise. Additionally, fuel cells have much higher energy conversion efficiencies than traditional fuel combustion power sources.

The initial development of fuel cell technology can be traced back to a variety of experimental electrochemical research in Britain in the early 1800's. Sir William Grove is generally credited with inventing the fuel cell in 1839 through a collection of research related to a "gas voltaic battery," proving an electrical current could be produced from a reaction of hydrogen and oxygen in the presence of a platinum catalyst. The term "fuel cell" was later coined in 1889 by subsequent German electrochemist researchers using coal gas fuel (FuelCellToday, 2019).

The first workable fuel cell device was demonstrated in 1959 by Cambridge professor Francis Bacon. Using modified fuel cells from Bacon, U.S. manufacturer Allis-Chalmers, in collaboration with the U.S. Air Force, produced a variety of fuel cell-powered demonstration equipment, including an agricultural tractor, forklift, golf cart and submersible vessel (FuelCellToday, 2019). Fuel cell technology developed considerably as a result of the newly formed National Aeronautics and Space Administration (NASA). Several fuel cell applications for onboard power were implemented for space vehicle applications for the Mercury and Gemini manned space missions. These efforts culminated in the development of a fuel cell system that provided electrical power and drinking water for the astronauts onboard the Apollo manned space mission.

National energy security issues and increased emphasis on clean air in the 1970s and 1980s served as market drivers for the development of clean, energy efficient technologies. Fuel cell research efforts concentrated on improving hydrogen fuel systems and increasing fuel cell power densities. Manufacturers began concentrating on market application demonstrations of fuel cells for transportation, stationary power and portable power devices. As a result of zero emission vehicle mandates introduced in California in the 1990s (FuelCellToday, 2019), manufacturer fuel cell research focused on small stationary applications to improve commercial market potential and enhance transportation capabilities. The latter caught the interest of the global automaker industry, resulting in extensive research programs by companies such as Ford, Chrysler, General Motors and Toyota.

Supported by government and private sector funding and investment and increased concerns over global climate change, fuel cell research over the last decade has continued to support both early market applications. Fuel cell commercialization efforts intensified around 2007 when products began selling with warranties and service capabilities. Commercial markets for fuel cell products have now been established for material handling equipment, transit buses, passenger cars, freight trucks, portable and auxiliary power units, and small and large -scale stationary power systems. As a result of early commercial success, the fuel cell system supply chain has developed in conjunction with advancements in global fuel cell manufacturing capacity and implementation of hydrogen fuel delivery infrastructure.

In its simplest form (Figure 2), a fuel cell is comprised of a negative electrode (anode) and a positive electrode (cathode) sandwiched around an electrolyte (membrane). Hydrogen-rich fuel is supplied to the anode while air (oxygen) is supplied to the cathode. A catalyst at the anode acts to separate the hydrogen molecules in the fuel into protons and electrons. The protons flow through the electrolyte membrane to the cathode, and the electrons flow through an external circuit, creating a flow of direct current (DC) electricity. Electrolytes can be either solid-based or liquid-based and facilitate the separation and flow of the protons and electrons between the electrodes. At the cathode, the protons combine with the oxygen and the electrons in the presence of a catalyst to produce the byproducts of water. The electrochemical reaction also produces heat.

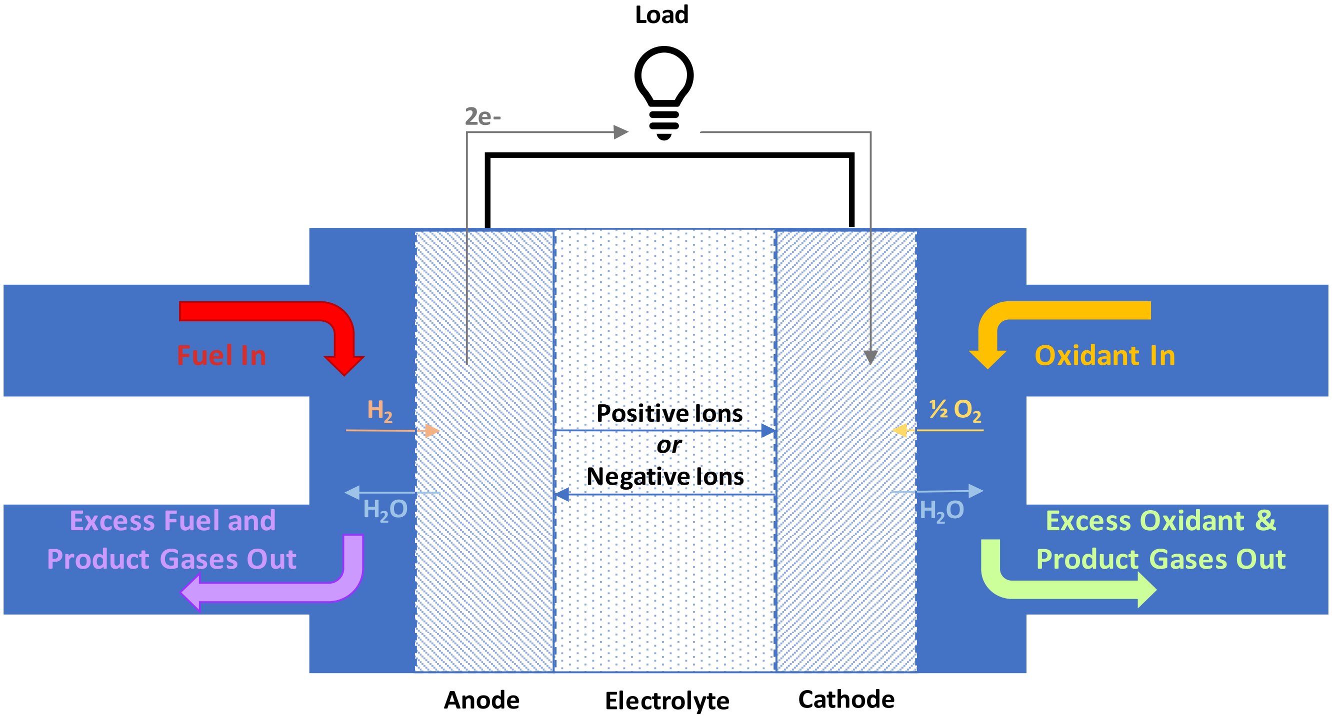

Figure 2. Basic Fuel Cell Schematic

Fuel cells are scalable in that they can combine to form fuel cell systems, thereby meeting increasing power demands for a variety of applications. Although fuel cell systems vary depending on fuel cell type, all systems include the following basic components (U.S. Department of Energy Fuel Cell Technologies Office, 2019):

- **Fuel Cell Stack** – The fuel cell stack is comprised of multiple individual fuel cells of the same type stacked in series. A typical stack contains hundreds of fuel cells. The power density of the fuel cell stack varies according to fuel cell type, cell size, operating temperatures and pressure of the fuel gases supplied to the cells.
- **Fuel Processor** – A fuel processor is used to produce a fuel suitable for supplying the fuel cell stack. The processor and its components depend on the fuel source and the type of fuel cell. For pure hydrogen gas fuels, fuel processors may constitute a simple sorbent bed to remove impurities. Hydrocarbon-based fuels like natural gas may require multiple reactors and sorbent beds. In these cases, external reformers are typically used to break down the hydrocarbons into hydrogen gas and carbon compounds, which then continue to be processed to convert CO to its byproduct, CO_2, and remove sulfur (S) compounds and other impurities using sorbent beds. The removal of impurities is critical to ensuring catalysts are not "poisoned" (that is, deactivate catalyst surfaces) in the fuel cells, thereby reduced fuel cell efficiencies. Some fuel cell types operate at high enough temperatures to allow for "internal fuel reforming" in the fuel cell; however, sorbent beds are still required to remove impurities.
- **Power Conditioners** – While fuel cell systems produce DC electrical power, this power must still be conditioned using inverters to match the electrical needs of the application. This can include modification

of current, voltage and frequency of output of the fuel cell system. The power conditioning step typically reduces fuel cell system efficiency by 2 to 6 percent.

- **Air Compressors** – Since fuel cell efficiency increases with gas supply pressure, air compressors are used to increase the pressure of the inlet air supply to the fuel cell stack.
- **Humidifiers** – For some fuel cell systems, humidification is employed to keep the fuel cell membrane from becoming too dry and impacting efficiency. In some systems, the water byproduct from the fuel cells is recycled to humidify the air supply.

2.2 Fuel Cell Types and Characteristics

In general, fuel cells are characterized according to the type of electrolyte they contain. The electrolyte dictates the reactions that take place in the fuel cell, and also determine the fuel cell’s operational temperatures, functionality, and materials composition. The most common fuel cell types are:

- Polymer Electrolyte Membrane
- Alkaline
- Phosphoric Acid
- Molten Carbonate
- Solid Oxide

The following section discusses each common fuel cell type and their respective characteristics, including design, functionality, operational temperatures and limitations, durability, maintenance considerations, and market applications to date.

2.2.1 Polymer Electrolyte Membrane

Polymer electrolyte membrane fuel cells (PEMFC) typically use a water-based acidic polymer membrane as their electrolyte. PEMFCs, also known as proton exchange membrane fuel cells, utilize platinum-based catalysts at both electrodes. As illustrated in Figure 3, hydrogen is split at the anode via the platinum catalyst and hydrogen ions pass through the membrane while the electrons are routed through an external circuit, generating the electrical current output. At the cathode, the hydrogen protons and electrons are combined with oxygen (introduced in pure form or from air) to produce water and reaction heat.

PEMFCs are one of the most commonly used fuel cell types and can be found in a variety of commercial applications today. They offer high power density coupled with low weight and volume. PEMFCs also operate at relative low temperatures, typically below 100^{o}C, allowing for quick start-up times and less thermal wear on components. All these characteristics make PEMFCs suitable for vehicle and mobile equipment, as well as mobile power supply devices (FuelCellToday, 2019).

The platinum-based catalysts used in PEMFCs drive up their capital costs and increase their susceptibility to catalyst site “poisoning” from fuel contaminants like CO or S. Depending on the hydrogen source, an upstream reactor may be added to PEMC systems to limit anode exposure to such contaminants (Barbir, 2013).

PEMFCs can also operate at higher temperatures by utilizing a mineral, acid-based electrolyte rather than a water-based version. This allows PEMFCs to operate at up to 200^{o}C. The higher temperature operation makes PEMFCs less vulnerable to CO poisoning, thus increasing their ability to process hydrogen fuels from reforming feeds. This use of the mineral, acid-based electrolyte also eliminates the need for a humidifier in the PEMFC system (FuelCellToday, 2019).

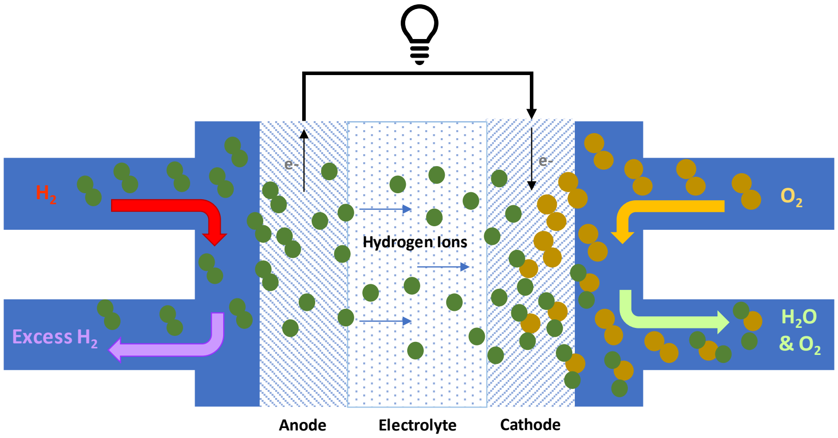

Figure 3. PEMFC Process Schematic

PEMFC Characteristic	Typical
Electrolyte	Water- or mineral-based acidic polymer
Operating Temperature	60 – 100°C (high temperature variant up to 200°F)
Contaminant Poisoning Tolerance	Low to CO and S
Commercial Applications	On-road vehicles, mobile nonroad equipment, mobile power supplies, stationary power sources
Manufacturers	Ballard Power, Plug Power, Horizon Fuel Cell Technologies, H2 PowerTech, Hydrogenics/Cummins, and PowerCell

2.2.2 Alkaline

Alkaline fuel cells (AFCs) were some of the first fuel cells developed, attracting market interest in the early 1960's under NASA's Space Program. Early AFCs utilized an aqueous solution containing potassium hydroxide in a porous matrix (usually asbestos) as the electrolyte. A variety of catalysts are used for anodes and cathodes, including nickel, metal oxides and noble metals (E4etch, 2020). As shown in Figure 4, negatively charged hydroxide ions formed at the cathode pass through the electrolyte and combine with hydrogen at the anode to produce water and electrons.

AFCs operate at 70-100°C with an electrochemical conversion efficiency of about 60 percent. Conversion efficiencies can be dramatically affected, however, by AFC susceptibility to CO_2 poisoning from the fuel or oxidant side of the fuel cell. Such poisoning leads to carbonate buildup in the electrolyte, requiring the application of fuel and oxidant supply removal processes and increasing the overall cost of the fuel cell system (U.S. Department of Energy Fuel Cell Technologies Office, 2019) (Williams, 2011).

Additional operational issues with AFCs include wettability, component corrosion and management of differential pressures.

Recent developments have resulted in the use of alkaline polymer membrane electrolytes. Known as alkaline membrane fuel cells (AMFCs), AMFCs are more tolerant to CO_2 poisoning but exhibit issues with membrane durability, water management and power density (U.S. Department of Energy Fuel Cell Technologies Office, 2019).

To date, commercial applications of AFCs/AMFCs include space, military, and back-up and distributed power.

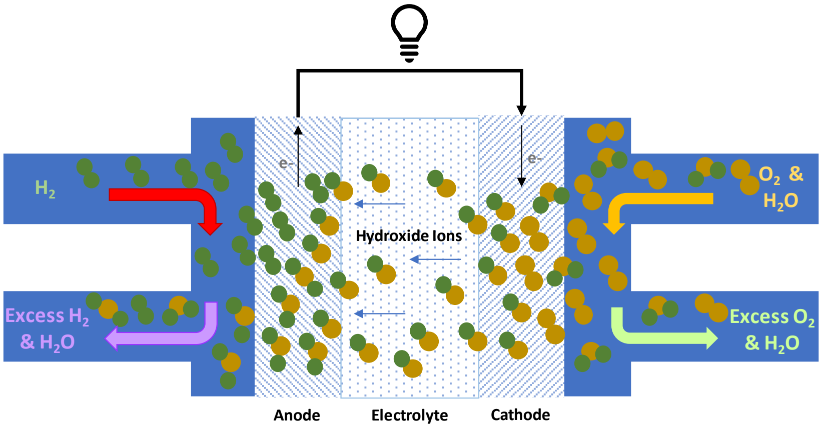

Figure 4. AFC Process Schematic

AFC/AMFC Fuel Cell Characteristic	Typical
Electrolyte	Aqueous solution containing potassium hydroxide in a porous matrix, or alkaline membrane
Operating Temperature	70 – 100°C
Contaminant Poisoning Tolerance	Low to CO_2
Commercial Applications	Stationary power and remote power applications
Manufacturers	AFC Energy and GenCell

2.2.3 Phosphoric Acid

Development of phosphoric acid fuel cells (PAFCs) began in the U.S. in the 1960’s. PAFCs utilize concentrated liquid phosphoric acid on a silicon carbide matrix as an electrolyte. The fuel cell’s electrodes consist of porous carbon with platinum catalysts. In PAFCs, hydrogen ions created at the anode pass through the electrolyte to the cathode, where they combine with oxygen and electrons to produce water (FuelCellToday, 2019), as shown in Figure 5. The operating temperatures range between 150-200°C. The electrochemical efficiency of PAFCs are lower than other fuel cell types at 40 percent, however, when used for CHP applications, overall efficiencies can exceed 80 percent (U.S. Department of Energy Fuel Cell Technologies Office, 2019) (Williams, 2011).

Compared with other low temperature fuel cells, PAFC tolerance to CO_2 exceeds that of AFCs, and their tolerance to CO exceeds that of PEMFCs (FuelCellToday, 2019). Higher tolerances enable PAFCs to operate with a variety of fuels, including natural gas, petroleum products, and coal liquids and gases. PAFCs tend be large and heavy, with lower power densities as compared to other fuel cell types. They also require much higher levels of platinum catalysts and are therefore more expensive than other fuel cells. PAFCs properties increase the importance of stricter water management practices due to its liquid electrolyte and moderately high operating temperatures. Start-up durations are longer with PAFCs compared to other low temperature fuel cells. To date, most applications of PAFCs have involved stationary power and distributed generation (DG).

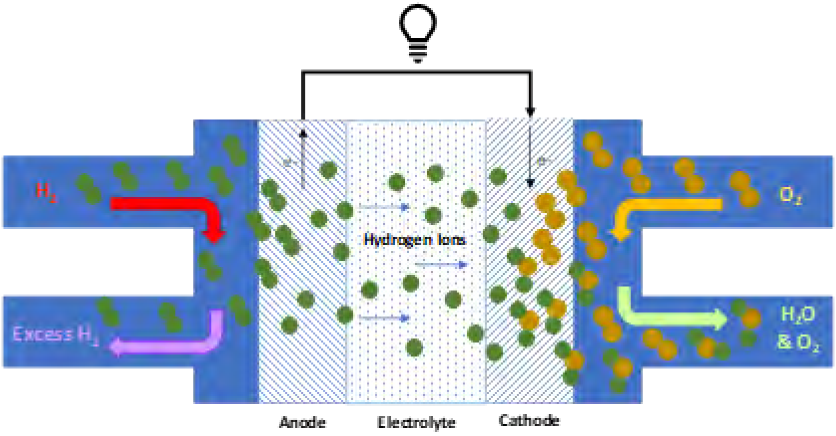

Figure 5. PAFC Process Schematic

PAFC Fuel Cell Characteristic	Typical
Electrolyte	Phosphoric acid in a porous matrix or polymer membrane
Operating Temperature	150 – 200°C
Contaminant Poisoning Tolerance	High to CO and CO_2
Commercial Applications	Stationary power
Manufacturers	Doosan Fuel Cell America, Fuji Electric, Toshiba

2.2.4 Molten Carbonate

Molten carbonate fuel cells (MCFCs) employ a molten carbonate salt (lithium, sodium, and potassium) in a porous, chemically inert matrix. MCFCs are considered high temperature fuel cells because they typically operate at 600-700°C. As a result of these high temperatures, MCFCs do not require precious metal catalysts for anode and cathode electrodes. Instead, nickel catalysts are typically used for electrodes, thereby reducing system costs (FuelCellToday, 2019). The high operating temperatures of MCFCs enable internal reforming of a wide range of fuel sources, including natural gas, other hydrocarbons, and petroleum-based fuels, thus eliminating the need for external reforming and its associated costs.

Note in Figure 6 that a CO_2 supply is required at the cathode, as carbonate ions pass through the electrolyte and are consumed in reactions at the anode. MCFC can achieve electrochemical efficiencies between 50 and 60 percent; when MCFC waste heat is also utilized, however, overall efficiencies can exceed 80 percent (U.S. Department of Energy Fuel Cell Technologies Office, 2019) (Williams, 2011) (Dincer & Rosen, 2013). MCFCs are highly resistant to CO and CO_2 poisoning, which enhances their fuel flexibility. However, the primary challenge with MCFCs is long-term durability. High corrosivity of the electrolyte and the higher operating temperatures leads to quicker degradation rates in MCFC components. According to the DOE, researchers are currently investigating new component materials and cell designs to increase MCFC lifetimes from their current 40,000-80,000 hours (U.S. Department of Energy Fuel Cell Technologies Office, 2019).

Market applications for MCFCs have primarily focused on stationary power generation for electrical utility, industrial and military applications, including generation in the megawatt capacity.

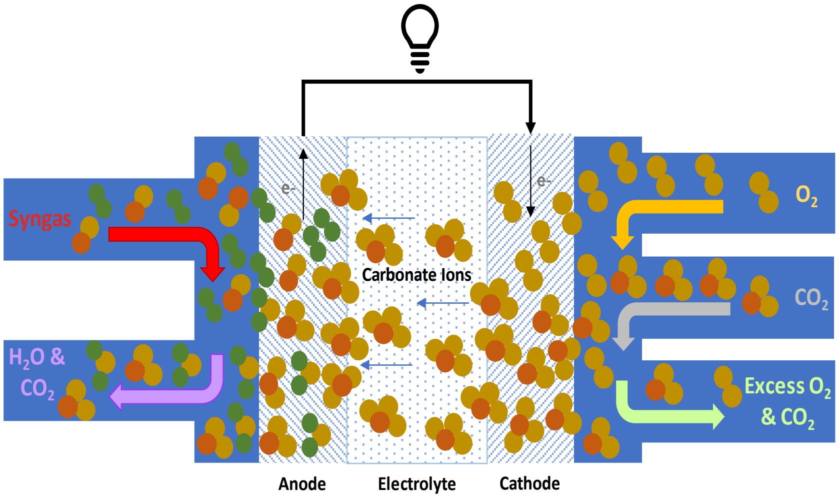

Figure 6. MCFC Process Schematic

MCFC Fuel Cell Characteristic	Typical
Electrolyte	Molten lithium, sodium, and potassium carbonates in a porous matrix
Operating Temperature	600 – 700°C
Contaminant Poisoning Tolerance	High to CO and CO_2
Commercial Applications	Large stationary power generation
Manufacturers	Fuel Cell Energy

2.2.5 Solid Oxide

Solid oxide fuel cells (SOFC) utilize non-porous ceramic compounds of metal (e.g., calcium or zirconium) oxides as electrolytes. As shown in Figure 7, negative oxygen ions pass through the electrolyte to the anode where they combine with hydrogen and CO to produce water vapor and CO_2.

SOFCs operate at very high temperatures, typically ranging between 500-1,000°C. These high temperatures alleviate the need for catalytic material at the electrodes (FuelCellToday, 2019). The high temperatures also increase SOFC tolerance to fuel contaminant positioning, such as CO, CO_2 and even S, and provides considerable fuel source flexibility (e.g., natural gas and syngas). Further, the high temperature operation of SOFCs enables internal reforming of a variety of fuel feedstocks in the fuel cell, eliminating the need and associated cost for an external reformer catalyst. Relative to some other fuel cell types, SOFC fuel conversion efficiencies are high at 60 percent. If the waste heat generated from SOFCs is properly harnessed, overall efficiencies can approach 80 percent (U.S. Department of Energy Fuel Cell Technologies Office, 2019) (Williams, 2011).

As a result of the high temperature operation, start-up with SOFCs takes longer than other types of fuel cells, and SOFCs are designed to withstand the higher temperatures, including the use of heat resistant (and often higher cost) materials for sensitive components. The systems also need to be thermally insulated to prevent heat loss and shielded to prevent personnel exposure. Such requirements often limit or constrain SOFC applications in the marketplace. Some manufacturers have opted for lower temperature (500-600°C) SOFCs that use stainless steel as a replacement material for brittle ceramic components, allowing for shorter start-up times and potentially higher durability for some applications.

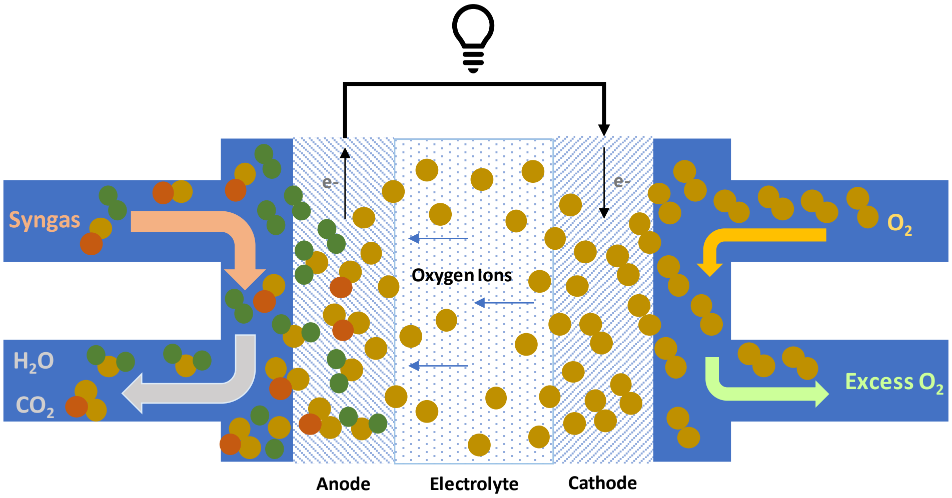

Figure 7. SOFC Process Schematic

SOFC Fuel Cell Characteristic	Typical
Electrolyte	zirconium oxide stabilized with yttrium oxide
Operating Temperature	500 – 1,000°C
Contaminant Poisoning Tolerance	High to CO, CO_2, and S
Commercial Applications	Stationary power, small portable power, and CHP
Manufacturers	Ceres Power, Bloom Energy, FuelCell Energy/Versa Power, and Ceramic Fuel Cells

2.2.6 Summary of Common Fuel Cell Type Characteristics

Table 8 lists a summary Table of the primary fuel cell types and their corresponding characteristics (U.S. Department of Energy Fuel Cell Technologies Office, 2019). The fuel cell types with the highest operating temperatures, MCFCs and SOFCs, can achieve internal reforming, allowing for a wide range of fuels and greater tolerance for fuel and oxidant contaminants. PEMFCs, AFCs and PAFCs all operate at much lower temperatures, requiring greater use of electrode catalysts for supporting reaction processes and consequently exhibiting lower tolerances for fuel and oxidant contaminants. This, in turn, can lead to catalyst poisoning. However, the lower operating temperatures also reduce the need for heat shielding and insulation, allowing for more flexibility in market applications.

2.3 Fuel Cell Market Status

2.3.1 Worldwide Market Status

As discussed, a variety of fuel cell transportation and power applications have emerged on the global market. Figure 8 presents a variety of recent worldwide fuel cell market data points (E4tech, 2018). As shown, transportation (primarily on-highway applications and material handling equipment) and stationary power applications have dominated the recent market, with a combined total of about 69,000 fuel cell shipments equating to over 800 MW shipped capacity. Asia is the strongest regional fuel cell market, accounting for almost 75 percent of total worldwide fuel cell shipments in 2018. Although North America accounted for a much smaller percentage of worldwide shipments at about 13 percent in 2018, the region accounted for about 52 percent of total MW capacity, and an average fuel cell unit shipment of about 42 kW. This reflects a growing U.S. market for larger fuel cells in both transportation and stationary power applications, while Asian markets have capitalized on smaller residential power applications. PEMFCs continue to predominate in the marketplace, accounting for about 57 percent of total worldwide fuel cell shipments and 73 percent of total MW capacity in 2018. SOFCs were a distant second, with about 37 percent of shipments and 11 percent of MWs. Direct methanol fuel cells (DMFCs) (a specialized form of PEMFCs that can operate directly on methanol), PAFCs, AFCs and MCFCs collectively made up about 5 percent of worldwide shipments and 15 percent of shipped MW capacity in 2018.

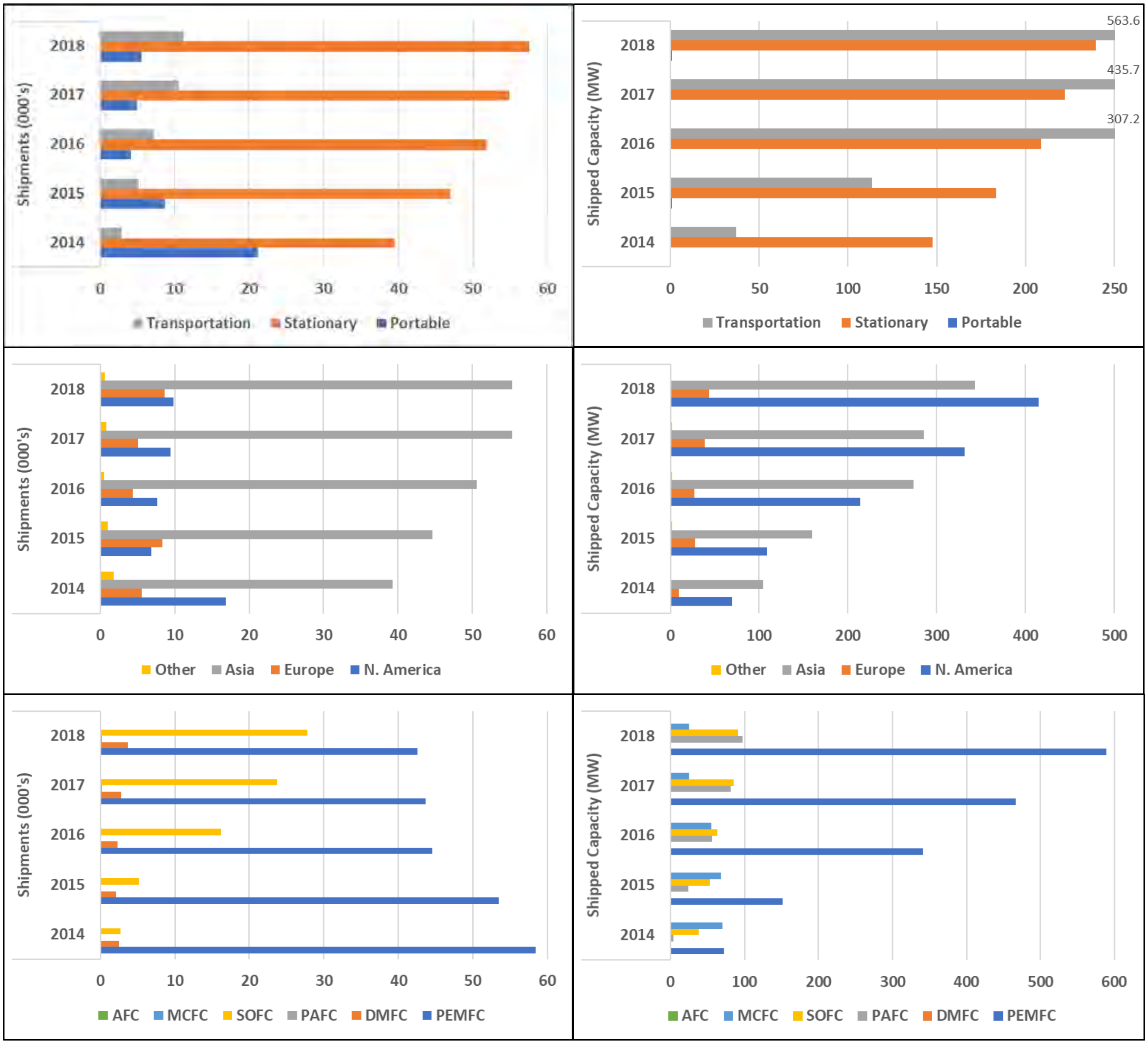

Figure 8. Worldwide Fuel Market Data (E4tech, 2018)

Table 8. Summary of Operating Characteristics by Fuel Cell Type[11]

Type	Common Electrolyte	Operating Temp	Typical Stack Size	Electrical Efficiency (LHV)	Applications	Advantages	Challenges
PEMFC	Perfluoro sulfonic acid	<120°C	<1 kW–100 kW	60% direct H_2;[a] 40% reformed fuel[b]	• Backup power • Portable power • Distributed generation • Transportation • Specialty vehicles	• Solid electrolyte reduces corrosion and electrolyte management problems • Low temperature • Quick start-up and load following	• Expensive catalysts • Sensitive to fuel impurities
AFC	Aqueous potassium hydroxide soaked in a porous matrix, or alkaline polymer membrane	<100°C	1–100 kW	60%[c]	• Military • Space • Backup power	• Wider range of stable materials allows lower cost components • Low temperature • Quick start-up	• Sensitive to CO_2 in fuel and air • Electrolyte management (aqueous) • Electrolyte conductivity (polymer)
PAFC	Phosphoric acid soaked in a porous matrix or imbibed in a polymer membrane	150°–200°C	5–400 kW, 100 kW module (liquid PAFC) <10 kW (polymer membrane)	40%[d]	• Distributed generation	• Suitable for CHP • Increased tolerance to fuel impurities	• Expensive catalysts • Long start-up time • Sulfur sensitivity
MCFC	Molten lithium, sodium, and/or potassium carbonates, soaked in a porous matrix	600°–700°C	300 kW–3 MW, 300 kW module	50%[e]	• Electric utility • Distributed generation	• High efficiency • Fuel flexibility • Suitable for CHP • Hybrid/gas turbine cycle	• High temperature corrosion and breakdown of cell components • Long start-up time • Low power density
SOFC	Yttria stabilized zirconia	500°–1,000°C	1 kW–2 MW	60%[f]	• Auxiliary power • Electric utility • Distributed generation	• High efficiency • Fuel flexibility • Solid electrolyte • Suitable for CHP • Hybrid/gas turbine cycle	• High temperature corrosion and breakdown of cell components • Long start-up time • Limited number of shutdowns

[a] NREL Composite Data Product 8, "Fuel Cell System Efficiency"

[b] Panasonic Headquarters News Release, "Launch of New 'Ene-Farm' Home Fuel Cell Product More Affordable and Easier to Install"

[c] G. Mulder et al., "Market-ready stationary 6 kW generator with alkaline fuel cells," ECS Transactions 12 (2008) 743-758

[d] Doosan PureCell Model 400 Datasheet

[e] FuelCell Energy DFC300 Product Specifications

[f] Ceramic Fuel Cells Gennex Product Specifications

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[11] U.S. Department of Energy Fuel Cell Technologies Office website, www.energy.gov/eere/fuelcells/fuel-cells.

2.3.2 Transportation Market Applications

In terms of fuel cells for transportation markets, leading on-road applications include light duty passenger vehicles, transit buses and drayage vehicles. Small forklifts predominate among nonroad applications. Current market status for these applications is provided below including those applications not specifically at ports.

2.3.2.1 Light Duty Passenger Vehicles

Given the scalability of fuel cell technology and its potential market size, light duty passenger vehicle applications will support fuel cell technology market penetration across sectors, including the port sector. According to the Hydrogen Analysis Research Center (HARC) (Hydrogen Analysis Resource Center , 2019), more than 5,000 light duty fuel cell prototype or commercial vehicle deployments have occurred at over 25 locations across the country since 2007. California accounts for the majority of these deployments, primarily due to the state's commitment to fuel cell vehicles and hydrogen delivery system demonstrations.

2.3.2.2 Transit Buses

A considerable amount of research and development have contributed to fuel cell transit bus applications over the last decade. Transit bus applications account for some of the first mobile applications of fuel cells. The first fuel cell transit bus was demonstrated in 2002 in the SunLine Transit fleet in California. Since 2007, 180 fuel cell transit and shuttle buses have been deployed or are soon to be deployed in locations across the country, according to the HARC (Hydrogen Analysis Resource Center , 2019). The majority of deployments have occurred in California, but other demonstrations have been rolled out in Delaware, Hawaii, and Ohio.

2.3.2.3 Heavy-Duty Drayage Vehicles

Drayage trucks are a frequent application for demonstrating emerging fuel cell technology platforms. Drayage services include hauling freight between ports and intermodal terminal and warehouse locations.

A variety of fuel cell and fuel cell range extender drayage truck demonstrations are ongoing across the country. The HARC database includes a total of 17 fuel cell-powered heavy-duty drayage trucks with planned deployment dates between 2015 and 2021 (Hydrogen Analysis Resource Center , 2019). The majority of these pre-commercial trucks, comprising both fuel cell and fuel cell range extender systems, have been deployed in California at the Ports of Long Beach and Los Angeles.

Some examples of these pre-commercial demonstration programs include the following:

- Zero Emission Cargo Transportation II (ZECT II) Program (Impullitti & Ha, 2019) – This program involves four OEM project teams that develop and demonstrate fuel cell drayage trucks. Each OEM project team is developing electric powertrain trucks with PEMFC range extenders as follows:
    - *BAE/Ballard/Kenworth* – The prototype truck under development incorporates a BAE HybriDrive system powertrain with a 100-kWh Lithium ion battery pack. One 180-kW alternating current (AC) electric motor is mounted on each rear axle. A Ballard 100-kW fuel cell range extender auxiliary power unit provides power to charge the battery pack. The truck operates primarily off the battery pack, with the fuel cell maintaining battery pack state of charge within a specified range. The system incorporates 30 kg of onboard hydrogen fuel storage, which provides approximately 110-120 miles of range between re-fueling. The system power output is comparable to that of a heavy-duty diesel engine.
    - *Hydrogenics/Siemens* – The Daimler truck platform will incorporate a Siemens ELFA electric powertrain with a Hydrogenics Celerity Plus 60-kW range extender fuel cell. Truck range is anticipated to exceed 150 miles, with a hydrogen refueling time of 10-15 minutes.

    - *TransPower/Hydrogenics/Navistar* – Two trucks will be developed with TransPower's ElecTruck electric powertrain and 120-kWh battery packs. One truck will include a 30-kW Hydrogenics fuel cell range extender, while the other will include a 60-kW version. Both trucks will store 25-30 kg of high-pressure hydrogen. Fuel economy is estimated to be 7.37 miles per kg hydrogen. Truck range is expected to range between 135-200 miles.
    - *U.S. Hybrid/US FuelCell/International* – Two trucks will be developed with a U.S. Hybrid electric powertrain (320-kW) and a lithium ion 26-kWh battery pack. The trucks will include an 80-kW U.S. FuelCell PureMotion range extender fuel cell. Each truck will maintain 20 kg of 350 bar hydrogen storage, with an estimated refueling time of less than ten minutes and an expected range of 150-200 miles.

All of the project trucks will be operated along major drayage truck corridors between the Port of Los Angeles, Port of Long Beach, and the Intermodal Container Transfer Facility, a near-dock rail facility. The program was initiated in 2018, and all trucks are expected to be deployed by early 2020.

- <u>Project Portal and Project Portal 2.0 Programs</u> – Toyota, in cooperation with Kenworth, initiated a program in 2017 to develop a prototype heavy duty fuel cell-powered drayage truck for demonstration at the Ports of Los Angeles and Long Beach. The initial "Alpha" truck incorporated two PEMFCs (totaling 230-kW) originally designed for Toyota's commercially available light duty Mirai vehicle. The truck uses a small battery pack of 12-kWh, with a range of about 200 miles. The Alpha truck accumulated over 10,000 miles in actual drayage service. A "Beta" truck was employed in 2018, which offered a longer range (200-300 miles) as compared to the Alpha version.
- <u>FAST TRACK Fuel Cell Truck Project</u> (Landberg, 2019) – In 2019, TransPower is expected to lead the development and demonstration of five heavy duty drayage trucks with fuel cell range extenders at the Ports of Los Angeles and San Diego. TransPower is integrating its T-NMC battery-electric and energy storage system with Loop Energy's FC-REX range extender fuel cells on two Peterbilt 579 truck platforms. Truck range is projected to exceed 200 miles. The trucks will be deployed for a one-year period in December 2019.
- <u>Zero-Emission Freight "Shore to Store" Project</u> – Toyota is collaborating with Kenworth, Ballard Power Systems and Shell Global to develop and demonstrate hydrogen fuel cell-powered heavy-duty drayage trucks at the Port of Los Angeles. A total of ten trucks will be developed in conjunction with two hydrogen fueling stations. The trucks will be developed based on Kenworth's T680 platform. The fuel cell power system (two 114 kW fuel cell stacks and 12 kWh battery pack) affords the trucks 300 miles of range based on 60 kg of hydrogen storage. The trucks will be operated by Toyota Logistics Services (4 trucks), United Parcel Services (3 trucks), Total Transportation Services Inc. (2 trucks) and Southern Counties Express (1 truck). In addition, the project will install two hydrogen refueling stations by Shell Global. The refueling stations will be integrated with three regional stations, located at Toyota facilities around the Los Angeles region, to support drayage truck refueling. The first of ten trucks were deployed in April 2019 (U.S. Department of Energy-AFDC, 2019), and the project is anticipated to be completed in 2021.

2.3.3 Stationary and Portable Power Applications

The effectiveness of fuel cells in stationary and back-up power applications has been demonstrated in a variety of sectors. For ports, fuel cell back-up power and auxiliary power may be useful in resiliency planning. The HARC has tracked stationary and back-up power fuel cell installations greater than 25 kW since 2007 (Hydrogen Analysis Resource Center , 2019). As of September 2018, this database contains 580 active installations across the country, totaling over 350 MW.

Waste heat from stationary fuel cell systems (especially MCFCs and SOFCs) can also be used to support thermal heating and cooling loads at facilities. When combining CHP opportunities with fuel cells, overall system efficiencies (electrical and thermal) significantly increase. The HARC database listed 64 active installations of CHP applications, totaling approximately 64 MW. The majority of these applications were achieved in California, Connecticut, and New York (Hydrogen Analysis Resource Center , 2019)

2.3.3.1 Stationary Power Generation Systems

Stationary power generation remains a dominant application for fuel cell technology across residential, commercial, and industrial sectors worldwide. SOFC, MCFC and PAFC fuel cell technologies are still prevalent in high power systems, while PEMFCs occupy a market niche in low power systems. MCFCs have also gained market foothold due to their use in tri-generation systems (providing electric power, heat, and hydrogen), including applications in which waste biogas provides a fuel source. Stationary power fuel cell system costs continue to remain relatively high as compared to competitive traditional technologies. Installed costs for stationary power fuel cell systems range from about $4,000/kW for large prime power systems to over $20,000/kW for small prime power systems (National Renewable Energy Laboratory, 2018).

2.3.3.2 Back-up Power Systems

Back-up power systems provide emergency electrical power for critical or required systems during a power outage. Back-up power is typically used intermittently, with long periods of inactivity. Standby diesel-fueled generators typically serve as a back-up power source. However, commercially available fuel cells are well-suited for both small and large back-up power systems. An NREL study on telecommunication back-up power systems illustrates the effectiveness of fuel cells in back-up power applications (Kurtz, 2015). The study includes a total of 136 U.S. installations of small (3-6 kW) fuel cell back-up power units with refillable stationary hydrogen storage modules (HSM). On average, the units exhibited a 99.5 percent start-up reliability over a three-year period. Over the same period, the average mean time between interrupted operation (MTBIO) was 94 percent. Annualized cost of ownership for the fuel cell systems was comparable to that of similar diesel systems. The NREL also offered an assessment of fuel cell back-up power system performance status, as provided in Table 9. Current shortcomings relative to diesel-fueled generators included capital cost and long-term durability, but cited advantages included emissions, noise, weight, efficiency, and maintenance costs.

Table 8. Fuel Cell and Diesel Back-up Power System Comparison

Back-up Power System Parameter	Fuel Cell vs. Diesel Generator
Reliability	+
Capital Cost ($/kW)	-
Extended Run Time	=
Emissions	++
Noise	+
Weight	+
Efficiency	+
Annual Fuel Cost	+
Annual Maintenance Cost	+
Maintenance Frequency	++
Refurbishment	=
Remote Conditioning and Check	+
Operational Lifetime	-

*Table Designations: ++ much better; + better; = same; - worse

3. Fuel Cell Applications and Characteristics for Ports

Marine port facilities provide potential applications for fuel cell technology, including a variety of on-highway vehicles, nonroad vehicles, rail, marine, and stationary power applications. Many of these applications have been or are currently being explored through formal demonstrations of pre-commercial and commercial fuel cell equipment. This report does not focus on heavy duty drayage trucks; however, there are a number of ongoing port demonstrations outlined in Appendix A. Appendix A also provides a compilation of fuel cell equipment demonstrations at U.S. port locations from 2010 to 2020.

The remainder of this report will focus on fuel cell technologies in relation to the following port-related equipment areas: nonroad materials handling equipment, switcher locomotives, marine propulsion and auxiliary power, and stationary power generation. Each port equipment topic includes an outline of typical diesel-fueled equipment and associated fuel cell-powered equipment currently on the market or under development.

3.1 Nonroad Materials Handling Equipment

Nonroad vehicle equipment has favorable characteristics for fuel cell technology application at port facilities. In particular, ports material handling equipment such as forklifts, yard tractors and cargo handlers are good candidates for fuel cells. Each type of equipment is discussed below.

3.1.1 Forklifts

3.1.1.1 Diesel-Fueled

Diesel-fueled forklifts are key to maximizing cargo handling efficiency at most port facilities. A reasonable representation of average diesel forklift characteristics used at ports is presented in Table 10 (Starcrest Consulting Group, LLC, 2015) (Starcrest Consulting Group, LLC, 2016) (Lindhjem, 2018) (California Air Resources Board , 2019). The data incorporates Figures from three ports locations across the U.S. (Starcrest Consulting Group, LLC, 2015), (Starcrest Consulting Group, LLC, 2016), (Lindhjem, 2018), as well as average Figures from the California Air Resources Board's (CARB) 2011 survey on 14 ports and 16 rail yards in California (California Air Resources Board , 2019). Based on these port forklift inventories, forklift age ranges between about 8–13 years. The forklifts displayed average horsepower levels between about 75–175 horsepower and showed average annual runtimes ranging from about 500–2,200 hours. Representative forklift load factors for the various port locations ranged from 0.30-0.59.

3.1.1.2 Fuel Cell-Powered

At present, warehouse forklifts represent a strong commercial market for mobile fuel cells, typically in the electric motor-driven Class I, II or III applications[12]. Fuel cells in warehouse applications produce zero emissions and significantly lower noise emissions, both of which benefit warehouse environments for employees. Fuel cell forklifts in warehouse environments are favorable in many cases to battery-electric versions due to advantages associated with fuel range, refueling durations and cold climate performance, all of which increase equipment productivity. Other advantages include smaller energy footprints for associated infrastructure, lower labor requirements, power consistency over the duty cycle, and lower operational costs (Ramsden, 2013) (U.S. Postal Service, 2018). Through year 2017, the DOE estimates that nearly 22,000 fuel cell forklifts were deployed across the country, representing over 140 MW of total fuel cell systems (DOE Hydrogen and Fuel Cells Program , 2018). Similar to other mobile applications, PEMFCs are the predominant fuel cell type used in forklift applications.

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[12] Class I are Electric Motor Rider Trucks; Class II are Electric Motor Narrow Aisle Trucks; and Class III are Electric Motor Hand Trucks or Hand/Rider Trucks.

In support of DOE programs, the NREL has conducted a number of studies and evaluations of fuel cell forklift applications. In a 2016 study, the NREL presented the results of an evaluation of over 1,000 commercial fuel cell material handling equipment stationed across the country in various applications (Ainscough, 2016). A key observation from the study was that current fuel cell stack durability requires continued improvement for long-term market viability. The NREL found that only about half of the fuel cell equipment in the study have achieved more than 10,000 hours of operation before reaching 10 percent voltage degradation.

Table 10. Typical Port Location Diesel-Fueled Forklift Operational Characteristics

Total Forklifts	Forklift Age (Yr)			Forklift Horsepower			Forklift Annual Operation (Hr)			Avg Load Factor
	Min	Max	Avg	Min	Max	Avg	Min	Max	Avg	
Port of Long Beach Inventory, 2014										
100	< 1	35	8	50	200	134	0	2,306	498	---
Port Everglades Inventory, 2015										
177	---*	---	9	---	---	76	---	---	659	0.59
Port of Oakland Inventory, 2017										
14	---	---	---	---	---	169	---	---	561	0.30
CARB, California Port Forklift Inventory, 2011										
---	---	---	12.7	---	---	---	---	---	701	0.30
CARB, California Railyard Forklift Inventory, 2011										
---	---	---	12.7	---	---	---	---	---	2,234	0.30

* "---" denotes data unavailable

In a separate study in 2013, the NREL evaluated fuel cell forklift equipment implemented under hundreds of federally funded demonstration projects (Ramsden, 2013). For multi-shift applications of material handling equipment, the study determined that fuel cell-powered units offered advantages over battery-electric versions, since fuel cell units can operate longer without refueling, can be refueled in much shorter durations and can operate in longer durations without power degradation. These benefits translate to improved total cost of ownership. Results are shown in Figure 9 in 2020 dollars (Ramsden, 2013). The NREL's analysis reviewed a range of capital and operational costs such as capital costs of battery and fuel cell systems, cost of supporting infrastructure, maintenance costs, warehouse space costs, and labor costs. Overall, the study determined that total cost of ownership was 10 percent lower with fuel cell Class I and II forklifts compared with battery-electric versions, and about 5 percent lower for Class III forklifts. The study did not evaluate potential improvements in fleet productivity and potential cost savings for the fleet. However, the analysis included a federal tax credit available to commercial entities for reducing capital cost; nevertheless, the fuel cell forklifts would still realize cost savings even without the credit. In reviewing the cost components, the NREL indicated that fuel cell systems are currently more expensive relative to comparable battery-electric systems. Additionally, although the costs of hydrogen fuel and refueling infrastructure exceed battery-electric equipment costs, fuel cell-related costs are offset by lower labor costs and lower facilities expenses (e.g., cost of building space).

While commercial fuel cell-powered products are currently aimed at forklift applications with lift capabilities generally lower than used by ports, the scalability of fuel cell power plants enables eventual product offerings in these higher forklift classes. For example, Toyota Industries' commercial forklift product uses the same fuel cell structure as the Toyota Mirai fuel cell sedan, albeit with only about half the total number of cells in the stack.

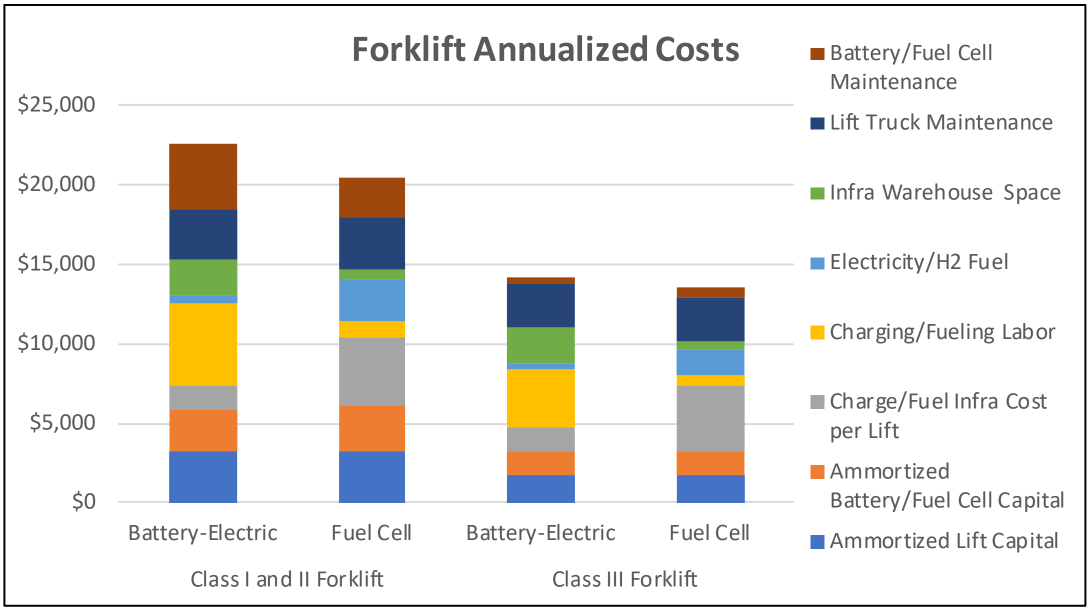

Figure 1. NREL Total Cost of Ownership for Material Handling Equipment

3.1.2 Yard Tractors

3.1.2.1 Diesel-Fueled

Table 11 illustrates typical diesel-fueled yard tractor fleet and operational characteristics at port locations. In addition to data cited from previous port inventories (Starcrest Consulting Group, LLC, 2015) (Starcrest Consulting Group, LLC, 2016) (California Air Resources Board , 2019) (Lindhjem, 2018), Table 11 includes the results of a study of yard tractor load factors for the Port of Long Beach (Starcrest Consulting Group, LLC, 2008). The study evaluated the duty cycles of 85 operational yard tractors to calculate a CARB-approved average load factor of 0.39. Using the data from these port yard tractor inventories, port yard tractors are, on average, about 5-12 years old with a horsepower rating between 175-200. Port yard tractors typically operate at about 1,200-4,600 hours per year.

Table 11. Typical Port Location Diesel-Fueled Yard Tractor Operational Characteristics

Total Yard Tractors	Yard Tractor Age (Yr)			Yard Tractor Horsepower			Yard Tractor Annual Operation (Hr)			Avg Load Factor
	Min	Max	Avg	Min	Max	Avg	Min	Max	Avg	
Port of Long Beach Inventory, 2014										
546	2	11	6	173	249	200	17	4,411	1,985	0.39
Port Everglades Inventory, 2015										
156	---	---	12	---	---	175	---	---	1,333	0.39
Port of Oakland Inventory, 2017										
105	---	---	---	---	---	201	---	---	1,249	0.39
CARB, California Port Forklift Inventory, 2011										
---	---	---	4.6	---	---	---	---	---	2,020	0.39
CARB, California Railyard Forklift Inventory, 2011										
---	---	---	4.6	---	---	---	---	---	4,627	0.39

Recent guidelines for zero/near-zero emission yard tractor testing and demonstrations published by the Port of Long Beach and Los Angeles offer some additional insight on yard tractor operations at ports (Port of Long Beach & Port of Los Angeles, 2017). In the guidance, typical yard tractor operations at ports were organized into three categories: ship work, rail work and dock work. Ship work covers the movement of containers loaded onto and from vessels; rail work covers containers movements onto and from cargo trains; and dock work includes the movement of containers within a terminal yard. In-use data indicates that rail work is the most load intensive for yard tractors. Ship and rail work include highly repetitive activities and constitute the majority (about 95 percent) of all yard truck activities at the ports. Table 12 provides a breakdown of in-use data from the ports.

The ports also identified minimum performance metrics for nonroad zero and near-zero yard tractors, shown in Table 12, and design duty cycle requirements for an 8-hour shift, listed in Table 13. For purposes of Tables 13 and 14, an "8-hour shift" consists of 25 percent rail work, 70 percent ship work, and 5 percent yard work (Port of Long Beach & Port of Los Angeles, 2017).

Table 12. Port of Long Beach/Port of Los Angeles Yard Tractor In-use Data Summary

Parameter	All Activities	Rail Work Only	Ship Work Only
Average Speed (mph)	7.5	8.9	7.0
Std. Dev. of Speed (mph)	3.4	4.2	3.2
Creep (percent)	21.4	15.1	23.3
Idle (percent)	40.1	31.7	41.8
Creep + Idle (percent)	61.5	46.8	65.1

Table 13. Port of Long Beach/Port of Los Angeles Minimum Performance Guidelines for Zero/Near-Zero Yard Tractors

Minimum Performance Guideline	Performance Metric
Design Duty Cycle	One (1) 8-hour shift with no opportunity charging/refueling assumed Two (2) 8-hour shifts with opportunity charging/refueling assumed
Freight Load Capacity	70,000 lbs. (loaded container plus chassis)
Top Speed	25 mph at zero grade (0% grade)
Gradeability at Vehicle Launch	20% grade at 81,000 GCW
Gradeability Sustained at 10 mph	15% grade at 81,000 GCW

Table 9. Port of Long Beach/Port of Los Angeles Design Duty Cycle - 8-hour Shift Minimum Requirements

Number of Container Movements (Pulls per Shift)	Duration (seconds)	Load (Lbs.)	Average Speed (mph)
84	60	45,000	9
30	45	50,000	8
6	120	30,000	15

3.1.2.2 Fuel Cell-Powered

Several companies have produced or are in the process of producing fuel cell yard trucks for port demonstrations, including Loop Energy, Ballard Power Systems and BAE Systems, and Transpower. These research truck platforms employ unique approaches to satisfy truck requirements. For example, Loop Energy's fuel cell range extender system incorporates a 56-kW fuel cell that generates electric power to charge an onboard battery pack (GlobeNewswire, 2017). The battery pack serves to supplement fuel cell electric power, ensuring that truck peak power demands are met. Through a regenerative braking system, a portion of energy normally lost from the braking function is captured to add charge to the batteries, enabling the use of a smaller sized battery pack.

The Ballard Power System approach couples a FCveloCity-HD 85 kW PEMFC with BAE System's HDS200 HybriDrive series propulsion system (200-kW electric motor) on a Capacity TJ9000 yard truck platform (up to 242,000 GCWR) (Ainscough, 2016). Two vehicles are being developed for demonstration at the Port of Los Angeles. The system includes 31.8-kWh of lithium ion battery storage with regenerative braking and 20 kg of hydrogen storage at 350 bar. To date, the manufacturers of this prototype truck have not indicated a desire to use higher pressure hydrogen gas storage, such as 700 bar, although such an approach could be done to increase onboard hydrogen energy. Similarly, while the manufacturers have not stated an intention to use liquid hydrogen storage, such an approach may be cost-effective at the high daily fuel volumes typically experienced in the yard tractor application. Of course, both the higher pressure and liquefied hydrogen storage approached would increase the fuel cell yard tractor's capital cost.

Appendix A provides additional information on port-related fuel cell yard truck demonstration project programs.

3.1.3 Cargo Handlers

3.1.3.1 Diesel-Fueled

Diesel-fueled cargo handlers (top loaders, side handlers, rubber-tired gantry cranes, and ship-to-shore (STS) cranes, among others) serve critical functions in most port operations, facilitating the movement of cargo containers within the terminal and supporting intermodal container transfers for on-road truck transport. The majority of cargo handler equipment are high power, heavy fuel use applications resulting from the severe daily duty cycles they experience. Although all of the cargo handler equipment types are important, the top loader application was selected as represenative of the cargo handler category and thus analyzed in greater depth for purposes of this study. Table 15 provides typical diesel top loader fleet and operational characteristics based on data from a variety of port sources (Starcrest Consulting Group, LLC, 2015) (Starcrest Consulting Group, LLC, 2016) (Lindhjem, 2018) (California Air Resources Board , 2019). Based on this inventory data, diesel top loaders are about 6-12 years old, have maximum power ratings between 300-375 horsepower, and operate annually about 1,400-2,300 hours.

Table 15. Typical Port Location Diesel-Fueled Top Loader Operational Characteristics

Total Top Loaders	Top Loader Age (Yr)			Top Loader Horsepower			Top Loader Annual Operation (Hr)			Avg Load Factor
	Min	Max	Avg	Min	Max	Avg	Min	Max	Avg	
Port of Long Beach Inventory, 2014										
167	< 1	40	7	174	375	295	0	4,148	2,286	---
Port Everglades Inventory, 2015										
54	---	---	12	---	---	331	---	---	1,972	0.43
Port of Oakland Inventory, 2017										
123	---	---	---	---	---	313	---	---	1,388	0.59

Total Top Loaders	Top Loader Age (Yr)			Top Loader Horsepower			Top Loader Annual Operation (Hr)			Avg Load Factor
	Min	Max	Avg	Min	Max	Avg	Min	Max	Avg	
CARB, California Port Forklift Inventory, 2011										
---	---	---	5.9	---	---	---	---	---	1,884	0.59
CARB, California Railyard Forklift Inventory, 2011										
---	---	---	5.9	---	---	---	---	---	1,705	0.59

The operation of cargo handlers in most port environments is typically demanding, involving both lifting and transporting freight. Most North American ports operate according to three types of duty cycles: yard, dock and rail (Nuvera, 2019). Breakdowns of these duty cycles are shown in Figures 10 and 11 for the Port of Angeles as an example (Nuvera, 2019). Yard and dock duty cycles typically have multiple breaks over an 8-hour shift and are associated with longer idling times. Rail duty cycles are typically characterized by more intensive operations and much less frequent breaks per shift. Idling in yard and dock duty cycles comprise approximately 21 percent of total cycle duration, while idling in rail duty cycles accounts for only 6 percent of total cycle time. Hydraulics usage in the three cycle types constitutes between 27-32 percent of total duration, while combined (simultaneous equipment driving and hydraulics usage) usage comprises another 29-35 percent.

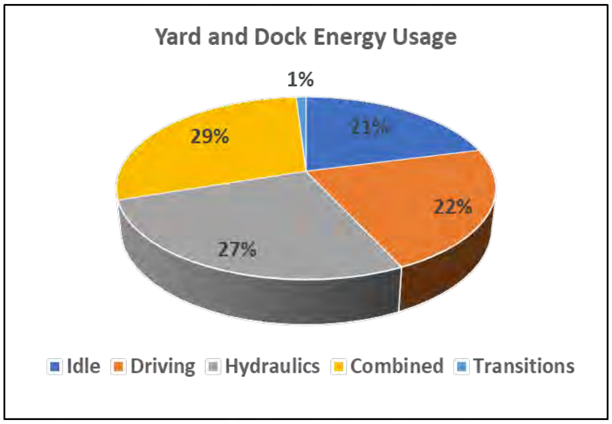

Figure 10. Typical Energy Usage for Top Loader Operation under Yard and Dock Duty Cycles

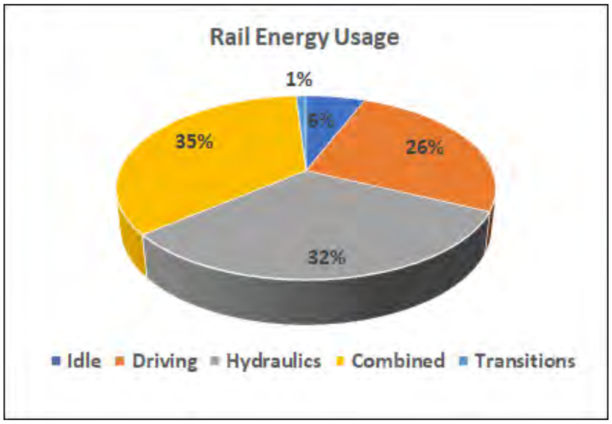

Figure 2. Typical Energy Usage for Top Loader Operation under Rail Duty Cycles

3.1.3.2 Fuel Cell-Powered

As a result of the demanding duty cycles for typical top loader operation, pre-commercial fuel cell units have focused on hybrid platforms with combined fuel cell electric and battery powertrains. These hybrid platforms provide additional flexibility for meeting maximum energy use and power output demands[13]. For example, Hyster-Yale Group, along with its subsidiary, Nuvera, is developing a fuel cell-battery hybrid container handler. The research platform incorporates a 90-kW Nuvera PEMFC with 20 kg hydrogen storage (350 bar) and 200-kWh lithium ion battery pack (Nuvera, 2019). While the total onboard energy storage (hydrogen and batteries combined) may not satisfy the energy needs of a complete shift in some port applications, the use of mobile hydrogen refuelers can be employed, similar to diesel equipment refueling practices. The platform incorporates an energy recovery system that captures energy typically lost during braking and lowering loads to charge the batteries. Hyster is also examining 700 bar gaseous hydrogen storage and liquid hydrogen storage as a means of increasing onboard energy storage density over the original 350 bar pressure system. Both of these types of storage would increase the overall

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[13] ERG was not able to identify performance data for pre-commercial fuel cell units as of the writing of this report, although this data will likely become available as equipment demonstration projects across the county progress.

capital costs of the fuel cell top loader application. In addition, for an upcoming demonstration project at the Port of Los Angeles, Hyster is collaborating with WAVE to incorporate its inductive (“wireless”) charging system and, consequently, to increase useable daily battery storage for the application. The charging system can be accessed during periods of equipment idling or staging over the course of the day.

Appendix A provides additional information on port-related fuel cell cargo handler demonstration project programs.

3.2 Switcher Locomotives

3.2.1 Diesel-Fueled

Switcher locomotives are central to port-related railyard operations. Switcher locomotives are used for moving, assembling and disassembling freight rail cars in short distances in and around port terminals.

According to the federal regulations for locomotives in 40 CFR § 1033.901, switcher locomotives typically have a total maximum rated power of 2,300 horsepower or less (one engine or multiple engines combined). Switcher locomotives are typically powered by diesel- electric generator (genset) systems, in which the diesel engine drives a generator that provides electricity to the locomotive’s traction motors.

As reported in a recent CARB technical document (California Air Resources Board, 2016), the current California switcher locomotive inventory consists of two types of locomotives depending on their age. The first is a traditional, older platform locomotive incorporating a single diesel-electric engine genset. The second type incorporates a newer, multi-engine diesel-electric genset platform. The older type is often a line haul locomotive that gets relegated to regional or switcher service after 15-20 years of line haul service. Some of these older switcher locomotives achieve overall service lifespans of 50 years. Switcher locomotives may receive several engine rebuilds or repowers over the course of their lifetimes.

As shown in Table 16, the older switcher platform incorporates one two-stroke, sixteen-cylinder diesel engine, while the new platform employs three four-stroke, six-cylinder diesel engines. Total horsepower for both platforms is similar (2,000 versus 2,100 horsepower). Total locomotive weights between the two platforms are similar for four-axle versions, but six-axle versions of the new platform are significantly heavier.

Table 10. Typical California Switcher Locomotive Specifications

Key Locomotive Specifications	Traditional, Older Locomotive Platform (EMD GP38-2)	Newer Locomotive Platform (NREC 3-Engine Genset)
Locomotive Weight (lbs.)	250,000	268,000 (4 axle) 395,000 (6 axle)
Locomotive Starting Tractive Effort (STE) (lbs. Force)	61,000	80,000
Engine Maximum Rated Speed (RPM)	800	1,800
Engine Cycle/Stroke	Two	Four
Engine Cylinders	16	6
Engine Horsepower	2,000	2,100 (3 x 700 hp)
Fuel Tank Capacity (Gallons)	1,700	2,900
Maximum Rated Locomotive Speed (MPH)	65	70

Locomotive operation is comprised of various load/power modes called notches. The federal regulations (under 40 CFR § 1033.530) for measuring locomotive emissions defines a switcher locomotive duty cycle as shown in Table 17. Note that idle operation makes up almost 60 percent of the duty cycle, while the lower notches (#1-4) constitute another 34 percent. Thus, under the federal switcher locomotive duty cycle, idle and lower notch (lower load/power) operation make up about 94 percent of typical switcher operations. The CARB has estimated that a Californian switcher locomotive consumes up to 140 gallons of diesel fuel per day and 10,000-50,000 gallons of diesel fuel annually.

A 2018 air emissions inventory report for the Port of Oakland (Lindhjem, 2018) described switcher locomotive use for the Oakland International Gateway (OIG) rail yard, which is operated by the Burlington Northern Santa Fe (BNSF) railway. One switcher is typically assigned to the OIG at any given time, although different locomotives are rotated in and out of this service. In 2018, the switcher locomotives included GM-EMD, GP-25 or GP-60 models. The GP-25 has a single diesel engine rated at 2,500 horsepower, while the GP-60 has two diesel engines with a total rated capacity of 3,600 horsepower. Table 18 provides the reported switcher duty cycle for the OIG railyard, indicating total time spent at idle or notch #1-4 load modes is over 95 percent (Lindhjem, 2018). Average switcher utilization at the OIG yard in 2015 was 2,738 hours, and 2,157 hours in 2017.

Table 17. Federal Switcher Locomotive Duty Cycle under 40 CFR § 1033.530

Test Mode	Percent Time in Mode
Low and Normal Idle	59.8%
Dynamic Brake	0%
Notch 1	12.4%
Notch 2	12.3%
Notch 3	5.8%
Notch 4	3.6%
Notch 5	3.6%
Notch 6	1.5%
Notch 7	0.2%
Notch 8	0.8%
Total	100%

Table 18. Typical Switcher Locomotive at Port of Portland's OIG Railyard

Throttle Notch	Time in Mode
Idle	59.8%
Dynamic Braking	1.4%
1	6.6%
2	15.0%
3	9.5%
4	4.4%
5	1.9%
6	0.3%
7	0.0%
8	1.0%
Total	100%

3.2.2 Fuel Cell-Powered

The BNSF Railway developed an early pre-commercial fuel cell switcher locomotive in 2009 (California Air Resources Board, 2016). The BNSF conducted in-service field demonstrations with the fuel cell switcher in Los` Angeles, CA; Hill Air Force Base, Utah; and Topeka, Kansas (California Air Resources Board, 2016). Called the BNSF 1205, the switcher incorporated a hybrid platform consisting of a 250-kW PEMFC integrated with a lead acid traction battery system. The platform was retrofitted on an existing EMD GP9 switcher locomotive (280,000 lbs.) platform. The BSNF 1205 included 14 carbon-fiber composite 350 bar compressed hydrogen storage tanks and 600V DC traction motors. The fuel cell provided continuous power to charge the battery pack, while the battery pack provided peak power demands in excess of the fuel cell's output (about 1,500 kW total). In 2010, the BNSF 1205 platform was upgraded to include a 500-kW PEMFC, one MW lithium ion battery pack and twice the hydrogen storage volume (California Air Resources Board, 2016). Following field trials, the BNSF 1205 was dismantled.

Higher pressure (such as 700 bar) gaseous storage or liquefied hydrogen storage would both be viable design considerations for future fuel cell switcher locomotive applications. Given the overall fuel use requirements for typical switcher applications, liquefied hydrogen could in fact be more cost-effective than higher pressure hydrogen storage both for onboard storage and for onsite delivery/storage or production/storage scenarios.

While the BSNF Railway's fuel cell switcher demonstration provided meaningful data regarding this application, it should be noted that additional R&D will be necessary to address a variety of fuel supply and infrastructure needs, safety requirements, and high equipment and fuels costs before fuel cell switcher locomotives can achieve reasonable market penetration. Listed below are some encouraging recent developments (Caterpillar, 2021):

- In December 2021, Caterpillar, BNSF, and Chevron agreed to pursue hydrogen fuel cell locomotive demonstration. The goal of the demonstration is to confirm the feasibility and performance of hydrogen fuel for use as a viable alternative to traditional fuels for line-haul rail. Hydrogen has the potential to play a significant role as a lower-carbon alternative to diesel fuel for transportation, with hydrogen fuel cells becoming a means to reduce emissions.

- Canadian Pacific is increasing the number of hydrogen locomotive conversions in its fleet from one to three and adding hydrogen production and fueling facilities. The program is planned to create a global center of excellence in hydrogen and freight rail systems in Canada.

The demonstration and conversion listed above along with additional projects are underway are setting the stage to advance fuel cell locomotive technology worldwide.

3.3 Marine Propulsion and Auxiliary Power

3.3.1 Diesel-Fueled

For purposes of this report and the application of fuel cell power systems, maritime applications refer to harbor craft such as tugs, ferries, work boats and waste trawlers. Fuel cell power systems are candidate replacements for conventional diesel engines, diesel engine hybrid systems and auxiliary engine systems.

Table 19 lists the 2014 harbor craft inventory information for the Port of Long Beach and provides a reasonable summary of the types of diesel-fueled harbor craft in service at U.S. ports (Starcrest Consulting Group, LLC, 2015). The table provides data for both main propulsion and auxiliary power engines.

Table 11. Port of Long Beach 2014 Harbor Craft Inventory Information

Harbor Craft Type	Number of Vessels	Engine Type	Number of Engines	Model Year			Horsepower			Annual Hours of Operation		
				Min	Max	Avg	Min	Max	Avg	Min	Max	Avg
Assist Tugboat	14	Main	29	1980	2012	2003	600	2,540	1,908	65	2,197	1,462
		Aux	29	1980	2013	2007	67	425	181	9	4,068	1,732
Excursion	8	Main	14	1982	2013	2006	70	650	393	100	2,100	878
		Aux	6	2009	2012	2010	50	90	77	50	2,000	1,317
Ferry	12	Main	26	1998	2013	2008	180	2,300	1,718	1,200	1,500	1,258
		Aux	18	2003	2013	2009	18	120	67	750	1,500	833
Harbor Tugboat	12	Main	25	2003	2012	2009	250	1,500	711	85	1,088	389
		Aux	21	2005	2012	2009	22	107	48	70	946	302
Work Boat	4	Main	7	2005	2013	2010	210	675	487	62	1,909	1,237
		Aux	8	1968	2013	1998	27	101	57	548	2,079	1,135

3.3.2 Fuel Cell-Powered

Although less common than other applications, fuel cells are being investigated in maritime applications as possible alternatives to traditional marine diesel and fuel oil power plants across the world. In the U.S., SNL recently completed a feasibility study of fuel cell propulsion power applicability in maritime vessels (Minnehan & Pratt, 2017). The study examined 14 different vessel types and routes, from small passenger and fishing boats on short trips to large ocean-going cargo ships. Study results indicated that hydrogen fuel cells are viable in all but one of the 14 vessel applications. Liquid hydrogen, rather than high pressure gaseous hydrogen, was the preferred method of onboard storage. In general, SNL found that the limiting factor for many of the maritime vessel applications was not power capacity or onboard energy storage, but rather available volume onboard the vessels for accommodating both the fuel cell and hydrogen storage system(s).

Under funding by the U.S. Maritime Administration and in collaboration with the Port of San Francisco, SNL conducted a feasibility and design study of a high-speed passenger ferry powered by fuel cells (Pratt & Klebanoff, 2016). The conceptual ferry, commonly called the "San Francisco Bay Renewable Energy Electric Vessel with Zero Emissions" (SF-BREEZE), would be capable of carrying 150 passengers and traveling two, 50-mile roundtrips at a top speed of 35 knots before requiring refueling. The vessel would incorporate 41 120-kW PEM fuel cell racks, 1,200 kg (4,500 gallons) of liquid hydrogen. The study results found the SF-BREEZE concept technically and economically feasible in San Francisco Bay. An additional well-to-"waves" analysis of the concept determined that, in conjunction with liquid hydrogen produced from renewable energy, fuel cell vessel emission reductions equated to 99.1 percent NO_x emissions, 99.2 percent hydrocarbons, and 98.6 percent particulate matter (PM_{10}) relative to a comparable diesel-fueled, Tier 4 compliant engine-powered vessel (Klebanoff, et al., 2017). Fuel cell vessel cost was estimated at 1.5-3.5 times higher than a comparable diesel vessel. O&M costs were 2-8 times higher due to PEMFC costs. However, with the zero emissions and renewable hydrogen benefits associated with the SF-BREEZE, SNL estimated that the 30-year lifetime societal benefits would range between $2.6-11 million. Although the study found that the SF-BREEZE concept could viably meet the ferry needs of the San Francisco Bay Area at high speeds, SNL also recognized that its specifications (most notably the 35-knot top speed) were unique relative to more common ferry applications in the U.S. For example, the average ferry speed across all applications is 6-15 knots. Thus, for most common ferry applications, fuel cell and fuel storage requirements could be decreased, resulting in lower overall vessel costs, especially in comparison with comparable diesel vessels.

Following the completion of the Sandia National Laboratories' report "Feasibility of the SF-BREEZE: a Zero-Emission, Hydrogen Fuel Cell, High-Speed Passenger Ferry", technology partners and the US Coast Guard began working on permitting the hydrogen fuel systems for maritime vessels. In 2022, All American Marine, Inc. (AAM) and the vessel owner SWITCH Maritime (SWITCH) began conducting sea trials of the vessel "Sea Change", a 70-foot, 75-passenger zero-emissions, hydrogen fuel cell-powered, electric-drive ferry that will operate in the California Bay Area (All American Marine, 2022).

International research and development of fuel cell propulsion systems for marine applications has progressed steadily, with particular focus on harbor craft applications with lower power and shorter-range requirements (U.S. Department of Energy-AFDC, 2019). Some examples of fuel cell marine vessel demonstration projects undertaken in the last three years or planned for the near-term are provided in Table 20 (Tronstad, 2017) (Blenkey, 2019). The German National Innovation Program (NIP) has funded the development of several E4Ships marine vessel fuel cell projects. Two of the projects concentrate on fuel cells for onboard auxiliary power, while the other two projects incorporate fuel cell propulsion power systems. These projects use a range of fuel cell types and fuels. Vessel types include passenger ferries, inland cruise boats and push/tow boats. In a separate FLAGSHIPS project in France, a new build fuel cell push boat is in the development stage, with projected delivery in 2021. In each of these push/towboat applications, fuel cells are part of hybrid platforms that also incorporate substantial battery packs for meeting overall power and energy demands.

Table 20. Examples of Recent International Marine Vessel Fuel Cell Projects

Euro Project	Vessel Type	System	Fuel Cell Application	Timeframe	Fuel
E4Ships - Pa-X-ell	Passenger Cruise	Two 30 kW HTPEMFC	Onboard Auxiliary Power	Phase 2: 2017-2022	Methanol
E4Ships – SchIBZ	Passenger/Goods	100-kW SOFC	Onboard Auxiliary Power	Phase 2: 2017-2022	Low Sulfur Diesel
E4Ships - RiverCell	Inland River Cruise	250-kW HTPEMFC	Baseload Hybrid Propulsion and Auxiliary Power	Phase 2: 2017-2022	Methanol
E4Ships – Elektra	Inland Push/towboat	Two 100-kW HTPEMFC	Baseload Hybrid Propulsion and Auxiliary Power	Phase 2: 2017-2024	Gaseous Hydrogen
FLAGSHIPS – CFT	Inland Push/towboat	400-kW PEMFC	Hybrid Propulsion and Auxiliary Power	2021	Gaseous Hydrogen

3.4 Stationary Power

3.4.1 Diesel-Fueled

Documented inventory and operational data for current diesel genset power applications at port locations were not available in the literature. However, a multitude of diesel-fueled stationary power applications at ports provide both primary and back-up power supplies for buildings, processes, and critical infrastructure. The power output of these applications ranges from a few kW to over one MW.

3.4.2 Fuel Cell-Powered

Various opportunities exist to displace diesel-fueled power generation applications with fuel cell systems at port locations. Fuel cell types for such applications include PEMFCs, PAFCs, MCFCs and SOFCs. Fuel cell power applications at ports may include shore-side power for ocean going vessels, overhead electric cranes, office buildings, warehouses, control systems and security operations. Fuel cells provide high quality and reliable electrical power, consequently improving site resiliency and power redundancy. Fuel cells generate higher electrical efficiencies and produce less noise as compared to diesel gensets.

For example, two stationary power fuel cells were installed at the U.S. Navy Submarine Base in Groton, Connecticut. The Fuel Cell Energy SureSource 4000™ MCFC power plants were developed to provide long-term power supply, with a total system capacity of 7.4 MW. The fuel cell park met a majority of the average daily energy needs of Submarine Base New London, and any excess power was exported to the Groton Utilities distribution system.

In another example of a fuel cell power system, SNL led the development and demonstration of a containerized fuel cell generator (Pratt & Chan, Maritime Fuel Cell Generator Project, 2017). Project partner Hydrogenics designed and built this first-of-its-kind generator to meet the technical specifications determined jointly by the project team. It consisted of a 20-foot ISO standard "hicube" shipping container with a 100-kW PEMFC rack, a power inverter, ultracapacitors for short term transient loading, a cooling system, hydrogen storage, a system controller, and data acquisition equipment. The system's Type III hydrogen tanks held 72 kg of hydrogen at 350 bar and had a rated power of 100 kW, 240 VAC 3-phase. This particular generator was designed to provide power for up to 10 refrigerated containers at a time. The system was assumed to have a 10-year lifetime, with one fuel cell replacement over its lifetime.

Following a six-month field trial at the Foss Maritime facility, the fuel cell generator was placed in service to power refrigerated containers pier side between August 2015 and June 2016. The generator was used on 52 different days for a total of 278 hours. The generator achieved a 5-minute continuous peak power of 91.3 kW (gross) and averaged 29.4 kW (gross) during this period, for a total energy generation output of 7,285 kWh. The system's net energy efficiency ranged from 36-54 percent over a load range of 16-62 percent. The fuel cell generator displaced 865 gallons of diesel fuel and more than 16 metric tons (MT) of CO_2 emissions as compared to an existing 350-kW Tier 3 diesel generator. Generator operators reported inconsistent start-up as the primary issue, which was attributed to a communication problem between the overall system controller, inverter, and fuel cell rack. In this case, the start-up issue related to control system issues and not the PEMFC itself. (PEMFC start-up is typically fast, as opposed to high temperature MCFC or SOFC, which require much longer start-up durations to reach operational temperatures). The generator did not experience any safety-related issues and did not exhibit any signs of deterioration.

SNL's cost analysis found that the capital cost of the generator system was likely three-times higher than a comparable diesel-fueled generator due to balance of plant (BOP) costs, even with fuel cell system costs achieving DOE cost targets. Fuel costs are expected to make up a large portion of operating expenses in the near-term.

While liquid hydrogen storage is certainly a viable option for supporting stationary power fuel cell applications, high pressure gaseous hydrogen storage is generally a more cost-effective option. In many stationary power applications, available space for locating hydrogen storage is less of a concern and so lower cost higher pressure storage would be selected. For facilities with higher hydrogen fuel volume requirements, and/or multiple fuel cell applications (including stationary power) supported by central storage, liquid hydrogen storage could be a more cost-effective option. Appendix A provides additional information on port-related fuel cell stationary power demonstration programs.

4. Fuel Cell Fuel Supply Infrastructure

While hydrogen is considered the predominant fuel for future fuel cell applications, other fuel sources offer potential as both hydrogen carriers and as direct fuels in fuel cell technologies. This section focuses primarily on hydrogen supply infrastructure but also discusses current non-hydrogen fuel supplies and their possible utility to future fuel cell demand.

4.1 Hydrogen Production, Storage, and Transport Technologies

Current annual hydrogen production in the U.S. is about 10 million metric tons. The primary markets for hydrogen are the petroleum refining industry (68 percent) and fertilizer production (about 21 percent) industry. Refinery-related production of hydrogen is the most common today, followed by merchant and then captive production (DOE Hydrogen and Fuel Cell Program, 2018). In the U.S., about 1,600 miles of hydrogen pipeline are laid out to support the local and regional delivery of hydrogen.

While the hydrogen market is positioned to support the petroleum refining and fertilizer industries in the U.S., the hydrogen fuel cell market is still in its infancy. At present, end-users can secure a local supply of hydrogen from equipment manufacturers. Fuel cell equipment manufacturers work directly with hydrogen suppliers, in many cases offering turn-key solutions for delivering and dispensing hydrogen onsite to support their customers. Industrial gas supply companies such as Air Products, Praxair, and Air Liquide USA are the primary suppliers of hydrogen.

The expansion of existing production, storage and distribution infrastructure is necessary to meet future market hydrogen demand for fuel cell equipment and other end sectors. The expansion of hydrogen infrastructure will likely begin near existing hydrogen production centers. The sections below discuss the various approaches to hydrogen production, storage, transport, and dispensing, all of which can be adopted in the near- and long-terms to meet future fuel demands for ports and other end users.

4.1.1 Hydrogen Production Technologies

Multiple existing or developing hydrogen production technologies can be employed to meet hydrogen fuel demand. Several of these technologies are discussed below.

4.1.1.1 Steam Methane Reformation

About 95 percent of hydrogen today is produced through a thermochemical process known as SMR. SMR has been widely used in the chemical and refining industries, with current large-scale hydrogen plant capacities over 500,000 kg/day and conversion efficiencies around 72 percent (Ogden, 2018). The SMR process typically utilizes natural gas as the feedstock, although other hydrocarbon-based fuels can also be used. Natural gas and natural gas liquid feedstocks are derived from gas wellheads, gas production plants and refineries. The existing natural gas pipeline transmission and distribution system is expansive, providing fuel access to the majority of the U.S. According to the EIA, the system is comprised of about three million miles of pipeline, linking production and storage facilities with end use markets across the nation (U.S. EIA, 2019). In 2017, over 25 trillion cubic feet of natural gas was delivered through the U.S. pipeline system (5). Pipeline natural gas varies considerably across the country but is primarily a mixture of methane (about 90 percent) and small amounts of light hydrocarbons (e.g., ethane and propane), nitrogen, oxygen, and CO_2.

Since natural gas contains a small amount of sulfur (and pipeline natural gas contains sulfur mercaptans for odor), the fuel may first undergo a desulfurization process that uses activated carbon and/or zinc oxide to prevent poisoning of the SMR catalysts. The natural gas is then reacted with high temperature steam over a nickel-based catalyst to produce synthesis gas containing hydrogen, CO, and a small amount of CO_2. The water-gas shift reaction is then applied, in which the CO and steam are reacted to produce CO_2 and additional hydrogen. Lastly, pressure swing adsorption removes CO_2 and impurities, resulting in highly pure hydrogen gas.

SMR is energy efficient and cost-effective for large-scale hydrogen production. One drawback of SMR is that CO_2 emissions are produced as a byproduct. However, CO_2 emissions can be reduced by 80-90 percent through the use of carbon capture and sequestration (CCS) technologies. CCS typically adds 10-20 percent to a large SMR plant's capital costs, 10-30 percent to the levelized cost of hydrogen production, with a 1-2 percent decrease in overall plant efficiency (Ogden, 2018).

SMR processes are also available for onsite, small plant applications. While more costly to operate per unit volume of hydrogen production, these small-scale units have been implemented to directly support fuel cell power systems as well as hydrogen refueling stations (Ogden, 2018). Of course, the use of small-scale SMR plants onsite also reduces hydrogen transport costs, as the existing natural gas distribution system can deliver natural gas to the site for hydrogen production. In addition to onsite SMR hydrogen production for hydrogen-fueled fuel cells, recent research on new anode catalyst materials for solid oxide fuel cells has increased the potential for onsite direct fueling of fuel cells (that is, internal reforming) with natural gas.

4.1.1.2 Partial Oxidation

Another existing process, partial oxidation of natural gas (methane), involves the reaction of natural gas with less than stoichiometric levels of oxygen (usually from air), resulting in a synthesis gas stream of hydrogen, CO, nitrogen (if air is used as a reactant rather than oxygen), and a small amount of CO_2 and other trace products. Using the water-gas shift reaction then converts the CO to CO_2 and produces additional hydrogen. The partial oxidation process for natural gas tends to be faster but has a lower hydrogen conversion efficiency than SMR.

4.1.1.3 Gasification

Gasification processes have been developed for hydrogen production from both coal and biomass feedstocks. Gasification involves the reaction of coal with oxygen and steam at high pressures and temperatures. This reaction produces synthesis gas made up of CO, hydrogen, and impurities. The impurities are removed from the synthesis gas, which then undergoes the water-gas shift reaction to produce CO_2 and additional hydrogen. One disadvantage of coal gasification processes is that coal has a high carbon density, resulting in high CO_2 emissions. Thus, the CO_2 byproduct from the process must generally be collected using CCS technology, which decreases overall system cost efficiency.

Biomass gasification involves the high temperature reaction of biomass with oxygen and/or steam to produce CO, hydrogen, and CO_2. The CO is then processed using the water-gas shift reaction to produce CO_2 and additional hydrogen. The CO_2 from the process is collected and processed using CCS technology. Since biomass also consumes CO_2 in its growth cycle, overall net CO_2 emissions are much lower as compared to the coal feedstock gasification process. When coupled with CCS technology, biomass gasification can potentially achieve near-zero net CO_2 emissions.

4.1.1.4 Electrolysis

Electrolysis is the process of splitting water into hydrogen and oxygen when applying an electric power source. Electrolyzers are devices that employ electrolysis for producing hydrogen gas. Electrolyzers are similar to fuel cells in many ways but are designed to receive electricity rather than produce it. Likewise, electrolyzers produce hydrogen rather than consume it. In its simplest form, electrolyzers are comprised of an anode, cathode, and electrolyte. Like fuel cells, electrolyzer cells are categorized by their electrolyte type and can be combined to form a cell stack. In addition to the cell stack, an electrolyzer system typically includes a cooling system, an upfront water treatment system to purify the water supply and a post-processing phase to meet hydrogen purity requirements. For power supplied by the electricity grid, the system also includes an inverter for converting alternating current (AC) to DC power for use in the electrolysis process.

As illustrated in Table 21, modern commercial electrolyzers utilize polymer electrolyte membrane (PEM) and alkaline electrolytes, while solid oxide versions remain in the developmental phase (U.S. DOE Hydrogen and

Fuel Cell Technologies Office, 2020). PEM electrolyzers operate at low temperatures (70–90°C) using a solid polymer electrolyte, enabling hydrogen ions to pass through the membrane to combine with electrons at the cathode and form hydrogen gas. Alkaline electrolyzers operating at low temperatures (100–150°C) create and transfer hydroxide ions through the electrolyte (alkaline solution of sodium or potassium hydroxide) to generate hydrogen at the cathode. Current solid oxide electrolyzers, which operate at much high temperatures (700–800°C), utilize solid ceramic oxygen ion-conducting electrolytes. At the cathode, water combines with electrons to form hydrogen and negatively charged oxygen ions. The oxygen ions then pass through the electrolyte to the anode to form oxygen and electrons for the external circuit. Another promising solid oxide electrolysis concept involves proton-conducting electrolytes. In this concept, ion transfer through the electrolyte passes from anode to cathode. The lower operating temperatures of the proton-conducting solid oxide electrolytes facilitates thermal management and lower cost stack and BOP materials use. Additional research is needed to improve durability and reliability and to optimize electrolyte and electrode material selections.

Table 12. Comparison of Electrolyzer Types

Parameter	Electrolyzer Type		
	PEM	**Alkaline**	**Solid Oxide**
Advantages	• Commercial • Low operating temperatures • High power densities • Low start-up time • Low electricity consumption	• Commercial • Low operating temperatures • Low start-up time • Low system costs (\$/kW) • Low electricity consumption • High median system lifetime	• High system efficiency • High current densities • Low electricity consumption
Remaining Challenges	• Higher system costs (\$/kW)	• Low current densities • Low power densities	• Pre-commercial • High operating temperatures • Durability • High start-up time

Commercial electrolyzers available today consist of smaller plants (up to 1,500 kg/day capacity) that are best suited for onsite hydrogen production. Electrolysis generally relies on power generated from the electrical grid (U.S. DOE Hydrogen and Fuel Cell Technologies Office, 2020). As such, electricity generation sources of electricity an vary significantly, affecting the economic viability of the electrolyzer and increasing its overall net CO_2 and other pollutant emissions. For this reason, researchers are investigating the use of onsite renewable energy sources (e.g., wind and solar) to power electrolyzers. There is emerging consensus on the role of renewable energy sources in improving electrolyzer plant capacities and, in turn, making electrolyzer products more competitive in the marketplace. Further, the intermittent nature of renewable energy offers opportunities to synergize with electrolyzer hydrogen production to expand the available energy from both. That is, electrolyzers can use excess electricity generation from renewable sources to produce hydrogen for storage which can then be used later as an onsite or transportable energy source.

4.1.1.5 Biomass-to-Liquids (BTL)

Liquid fuels derived from biomass, such as ethanol or bio-oils, created from thermochemical processes could prove viable for end-use processing into hydrogen. As liquid fuels, BTL fuels have much higher energy densities than pure hydrogen. BTL fuels can be produced in large quantities at centralized plants and can then be transported much more cost-effectively relative to pure hydrogen. The net CO_2 emission footprints of BTL fuels are lower than other hydrogen carriers, especially when accounting for efficiencies in liquid fuel transportation and storage. Upon reaching end-use sites, BTL fuels can be stored in liquid tanks and then reformed to hydrogen product (using processes similar to SMR for natural gas). BTL fuels are, however, more chemically complex than typical natural gas fuels and, consequently, different catalyst packages are required.

4.1.1.6 Microbial Biomass Conversion

Microbial biomass conversion is a fermentation process in which biomass feedstock is broken down by selective microbes to ultimately produce hydrogen gas. The process is referred to as “dark fermentation” since it does not require light or photosynthetic activity. Depending on the biomass and types of microbes, the fermentation process uses a variety of enzymes to facilitate hydrogen production. Reactor temperature control is key to maintaining microbe life and process activity. Microbial biomass conversion systems are still in the research phase, but plant capacities are projected to scale up in the mid-term. However, increased hydrogen yields, as well as production rates, are essential to commercializing the technology.

4.1.1.7 Ammonia Cracking

As a carbon-free hydrogen carrier, ammonia (NH_3) is a potential future fuel source for fuel cells. Ammonia is the second most-produced chemical globally at over 100 million tons per year for a variety of industrial sector markets (Lan, 2014). Ammonia is an attractive potential fuel source for fuel cells because existing infrastructure can support storage and transportation. The predominant method of ammonia production is the Haber-Bosch process, in which nitrogen and hydrogen are heated to 400-650°C using an iron catalyst at high pressure. Ammonia production processes typically receive hydrogen feedstock from natural gas SMR. Using these combined methods, the production of ammonia is generally energy and cost intensive and produces high CO_2 emissions. Alternatively, ammonia produced using renewable energy coupled with water electrolysis would make ammonia a more sustainable and cost-effective hydrogen source.

Hydrogen production from ammonia can be realized through ammonia cracking processes, which use temperatures above 400°C and catalysts. Ammonia cracking technology can be applied in large-scale centralized hydrogen plants or deployed at small commercial plants to produce hydrogen directly onsite for fuel cell use. The latter affords the considerable benefits (energy density and costs) of ammonia as a hydrogen carrier in delivering hydrogen to the fuel cell end use compared with the distribution and delivery of compressed or cryogenic hydrogen. Furthermore, at smaller scales, ammonia cracking is more cost competitive than steam methane reforming (Cheddie, 2012).

4.1.2 Hydrogen Production Process Feedstock, Water Requirements, and Emissions

Table 22 provides a summary of feedstock, energy use and water consumption requirements for various hydrogen production processes (Mehmeti, 2018). Several of the hydrogen production processes have significant water consumption requirements, especially the biomass-related processes. These water requirements can impact hydrogen production plant location in the country, considering competing end-use markets for water supplies for thermoelectric power, irrigation, public, industrial, domestic, livestock, aquaculture, and mining. In terms of electricity consumption, the two electrolytic processes (E-PEM and E-SOEC) far exceed the electricity use of the other hydrogen production processes.

Table 13. Summary of Hydrogen Production Process Characteristics

Type/Conversion Pathway	Thermo-Chemical				Electrolysis	
	Steam Methane Reforming (SMR)	**Coal Gasification (CG)**	**Biomass Gasification (BMG)**	**Biomass Reformation (BDL-E)**	**Proton Exchange Membrane (E-PEM)**	**Solid Oxide Electrolysis (E-SOEC)**
Feedstock	Natural Gas	Coal	Corn Stover	Ethanol	Electricity	Electricity
Natural Gas (MJ/kg H_2)	165	---	6.228	---	---	50.76

Type/Conversion Pathway	Thermo-Chemical				Electrolysis	
	Steam Methane Reforming (SMR)	Coal Gasification (CG)	Biomass Gasification (BMG)	Biomass Reformation (BDL-E)	Proton Exchange Membrane (E-PEM)	Solid Oxide Electrolysis (E-SOEC)
Coal (kg/kg H_2)	---	7.8	---	---	---	---
Biomass (kg/kg H_2)	---	---	13.5	6.54	---	---
Electricity (kWh/kg H_2)	1.11	1.72	0.98	0.49	54.6	36.14
Water (kg/kg H_2)	21.869	2.91	305.5	30.96	18.04	9.1

Table 23 lists emission values per kg hydrogen for the same hydrogen processes. Not surprisingly, heavy reliance on coal in the coal gasification (CG) process, and grid electricity in the case of the two electrolytic processes, results in considerably higher CO_2 equivalent emissions in comparison to the other production processes. (Although the grid electricity generation mix was not specified in the study, the same electricity generation mix was applied across each hydrogen production process (Mehmeti, 2018)). When using renewable energy-generated electricity for the same two electrolytic processes (E-PEM-R and E-SOEC-R), these processes produce some of the lowest CO_2 equivalent emissions. Between the two biomass-related hydrogen production processes (BMG and BDL-E), biomass gasification produces the lowest CO_2 equivalent emissions. Similarly, the coal gasification and two grid-based electrolysis processes produced the highest NO_x and PM emissions. The biomass reformation process (BDL-E) produced higher NO_x and PM emissions than the biomass gasification process (BMG). Both renewable energy-based electrolysis processes produce some of the lowest concentrations of NO_x and PM emissions. In terms of SO_2, the worst performing processes were coal gasification, biomass reformation and grid-based electrolysis. Renewable energy-based electrolysis generated notably low levels of SO_2 emissions. Overall, renewable energy-based electrolysis and biomass gasification produced the lowest emissions, while coal gasification and grid-based electrolysis accounted for the highest emission concentrations.

Table 23. Midlife Lifecycle Emission Values (per kg hydrogen) of Hydrogen Production Processes

Unit	SMR	CG	BMG	BDL-E (Corn)	E-PEM	E-PEM-R	E-SOEC	E-SOEC-R
Kg CO_2eq	12.13	24.2	2.67	9.193	29.54	2.21	23.32	5.10
Kg NO_x-eq	0.0089	0.055	0.00382	0.037	0.0492	0.0041	0.0353	0.0052
Kg $PM_{2.5}$-eq	0.002	0.039	0.00284	0.007	0.0337	0.0041	0.0222	0.0025
Kg SO_2-eq	0.0087	0.139	0.03706	0.124	0.1087	0.0118	0.0724	0.0078

4.1.3 Hydrogen Storage and Transport Technologies

There is a variety of fuel transport and storage methods that can be employed for hydrogen production. For example, fuel can be transported/stored as pressurized gas or liquefied product, as illustrated in Figure 12.

4.1.3.1 Bulk Storage

Prior to transport to regional or local end-use markets, hydrogen is typically stored in bulk storage tanks at production facilities or terminals. Hydrogen can be stored in bulk as a gaseous product under pressure or as a cryogenic liquid.

High Pressure Hydrogen Gas

High-pressure hydrogen storage is typically accomplished using large cylindrical steel storage tanks. The tanks can be manifolded together for loading and dispensing. The tanks are typically composed of all-steel or steel fiber-wrapped steel. To increase the energy density of the stored hydrogen, hydrogen pressures typically range between 2,500-5,000 psi. Compressors are used to pressurize hydrogen process feeds as necessary in preparation for bulk storage.

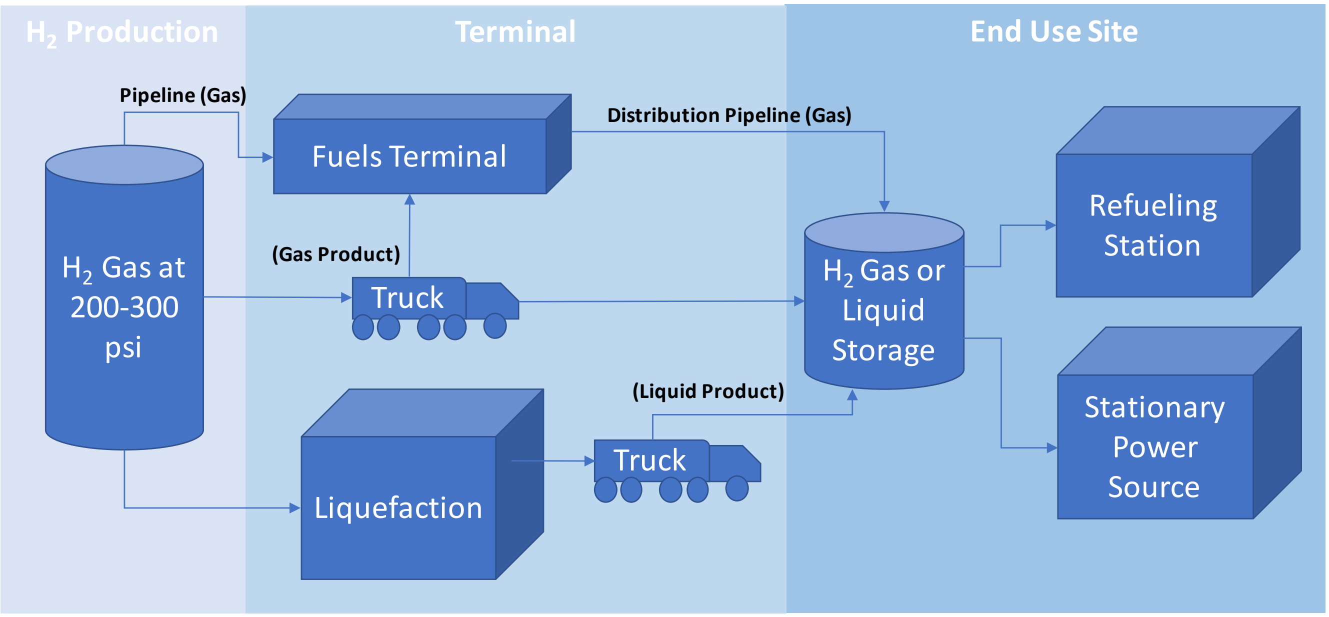

Figure 3. Hydrogen Transport and Distribution Modes

Geologic storage is an alternative method of bulk hydrogen storage. Salt caverns, aquifers and hard rock caverns are the three most commonly used geological bulk storage options today. Although geological bulk storage provides opportunities for storing large volumes of hydrogen, additional research is necessary to determine the efficacy of geological storage in relation to hydrogen product and fuel cells.

Cryogenic Hydrogen Liquid

Cryogenic tanks can also be used to store bulk quantities of hydrogen. Storing hydrogen as a cryogenic liquid significantly increases its energy density, which makes it more favorable to pressurized storage for large volumes (the energy density of liquid hydrogen is about twice that of high-pressure hydrogen). To liquefy hydrogen, the hydrogen must be cooled below its boiling point (-253°C). The liquid hydrogen product is then stored at low pressures in vacuum-insulated tanks and an outer carbon steel shell. To prevent the tank from over-pressurizing, the tanks must be periodically vented to release “boil off” hydrogen vapor. Bulk tanks are typically cylindrical; however, spherical tanks are also in use today. Tank sizes typically range from 1,500-25,000 gallons.

The liquefaction process is very energy intensive and costly. Larger volume liquefaction reduces costs compared to small-scale liquefaction so onsite processes are not very common.

4.1.3.2 Pipeline Transport

Over 1,600 miles of hydrogen pipeline are in place in the U.S. (U.S. Drive Partnership, November 2017). The majority of this existing pipeline is located in California, Louisiana, and Texas for supporting large-scale hydrogen production for the petroleum refining industry. The individual pipelines along this network range from 1-597 miles.

For a mature hydrogen fuel market, pipelines would be one of the most cost-effective means of transporting large quantities of hydrogen from centralized hydrogen production plants to regional and local hydrogen terminals, where it could then be distributed via smaller pipelines, by rail, or by tank truck. However, since hydrogen gas has such low energy density, higher pipeline pressures would be required to achieve energy flows comparable to natural gas pipelines. Multi-stage, positive displacement compressors are needed to achieve pressures typically between 1,000-1,500 psi, which have higher capital and maintenance costs than lower pressure compressors. These compressors are specially equipped for hydrogen use, including tight tolerances and seals. Hydrogen compressor station spacing along pipelines would likely be similar to that of comparable natural gas pipelines at 40–100 miles.

Typically, pipelines are made of carbon steel. Hydrogen has shown a propensity to embrittle steel and welds over time, which can influence pipeline life. Previous research has characterized the extent of these effects to inform codes and standards that guide pipeline design, and to enable the use of novel materials in pipeline service. One such material is fiber reinforced polymer (FRP). FRP is widely used in upstream oil and gas operations and was recently accepted into the ASME B31.12 Code for Hydrogen Piping and Pipelines for high-pressure hydrogen service. FRP is about 20 percent cheaper to install than steel because FRP can be extruded in longer lengths, thus requiring less welding for an equivalent length installed (U.S. Drive Partnership, November 2017).

Since installing new hydrogen pipeline is capital intensive, another concept being researched is the modification of the existing natural gas pipeline to transport pure hydrogen or a blend of natural gas and up to 15 percent hydrogen by volume. In the latter case the hydrogen could then be separated from the natural gas downstream at the terminal or end-use location using separation and purification technologies. Necessary pipeline modification in both cases are under research.

4.1.3.3 Truck/Rail/Barge/Ship/Pipeline Transport to End Use

Truck transport is typically employed to distribute hydrogen from production sites or storage terminals at the regional and local level. Hydrogen can be transported in high pressure or liquid form via truck. Trailer-mounted storage cylinders called tube trailers are used for high-pressure hydrogen. The cylinders are typically comprised of steel, with high-pressure hydrogen stored between 2,500-7,250 psi (U.S. Drive Partnership, November 2017). Steel, fiber-wrapped cylinders for lower weight and higher pressures (and thus greater storage energy density) are also being developed. Although less common, gaseous hydrogen can also be transported via local or regional pipeline to the end-use site. In the case of truck or pipeline transport, the pressurized hydrogen gas is transferred to onsite storage cylinders for serving the onsite fuel cells. Another option is for the tube trailers, either trailer-fixed or skid-mounted on the trailer, to be dropped on the site for temporary storage and then swapped with a new load when the hydrogen gas is depleted.

Liquid hydrogen tank trailers are also used for truck transport. The tank trailers are vacuum-insulated tanks with inner stainless steel and outer carbon steel, capable of holding about 18,000 gallons of liquid hydrogen. Since tank trailers can hold a greater mass of hydrogen than high-pressure tube trailers, tank trailer transport is typically used for longer distance deliveries. Although less common, liquid hydrogen can also be transported long distances via rail car, ship, and barge.

4.1.3.4 Hydrogen Delivery to Fuel Cell Equipment

As explained above, pure hydrogen can be delivered to end-use sites in either gaseous or liquid form. In both cases, however, final delivery of hydrogen to the fuel cell application is in gaseous form.

Gaseous Hydrogen Delivery

For stationary power fuel cell applications, onsite storage cylinders are typically at sufficient pressure to directly supply the equipment. The stored gas may need to be dropped in pressure through a series of pressure regulators to match necessary hydrogen supply pressures for the stationary fuel cells.

In the case of mobile fuel cell equipment, the stored hydrogen gas would typically be boosted in pressure to increase the stored hydrogen energy density onboard the mobile equipment application. Figure 13 illustrates a typical high-pressure gaseous delivery station for mobile equipment applications. The gas delivery station includes a hydrogen storage, compressor(s), a cascade storage cylinder system and a high-pressure dispenser. The hydrogen compressor pressurizes hydrogen gas to higher pressures in the cascade system. Compressors are typically non-lubricated to avoid possible contamination of the hydrogen gas and runoff of electric grid power. The cascade storage is pressurized by the compressor to higher pressures than will eventually be delivered to the equipment. Pressurized gas is delivered to the equipment via an electronic dispenser. The dispenser controls gas delivery from the cascade system, preferentially accessing cylinders at different pressures for faster dispensing for individual equipment storage pressure limitations and current pressure status. Typically, most dispensers are configured to provide hydrogen gas at either 350 bar (5,000 psi) or 700 bar (10,000 psi) pressures to match equipment hydrogen storage system pressures. In some systems, the compressor will be used to supplement the cascade storage in meeting the highest pressures the dispenser demands. Other mobile applications may operate at lower pressures and thus appropriate dispensers would need to be acquired for this equipment. Since heat is generated in the gas compression process, hydrogen stations often incorporate heat exchangers to reduce the temperature of the gas entering the equipment storage tank, as higher gas temperatures impact the amount of gas that can be stored in the tank at a given pressure.

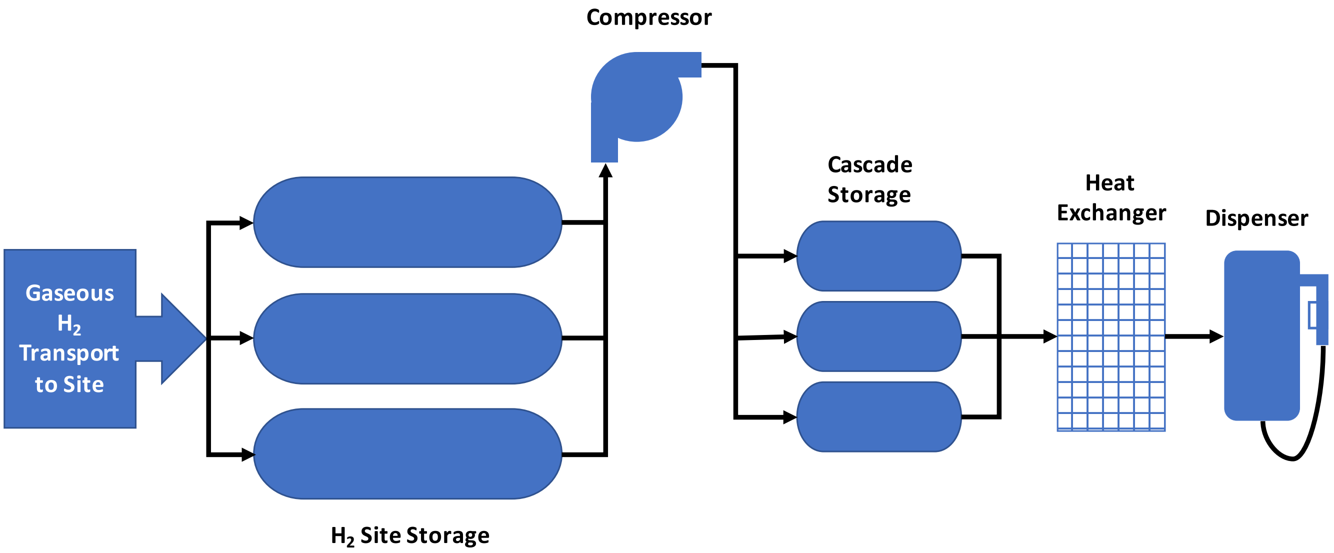

Figure 4. High-Pressure Gaseous Hydrogen Delivery System

Liquid Hydrogen Delivery

For large-scale production of liquid hydrogen, liquefaction is performed upstream and then delivered to the end-use site. The liquid hydrogen is pumped into onsite vacuum-insulated tanks for storage until ready for delivery to onsite fuel cell equipment. Liquid hydrogen can also be delivered in vacuum-insulated tanks on trailers or skids, which can then be connected to the fuel delivery system and replaced when empty.

Figure 14 shows a typical liquid hydrogen delivery system for mobile fuel cell applications. The system includes onsite cryogenic storage, a high-pressure cryogenic pump, vaporizer, storage cascade system and dispenser system. The cryogenic pump increases the liquid hydrogen pressure before the hydrogen is directed to the vaporizer. The vaporizer acts as a heat exchanger, in which ambient air or warm water converts the liquid hydrogen to gaseous hydrogen at pressure. The vaporizer outlet produces high-pressure hydrogen gas that can be fed into the cascade storage system, or, if necessary, be boosted in pressure again with a hydrogen compressor before entering the cascade system. The gaseous hydrogen dispenser then controls cascade storage release in order to achieve necessary fast fill-up times at the fuel cell vehicle's required hydrogen gas storage pressures.

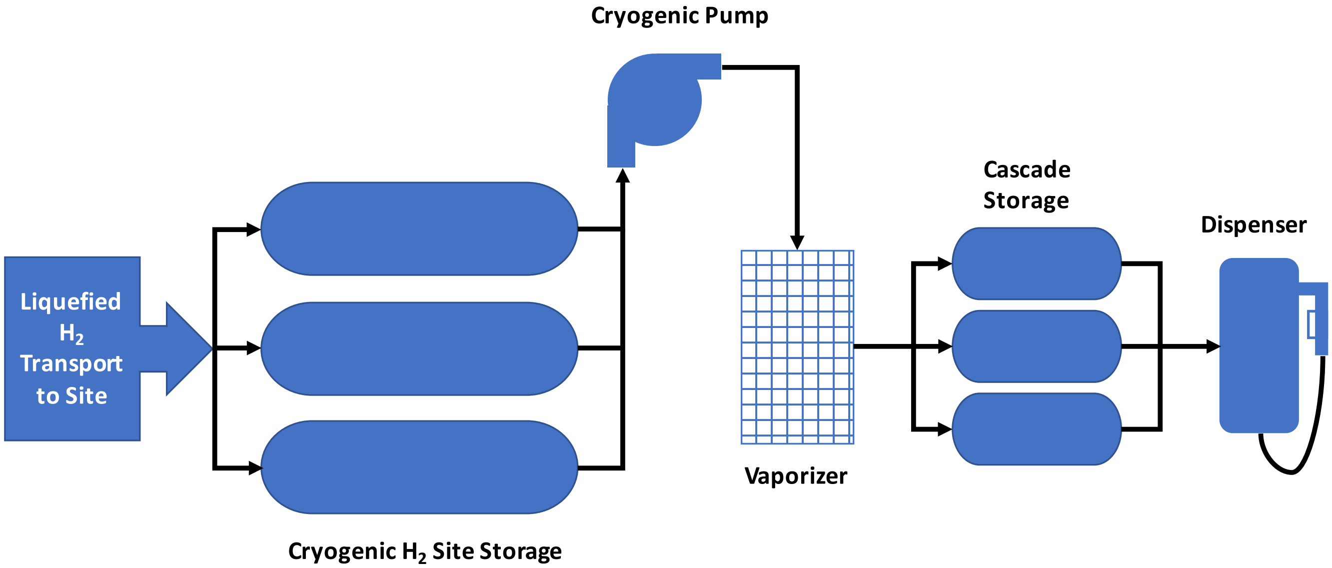

Figure 5. Liquid Hydrogen Delivery System

For stationary fuel cell applications, a dedicated vaporizer along with a pressure regulation system would be necessary to provide inlet hydrogen gas matching the pressure and temperature requirements of the fuel cell.

4.1.3.5 Hydrogen Fuel Safety Considerations

All types of fuel energy carriers have inherent safety concerns. Since many of the fuel properties of hydrogen are significantly different than conventional diesel, fuel safety considerations related to the storage, transport and dispensing of the fuel vary according to fuel type. These differences can be addressed through preparation and proper facility design. In generally considering fuel types and safety compared to diesel fuel, hydrogen gas is more like compressed natural gas (CNG) and cryogenic hydrogen is more like liquid propane gas. Awareness among field personnel is critical to safe operations and emergency response plans, and training programs should be updated when introducing hydrogen fuel cell equipment. Ongoing research and development on hydrogen and fuel cell technologies is informing co-des and standards associated with hydrogen use.

Diesel is generally considered a very stable and safe fuel at typical ambient conditions due to its low volatility (low vapor pressures) and relatively high flash point[14] (above 140°F). Diesel fuel also has a relatively narrow flammability range of about 1–10 volume percent in air. When ignited, diesel fuel burns with a visible flame. In comparison, hydrogen exists in gaseous form at typical ambient conditions, enabling hydrogen to readily mix with air when released. Hydrogen is colorless and odorless. Unlike natural gas, odorants (sulfur-based surfactants) are not typically added to hydrogen fuels, because odorants would be detrimental to fuel cell

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[14] The lowest temperature at which a flammable liquid gives off enough vapors to form an ignitable mixture with air.

catalyst performance. Lastly, hydrogen has a very broad flammability range at 4–74 percent volume in air. When ignited, hydrogen burns very fast and with a nearly invisible flame.

Enclosed areas for maintenance and indoor parking for hydrogen fuel cell equipment, specifically in relation to hydrogen fuel releases, also require careful consideration. Many existing enclosed areas and garage/parking facilities originally designed for diesel equipment are not necessarily equipped to address hydrogen fuel leaks. As opposed to diesel fuel vapors, which are heavier than air and tend to pool near the floor, hydrogen is lighter than air and will quickly rise to the ceiling. Many existing facilities have ventilation systems near the floor instead of, near the ceiling. Additional ventilation and/or appropriate lighting and fixtures (i.e. designed to avoid the possibility of sparks or heat that could ignite gas) may need to be installed before deploying hydrogen fuel cell equipment in existing facilities. Facilities may also have hydrogen sensors installed at the highest points of facilities to detect hydrogen leaks before hydrogen concentrations reach the lower flammable limit. Overall, with necessary precautions and operational changes to accommodate fuel property differences with hydrogen.

There are also additional considerations for liquid hydrogen fuel storage, transport, and handling. As a cryogenic liquid maintained at temperatures below hydrogen's boiling point (-423°F), extreme care must be taken to ensure the safe transfer and dispensing of the fuel. In addition, pumps, hoses, and nozzles exposed to the fuel should be insulated to prevent severe frost bite for personnel exposed to these components. The highly insulated liquid hydrogen storage tanks also tend to gain heat slowly over time, resulting in product "boil-off" vapor releases. Boil-off can occur in both stationary storage tanks as well as storage tanks on vehicles. For this reason, care must be taken to ensure boil-off releases cannot collect in indoor spaces or near active ignition sources.

4.2 Future Potential Hydrogen Production and Delivery Pathways

In terms of future hydrogen fuel use markets such as marine ports, there are likely to be two primary pathways describing hydrogen production to end use delivery: Centralized and Distributed Pathways.

With regards to centralized hydrogen pathways, pure hydrogen is produced in large-scale plants (50,000-500,000 kg/day) for serving regional or even national end-use markets. Centralized production site locations may be selected for proximity to necessary process feedstocks or existing infrastructure. Once hydrogen is produced in the centralized plants, the hydrogen is stored and transported to end-use sites via pipeline, truck or rail for storage and later fuel cell use. New investments in this infrastructure may be necessary to reach specific markets. Centralized plants will have higher capital costs but will benefit from economies of scale operations.

Conversely, the distributed hydrogen pathway involves hydrogen production directly at or near the end use site(s). In this case, hydrogen carrier feedstocks such as natural gas or hydrocarbon fuels may be transported to end-use sites using existing transport infrastructure for these feedstocks, avoiding infrastructure investment costs. Once at end-use sites, fuel feedstocks can be stored before later processing into hydrogen for fuel cell applications. As discussed above, a variety of small plant processes (< 1,500 kg/day) are currently available for producing hydrogen onsite, including natural gas SMR and water electrolysis.

It should be noted that hydrogen production pathways for facilities between 1,500 and 50,000 kg/day may also evolve for serving intermediate-sized local or regional hydrogen markets (U.S. Drive Partnership, November 2017). These semi-central facilities may directly serve municipal or multiple municipal markets. Over time, semi-central facilities may evolve and grow to central plants serving larger and geographically wider regions.

The choice of centralized versus distributed hydrogen production will depend on a number of factors. These include availability and proximity to feedstocks and process energy sources; size of regional or local markets; hydrogen production process efficiency costs; and market, environmental and socioeconomic impacts.

Figure 15 presents a summary and timeline for current and projected hydrogen production technologies according to typical plant capacities and centralized and distributed pathways (DOE Fuel Cell Technologies Office, 2019). As noted, the near and mid-term hydrogen production candidates for centralized pathways include natural gas reforming, biomass and coal gasification, and renewable energy supported electrolysis. For distributed pathways, the most promising technologies include natural gas reforming, electric grid- and solar-based electrolysis, bio-derived liquids, and microbial biomass conversion.

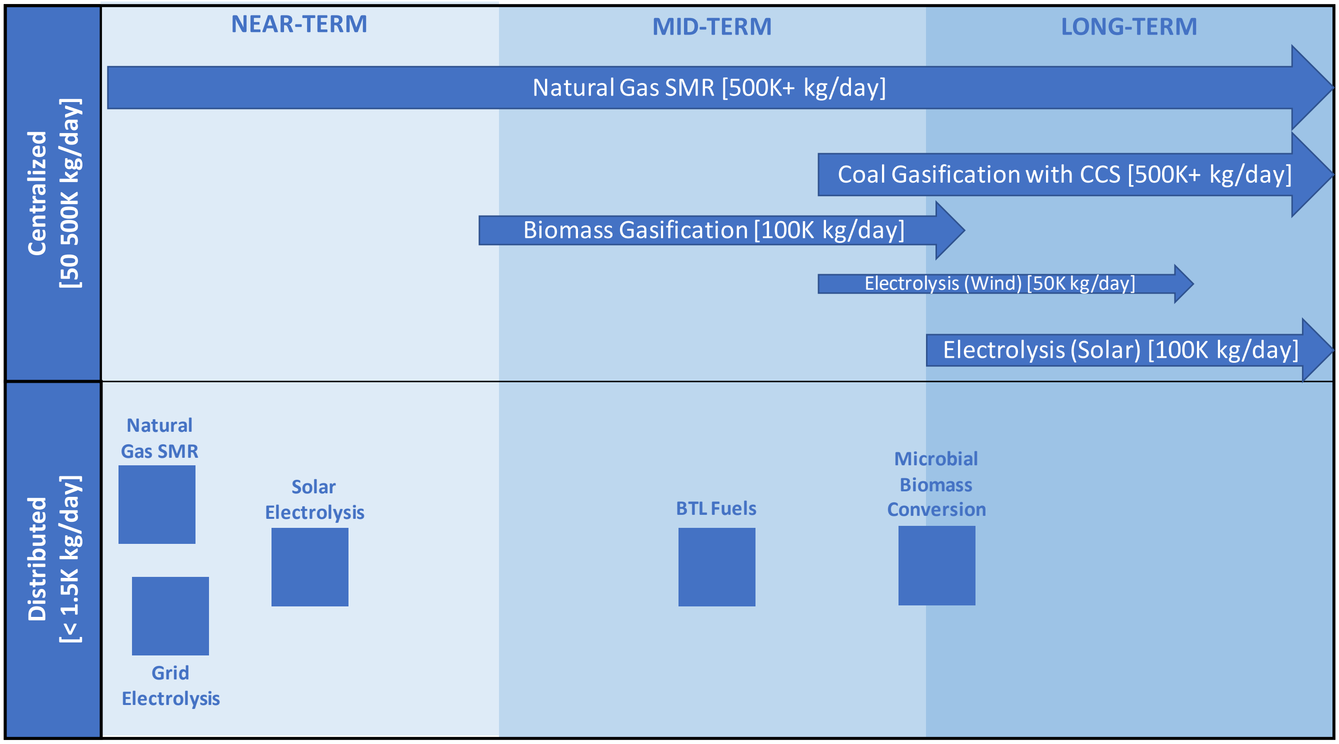

Figure 6. Current and Future Potential Centralized and Distributed Hydrogen Production Technologies

4.2.1 Centralized Hydrogen Pathways

As noted in Figure 15, there are four primary hydrogen production technologies for centralized pathways, all of which are likely to be viable in the near to mid-term, including natural gas SMR, coal gasification, biomass gasification and electrolysis using renewable energy. While each has significant potential for serving future hydrogen markets, some of these options will likely be more regionally than nationally significant for centralized hydrogen production.

As discussed previously, natural gas SMR is currently the most prevalent means of producing hydrogen today, accounting for more than 95 percent of annual U.S. hydrogen production. Future SMR hydrogen production would benefit from the expansive natural gas pipeline network across the country, allowing for easy access to natural gas feedstocks for local and regional hydrogen product markets. A recent analysis by the NREL identified SMR centralized hydrogen production potential in the U.S. using natural gas well data from the EIA (U.S. DOE Hydrogen and Fuel Cell Technologies Office, 2020). Due to competing markets for natural gas, the analysis assumed that that only 30 percent of the current natural gas production capacity would be available for hydrogen production. The results indicated that there is strong potential for centralized natural gas SMR hydrogen production in Colorado, Louisiana, New Mexico, Oklahoma, Texas, Utah, and Wyoming. (Of course, the water use constraints in Colorado and Texas may mitigate some of this potential). These centralized hydrogen production facilities could generally serve coastal ports on the Western and Southern coasts, as well as inland ports along the Mississippi River and Great Lakes regions.

The same NREL study analyzed the centralized hydrogen production potential for coal gasification by state based on EIA coal production data (Milbrandt & Mann, 2009). The analysis indicated that the states of Arizona, Colorado, Kentucky, New Mexico, Pennsylvania, West Virginia, and Wyoming all offer significant potential for hydrogen production from coal gasification based on ready access to railroad infrastructure for coal feedstock transport and finished hydrogen product delivery to regional markets. Centralized hydrogen production facilities located in these states would support west and east coast port locations, as well as inland ports along the Mississippi River and the Great Lakes. Existing railroad infrastructure could serve hydrogen product transport to these markets.

In a separate study, the NREL assessed hydrogen production potential from national biomass gasification and electrolysis using wind and solar resources (Melaina, Penev, & Heimiller, 2013). The NREL determined that the highest potential for hydrogen production from biomass resources exists in the Midwestern states of Iowa, Illinois, Indiana, Nebraska, and Ohio, as well as states along the Mississippi River, including Alabama and Arkansas. There is additional regional potential in the Northwestern states of Washington and Oregon and in the Mid-Atlantic and Southeastern states. Biomass feedstock transport for these locations could be achieved via barge and rail given available waterways and existing rail infrastructure, and gaseous or liquefied hydrogen product could be transported using the same infrastructure depending on proximity to regional liquefaction plants.

In the case of hydrogen electrolysis using large-scale wind and solar energy resources, the NREL determined that solar energy is the predominant resource, with strong potential in the upper and central Midwest (Indiana, Iowa, Illinois, Minnesota, Ohio, North Dakota and South Dakota); along the Mississippi River (Alabama, Arkansas and Louisiana); and in many of the southern state regions (Arizona, New Mexico, Florida, Georgia and Texas). There is significant offshore wind resource potential along the east and west coasts, as well as along some of the Gulf coast states (Louisiana and Texas). Both solar and wind resources could serve centralized gaseous and liquefied hydrogen production in many areas of the country, including regions that could support future hydrogen use at inland and coastal port locations. Table 24 provides an overall summary of regional centralized hydrogen production potential based on the NREL's analyses.

Table 24. States with High Potential for Centralized Hydrogen Production

State	SMR	Coal Gasification	Biomass Gasification	Electrolysis with Solar	Electrolysis with Wind
Alabama			✓	✓	
Arizona		✓		✓	
Arkansas			✓	✓	
Colorado	✓	✓			✓
Florida				✓	
Georgia				✓	✓
Illinois			✓	✓	
Indiana			✓	✓	
Iowa			✓	✓	✓
Kentucky		✓			
Louisiana	✓			✓	✓
Minnesota				✓	

State	SMR	Coal Gasification	Biomass Gasification	Electrolysis with Solar	Electrolysis with Wind
Nebraska			✓		✓
New Mexico	✓	✓		✓	✓
North Dakota				✓	✓
Ohio			✓	✓	
Oklahoma	✓				✓
Pennsylvania		✓			
South Dakota				✓	
Texas	✓			✓	✓
West Virginia		✓			
Wyoming	✓	✓			✓

4.2.2 Distributed Hydrogen Pathways

Three viable distributed hydrogen production technologies include onsite natural gas SMR, onsite ethanol stream reforming (ESR) and onsite electrolysis using the electric grid. In each of these cases, the hydrogen produced onsite with these small plant processes is pressurized and stored in cylinders until directed to the gaseous hydrogen delivery system.

The expansive U.S. natural gas pipeline system supports the use of natural gas as a viable hydrogen carrier source for distributed hydrogen production. Natural gas feedstock can support both onsite SMR to produce pure hydrogen and direct use as a fuel through internal fuel cell reforming depending on the fuel cell type.

Biomass-derived fuels such as ethanol are also viable hydrogen fuel carrier candidates for distributed hydrogen production. Biomass-derived ethanol is already mass produced across the country. Most of the ethanol produced today is derived from corn or sorghum feedstocks, although research continues to explore ethanol production from cellulosic biomass feedstocks (such as switchgrass). Ethanol is advantageous as a liquid fuel, as ethanol has a higher energy density than natural gas and can be transported much more efficiently and cost-effectively. Due to its use in chemical markets and as a gasoline additive, ethanol is already widely transported in large quantities by barge, rail, and tank truck.

Of course, water is a common feedstock among the distributed hydrogen production processes. Although water volume requirements are much lower as compared to large-scale centralized production plants, water usage for small-scale distributed plants could be a concern for ports located in heavy water usage areas such as Texas and California. Water use is also important considering competitive water-use markets, or if port locations already operate under water restrictions as a significant local water consumer. While the water distribution system in the U.S. is ubiquitous and port locations are therefore well-served, water use for small-scale electrolysis is higher than other distributed production processes. For example, in a recent Argonne National Laboratory (ANL) study it was estimated that the water consumption for distributed hydrogen electrolysis was about 17 percent higher than distributed hydrogen SMR processes for the same hydrogen production yield (Elgowainy, 2016).

Small-scale natural gas SMR plants are commercially available for providing onsite hydrogen production. These systems are less efficient and more costly to operate per unit volume of hydrogen production than large-scale SMR plants, but they have been used to directly support fuel cell power systems and refueling stations. In the case of ethanol as a hydrogen fuel carrier, ethanol can be stored in aboveground or underground tanks before being pumped to a small-scale hydrogen production ESR plant. ESR is similar to SMR in terms of operating temperatures, hydrogen yields, energy efficiency and production cost (Tayade, 2012).

Water electrolysis is the second most commonly used hydrogen production process behind SMR. Today's commercially available electrolyzers utilize polymer electrolyte membrane and alkaline electrolytes. Although electric grid power is most common for small-scale electrolyzers, research is exploring wind or solar power potential, with the aim of improving small-scale economics and lifecycle emissions.

4.3 Non-Hydrogen Fuel Supplies for Direct Fuel Cell Use

Several non-hydrogen fuel sources offer potential for direct fueling of fuel cells at ports. These include natural gas, ammonia, and methanol. Each is discussed below.

4.3.1 Natural Gas

The abundance of natural gas resources in the U.S. ensures its wide availability and use across a variety of demand sectors in the future. As discussed above, natural gas will be a key fuel source for supporting onsite production of hydrogen under distributed hydrogen pathways. Natural gas can also be used directly as a fuel source for some types of fuel cells such as MCFCs and SOFCs. These high temperature fuel cells require less catalytic electrode materials and allow for less fuel processing due to internal fuel reforming. The general availability of natural gas supplies for most U.S. port locations offers significant potential for direct natural gas use in stationary fuel cell applications using MCFC and SOFC technologies. Natural gas is extensively pipelined across the U.S. with local pipeline networks serving municipal jurisdictions and/or large demand centers such as ports. Natural gas can also be delivered onsite in bulk cryogenic liquid form where is can be stored for later gaseous pipeline distribution to stationary fuel cell application.

Pipeline natural gas typically contains sulfur compounds (e.g., mercaptans) for producing an odor in the gaseous product. (The odor affords easier detection of pipeline gas leaks.) Depending on gas sulfur levels, additional fuel processing may be necessary to reduce sulfur compounds in the fuel prior to fuel cell use. SOFC fuel cells tend to have higher fuel sulfur tolerance due to their high temperature operation and typically lower catalytic materials (FuelCellToday, 2019).

4.3.2 Methanol

Methanol, or methyl alcohol, is a commonly used feedstock supporting a variety of market sectors in the U.S. including the chemical, petroleum and refined product, and plastics industry. The global methanol market in 2019 was about 98 million metric tons according to the Methanol Institute (Methanol Institute, 2020). Methanol is produced from syngas created from natural gas production. As a liquid fuel, methanol's energy content is higher than natural gas but lower than ethanol or gasoline on an equivalent volume basis. Methanol is transported as a liquid via tanker ship, barge, pipeline, rail, and truck (Methanol Institute, 2013). Methanol is flammable and burns with a nearly invisible flame. Methanol is toxic to humans, but when released it readily biodegrades and is miscible with water.

Direct methanol fuel cells (DMFCs) were developed in the U.S. in the 1990s. A DMFC is essentially a specialized form of PEMFC that utilizes an aqueous methanol mixture as its fuel source. DMFCs incorporate polymer membranes for their electrolyte. However, platinum-ruthenium catalysts are used at their anodes which breaks down the methanol molecules into hydrogen ions and CO_2. This eliminates the need for an external fuel reformer to produce hydrogen. The hydrogen ions then pass through the electrolyte and combine with oxygen at the cathode to form water. To date, DMFCs have primarily been used for small portable power applications for cell phones and laptop computers as well as military power applications for the battlefield. According to the Methanol Institute, global methanol demand for DMFC applications was about 12,000 metric tons.

4.3.3 Ammonia

As mentioned above, the current ammonia market is about 100 million tons per year for serving agriculture, pharmaceutical, petroleum, and plastic industries in the U.S. As a result, existing supply infrastructure is already in place across the U.S. for potentially serving fuel cell end users. Ammonia is typically liquified and stored in large refrigerated storage tanks as ammonia's boiling point is only -33°C. Thus, ammonia is transported as a refrigerated bulk liquid product via ship or barge and can be transported to local markets as a low-pressure liquid (like propane) via pipeline, barge, tank car, and tank truck. Ammonia has comparable energy density to methanol and about twice that of liquid hydrogen on an equivalent volume basis. In terms of safe handling and distribution, ammonia has a narrower flammability range than hydrogen and burns with a visible flame as opposed to hydrogen's invisible flame. Ammonia releases from infrastructure are a significant challenge for human exposure scenarios, but releases are detectable at less than 1 ppm in air and generally dissipate quickly in gaseous form.

Ammonia can be utilized as a direct fuel for some fuel cell types. PEMFCs are not good candidates for direct ammonia use due to their low operating temperatures (lower ammonia conversion potential) and subsequent ammonia crossover issues, and potential poisoning of anode electrode catalysts. Recent research on direct ammonia AFC, AMFC, and SOFC applications is progressing but still in pre-commercial development. The higher temperatures of SOFCs hold promise for achieving similar efficiencies and power densities as hydrogen-fueled SOFCs, but challenges with long-term durability persist.

5. Port Fuel Cell Equipment, Infrastructure, and Fuel Costs

5.1 Hydrogen Infrastructure and Delivery Costs

The methods for producing, transporting, and dispensing hydrogen vary considerably. Regionally specific refueling solutions involving most cost-effective delivery of hydrogen product to individual port locations will ultimately determine which delivery pathways are most successful. A breadth of hydrogen refueling solutions and their associated cost is presented and discussed in this section. The discussion includes estimated hydrogen refueling station capital and operating costs according to station capacity and type of hydrogen product delivered. In addition, the section presents a methodology for estimating overall delivered hydrogen costs, accounting for hydrogen production process, transport and distribution type, and station/dispensing type.

5.1.1 Refueling Station Capital and Operating Costs

In recent work on hydrogen refueling costs (Melaina & Penev, Hydrogen Station Cost Estimates: Comparing Hydrogen Station Cost Calculator Results with Other Recent Estimates, 2013) (Hecht & Pratt, 2017) (McKinney, 2015), researchers reported on a variety of results, including refueling station capital and operating costs developed by the University of California-Davis based on California station installations. Station capital costs were estimated according to station capacity (kg hydrogen dispensed per day) as well as station type and hydrogen delivery method. Researchers also provided estimates for natural gas and electricity consumption as well as annual maintenance associated with hydrogen station types, including onsite SMR and electrolysis processes. Using this information and reported average industrial prices (U.S. Energy Information Administration, 2020) for natural gas ($4.17/1000ft^3) and electricity ($0.0688/kwh) in 2018, estimates of levelized hydrogen refueling station capital and operating costs are shown in Table 25 for a variety of hydrogen delivery and station types. Gaseous hydrogen (GH2) and liquid hydrogen (LH2) delivery shown in the Table represent delivery by truck. Conventional hydrogen stations represent those stations customized and assembled onsite, while modular stations describe stations assembled by manufacturers offsite and then delivered to the site on a skid or trailer. In general, the station cost Figures of Table 25include a single dispenser capable of dispensing both 350 and 700 bar hydrogen (Melaina & Penev, Hydrogen Station Cost Estimates: Comparing Hydrogen Station Cost Calculator Results with Other Recent Estimates, 2013) (Hecht & Pratt, 2017) (McKinney, 2015).

It should be noted that station capital costs on per kg dispensed basis in Table 25 are inversely proportional to station capacity. Stated another way, station capital costs on a per kg dispensed basis are higher for smaller capacity stations than for larger stations. Further, there is a difference in station capital costs on a per kg dispensed basis between the centralized delivery stations and the distributed delivery stations. This is due to the additional costs associated with onsite SMR and electrolysis production. However, as will be addressed below, the overall cost of delivered hydrogen from these distributed production stations becomes competitive with those of centralized production when accounting for centralized production and transport costs.

From a station operating cost standpoint, centralized production served stations generally had lower costs than distributed served stations for the same hydrogen dispensed capacity. The onsite electrolysis stations exhibited the highest operating costs due primarily to their intensive electricity usage in producing hydrogen from water.

California is leading the charge to develop hydrogen refueling infrastructure in the U.S. The California Energy Commission is expanding California's network of hydrogen refueling stations throughout the state. Hydrogen fuel cell electric vehicles are expected to play a key role in achieving the state's goal of getting 1.5 million zero-emission vehicles on California roads by 2025. To support the fuel cell electric cars and increase deployment, the Commission is investing in a network of 100 public hydrogen stations.[15] Efforts are also underway to expand hydrogen fueling locations in Hawaii and across the East coast, with other markets expected to develop as consumer demand increases. Hydrogen infrastructure is also developing for buses, medium-duty fleets, and material handling equipment. [16]

5.1.2 Dispensed Hydrogen Price

The ultimate cost for dispensed hydrogen ($/kg) must account for all production and delivery pathway elements. This is especially important for centralized production pathways that include costs for production and transport to the site on top of amortized costs for station capital cost recovery and operations. This also affords the ability to assess differences in hydrogen delivered costs from regional production and delivery sources, and to allow for apples-to-apples comparisons of total dispensed costs for centralized and distributed production.

To estimate these pathways costs, several studies on specific hydrogen pathway cost elements were reviewed (Lipman, 2011) (DOE Hydrogen and Fuel Cell Technical Advisory Committee, 2013) (DOE Fuel Cell Technologies Office, 2019). Table 26 lists final estimated levelized cost figures on a per kg hydrogen produced and transported basis for centralized production and transport pathways. The total delivered hydrogen cost in the Table represents the summation of the production and transport costs for each delivery type. Thus, central NG-SMR production ($1.47/kg) with tube trailer delivery ($1.50/kg) equates to a $2.97/kg delivered cost to the station/site. Based on these figures and placing the previously determined refueling station capital and operating costs of Table 25 on annualized per kg dispensed bases, final estimated dispensed hydrogen costs were determined for both centralized and distributed production pathways. While hydrogen station lifetimes can vary, a conservative station lifetime of ten years was selected for representing the lower end of this lifetime range (Melaina & Penev, Hydrogen Station Cost Estimates: Comparing Hydrogen Station Cost Calculator Results with Other Recent Estimates, 2013).

The dispensed hydrogen cost results are provided in Table 27 and represent estimates of levelized hydrogen costs for dispensing the fuel to end use equipment. Note that centralized station dispensed hydrogen costs ranged from $4.98-9.84/kg depending on the hydrogen production type, delivered product type (gaseous or liquid), and the station type and capacity. Onsite dispensed hydrogen costs ranged from $5.43-12.28/kg. For centralized pathways, delivered hydrogen costs were lowest with SMR produced gaseous product delivered to conventional stations. For distributed pathways, onsite SMR produced the lowest delivered hydrogen costs. In general, these estimates align with DOE projections for hydrogen costs in year 2025 of about $5-10/kg and longer-term hydrogen costs of less than $4/kg (Satyapal, 2018). While the delivered hdyrogen cost estimates of Table 27 represent sations capable of dispensing either 350- or 700-bar pressures, it should be noted that refueling at 350-bar pressures are reported to be up to $2/kg lower due to less required compressor operation at these the lower pressure (McKinney, 2015).

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[15] California Energy Commission. Hydrogen Vehicles and Refueling Infrastructure. https://www.energy.ca.gov/programs-and-topics/programs/clean-transportation-program/clean-transportation-funding-areas-1

[16] U.S. Department of Energy. Alternative Fuels Data Center. Hydrogen Fueling Stations. https://afdc.energy.gov/fuels/hydrogen_stations.html

Table 14. Estimated Hydrogen Refueling Station Capital and Operating Costs by Hydrogen Delivery Method

								Estimated Annual Station Costs				
Hydrogen Refueling by Site Delivery Type	Assume H2 Station Capacity (kg/day)	Station Capital Cost ($)	Station Cost Per Capacity [$/(kg/day)]	Average Station Natural Gas Use (MMBtu/kg H2)	Average Station Electricity Use (kWh/kg H2)	Average Industrial Natural Gas Price ($/1000 ft^3)	Average Electricity Price ($/kWh)	10-Year Annualized Station Cost ($)	Annual Natural Gas Cost ($)	Annual Electricity Cost ($)	Annual Maintenance Cost ($)	Total Annual Costs ($)
Centralized Hydrogen Production and Delivery												
Conventional, GH2 delivered	100	1,510,000	15,100	---	1.25	---	0.0688	151,000	---	3,139	19,630	173,769
Conventional, GH2 delivered	200	1,690,000	8,450	---	1.25	---	0.0688	169,000	---	6,278	21,970	197,248
Conventional, GH2 delivered	300	1,860,000	6,200	---	1.25	---	0.0688	186,000	---	9,417	24,180	219,597
Modular, GH2 delivered	100	1,860,000	18,600	---	1.25	---	0.0688	186,000	---	3,139	24,180	213,319
Modular, GH2 delivered	200	2,740,000	13,700	---	1.25	---	0.0688	274,000	---	6,278	35,620	315,898
Conventional, LH2 delivered	350	2,780,000	7,943	---	0.81	---	0.0688	278,000	---	7,119	30,580	315,699
Distributed Hydrogen Production and Delivery												
Conventional, Onsite SMR	100	2,740,000	27,400	0.156	3.08	4.17	0.0688	274,000	23,744	7,734	35,620	341,098
Conventional, Onsite SMR	200	3,830,000	19,150	0.156	3.08	4.17	0.0688	383,000	47,488	15,469	49,790	495,747
Conventional, Onsite SMR	300	4,430,000	14,767	0.156	3.08	4.17	0.0688	443,000	71,232	23,203	57,590	595,025
Conventional, Onsite Electrolysis	100	2,380,000	23,800	---	55.2	---	0.0688	238,000	---	138,618	30,940	407,558
Conventional, Onsite Electrolysis	200	2,980,000	14,900	---	55.2	---	0.0688	298,000	---	277,236	38,740	613,976
Conventional, Onsite Electrolysis	300	3,450,000	11,500	---	55.2	---	0.0688	345,000	---	415,855	44,850	805,705
Modular, Onsite Electrolysis	100	2,740,000	27,400	---	55.2	---	0.0688	274,000	---	138,618	35,620	448,238
Modular, Onsite Electrolysis	200	3,140,000	15,700	---	55.2	---	0.0688	314,000	---	277,236	40,820	632,056
Modular, Onsite Electrolysis	300	3,450,000	11,500	---	55.2	---	0.0688	345,000	---	415,855	44,850	805,705

Table 15. Estimated Hydrogen Production and Transport Costs

	Production Costs			Transport Costs		Total Delivered Hydrogen Cost to Station		
Hydrogen Refueling by Site Delivery Type	Central NG-SMR ($/kg)	Central Coal w/CCS ($/kg)	Central Biomass ($/kg)	Tube Trailer Delivery to Station ($/kg)	Liquid Tanker Delivery to Station ($/kg)	Total NG-SMR H2 Delivered Cost ($/kg)	Total Coal H2 Delivered Cost ($/kg)	Total Biomass H2 Cost ($/kg)
Mobile Refueler (100 kg/day)	$1.47	$1.82	$2.50	$1.50	---	$2.97	$3.32	$4.00
GH2 delivery via truck (100 kg/day)	$1.47	$1.82	$2.50	$1.50	---	$2.97	$3.32	$4.00
GH2 delivery via truck (180 kg/day)	$1.47	$1.82	$2.50	$1.50	---	$2.97	$3.32	$4.00
LH2 delivery via truck (100 kg/day)	$2.94	$3.64	$5.00	---	$0.75	$3.69	$4.39	$5.75
LH2 delivery via truck (400 kg/day)	$2.94	$3.64	$5.00	---	$0.75	$3.69	$4.39	$5.75
LH2 delivery via truck (1000 kg/day)	$2.94	$3.64	$5.00	---	$0.75	$3.69	$4.39	$5.75

Table 27. Final Estimated Dispensed Hydrogen Costs by Production and Delivery Type

		Annualized Station Cost Estimates			
Hydrogen Refueling by Site Delivery Type	Assumed Station H2 Capacity (kg/day)	Total NG-SMR Produced/ Dispensed Cost ($/kg)	Total Coal Produced/Dispensed Cost ($/kg)	Total Biomass Produced/Dispensed Cost ($/kg)	Total On-site Produced/ Dispensed Cost ($/kg)
Centralized Production Pathways					
Conventional, GH2 delivered	100	$7.73	$8.08	$8.76	---
Conventional, GH2 delivered	200	$5.67	$6.02	$6.70	---
Conventional, GH2 delivered	300	$4.98	$5.33	$6.01	---
Modular, GH2 delivered	100	$8.81	$9.16	$9.84	---
Modular, GH2 delivered	200	$7.30	$7.65	$8.33	---
Conventional, LH2 delivered	350	$6.16	$6.86	$8.22	---
Distributed Production Pathways					
Conventional, Onsite SMR	100	---	---	---	$9.35
Conventional, Onsite SMR	200	---	---	---	$6.79
Conventional, Onsite SMR	300	---	---	---	$5.43
Conventional, Onsite Electrolysis	100	---	---	---	$11.17
Conventional, Onsite Electrolysis	200	---	---	---	$8.41
Conventional, Onsite Electrolysis	300	---	---	---	$7.36
Modular, Onsite Electrolysis	100	---	---	---	$12.28
Modular, Onsite Electrolysis	200	---	---	---	$8.66
Modular, Onsite Electrolysis	300	---	---	---	$7.36

5.2 Port Fuel Cell Equipment Costs by Port Application

This section presents a cost review of diesel-fueled and hydrogen fuel cell-powered port-related equipment. The port equipment applications include nonroad materials handling equipment, switcher locomotives, marine craft, and stationary power generation equipment. The diesel-fueled and hydrogen fuel cell-powered equipment and associated operational data covered in this section are based on those previously identified in Section 3 (“Fuel Cell Applications and Characteristics for Ports”) of this report.

5.2.1 Forklift Costs

Based on the port inventory data previously presented in Section 3 of this report, the following average characteristics were assumed for a port forklift for costing purposes:

- Age range between 8–13 years old; assume 10-year useful life.
- Rated power range between 75-175 hp; assume 75 hp
- Annual utilization range between 500–2,200 hours; assume 1,500 hours
- Average load factor 0.30–0.59; assume 0.39

In order to derive representative costs for both conventional diesel and fuel cell forklifts, a recent study by NREL was referenced which evaluated fuel cell forklift equipment implemented under hundreds of federally funded demonstration projects (Ramsden, 2013). For purposes of the forklift analysis, Class V diesel forklift costs were derived based on online vendor quotes. Fuel cell forklift capital costs were estimated based on NREL report Figures but adjusted upward for the larger Class V forklifts assumed for ERG's analysis.

Both the Class V diesel and fuel cell forklifts are operated 1,500 hours annually and have ten-year lifetimes. In order to assess annual fuel costs, gaseous hydrogen fuel prices based on DOE current and long-term estimates was assumed (Satyapal, 2018). Diesel fuel pricing reflected EIA forecasted Figures for average low sulfur diesel fuel (U.S. Energy Information Administration, 2020).

The cost analysis results are provided in Table 28 for calendar years 2020 and 2030. The year 2020 capital and annual maintenance costs represent today's market costs. Year 2030 costs included applied average annual inflation (two percent per year). In addition, year 2030 fuel cell equipment costs were derived by applying DOE fuel cell system cost reduction projections for near- and long-term high-volume production to the year 2020 forklift cost estimate (Satyapal, 2018).

As shown for year 2020, the fuel cell forklift upfront cost was almost twice that of a comparable diesel-fueled version. Year 2020 annual operating costs for forklifts were almost twice those of diesel units due mainly to higher hydrogen fuel prices. In year 2030, as fuel cell technology evolves and assumed manufacturing volumes increase, capital costs were only about 25 percent higher for fuel cell forklifts. Annual operating costs in 2030 were 18 percent lower as lower hydrogen fuel prices prevail in the marketplace due to high-volume production.

Table 28. Estimated Cost Comparison of Diesel and Fuel Cell Forklifts

Diesel Forklift Cost Elements		Fuel Cell Forklift Cost Elements	
Assume 10-yr Lifetime		Assume 10-yr Lifetime	
Calendar Year 2020			
Diesel Fuel Price ($/gal)	$3.33	Hydrogen Fuel Price ($/kg)	$13.00
Total Capital Investment	$45,000	Total Capital Investment	$84,194
Total Annual Operating Costs	$11,242	Total Annual Operating Costs	$19,736
Annual Forklift Fuel Cost	$7,992	Annual Forklift Fuel Cost	$13,736
Annual Forklift Maintenance Cost	$3,250	Annual Forklift Maintenance Cost	$6,000
Calendar Year 2030			
Diesel Fuel Price ($/gal)	$3.76	Hydrogen Fuel Price ($/kg)	$5.00
Total Capital Investment	$54,855	Total Capital Investment	$71,068
Total Annual Operating Costs	$12,996	Total Annual Operating Costs	$10,768
Annual Forklift Fuel Cost	$9,034	Annual Forklift Fuel Cost	$5,283
Annual Forklift Maintenance Cost	$3,962	Annual Forklift Maintenance Cost	$5,485

5.2.2 Yard Tractor Costs

Based on the port inventory data previously presented in Section 3 of this report, the following average characteristics were assumed for a port yard tractor for costing purposes:

- Age range between 5–12 years old; assume 12-year useful life
- Rated power range between 175-200 hp; assume 175 hp
- Annual utilization range between 1,200-4,600 hours; assume 1,600 hours
- Average load factor 0.39; assume 0.39

Based on available information for both conventional diesel-fueled and fuel cell hybrid range extender yard tractors, staff estimated typical capital and operational costs for comparison. In both cases, assumptions include 12-year lifetimes and 1,600 annual hours of operation. The diesel yard tractor incorporated a diesel engine meeting federal Tier 4 emission standards, while the fuel cell platform incorporated a system similar to the pre-commercial Ballard/BAE Systems fuel cell yard tractor. The Ballard Power System couples a FCveloCity-HD 85-kW PEMFC with a BAE System's HDS200 HybriDrive series propulsion system on a Capacity TJ9000 yard tractor platform (maximum 242,000 GCWR). The system includes 31.8-kWh of lithium ion battery storage, and 20 kg of hydrogen storage at 350-bar (Green Car Congress, 2018). The yard tractor analyses also assumed the same hydrogen fuel and diesel fuel pricing as for the forklift analysis above.

Table 29 displays the cost comparison results for the yard tractor. Note that the 2020 incremental capital cost for the fuel cell yard tractor was about $115,000 compared to a conventional diesel version. Based on the assumption of the fuel cell top loader evolving to commercial, high-volume status, and using associated DOE cost projections (Satyapal, 2018), the incremental capital cost relative to diesel units reduced to about $48,000 in 2030. Annual maintenance cost with the fuel cell yard tractor was higher in 2020 based on assumed one-time lifetime replacement of the fuel cell and battery pack (compared with one engine repower with the diesel unit). More robust fuel cell platform designs and associated lower replacement costs in 2030 placed fuel cell yard truck annual maintenance cost at only slightly higher than for its diesel counterpart. While fuel cell fuel costs were much higher than for diesel in 2020, in 2030 fuel cell fuel costs were estimated to be over 40 percent lower assuming the high-volume hydrogen price of $5/kg.

Table 29. Estimated Cost Comparison of Diesel and Fuel Cell Yard Tractors

Diesel Yard Tractor Cost Elements		Fuel Cell Yard Tractor Cost Elements	
Assume 12-yr Lifetime		Assume 12-yr Lifetime	
Calendar Year 2020			
Diesel Fuel Price ($/gal)	$3.33	Hydrogen Fuel Price ($/kg)	$13.00
Total Capital Investment	$110,000	Total Capital Investment	$225,000
Total Annual Operating Costs	$22,981	Total Annual Operating Costs	$38,464
Annual Yard Tractor Fuel Cost	$19,181	Annual Yard Tractor Fuel Cost	$32,966
Annual Yard Tractor Maintenance Cost	$3,800	Annual Yard Tractor Maintenance Cost	$5,498
Calendar Year 2030			
Diesel Fuel Price ($/gal)	$3.76	Hydrogen Fuel Price ($/kg)	$5.00
Total Capital Investment	$134,089	Total Capital Investment	$182,704
Total Annual Operating Costs	$26,314	Total Annual Operating Costs	$17,799
Annual Yard Tractor Fuel Cost	$21,681	Annual Yard Tractor Fuel Cost	$12,679
Annual Yard Tractor Maintenance Cost	$4,632	Annual Yard Tractor Maintenance Cost	$5,120

As noted above, the fuel cell yard tractor capital cost in Table 29 is based on the pre-commercial Ballard/BAE Systems/Capacity system which incorporated 20 kg of onboard hydrogen storage at 350-bar pressure. Higher energy density storage systems like 700-bar pressure tanks or cryogenic liquid hydrogen tanks could also be incorporated in this platform in the future to increase onboard storage volumes or reduce storage system weight/volume footprints for the original hydrogen storage mass (20 kg). To assess the cost impacts of these alternative hydrogen storage systems, low production volume storage system costs were first estimated based on recent hydrogen storage cost research (Rivard, 219) (Law, 2011) and then applied to the fuel cell yard tractor application. The analysis indicated that the use of 700-bar pressure tanks for the same 20 kg of hydrogen storage would increase the cost of the fuel cell yard tractor by about $4,469 over the use of the original 350-bar pressure tanks. If liquid hydrogen tanks were utilized, it was estimated that the fuel cell yard tractor cost would decrease by about $5,276 compared with the original 350-bar pressure tanks.

5.2.3 Cargo Handlers (Top Loaders) Costs

A top loader was assumed to represent port cargo handler equipment. Based on the port equipment inventory data discussed previously in Section 3 of this report, the following average characteristics were assumed for a port top loader for costing purposes:

- Age range between 6–12 years old; assume 12-year useful life
- Rated power range between 300–375 hp; assume 350 hp
- Annual utilization range between 1,400–2,300 hours; assume 2,000 hours
- Load factor range of 0.43–0.59; assume average of 0.59

Based on available information for both conventional diesel-fueled and fuel cell hybrid range extender yard trucks, staff derived typical capital and operational costs. In both cases, assumptions included 12-year lifetimes and 2,000 annual hours of operation. The diesel top loader incorporated a federal Tier 4 compliant engine. The pre-commercial Hyster/Nuvera fuel cell platform, which incorporates a 90-kW Nuvera PEMFC range extender with 20 kg hydrogen storage (350 bar) and 200-kWh lithium ion battery pack (Nuvera, 2019), was the basis for the fuel cell top loader. The analysis assumed similar hydrogen and diesel fuel prices as for forklifts and yard tractors.

Table 30 provides an estimated cost comparison between the diesel and fuel cell hybrid top loader. The 2020 incremental capital cost for the fuel cell top loader (about $142,000) reflected its current pre-commercial status. Using DOE cost projections, the 2030 incremental cost estimate reduced to about $77,000. Estimated 2020 annual maintenance costs for the fuel cell top loader were higher due to assumed one-time fuel cell and battery pack replacement compared with one diesel engine repower over the 12-year lifetime. As with yard trucks, 2030 annual maintenance costs improved relative to diesel units due to lower associated fuel cell and battery replacement costs. While 2020 fuel costs for the fuel cell top loader were significantly higher than for diesel, the assumed high-volume hydrogen pricing in 2030 reduced fuel cell fuel costs to 42 percent lower compared with diesel.

Table 30. Estimated Cost Comparison of Diesel and Fuel Cell Cargo Handlers

Diesel Cargo Handler (Top Loader) Cost Elements		Fuel Cell Cargo Handler (Top Loader) Cost Elements	
Assume 12-yr Lifetime		Assume 12-yr Lifetime	
Calendar Year 2020			
Diesel Fuel Price ($/gal)	$3.33	Hydrogen Fuel Price ($/kg)	$13.00
Total Capital Investment	$584,500	Total Capital Investment	$727,078
Total Annual Operating Costs	$77,717	Total Annual Operating Costs	$131,534
Annual Top Loader Fuel Cost	$72,594	Annual Top Loader Fuel Cost	$124,767
Annual Top Loader Maintenance Cost	$5,123	Annual Top Loader Maintenance Cost	$6,767
Calendar Year 2030			
Diesel Fuel Price ($/gal)	$3.76	Hydrogen Fuel Price ($/kg)	$5.00
Total Capital Investment	$712,502	Total Capital Investment	$789,997
Total Annual Operating Costs	$88,302	Total Annual Operating Costs	$54,498
Annual Top Loader Fuel Cost	$82,058	Annual Top Loader Fuel Cost	$47,987
Annual Top Loader Maintenance Cost	$6,244	Annual Top Loader Maintenance Cost	$6,511

As noted, the pre-commercial Hyster/Nuvera fuel cell top loader design is the basis of the capital cost shown in Table 30. The Hyster/Nuvera system utilized an onboard hydrogen storage system comprising 20 kg at 350-bar pressure. The cost impacts of using 700-bar pressure and liquid hydrogen storage systems were also estimated. Low production volume storage system costs were first estimated based on recent hydrogen storage cost research (Rivard, 219) (Law, 2011) and then applied to the top loader application. The use of 700-bar pressure tanks would increase the cost of the fuel cell top loader by about $4,469 compared to the original 350-bar pressure tanks for the same 20 kg hydrogen storage. For liquid hydrogen tanks, results indicated a decrease of $5,276 compared to the original 350-bar pressure tanks for the same 20 kg hydrogen storage.

5.2.4 Switcher Locomotive Costs

For analysis purposes, the pre-commercial BNSF 1205 fuel cell switcher locomotive formed the basis for cost comparisons of a fuel cell and a conventional diesel switcher locomotive. BNSF Railway developed the BNSF 1205 fuel cell switcher in 2009 retrofitted from an original diesel EMD GP9 switcher locomotive. The BNSF 1205 had a 500-kW PEMFC and 1-MW battery pack (California Air Resources Board, 2016). Back in 2010, CARB estimated that the BNSF 1205 prototype cost about $3.5 million to develop. A comparable Tier 4 diesel switcher locomotive (about 2,000 hp) was estimated to cost around $1.1 million. In order to develop a more contemporary (that is, present day) cost for a fuel cell hybrid switcher, adjustments to the 2009 costs were made to account for cost reductions in both lithium ion batteries and PEMFCs (Howell) (Wilson, 2017). Adjustments were also made assuming market-based production volumes and U.S. Bureau of Labor Statistics rail industry producer price indices. Staff also assumed a 20-year useful life for both switchers, assuming each locomotive was used in line haul service for 20 years prior to being transferred to switcher service.

Table 31 lists the results for the cost comparison of the fuel cell hybrid switcher locomotive and a Tier 4 diesel multi-genset locomotive. An average diesel fuel cost of $2.07/gallon was assumed for 2020 based on 2019 Class I railroad financial reports filed with the Surface Transportation Board (STB) (Surface Transportation Board, 2019). A diesel fuel cost of $2.34/gallon was assumed for 2030 based on EIA forecasting for low sulfur diesel fuel (U.S. Energy Information Administration, 2020). Gaseous hydrogen fuel costs were assumed similar to those for forklifts, yard tractors, and top loaders. Note that the estimated incremental capital cost of the pre-commercial fuel cell switcher in 2020 was about $1.9 million. Average diesel switcher annual maintenance was assumed based on STB Class I railroad financial reports filed in 2019 (Surface Transportation Board, 2019). Due to fuel cell and battery replacement costs approximately halfway (assuming 10-year lifetimes for the original fuel cell stack and battery pack) through its 20-year lifetime, annual maintenance costs were higher than those of the diesel switcher which included one engine repower over its lifetime. While fuel cell switcher annual operating costs in 2020 were over twice those of the diesel switcher, fuel cell annual operating costs were only about 16 percent higher in 2030.

Table 16. Estimated Cost Comparison of Diesel and Fuel Cell Switcher Locomotive

Diesel Switcher Cost Elements		**Fuel Cell Switcher Cost Elements**	
Assume 20-yr Lifetime		Assume 20-yr Lifetime	
Calendar Year 2020			
Diesel Fuel Price ($/gal)	$2.07	Hydrogen Fuel Price ($/kg)	$13.00
Total Capital Investment	$1,544,000	Total Capital Investment	$3,466,543
Total Annual Operating Costs	$188,439	Total Annual Operating Costs	$504,700
Annual Switcher Fuel Cost	$98,739	Annual Switcher Fuel Cost	$390,000
Annual Switcher Maintenance Cost	$89,700	Annual Switcher Maintenance Cost	$114,700
Calendar Year 2030			
Diesel Fuel Price ($/gal)	$2.34	Hydrogen Fuel Price ($/kg)	$5.00
Total Capital Investment	$1,882,127	Total Capital Investment	$3,804,663
Total Annual Operating Costs	$220,955	Total Annual Operating Costs	$274,120
Annual Switcher Fuel Cost	$111,612	Annual Switcher Fuel Cost	$150,000
Annual Switcher Maintenance Cost	$109,344	Annual Switcher Maintenance Cost	$124,120

The fuel cell switcher locomotive capital cost of Table 31 assumed 70 kg hydrogen storage at 350-bar pressure. Both 700-bar pressure storage as well as liquid hydrogen storage are viable alternatives for the switcher application. Based on recent hydrogen storage cost research results (Rivard, 219) (Law, 2011), a higher incremental capital cost of $16,271 was estimated for using a 700-bar pressure storage system over the original 350-bar pressure system for the same 20 kg of hydrogen storage. In the case of liquid hydrogen storage, a lower incremental capital cost of $18,465 was estimated relative to the original 350-bar pressure system for the same 20 kg.

5.2.5 Marine Propulsion and Auxiliary Power System Costs

Limited information was available in the literature regarding fuel cell vessel and harbor craft capital costs. However, a SNL 2016 report detailing the costs for a high-speed, fuel cell-powered passenger ferry concept vessel (Pratt & Klebanoff, Feasibility of the SF-BREEZE: A Zero-Emission, Hydrogen Fuel Cell, High-Speed

Passenger Ferry, 2016) versus a comparable diesel vessel was used. Under funding by the U.S. Maritime Administration, SNL conducted a feasibility and design study of the vessel, called the SF-BREEZE concept. The ferry as specified would be capable of carrying 150 passengers and travel two 50-mile roundtrips at a top speed of 35 knots before needing refueling. The vessel would incorporate 41 120-kW PEM fuel cell racks and 1,200 kg (4,500 gallons) of liquid hydrogen.

Based on selected SNL report cost Figures for the SF BREEZE, comparative costs were derived for a fuel cell and comparable diesel propulsion ferry boat. The cost results are presented in Table 32. A 20-year lifetime was assumed for both applications. Both vessels included a 120-kW auxiliary load supported by a single fuel cell on the fuel cell vessel and by an auxiliary engine in the diesel vessel. Note that the analysis assumed liquid hydrogen fuel prices which typically incurs higher costs due to liquefaction processes. The difference between gaseous hydrogen and liquid hydrogen fuel prices was about 28 percent based on the previous hydrogen station analysis results of this section; however, since a larger fuel dispensing system was needed for the ferry application (about 1,500 kg/day), lower associated fueling station costs were assumed, resulting in liquid hydrogen fuel prices of $11.69/kg and $4.40/kg for 2020 and 2030, respectively (Connelly, 2019).

The total capital cost of the fuel cell vessel was about 50 percent higher than that of the diesel vessel in 2020 due in part to the fuel cell power plants and onboard liquid hydrogen storage tanks. Assumed improvements for fuel cell and vessel designs reduced the incremental cost to about 8 percent higher in 2030. In 2020, the fuel cell vessel’s annual operating costs were about four times that of its diesel counterpart. The fuel cell vessel’s 2020 annual operating cost included the requirement for three fuel cell powerplant replacements during the 20-year life. The 2020 fuel energy requirement for the fuel cell boat was also about 28 percent higher than that of the diesel boat due to higher weight from hydrogen storage system and a slightly less efficient hull design. Based on assumed improved fuel cell platform and vessel design to achieve weight parity with comparable diesel vessels, resulting in reduced fuel costs, fuel cell operating costs were about 45 percent higher than diesel.

Table 17. Cost Comparison of Diesel and Fuel Cell Ferry Boat

Diesel Ferry Cost Elements		Fuel Cell Ferry Cost Elements	
Assume 20-yr Lifetime		Assume 20-yr Lifetime	
Calendar Year 2020			
Diesel Fuel Price ($/gal)	$3.33	Hydrogen (Liquid) Fuel Price ($/kg)	$11.64
Total Capital Investment	$11,600,000	Total Capital Investment	$17,166,000
Total Annual Operating Costs	$1,713,086	Total Annual Operating Costs	$6,751,790
Annual Ferry Fuel Cost	$1,313,086	Annual Ferry Fuel Cost	$5,751,790
Annual Ferry Maintenance Cost	$400,000	Annual Ferry Maintenance Cost	$1,000,000
Calendar Year 2030			
Diesel Fuel Price ($/gal)	$3.76	Hydrogen (Liquid) Fuel Price ($/kg)	$4.40
Total Capital Investment	$14,140,335	Total Capital Investment	$15,258,100
Total Annual Operating Costs	$1,971,870	Total Annual Operating Costs	$2,858,896
Annual Ferry Fuel Cost	$1,484,272	Annual Ferry Fuel Cost	$1,927,787
Annual Ferry Maintenance Cost	$487,598	Annual Ferry Maintenance Cost	$931,110

5.2.6 Stationary Power Generator Costs

For purposes of determining a detailed cost comparison of diesel-fueled and fuel cell-powered stationary power generators, staff referenced elements of an SNL study of a containerized fuel cell generator (Pratt & Chan, Maritime Fuel Cell Generator Project, 2017). The fuel cell generator design provided primary power to up to ten refrigerated containers. The Hydrogenics fuel cell generator incorporated a 100-kW PEMFC rack with 72 kg of hydrogen at 350 bar and had a rated power of 100-kW, 240 VAC 3-phase. The analysis assumed a ten-year lifetime for the fuel cell generator and one required fuel cell replacement over its lifetime. It was also assumed that the diesel generator would require one engine rebuild over its ten-year lifetime.

The results of the cost comparison are shown in Table 33 for 3,000 hours per year of operation. The cost for the diesel genset represents a unit with a Tier 4 diesel engine. As shown in year 2020, the capital cost of the low volume production fuel cell generator was several times higher than that of the diesel generator. With assumed higher manufacturing volumes, the 2030 capital cost of the fuel cell generator was about 50 percent more than the cost of the diesel generator. Annual operating costs for the fuel cell generator in 2020 were about twice those of the diesel generator due primarily to higher fuel costs. However, 2030 fuel cell generator operating costs were about 28 percent lower resulting from much lower fuel prices and assumed annual maintenance costs.

Table 33. Estimated Cost Comparison of Diesel and Fuel Cell Power Generator

Diesel Generator (100 kW) Cost Elements		**Fuel Cell Generator (100 kW) Cost Elements**	
Assumed 10-yr Lifetine		Assumed 10-yr Lifetine	
Calendar Year 2020			
Diesel Fuel Price ($/gal)	$3.33	Hydrogen Fuel Price ($/kg)	$13.00
Total Capital Investment	$100,000	Total Capital Investment	$312,000
Total Annual Operating Costs	$31,553	Total Annual Operating Costs	$64,528
Annual Generator Fuel Cost	$26,453	Annual Generator Fuel Cost	$56,365
Annual Generator Maintenance Cost	$5,100	Annual Generator Maintenance Cost	$8,163
Calendar Year 2030			
Diesel Fuel Price ($/gal)	$3.76	Hydrogen Fuel Price ($/kg)	$5.00
Total Capital Investment	$121,899	Total Capital Investment	$174,124
Total Annual Operating Costs	$36,118	Total Annual Operating Costs	$29,279
Annual Generator Fuel Cost	$29,901	Annual Generator Fuel Cost	$21,679
Annual Generator Maintenance Cost	$6,217	Annual Generator Maintenance Cost	$7,601

5.3 Port Fuel Cell Equipment Annual Savings and Capital Cost Recovery

Based on the port fuel cell equipment cost analysis results above, the lifecycle savings for fuel cell equipment relative to comparable diesel fuel equipment was estimated. In addition, simple capital payback estimates based on capital cost investments and annual savings were derived. This analysis only quantified results for 2020 and 2030 cost assumptions. Results for both are discussed below.

5.3.1 Lifecycle Savings and Payback

Table 34 lists the incremental cost results for each port equipment type along with assumptions regarding average lifetime, annual utilization, and fuel prices. As indicated, none of the fuel cell equipment provided annual operational savings in 2020 relative to their diesel counterparts, shown as negative savings in the Table. This is due primarily from a high hydrogen fuel price in 2020 based on low-volume hydrogen production and truck delivery.

Table 34. Estimated Port Fuel Cell Equipment Payback by Calendar Year

Comparative Cost Parameter	Forklift	Yard	Cargo	Switcher	Ferry Boat	Generator
Assumed Useful Lifetime	10	12	12	20	20	10
Assumed Utilization (Hr/yr)	1,500	1,600	2,000	1,500	2,800	3,000
Year 2020						
Assumed Hydrogen Price ($/kg)	13.00	13.00	13.00	13.00	11.64	13.00
Assumed Diesel Price ($/gal)	3.33	3.33	3.33	2.07	3.33	3.33
Incremental Capital Cost ($)	39,194	115,000	142,578	1,922,543	5,566,000	212,000
Annual Operating Savings ($)	-8,494	-15,484	-53,817	-316,261	-5,038,704	-32,975
Estimated Simple Payback (Yrs)	None	None	None	None	None	None
Year 2030						
Assumed Hydrogen Price ($/kg)	5.00	5.00	5.00	5.00	4.40	5.00
Assumed Diesel Price ($/gal)	3.76	3.76	3.76	2.34	3.76	3.76
Incremental Capital Cost ($)	16,214	48,614	77,494	1,922,536	1,117,764	52,225
Annual Operating Savings ($)	2,227	8,515	33,804	-53,165	-887,027	6,839
Estimated Simple Payback (Yrs)	7.3	5.7	2.3	None	None	7.6

In 2030, a much lower hydrogen fuel price resulting from higher-volume production begins to support the fuel cell market. As a result, forklift, yard tractor, cargo handler (top Loader), and generator applications provided payback potential within the assumed lifetimes of the equipment. Of course, these payback results reflect the specific assumptions made for this equipment for purposes of this analysis. Higher equipment annual utilization, higher load factors, or a larger differential fuel price between hydrogen and diesel fuel, would improve the payback potential of the fuel cell equipment. For example, if a fuel cell yard tractor is operated for 4,600 hours versus the originally assumed 1,600 hours annually, simple payback duration as shown in Table 34 decreases from the 5.7 years to 1.9 years. Similarly, if the hydrogen fuel price in 2030 was $4/kg rather than the originally assumed $5/kg, the fuel cell yard tractor payback is reduced to 4.4 years. Thus, port equipment with higher annual utilization will exhibit faster capital payback than similar equipment with low annual utilization. Further, as hydrogen fuel price decreases in the future due to production volume increases and fuel delivery technology improvements, equipment payback potential relative to diesel fuel equipment will increase commensurately and this estimate done for 2040 or 2050 would yield different results.

6. Hydrogen Fuel Cell Lifecycle Emissions

This section outlines one basic framework for estimating fuel cell equipment lifecycle emissions for port applications. The framework can be used to identify hydrogen fuel-to-end use and fuel cell-to-end use pathways associated with fuel cell equipment in port applications for subsequent lifecycle emissions quantification relative to comparable diesel-fueled equipment.

6.1 Hydrogen Fuel Cycle and Fuel Cell Equipment Cycle

The proposed framework for fuel cell lifecycle emissions assessment relies on the total energy analysis methodology employed by ANL and other lifecycle assessment researchers. Total energy analysis for vehicle/equipment fuel usage encompasses energy use and emissions associated with the *Fuel Cycle* and the *Vehicle/Equipment Cycle* (Wang, 2012). The Fuel Cycle encompasses all energy- and emissions-related processes and activities of fuel feedstock extraction, fuel production, fuel product transport, distribution, and dispensing, and fuel usage by end use vehicles and equipment. The Vehicle/Equipment Cycle includes the energy- and emissions-related processes and activities of raw material extraction and transport, component production and assembly, vehicle and equipment transport to end use, and vehicle/equipment post-life disposal and/or recycling.

Using total energy analysis guidance, these same lifecycle elements can be organized for characterizing a Hydrogen Fuel Cycle and a Fuel Cell Equipment Cycle, as depicted in Figure 16. The Hydrogen Fuel Cycle in the Figure (shown in red) captures energy and emission expenditures for necessary feedstock exploration and extraction, hydrogen fuel production, hydrogen fuel product storage, transport, and dispensing, and onsite hydrogen fuel usage in fuel cell vehicles or equipment. The Fuel Cell Equipment Cycle (shown in blue) includes raw material recovery, processing, and fabrication, fuel cell equipment component production and assembly, and fuel cell equipment transport to end use, and post-life disposal or recycling. Note that while onsite equipment utilization is a component of both the Fuel Cycle and Equipment Cycle (resulting in a purple designation in the Figure), its energy and associated emissions contributions are typically attributed to the Fuel Cycle. As such, the Fuel Cycle is often labeled as the “Well-to-Wheels” (WTW) contribution of overall pathway scenario. With these generalized cycles defined, unique cycles for describing the likely near- and mid-term options for hydrogen production, hydrogen product transport, and fuel cell use at ports were derived.

6.2 Hydrogen Fuel Cycle Pathways

As previously discussed, two hydrogen pathways from production to end use delivery have evolved: *Centralized Hydrogen Production* and *Distributed Hydrogen Production*. In the case of centralized production, pure hydrogen is produced in large scale plants (50,000 to 500,000 kg/day) for serving regional or even national end use markets (DOE Fuel Cell Technologies Office, 2019). Hydrogen product from centralized plants is stored and then transported to end use sites. For distributed production, hydrogen fuel carriers such as natural gas are produced and transported using existing infrastructure to end use sites where hydrogen is then produced in small volumes (< 1,500 kg/day) on site and used by fuel cell equipment.

For purposes of this analysis, the hydrogen fuel cycle pathways involving centralized and distributed hydrogen production pathways were considered separately.

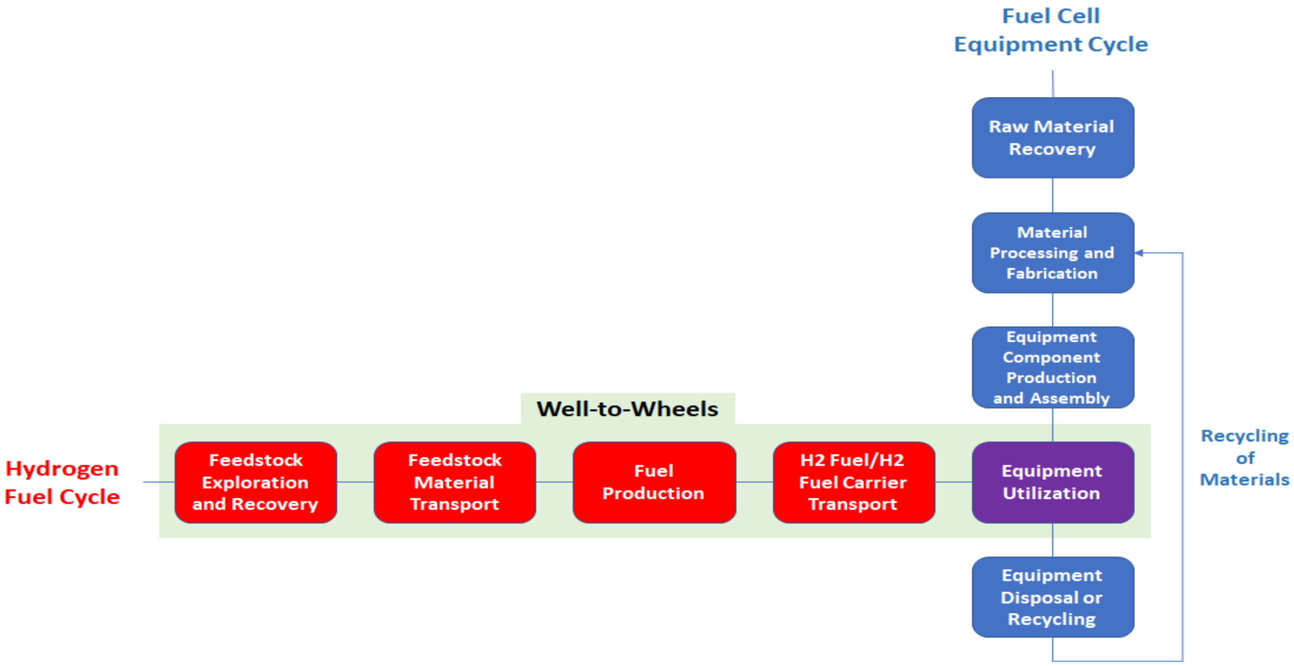
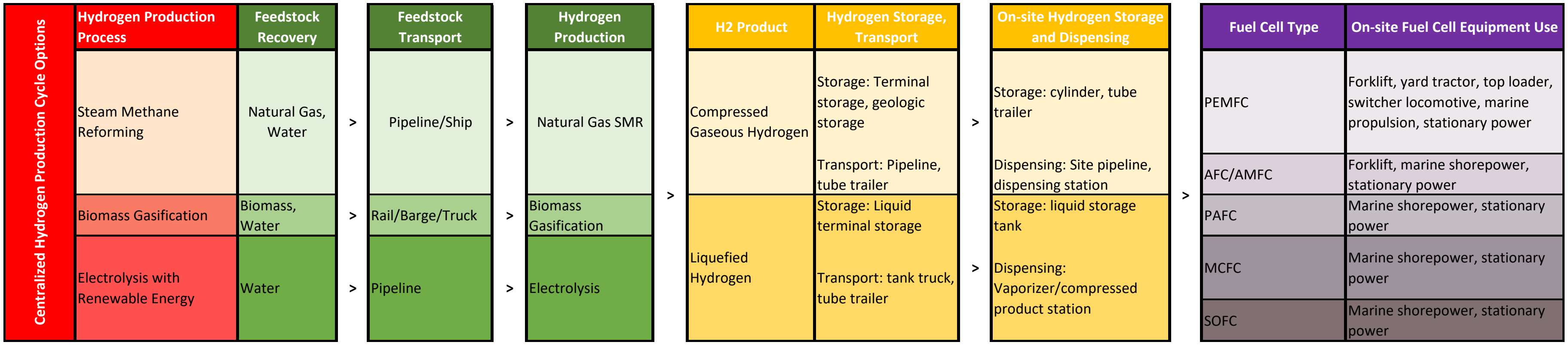


Figure 7. General Hydrogen Fuel Cycle and Fuel Cell Equipment Cycle Pathways

6.2.1 Centralized Hydrogen Production Scenarios

Figure 17 shows three potential hydrogen fuel cycle pathways for centralized hydrogen production scenarios (highlighted in red). These include Natural Gas SMR, Biomass Gasification, and Electrolysis Using Renewable Energy. Each of the three centralized production pathways have different fuel feedstock extraction, feedstock transport, and hydrogen production processes (as highlighted in green). These centralized hydrogen production pathways can support both high-pressure and liquefied hydrogen product transport and delivery (as shown in yellow in the Figure). Following centralized plant production, the hydrogen gas product is pressurized and transported either via long distance pipeline or sent to near-by terminal storage for eventual transport to market. In the case of liquefied hydrogen product transport, plant production feeds gaseous hydrogen to a liquefaction plant (typically via pipeline) where it is cooled under pressure to produce liquid hydrogen product. Liquefied hydrogen is then transferred via cryogenic pump to insulated tanker trucks for delivery.

Due to the higher energy intensity of hydrogen delivery via pressurized tube trailers, hydrogen transport and delivery via truck is generally relegated to 150 miles or less. Liquefied tank trailer transport is typically used for delivery distances up to 1,000 miles. Although not as common, liquid hydrogen can also be transported long distances via rail car, ship, and barge. In a recent study on hydrogen transport mode and distance impacts on greenhouse gas emissions, NREL found that gaseous hydrogen transport by truck produces lower WTW greenhouse gas emissions than liquified hydrogen truck transport at distances less than 400 miles for hydrogen produced via natural gas SMR (Melaina M. , 2017). The liquid hydrogen pathway requires the highest electricity use, and thus is very sensitive to regional electricity generation mix. The NREL results represented an average U.S. grid mix, but in U.S. locations with higher renewable energy-produced electricity, liquid product truck transport may have lower WTW greenhouse emissions than gaseous product truck transport. At a transport distance of 100 miles, both gaseous and liquified hydrogen truck transport produce substantially lower GHG emissions and water usage than pipeline transport for hydrogen production from natural gas SMR.



Centralized Hydrogen Production Cycle Options	Hydrogen Production Process	Feedstock Recovery		Feedstock Transport		Hydrogen Production		H2 Product	Hydrogen Storage, Transport		On-site Hydrogen Storage and Dispensing		Fuel Cell Type	On-site Fuel Cell Equipment Use
	Steam Methane Reforming	Natural Gas, Water	>	Pipeline/Ship	>	Natural Gas SMR	>	Compressed Gaseous Hydrogen	Storage: Terminal storage, geologic storage Transport: Pipeline, tube trailer	>	Storage: cylinder, tube trailer Dispensing: Site pipeline, dispensing station	>	PEMFC	Forklift, yard tractor, top loader, switcher locomotive, marine propulsion, stationary power
													AFC/AMFC	Forklift, marine shorepower, stationary power
	Biomass Gasification	Biomass, Water	>	Rail/Barge/Truck	>	Biomass Gasification		Liquefied Hydrogen	Storage: Liquid terminal storage Transport: tank truck, tube trailer	>	Storage: liquid storage tank Dispensing: Vaporizer/compressed product station		PAFC	Marine shorepower, stationary power
	Electrolysis with Renewable Energy	Water	>	Pipeline	>	Electrolysis							MCFC	Marine shorepower, stationary power
													SOFC	Marine shorepower, stationary power

Figure 8. Centralized Hydrogen Fuel Cycle Pathways

Hydrogen from centralized hydrogen production can then be delivered and stored on site as pressurized gaseous product or as liquefied product (as shown in yellow in Figure 17). Pressurized hydrogen is delivered to the site via tube trailer or distribution pipeline where it is transferred to onsite storage cylinders for serving fuel cell equipment. For stationary fuel cell applications, the onsite storage cylinders are typically at sufficient pressure to directly supply the equipment. In the case of mobile fuel cell equipment, hydrogen gas is further compressed to increase the stored hydrogen energy density onboard the vehicle application.

For liquefied hydrogen, the liquid product that is delivered to the site is pumped into onsite vacuum-insulated tanks for storage until ready for delivery to onsite fuel cell equipment. Liquid hydrogen can also be delivered in vacuum-insulated tanks on trailers or skids which can then connected to the fuel delivery system and replaced when empty.

As noted previously in the report, potential port fuel cell equipment applications include both mobile and stationary applications. Table 35 lists the assumed near- to mid-term port-related fuel cell equipment for centralized hydrogen production scenarios based on manufacturer research efforts and actual commercial developments to date. For those equipment applications that are still in the pre-commercial stage of development, the fuel cell type allocations are assumed to be the most likely candidates in the future once commercialized. Note that PEMFCs are the predominant fuel cell type for the equipment applications listed.

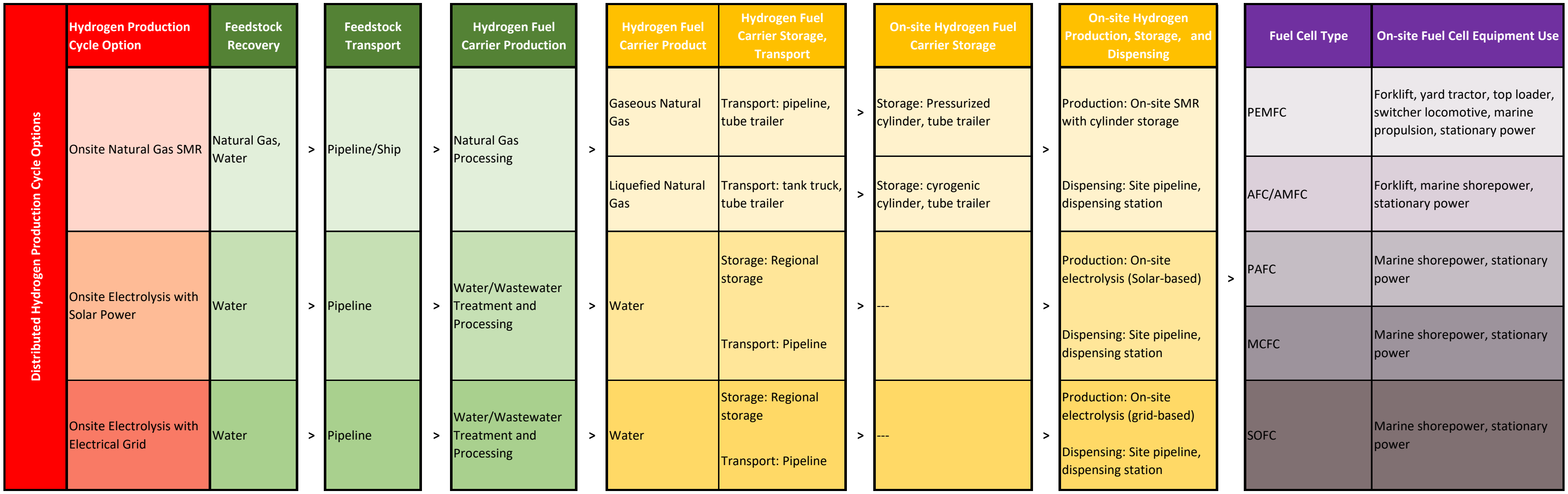
Table 18. Assumed Near- and Mid-Term Port Fuel Cell Equipment Applications

Typical Port Equipment Type	Hydrogen Dispenser Delivery	Assumed Fuel Cell Type by Application				
		PEMFC	AFC/ AMFC	PAFC	MCFC	SOFC
Forklift	Yes	✓				
Yard Tractor	Yes	✓				
Top Loader	Yes	✓				
Switcher Locomotive	Yes	✓				
Marine Propulsion and Auxiliary Power	Yes	✓				
Marine Shore Power	No - hydrogen gas direct line fed			✓	✓	✓
Stationary Power	No - hydrogen gas direct line fed	✓	✓	✓	✓	✓

6.2.2 Distributed Hydrogen Production Scenarios

Figure 18 illustrates three potential hydrogen fuel cycle pathways for distributed hydrogen production scenarios (highlighted in red). These include Onsite SMR, Onsite Electrolysis Using Solar Power, and Onsite Electrolysis Using Electric Grid.

As provided in Figure 18, the distributed production pathways have a variety of fuel feedstock extraction, feedstock transport, and hydrogen production processes (as highlighted in green). The expansive natural gas pipeline system across the U.S. supports the use of natural gas as a viable hydrogen carrier source for distributed hydrogen production. Small-scale SMR plants are commercially available for providing onsite hydrogen production. These systems are less efficient and more costly to operate per unit volume of hydrogen production than large-scale SMR plants, but they have been used to directly support fuel cell power systems and hydrogen refueling stations. Today’s commercially available electrolyzers utilize polymer electrolyte membrane and alkaline electrolytes. Although electric grid power is most common for small-scale



	Hydrogen Production Cycle Option	Feedstock Recovery		Feedstock Transport		Hydrogen Fuel Carrier Production		Hydrogen Fuel Carrier Product	Hydrogen Fuel Carrier Storage, Transport		On-site Hydrogen Fuel Carrier Storage		On-site Hydrogen Production, Storage, and Dispensing		Fuel Cell Type	On-site Fuel Cell Equipment Use
Distributed Hydrogen Production Cycle Options	Onsite Natural Gas SMR	Natural Gas, Water	>	Pipeline/Ship	>	Natural Gas Processing	>	Gaseous Natural Gas	Transport: pipeline, tube trailer	>	Storage: Pressurized cylinder, tube trailer	>	Production: On-site SMR with cylinder storage		PEMFC	Forklift, yard tractor, top loader, switcher locomotive, marine propulsion, stationary power
								Liquefied Natural Gas	Transport: tank truck, tube trailer	>	Storage: cyrogenic cylinder, tube trailer		Dispensing: Site pipeline, dispensing station		AFC/AMFC	Forklift, marine shorepower, stationary power
	Onsite Electrolysis with Solar Power	Water	>	Pipeline	>	Water/Wastewater Treatment and Processing	>	Water	Storage: Regional storage	>	---	>	Production: On-site electrolysis (Solar-based)	>	PAFC	Marine shorepower, stationary power
									Transport: Pipeline				Dispensing: Site pipeline, dispensing station		MCFC	Marine shorepower, stationary power
	Onsite Electrolysis with Electrical Grid	Water	>	Pipeline	>	Water/Wastewater Treatment and Processing	>	Water	Storage: Regional storage Transport: Pipeline	>	---	>	Production: On-site electrolysis (grid-based) Dispensing: Site pipeline, dispensing station		SOFC	Marine shorepower, stationary power

Figure 9. Distributed Hydrogen Fuel Cycle Pathways

electrolyzers, research is being conducted on wind or solar power to improve small-scale economics and lifecycle emissions.

The assumed near- to mid-term port-related fuel cell equipment of Table 35 above also apply for distributed hydrogen production scenarios. Mobile equipment will be fueled using a high-pressure hydrogen dispensing system fed by the onsite production plant and/or onsite storage. Depending on the fuel cell type, marine shore power and stationary power systems will be fueled directly by a hydrogen line from onsite production or storage.

6.3 Fuel Cell Equipment Cycle Pathways

The assumed Fuel Cell Equipment Cycle pathways for purposes of this analysis are presented in Figure 19. As listed in the Figure, the fuel cell equipment cycle pathways (shown in blue) related to ports are many. They represent the matrix of individual port equipment applications and fuel cell types assumed for this analysis, as well as their associated development pathways from material recovery, to assembly, to use at the ports, and finally disposal and recycling. Further discussion of these pathways follows below.

6.3.1 Raw Material Recovery and Processing

The primary differences in the individual fuel cell equipment pathways are associated with variances in fuel cell materials and processing (shown in Figure 19 in green), fuel cell type component production and assembly (shown in orange), and the material compositions and assembly for port equipment applications (shown in orange). Each fuel cell type/application combination has unique material composition and processing requirements, which is the reason separate pathways are shown for these combinations. Once identified, the energy use and emissions associated with the recovery and processing of individual materials must be assessed and compiled for each specific fuel cell/equipment combination.

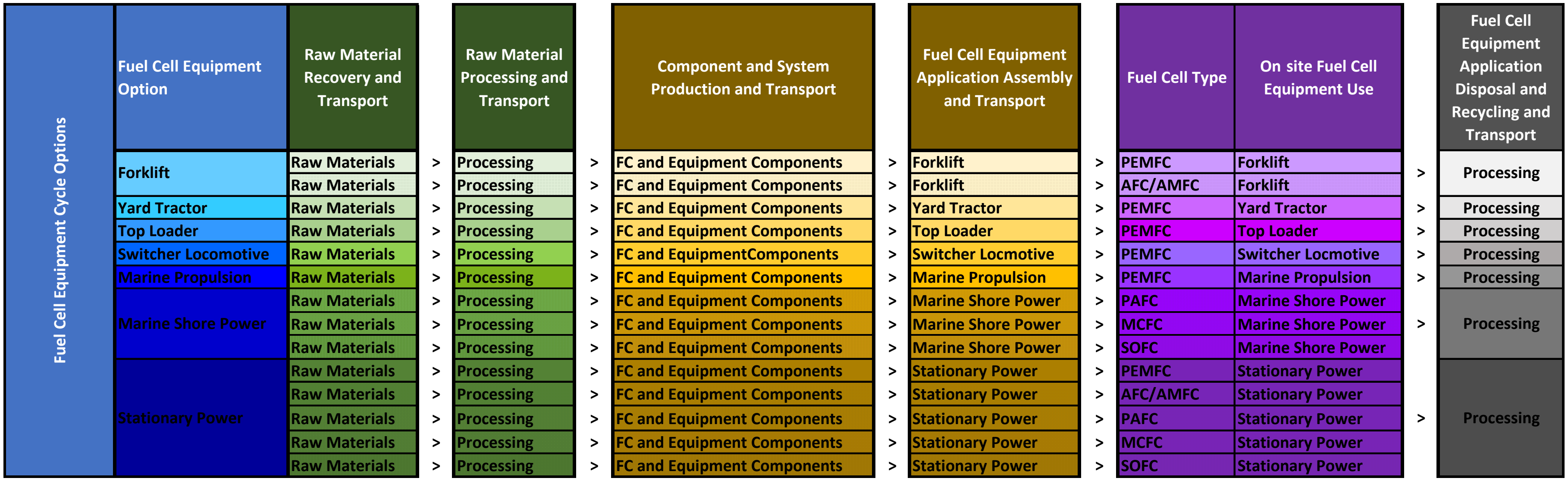
Materials can be characterized according to fuel cell functionality which include electrode/membrane assembly, current flow hardware, catalysts, and ancillary systems for storing and/or supplying and controlling fuel, air, cooling, and water to the fuel cell assembly. In many cases, fuel cell materials are not domestically produced and must be sourced internationally, increasing energy use and emissions. This is especially evident for specialized catalyst materials which are often mined and processed outside the U.S. Depending on material origins, transport methods may include ship, rail, and/or truck.

6.3.2 Equipment Component Production and System Assembly

Fuel cell systems vary depending on fuel cell type, but have the following basic components in common:

- Fuel Cell Stack
- Fuel Processor
- Power Conditioners
- Air Compressors
- Humidifiers

Similar to material supplies, many fuel cell components and full system assemblies are sourced internationally and then shipped to the final equipment assembly point.



Fuel Cell Equipment Cycle Options	Fuel Cell Equipment Option	Raw Material Recovery and Transport		Raw Material Processing and Transport		Component and System Production and Transport		Fuel Cell Equipment Application Assembly and Transport		Fuel Cell Type	On site Fuel Cell Equipment Use		Fuel Cell Equipment Application Disposal and Recycling and Transport
Fuel Cell Equipment Cycle Options	Forklift	Raw Materials	>	Processing	>	FC and Equipment Components	>	Forklift	>	PEMFC	Forklift	>	Processing
		Raw Materials	>	Processing	>	FC and Equipment Components	>	Forklift	>	AFC/AMFC	Forklift		
	Yard Tractor	Raw Materials	>	Processing	>	FC and Equipment Components	>	Yard Tractor	>	PEMFC	Yard Tractor	>	Processing
	Top Loader	Raw Materials	>	Processing	>	FC and Equipment Components	>	Top Loader	>	PEMFC	Top Loader	>	Processing
	Switcher Locomotive	Raw Materials	>	Processing	>	FC and EquipmentComponents	>	Switcher Locmotive	>	PEMFC	Switcher Locmotive	>	Processing
	Marine Propulsion	Raw Materials	>	Processing	>	FC and Equipment Components	>	Marine Propulsion	>	PEMFC	Marine Propulsion	>	Processing
	Marine Shore Power	Raw Materials	>	Processing	>	FC and Equipment Components	>	Marine Shore Power	>	PAFC	Marine Shore Power	>	Processing
		Raw Materials	>	Processing	>	FC and Equipment Components	>	Marine Shore Power	>	MCFC	Marine Shore Power		
		Raw Materials	>	Processing	>	FC and Equipment Components	>	Marine Shore Power	>	SOFC	Marine Shore Power		
	Stationary Power	Raw Materials	>	Processing	>	FC and Equipment Components	>	Stationary Power	>	PEMFC	Stationary Power	>	Processing
		Raw Materials	>	Processing	>	FC and Equipment Components	>	Stationary Power	>	AFC/AMFC	Stationary Power		
		Raw Materials	>	Processing	>	FC and Equipment Components	>	Stationary Power	>	PAFC	Stationary Power		
		Raw Materials	>	Processing	>	FC and Equipment Components	>	Stationary Power	>	MCFC	Stationary Power		
		Raw Materials	>	Processing	>	FC and Equipment Components	>	Stationary Power	>	SOFC	Stationary Power		

Figure 19. Fuel Cell Equipment Cycle Pathways

In addition to fuel cell components and systems, the production of the balance of equipment components and systems comprising each port application must also be accounted for. In the case of mobile equipment this includes the interior and exterior body, chassis and suspension, powertrain, transmission, electric systems, fluids, tires, and control systems. For components like batteries and fluids that will require replacement during the equipment's lifetime, additional energy and emissions assessments will be required based on typical replacement cycles.

6.3.3 Fuel Cell Equipment Application Assembly

Fuel cell equipment assembly consists of the unique component assembly requirements for the specific port equipment applications, including the incorporation of the fuel cell power and propulsion systems. Final fuel cell equipment assembled products can be transported via ship, rail, and/or truck.

6.3.4 Fuel Cell Equipment Application Disposal/Recycling

The final element of the Fuel Cell Equipment Cycle is equipment disposal and recycling. This accounts for the energy and emissions associated with assembled equipment disposal and/or dismantling for material recycling, Recycled materials used in original equipment production should be accounted for in the total fuel cell equipment cycle energy use and emissions.

6.4 Lifecycle Emissions Estimation Methodology, Tools, and Resources for Port Equipment Applications

The following section outlines one basic methodology, tools, and available resources for estimating the lifecycle emissions associated with operating fuel cell equipment in key applications at U.S. port locations. The methodology applies total lifecycle energy and emissions analysis for assessing lifecycle emissions for port fuel cell equipment relative to their conventional diesel counterparts. Available estimation tools are also discussed for supporting the methodology.

6.4.1 Proposed Lifecycle Emissions Estimation Framework

The near- and mid-term hydrogen fuel and fuel cell equipment cycle constructs discussed above in this section form the basis from which lifecycle emissions analysis can be conducted for evaluating the multitude of hydrogen production, distribution and delivery routes, and fuel cell equipment usage at U.S. ports. The proposed methodology covers fuel cycle, onsite use of port equipment, and port equipment cycle requirements separately, but assesses lifecycle emissions under each of these segments for both traditional diesel fuel and hydrogen fuel so that comparisons can be made. Pollutant coverage in the framework includes criteria pollutants, greenhouse gases, and MSATs. In all cases, pollutant coverage was dependent upon available models, emission factors, and emissions research. As a result, consistent pollutant coverage across lifecycle framework elements was not always possible. For example, MSAT pollutant coverage was only possible for port equipment-related emissions; MSAT pollutants related to fuel production, storage, and transport were not available given the scope of this initial assessment.

6.4.1.1 Fuel Cycle Well-to-Pump

For both the diesel fuel and hydrogen fuel cycle pathways, it is proposed that ANL's Greenhouse Gases, Regulated Emissions, and Energy use in Transportation (GREET) model be utilized. The model is available as GREET.Net with graphical interface or as GREET Excel which incorporates separate spreadsheet sub-models for fuel cycle and vehicle/equipment cycle analyses (Argonne National Laboratory, 2019).

GREET incorporates internal databases for assessing a multitude of conventional and alternative fuel cycles. For purposes of this analysis, the following fuel pathways were considered:

- U.S. Average Low Sulfur Diesel Fuel Production from Crude Oil

- Centralized Hydrogen Production: Natural Gas SMR, Biomass Gasification, and Electrolysis Using Solar Power
- Distributed Hydrogen Production: Natural Gas SMR, Electrolysis Using Solar Power, and Electrolysis Using Grid Electricity

The model can be used to derive energy consumption, GHG and criteria pollutant emissions, and water consumption for the "Well-to-Pump (WTP)" portion of the fuel cycle, that is, fuel feedstock extraction and transport, fuel production and transport, and fuel distribution and dispensing. The following WTP pollutants are available from GREET:

- Volatile Organic Compounds (VOC)
- Carbon Monoxide (CO)
- Nitrogen Oxides (NO_x)
- Particulate Matter 10 Microns and Smaller (PM_{10})
- Particulate Matter 2.5 Microns and Smaller ($PM_{2.5}$)
- Sulfur Oxides (represented as SO_2 in this analysis)
- Carbon Dioxide (CO_2)
- Methane (CH_4)
- Nitrous Oxide (N_2O)

Table 36 lists calendar year 2020 WTP results using 2019 GREET.Net[17] for conventional low sulfur diesel and various selected centralized and distributed gaseous and liquid hydrogen production pathways. Results are presented on a per diesel gallon[18] basis for the low sulfur diesel fuel pathway, and on a per kg hydrogen[19] produced basis for the hydrogen pathways. The following 2019 GREET.Net fuel pathways were utilized:

- Low Sulfur Diesel from Crude Oil
- Central Plants: Compressed G.H2 via Pipeline from Natural Gas (w/o CO_2 Sequestration)
- Central Plants: Compressed G.H2 via Pipeline from Solar Energy
- Central Plants: Compressed Gaseous Hydrogen via Pipeline from Biomass (H2A Model)
- Refueling Stations: Compressed G.H2 from Natural Gas (w/o CO_2 Sequestration)
- Refueling Stations: Compressed Gaseous Hydrogen from Electricity
- Central Plants: L.H2 from NA Natural Gas (w/o CO_2 Sequestration) (Simplified)
- Central Plants: Liquid Hydrogen from Biomass
- Central Plants: Liquid Hydrogen from Solar Power
- Refueling Stations: L.H2 from NA Natural Gas (w/o CO_2 Sequestration)
- Refueling Stations: Liquid Hydrogen from U.S. Electricity

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[17] 2019 GREET.Net, accessed December 2019.

[18] Low sulfur diesel lower heating value – 129,488 BTU/gal (Source: GREET.Net)

[19] Hydrogen lower heating value – Gaseous H_2 113,725 BTU/kg; Liquid H_2 113,822 BTU/kg (Source: GREET.Net)

For each pathway, default GREET.Net model assumptions were assumed except for the following year 2020 electricity generation mix based on the EIA's Annual Energy Outlook 2020:

Assumed 2020 U.S. Average Electricity Generation Mix (Percent)									
Coal	**Oil**	**Natural Gas**	**Nuclear**	**Hydro-electric**	**Biomass**	**Wind**	**Solar**	**Geothermal**	**Biogenic Waste**
22.0	0.6	40.3	19.0	7.0	1.6	6.5	1.5	0.5	0.5

In general, the Table 36 WTP results for the hydrogen production pathways are much more energy and water use intensive than diesel fuel production on a per unit fuel production basis. Centralized processes exhibited lower water consumption rates than distributed processes in general. Solar-based electrolysis (both centralized and distributed) displayed the lowest water consumption rates among the hydrogen pathways. Those hydrogen production pathways with lower fossil energy inputs such as centralized biomass gasification, solar-based electrolysis, and distributed solar-based electrolysis, exhibited the lowest criteria pollutants and GHG emissions in general. Further, liquid hydrogen production pathways tended to have higher energy use requirements due primarily to hydrogen liquefaction processes, and this higher energy use generally correlated with higher emissions. However, in the case of lquid hydrogen produced from centralized biomass gasification, the assumed use of biomass-generated electricity through integrated gasification combined cycle (IGCC) power for the liquefaction process resulted in lower net CO_2 emissions (process CO_2 minus biogenic CO_2) than gaseous hydrogen production from centralized biomass gasification. In addition, emissions from liquid hydrogen produced from centralized solar-based electrolysis were generally lower than those from gaseous hydrogen in Table 36 since the liquefied pathway assumed the liquefaction process was powered by solar power.

Since regional electricity generation can vary considerably across the U.S., several results for distributed, grid-based electrolysis were analyzed using 2019 GREET.Net. In addition to the previously described U.S. average mix, two additional grid electricity generation mixes were assumed for distributed, grid-based electrolysis as shown in Table 37: High Coal and Low Renewables Generation Mix and Low Coal and High Renewables Generation Mix. These assumed 2020 electricity resource mixes were as follows:

Additional Electricity Mix Types	**Assumed 2020 Electricity Generation Mixes (Percent)**									
	Coal	**Oil**	**Natural Gas**	**Nuclear**	**Hydro-electric**	**Biomass**	**Wind**	**Solar**	**Geothermal**	**Biogenic Waste**
High Coal/Low Renewables	92.0	0.0	2.1	0.0	3.0	0.0	2.9	0.0	0.0	0.0
Low Coal/High Renewables	0.0	0.2	0.3	4.0	60.0	5.0	17.0	13.5	0.0	0.0

The High Coal/Low Renewables and Low Coal/High Renewables cases were derived based on the range of electricity generation mixes reported by EIA at the state levels. Note that grid-based electrolysis with the U.S. Average Generation Mix required more energy and produced higher emissions than other hydrogen pathways on a per kg basis. Grid-based electrolysis with the High Coal/Low Renewables mix required even higher energy use and produced higher emissions than the U.S. Average mix resulting from its very high fossil energy input (94.1 percent). The Low Coal/High Renewables mix, conversely, generally produced the lowest emissions of the three electricity mix cases for distributed grid-based electrolysis due to its heavy reliance on renewable energy. These results indicate that distributed grid-based electrolysis in areas of the country served by electrical grids with high renewable energy input will have better lifecycle emissions than those with high fossil energy fractions.

Table 36. 2019 GREET WTP Results for Gaseous and Liquid Hydrogen Production

Hydrogen WTP Pathway	***Total Energy (BTU)***	***Fossil Energy Fraction***	**Water Use (gal)**	**Pollutant Emissions (grams)**								
				VOC	**CO**	**NO$_x$**	**PM$_{10}$**	**PM$_{2.5}$**	**SO$_x$**	**CO$_2$**	**CH$_4$**	**N$_2$O**
Diesel Fuel Production [per Gallon]												
Low Sulfur Diesel	23,149	0.99	2.9	0.97	1.54	2.61	0.20	0.16	0.88	1,640.00	14.04	0.03
Centralized Hydrogen Production (Gaseous Product) [per kg]												
Natural Gas SMR	63,511	0.96	5.6	1.37	2.71	3.35	0.54	0.38	3.36	10,550.00	26.65	0.09
Biomass Gasification	174,888	0.15	7.6	0.92	2.79	3.64	0.55	0.33	7.54	3,170.00	6.79	0.00
Electrolysis Solar	69,375	0.12	5.7	0.21	0.93	1.04	0.22	0.08	1.86	1,750.00	3.71	0.03
Distributed Hydrogen Production (Gaseous Product) [per kg]												
On-site Natural Gas SMR	79,618	0.97	5.4	1.94	6.29	7.43	0.43	0.29	3.34	11,470.00	40.30	0.26
On-site Electrolysis Solar	62,663	0.00	14.2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
On-site Electrolysis Grid (US Avg)	207,958	0.77	38.2	2.28	10.11	11.41	2.43	0.84	20.29	19,070.00	40.47	0.30
On-site Electrolysis Grid (High Coal/Low Renewable)	341,742	0.98	35.8	3.28	2.54	10.75	4.39	1.03	75.30	44,060.00	65.11	0.70
On-site Electrolysis Grid (Low Coal/High Renewable)	91,501	0.01	148.3	0.35	10.68	2.76	3.50	1.04	1.55	200.00	0.41	0.04
Centralized Hydrogen Production (Liquid Product) [per kg]												
Natural Gas SMR	110,666	0.92	9.9	1.71	4.21	5.23	0.89	0.51	6.22	13,360.00	32.62	0.14
Biomass Gasification[1]	257,339	0.07	5.3	1.94	3.37	5.22	0.74	0.50	21.88	1,770.00	4.25	0.96
Electrolysis Solar[2]	86,760	0.00	4.5	0.02	0.07	0.26	0.01	0.01	0.00	46.86	0.06	0.00
Distributed Hydrogen Production (Liquid Product) [per kg]												
On-site Natural Gas SMR	151,994	0.92	12.2	2.45	8.57	10.00	0.98	0.48	7.89	15,760.00	49.45	0.33
On-site Electrolysis Solar	94,841	0.00	15.3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
On-site Electrolysis Grid (US Avg)	265,628	0.77	42.3	2.69	11.92	13.45	2.87	0.99	23.92	22,490.00	47.71	0.35
On-site Electrolysis Grid (High Coal/Low Renewable)	423,312	0.98	40.8	3.86	2.99	12.67	5.18	1.22	88.77	51,940.00	76.76	0.82
On-site Electrolysis Grid (Low Coal/High Renewable)	128,200	0.01	174.4	0.42	12.59	3.25	4.12	1.22	1.82	240.00	0.48	0.05

[1] Pathway includes hydrogen liquefaction process supported by electricity generated from switchgrass integrated gasification combined cycle (IGCC) power plant.

[2] Pathway includes hydrogen liquefaction process supported by electricity generated from solar power.

6.4.1.2 Fuel Cycle Onsite Use (Pump-to-Wheels) of Port-related Equipment

The lifecycle results for equipment use are the remaining component of the full fuel cycle and are referred to as the "Pump-to-Wheels (PTW)" component. (Combining the WTP results with the PTW results provides the full fuel cycle, or "Well-to-Wheels (WTW)", results.) The GREET model does provide lifecycle results for equipment use but only for on-road vehicles and their typical duty cycles. Thus, for the port-related equipment, it is proposed that other models or sources are utilized for generating equipment use lifecycle emissions.

Table 37 provides a listing of recommended models and sources for estimating PTW lifecycle emissions. For port-related nonroad mobile diesel-powered equipment such as forklifts, yard tractors, and top loaders, the Nonroad module of EPA's MOtor Vehicle Emission Simulator (MOVES) should be used (U.S. EPA, 2019). MOVES is an emission modeling system that estimates emissions for mobile sources at the national, county, and project level for criteria air pollutants, greenhouse gases, and air toxics. MOVES-Nonroad can provide fuel consumption, exhaust emission, and evaporative emission estimates.

Table 37. Recommended Emission Estimation Models/Sources by Port Equipment Application

Port Equipment Application	Emissions Estimation Model/Source
Diesel Forklift	EPA MOVES-Nonroad model
Diesel Yard Tractor	EPA MOVES-Nonroad model
Diesel Top Loader	EPA MOVES-Nonroad model
Diesel Switcher Locomotive	EPA Locomotive Emission Factor Guidance, National Port Strategy Assessment
Marine Propulsion	EPA MOVES-Nonroad model, National Port Strategy Assessment
Stationary Power	EPA eGRID model, EPA AP-42 Emission Factors for Electric Power Generation, EPA Potential to Emit Calculator for CI Engines

For switcher locomotives, the analysis utilized EPA locomotive emission factors (U.S. EPA, Office of Transportation and Air Quality, 2019) and EPA's National Port Strategy Assessment methodologies (U.S. EPA, Office of Transportation and Air Quality, 2016) . For marine propulsion, the National Port Strategy Assessment provides a comprehensive methodology for estimating emissions for various vessel types and sizes. Similarly, the National Port Strategy Assessment, along with EPA's Shore Power Emissions Calculator, can used for estimating vessel shore power emissions. Finally, for stationary power sources EPA's Emissions & Generation Resource Integrated Database (eGRID) model was used for estimating electric generation emissions. The eGRID model can estimate regional emission rates based on electric power sources across the country. For estimating diesel standby power generator emissions, appropriate emission factors from EPA's AP-42 can and were employed. In the case of stationary power fuel cells using direct natural gas internal reforming manufacturer information was used as available to estimate emissions.

Based on these sources, PTW lifecycle factors for a variety of diesel-powered port equipment were identified and are presented in Table 38. The pollutants covered include the following: VOC, CO, NO_x, PM_{10}, $PM_{2.5}$, SO_2, CO_2, CH_4, N_2O, Benzene, Formaldehyde, Acetaldehyde, and Acrolein.

The PTW factors for diesel equipment in Table 38 are listed on a per gallon diesel basis. The average equipment model years and power levels assumed for purposes of the analysis in this report were based on the actual port equipment inventory information presented earlier in the report. Emission factors for port equipment representing different model years and/or power levels should be obtained from the previously mentioned sources in deriving port specific PTW estimates. To estimate equipment fuel use rates for this report, an average brake specific fuel consumption rate of 0.367 lb/hp-hr[20] was utilized from the EPA Nonroad

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[20] This value is from MOVES, based on MY 1988-1995 engines. It may not represent the latest in the literature.

model documentation dated July 2018 for each of the diesel port-related equipment (U.S. EPA, Office of Transportation and Air Quality, 2018). This documentation was also referenced for nonroad emission factors. An average fuel sulfur content of 15 ppm was assumed for all port equipment diesel fuel. Average fuel use rates of gallon per hour were derived by applying the assumed rated horsepower and load factor for each equipment type and an average diesel fuel density of 6.93 lb/gallon. Average fuel rates could also be obtained from diesel equipment manufacturers for specific models as available.

There are no PTW emissions for comparable hydrogen fuel cell port equipment since hydrogen fuel cells emit only water vapor and heat.

6.4.1.3 Fuel Cycle Well-to-Wheels

As noted above, full fuel cycle (WTW) energy and emission estimates for fuel cell port equipment applications can be derived by compiling WTP and PTW estimates. Table 39 provides the incremental WTW emission results[21] for port fuel cell equipment versus comparable diesel equipment for the gaseous hydrogen fuel delivery pathways listed in Table 36. Note that the results of Table 39 are presented on a hp-hr equivalent and efficiency adjusted basis[22]. That is, the results consider the energy content difference between hydrogen and diesel fuel as well as the increased energy efficiency of hydrogen fuel cells compared to diesel engines. Fuel cell equipment energy efficiencies for each port application were estimated based on fuel cell efficiencies (assuming PEMFCs), current fuel cell equipment drivetrain configurations, and estimated duty cycle efficiencies (Ahluwalia, 2020). Similar estimations were made for the baseline diesel equipment the fuel cell equipment would replace. Based on this analysis, the following relative energy efficiencies of each port equipment type was applied[23] to the WTP emission estimates of Table 36:

Estimated H_2 Fuel Cell to Diesel Energy Efficiency Ratio					
Forklift	**Yard Tractor**	**Top Loader**	**Marine Vessel**	**Switcher Locomotive**	**Stationary Generator**
2.52	2.52	2.52	1.35	1.77	2.04

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[21] WTW estimates for air toxic pollutants were not possible due to a lack of WTP estimates for these pollutants.

[22] Based on LHVs: 129,488 BTU/gal low sulfur diesel, 113,725 BTU/kg gaseous hydrogen, and 113,822 BTU/kg liquid hydrogen.

[23] WTP estimates were divided by the H_2 Fuel Cell to Diesel Energy Efficiency Ratios to obtain efficiency adjusted values.

Table 38. PTW Factors for Diesel-Fueled Port Equipment per Gallon Diesel Fuel

Diesel Port Equipment Type	Typical Propulsion Power	Pollutant Emissions (gm/gallon)												
		VOC	CO	NO_x	PM_{10}	$PM_{2.5}$	SO_2	CO_2	CH_4	N_2O	Benz	Form	Acet	Acro
Forklift	100	5.10	70.40	63.26	0.57	0.56	0.09	10,023	0.35	---	0.26	1.45	0.52	0.09
Yard Tractor	200	2.84	1.47	22.03	0.22	0.22	0.07	10,029	0.25	---	0.15	0.83	0.30	0.05
Top Loader	310	2.84	1.68	26.32	0.24	0.23	0.07	10,029	0.25	---	0.15	0.83	0.30	0.05
Assist Tugboat	1,908	3.81	35.25	138.17	3.64	3.53	0.09	9,729	0.14	0.44	0.09	0.85	0.30	0.06
Ferry	1,718	2.82	70.50	98.70	2.43	2.35	0.09	9,729	0.14	0.44	0.15	0.82	0.29	0.05
Harbor Tugboat	711	2.82	70.50	98.70	2.43	2.35	0.09	9,729	0.14	0.44	0.15	0.82	0.29	0.05
Switcher Locomotive	2,000	11.06	27.82	187.00	4.10	3.98	0.09	10,208	---	---	0.02	0.29	0.12	---
Power Generator	135	21.18	70.50	56.40	4.23	4.10	0.09	10,210	0.41	0.08	0.06	0.07	0.05	0.01

Table 39. Summary of WTW Emission Reductions for Fuel Cell Equipment/Gaseous Hydrogen Fuel Pathways Relative to Comparable Diesel-Fueled Equipment

Fuel Cell Equipment Type	Hydrogen Fuel Pathway	WTW Emission Reductions Relative to Diesel-Fueled Equipment (g/hp-hr) [Efficiency Adjusted]								
		VOC	CO	NO$_x$	PM$_{10}$	PM$_{2.5}$	SO$_2$	CO$_2$	CH$_4$	N$_2$O
Yard Tractor	Centralized NG SMR	0.063	0.035	0.458	0.004	0.004	-0.011	136.668	0.045	0.000
	Centralized Biomass Gasification	0.067	0.035	0.455	0.003	0.005	-0.049	202.697	0.222	0.001
	Centralized Electrolysis Solar	0.073	0.051	0.479	0.006	0.007	0.002	215.402	0.250	0.000
	Distributed NG SMR	0.058	0.003	0.421	0.005	0.005	-0.011	128.437	-0.078	-0.002
	Distributed Electrolysis Solar	0.075	0.060	0.488	0.008	0.007	0.019	231.060	0.283	0.001
	Distributed Electrolysis Grid (US Avg)	0.055	-0.031	0.386	-0.013	0.000	-0.163	60.440	-0.079	-0.002
	Distributed Electrolysis Grid (Hi Coal)	0.046	0.037	0.392	-0.031	-0.002	-0.655	-163.147	-0.300	-0.006
	Distributed Electrolysis Grid (Lo Coal)	0.072	-0.036	0.463	-0.023	-0.002	0.005	229.270	0.279	0.000
Forklift	Centralized NG SMR	0.108	1.400	1.274	0.011	0.011	-0.011	136.549	0.047	0.000
	Centralized Biomass Gasification	0.112	1.400	1.272	0.010	0.011	-0.048	202.578	0.224	0.001
	Centralized Electrolysis Solar	0.118	1.416	1.295	0.013	0.014	0.003	215.283	0.252	0.000
	Distributed NG SMR	0.103	1.368	1.238	0.011	0.012	-0.011	128.318	-0.076	-0.002
	Distributed Electrolysis Solar	0.120	1.425	1.304	0.015	0.014	0.019	230.940	0.285	0.001
	Distributed Electrolysis Grid (US Avg)	0.100	1.334	1.202	-0.006	0.007	-0.162	60.320	0.285	0.001
	Distributed Electrolysis Grid (Hi Coal)	0.091	1.402	1.208	-0.024	0.005	-0.654	-163.266	-0.298	-0.006
	Distributed Electrolysis Grid (Lo Coal)	0.117	1.329	1.280	-0.016	0.005	0.005	229.151	0.281	0.000
Cargo Handler (Top Loader)	Centralized NG SMR	0.063	0.040	0.543	0.004	0.004	-0.011	136.668	0.045	0.000
	Centralized Biomass Gasification	0.067	0.039	0.540	0.004	0.005	-0.049	202.697	0.222	0.001
	Centralized Electrolysis Solar	0.073	0.055	0.563	0.007	0.007	0.002	215.402	0.250	0.000
	Distributed NG SMR	0.058	0.008	0.506	0.005	0.005	-0.011	128.437	-0.078	-0.002
	Distributed Electrolysis Solar	0.075	0.064	0.573	0.009	0.008	0.019	231.060	0.283	0.001
	Distributed Electrolysis Grid (US Avg)	0.055	-0.027	0.471	-0.013	0.000	-0.163	60.440	-0.079	-0.002
	Distributed Electrolysis Grid (Hi Coal)	0.046	0.041	0.477	-0.031	-0.001	-0.655	-163.147	-0.300	-0.006
	Distributed Electrolysis Grid (Lo Coal)	0.072	-0.032	0.548	-0.023	-0.002	0.005	229.270	0.279	0.000
Assist Tugboat	Centralized NG SMR	0.072	0.683	2.732	0.067	0.067	-0.037	48.922	-0.164	0.008
	Centralized Biomass Gasification	0.079	0.682	2.727	0.067	0.068	-0.107	172.177	0.167	0.009

Fuel Cell Equipment Type	Hydrogen Fuel Pathway	WTW Emission Reductions Relative to Diesel-Fueled Equipment (g/hp-hr) [Efficiency Adjusted]								
		VOC	CO	NO_x	PM_{10}	$PM_{2.5}$	SO_2	CO_2	CH_4	N_2O
	Centralized Electrolysis Solar	0.091	0.713	2.770	0.072	0.072	-0.012	195.892	0.219	0.009
	Distributed NG SMR	0.062	0.623	2.664	0.069	0.068	-0.037	33.557	-0.392	0.005
	Distributed Electrolysis Solar	0.095	0.728	2.788	0.076	0.073	0.019	225.119	0.281	0.009
	Distributed Electrolysis Grid (US Avg)	0.057	0.560	2.597	0.035	0.059	-0.320	-93.371	-0.395	0.004
	Distributed Electrolysis Grid (Hi Coal)	0.040	0.686	2.608	0.003	0.056	-1.238	-510.732	-0.807	-0.002
	Distributed Electrolysis Grid (Lo Coal)	0.089	0.550	2.742	0.018	0.056	-0.007	221.779	0.274	0.009
Ferry	Centralized NG SMR	0.052	1.381	1.950	0.043	0.043	-0.037	48.922	-0.164	0.008
	Centralized Biomass Gasification	0.060	1.380	1.945	0.043	0.044	-0.107	172.177	0.167	0.009
	Centralized Electrolysis Solar	0.072	1.411	1.989	0.048	0.048	-0.012	195.892	0.219	0.009
	Distributed NG SMR	0.043	1.321	1.882	0.045	0.045	-0.037	33.557	-0.392	0.005
	Distributed Electrolysis Solar	0.075	1.426	2.006	0.052	0.050	0.019	225.119	0.281	0.009
	Distributed Electrolysis Grid (US Avg)	0.037	1.258	1.815	0.011	0.036	-0.320	-93.371	-0.395	0.004
	Distributed Electrolysis Grid (Hi Coal)	0.020	1.384	1.827	-0.021	0.033	-1.238	-510.732	-0.807	-0.002
	Distributed Electrolysis Grid (Lo Coal)	0.069	1.248	1.960	-0.006	0.032	-0.007	221.779	0.274	0.009
Harbor Tugboat	Centralized NG SMR	0.052	1.381	1.950	0.043	0.043	-0.037	48.922	-0.164	0.008
	Centralized Biomass Gasification	0.060	1.380	1.945	0.043	0.044	-0.107	172.177	0.167	0.009
	Centralized Electrolysis Solar	0.072	1.411	1.989	0.048	0.048	-0.012	195.892	0.219	0.009
	Distributed NG SMR	0.043	1.321	1.882	0.045	0.045	-0.037	33.557	-0.392	0.005
	Distributed Electrolysis Solar	0.075	1.426	2.006	0.052	0.050	0.019	225.119	0.281	0.009
	Distributed Electrolysis Grid (US Avg)	0.037	1.258	1.815	0.011	0.036	-0.320	-93.371	-0.395	0.004
	Distributed Electrolysis Grid (Hi Coal)	0.020	1.384	1.827	-0.021	0.033	-1.238	-510.732	-0.807	-0.002
	Distributed Electrolysis Grid (Lo Coal)	0.069	1.248	1.960	-0.006	0.032	-0.007	221.779	0.274	0.009
Switcher Locomotive	Centralized NG SMR	0.221	0.547	3.712	0.078	0.077	-0.024	100.225	-0.061	0.000
	Centralized Biomass Gasification	0.226	0.546	3.708	0.078	0.078	-0.077	194.232	0.192	0.001
	Centralized Electrolysis Solar	0.235	0.569	3.741	0.082	0.081	-0.004	212.321	0.231	0.000
	Distributed NG SMR	0.213	0.501	3.660	0.080	0.078	-0.023	88.506	-0.235	-0.003
	Distributed Electrolysis Solar	0.238	0.581	3.755	0.085	0.082	0.019	234.612	0.278	0.001
	Distributed Electrolysis Grid (US Avg)	0.209	0.453	3.609	0.054	0.071	-0.239	-8.304	-0.237	-0.003

Fuel Cell Equipment Type	Hydrogen Fuel Pathway	WTW Emission Reductions Relative to Diesel-Fueled Equipment (g/hp-hr) [Efficiency Adjusted]								
		VOC	CO	NO_x	PM_{10}	$PM_{2.5}$	SO_2	CO_2	CH_4	N_2O
	Distributed Electrolysis Grid (Hi Coal)	0.196	0.549	3.618	0.029	0.069	-0.940	-326.630	-0.551	-0.008
	Distributed Electrolysis Grid (Lo Coal)	0.234	0.445	3.719	0.041	0.069	0.000	232.065	0.273	0.000
Stationary Generator	Centralized NG SMR	0.424	1.397	1.131	0.082	0.080	-0.018	118.051	-0.008	0.001
	Centralized Biomass Gasification	0.429	1.396	1.128	0.082	0.081	-0.064	199.616	0.211	0.002
	Centralized Electrolysis Solar	0.436	1.416	1.157	0.085	0.084	-0.001	215.311	0.245	0.002
	Distributed NG SMR	0.417	1.357	1.086	0.083	0.081	-0.018	107.883	-0.159	-0.001
	Distributed Electrolysis Solar	0.439	1.426	1.168	0.088	0.084	0.019	234.652	0.286	0.002
	Distributed Electrolysis Grid (US Avg)	0.413	1.315	1.042	0.061	0.075	-0.205	23.886	-0.161	-0.001
	Distributed Electrolysis Grid (Hi Coal)	0.402	1.398	1.050	0.039	0.073	-0.813	-252.309	-0.433	-0.006
	Distributed Electrolysis Grid (Lo Coal)	0.435	1.308	1.138	0.049	0.073	0.002	232.442	0.282	0.002

Positive emissions reductions in Table 39 are highlighted in green, indicating that gaseous hydrogen fuel cell equipment WTW emissions are lower than those of diesel equipment per kg equivalent consumed, while negative values shown in red signify gaseous hydrogen fuel cell WTW emission reductions are higher than diesel. Similar WTW results can be obtained for the liquid hydrogen fuel pathways listed in Table 36 using the same methodology.

The WTW results show that hydrogen fuel cell-powered equipment in various port applications can achieve significant lifecycle emission reductions. Reductions in VOC and NO_x emissions were achieved across all port equipment types for each of the gaseous hydrogen fuel delivery pathways. CO emissions were generally lower for the majority of fuel cell equipment and gaseous hydrogen pathways, except for yard tractors and top loaders under the U.S. Average and Low Coal/High Renewables grid-based electrolysis pathway. Lower PM_{10} were determined for fuel cell equipment applications and gaseous hydrogen fuel pathways, except for yard tractors, forklifts, top loaders, ferries, and harbor tugboats under the grid electrolysis pathways. $PM_{2.5}$ emissions were lower for all port equipment applications and gaseous hydrogen fuel pathways except for yard tractors and top loaders under some grid-based electrolysis pathways. All fuel cell equipment produced higher SO_2 emissions for all gaseous hydrogen fuel pathways except for some solar-based electrolysis and low coal/high renewables grid-based electrolysis pathways. The increased SO_2 emissions result from higher levels created from gaseous hydrogen fuel feedstock processes, fuel production, and fuel compression. SO_2 levels were significantly higher for the U.S. average and high coal mix grid-electrolysis processes resulting from their intensive electricity use and high fossil fuel resources. WTW CO_2 emissions were significantly lower for fuel cell equipment for all gaseous hydrogen fuel pathways, apart from high coal/low renewables generation grid-based electrolysis and for some equipment applications, U.S. average grid-based electrolysis. Mixed results were observed for WTW CH_4 emissions across applications with generally higher values for natural gas SMR pathways, U.S. average grid electrolysis, and high coal/low renewables electrolysis, and lower values for biomass gasification, solar-based electrolysis, and low coal/high renewables electrolysis. Similarly, WTW results for N_2O emissions varied with higher levels from for natural gas SMR, U.S. average grid electrolysis, and high coal/low renewables electrolysis pathways, and lower values for biomass gasification, solar-based electrolysis, and low coal/high renewables electrolysis pathways, depending on the equipment application.

Upon review of individual pathway WTW results, all gaseous hydrogen fuel pathways provided significant emission reductions for most port equipment applications, although higher SO_2 emissions did occur in many cases. Again, these higher levels of SO_2 emissions were attributed to WTP hydrogen feedstock, production, transport (for centralized pathways), and gaseous hydrogen compression processes, not the fuel cell equipment PTW segment. Thus, the hydrogen WTP SO_2 emissions surpassed those of the diesel WTW (both WTP and PTW segments) pathway. Overall, the solar-based electrolysis pathway emerged as the highest performing hydrogen fuel pathway for both centralized and distributed cases. The performance of distributed grid-based electrolysis is highly dependent on the electricity generation mix. Regions of the country with high coal and low renewable resource electricity generation can be expected to produce significantly less favorable grid-based electrolysis pathway WTW emission results as compared to regions with low coal and high renewable resource generation mixes. Further, the WTW emission results presented here were dictated by specific assumptions for both WTP and PTW estimates. WTW results may vary depending on hydrogen production scenarios, feedstock and fuel transport modes, and port equipment types and sizes. As such, local and regional analysis can facilitate emissions assessments associated with hydrogen fuel cell equipment use at port locations.

6.4.1.4 Port-related Equipment Cycle

As a reminder, the equipment cycle includes the resources and energy necessary to produce, dispose of, and recycle equipment. The individual components of the equipment cycle include materials recovery, processing and transport, component fabrication and transport, equipment assembly and transport, and equipment disposal and recycling.

The GREET model provides both diesel and hydrogen fuel cell equipment cycle results, but only for on-highway vehicle types including light duty vehicles such passenger cars, sport utilities, and pickup trucks. While these results cannot be applied directly for the nonroad port-related equipment such as forklifts, yard tractors, and top loaders, this functionality could be modified for application to the nonroad equipment assuming similar manufacturing processes and energy intensities albeit for different material types and compositions.

To determine equipment cycle results, the GREET model assesses raw material recovery and processing, vehicle component production and vehicle assembly, and vehicle disposal and recycling (Burnham, Wang, & Wu, 2006). The model first estimates vehicle component weight for the major components of the vehicle including the body, chassis, batteries, fluids, powertrain (engine or fuel cell stack and auxiliaries), and transmission or gearbox. The component categories are comprised of systems and subsystems, and not every vehicle type has all the systems or subsystems. For all vehicle types within a category including fuel cell vehicles, the weights of the engine or fuel cell and transmission are scaled for equivalent performance requirements. Next, the model assigns a material composition to each major component and includes replacement schedules for component materials that are replaced over the vehicle’s lifetime. For vehicle disposal and recycling, the model estimates energy and emissions associated with scrap material recycling and fabrication for reuse. Based on the materials specified, the model also estimates energy use from material recovery to vehicle assembly.

The weight of each vehicle component is aggregated with the weights of other corresponding components and then divided by the total weight of all vehicle components to obtain component specific fractional weights. When the total vehicle weight is changed in the GREET model by the user, these fractional Figures along with material composition Figures are used to determine the weight of each material in a component category.

In order to estimate equipment cycle results for forklifts, yard tractors, and top loaders, for future assessments it is recommended that the fractional weight and material composition inputs in the GREET model be modified for representing these port equipment applications. This will require additional research to identify port equipment components, systems, and materials for inclusion in the model. These updated Figures can then be inputted appropriately into the model to assess equipment cycle results for the forklift, yard, tractor, and top loader categories. As a caveat to this approach, the GREET model currently only supports analysis on PEMFCs. Therefore, analysis on AFC/AMFC-powered forklifts for example would not be directly possibly, but extrapolation of the PEMFC-powered forklift results may be possible.

For the remaining port equipment types considered in this task, switcher locomotive, marine propulsion, and stationary power, the determination of an approach for equipment cycle estimation was not possible due to current limits on scope and budget. Significant additional lifecycle assessment research on these port equipment applications is recommended to fully assess their equipment cycle energy and emission contributions.

6.5 Port Locations and Regional Analysis Results

Regional analysis is important in assessing the energy use, greenhouse gas emissions, and costs associated with hydrogen fuel cell equipment use at port locations since the type of hydrogen production and the distances and modes for transporting hydrogen to the port site can greatly impact the results. Based on a port’s location, an assessment can be made regarding the most viable near- and mid-term hydrogen product pathways for delivery to the site. For example, a port located in Louisiana would have higher potential for hydrogen fuel service from a centralized natural gas SMR plant rather than a centralized coal gasification plant based on its geographical location.

The regional results can also assist in assessing hydrogen fuel product transport distances from viable production regions or from existing infrastructure networks to actual port locations. Hydrogen fuel and hydrogen fuel carrier transport-related energy use and emissions can be significant when considered long distances for site delivery. Additionally, in assessing gaseous versus liquefied hydrogen product delivery, gaseous hydrogen transport via truck or rail generally only makes economic sense for transport distances of less than 200 miles. For distances over 200 miles but less than 1,000 miles, liquefied hydrogen transport is more economically favorable.

Furthermore, port location in relation to available electricity generation source mix is also important. For port sites with regional electricity more reliant on fossil fuel-powered generation, the lifecycle emission reduction potential for hydrogen fuel cell use is lower given the high electricity requirements of some hydrogen production processes. For these sites, distributed hydrogen production using renewable energy sources may have higher emissions reduction potential.

6.6 Additional Analytical Sources

The U.S. Department of Energy's Hydrogen and Fuel Cell Program established the Hydrogen Analysis (H2A) Project to establish a repository of information and analytical results for the hydrogen and fuel cell research community (DOE Hydrogen Program, 2019). The project's website maintains the latest information on DOE programs and links to DOE-sponsored research including hydrogen production and delivery models and case studies. Relevant lifecycle model results and case studies for this task work include the following:

- Centralized Hydrogen Production (greater than 50,000 kg/day hydrogen production)
    - Coal Gasification
    - Natural Gas SMR
    - Biomass Gasification
- Distributed Hydrogen Production (100-1,500 kg/day hydrogen production)
    - Natural Gas SMR
    - Water Electrolysis (Grid)
    - Ethanal (Corn) ESR
- Hydrogen Delivery Methods
    - Hydrogen Pathways: gaseous hydrogen via pipeline, gaseous hydrogen via tube trailer and liquefied hydrogen via tank truck
    - Components Model: pipelines, compressors, tube trailers, liquefied tank trucks, liquefaction plants, gaseous tube storage, geologic storage gaseous terminals, and liquefied hydrogen terminals
    - Scenario model: geographic-specific scenarios for delivery infrastructure

The information contained under the H2A project can be used to directly inform the proposed lifecycle emissions analytical framework established in this report.

7. Future Hydrogen and Fuel Cell Market Penetration

7.1 Primary Factors for Future Fuel Cell Commercial Viability and Competitiveness

Fuel cell technology promises significant benefits for sustainable energy use into the future for a broad array of port applications. Among these benefits include lower criteria pollutants, greenhouse gas, and noise emissions, high energy efficiency and lower petroleum use, diverse fueling capability, and potentially lower maintenance requirements. While the benefits are many, a variety of key factors impact future fuel cell commercial viability and market competitiveness in ports and other sectors. These factors are equipment capital cost, equipment durability/reliability, equipment power/duty cycle performance, equipment operational hours/range, equipment maintenance/serviceability, and hydrogen fuel price. Each is discussed below.

7.1.1 Equipment Capital Cost

One of the key factors for future fuel cell technology competitiveness is capital cost. Fuel cell system costs are currently much higher than those for traditional diesel fuel technologies at comparable power levels. This cost disparity results from high-cost system designs and low-volume manufacturing. Table 40 displays DOE fuel cell system cost estimates for various applications and manufacturing volumes on a per kW basis (Satyapal, 2018). The Table also identifies DOE's program cost targets for each application which represent fuel cell system costs that would be market competitive on a lifecycle basis. None of the current high production volume fuel cell system costs currently achieve the DOE target values indicating that per unit costs need further reduction.

Table 19. Estimated Fuel Cell System Costs by Application and Production Volume

Cost/Production Metric	Forklifts (5 kW)	Back-up Power Systems (5 kW)	Stationary Power Systems (25 kW)
Low Volume Production Estimate ($/kW)	6,100 (100 units/yr)	7,400 (100units/yr)	3,000 (100 units/yr)
High Volume Production Estimate ($/kW)	2,800 (10,000 units/yr) 2,400 (50,000 units/yr)	3,200 (10,000 units/yr) 2,800 (50,000 units/yr)	2,000 (10,000 units/yr) 1,900 (50,000 units/yr)
DOE Target ($/kW)	NA	1,000	1,500

One element of current fuel cell research is on reducing costs for both fuel cell stack systems and balance of plant (BOP) components (compressors, pumps, etc.) that support overall fuel cell system operation. Fuel cell stack research is aimed at lowering fuel cell membrane and catalyst costs. Researchers are developing fuel cell catalysts with very low or no platinum group metal (PGM) content to lower stack system costs (DOE Fuel Cell Technologies Office, 2017). PGM catalysts are expensive but are important for durability and fuel impurity tolerance especially in high temperature fuel cell types that operate on syngas or mixed reformate fuels. In automotive applications, researchers have identified catalyst costs as the single highest cost element for high-volume production PEMFC fuel cell stacks. Researchers are also investigating cost reductions and improvements in BOP components. BOP costs for automotive fuel cell systems make up about half of their costs. Research is focused on lower cost external fuel processor reactors and sorbent bed systems for reforming syngas fuels and removing fuel impurities (e.g., sulfur). Current fuel clean-up technologies are effective at removing impurities but are very costly. Current practice is to customize fuel processors and clean-up technologies to match individual fuel and fuel cell applications which limits the ability for high-volume production and associated cost savings. This could potentially cause issues with fuel cell equipment inventories with varying fuel quality requirements depending on the fuel cell type and equipment application. Common fuel processor and clean-up systems capable of handling a variety of fuels will allow mass production and lower costs and support broader fuel cell deployment. For high temperature fuel cell types like SOFCs, MCFCs, and PAFCs, more temperature tolerance catalyst structures and subsystems are under development for better supporting high temperature operations and associated higher efficiencies.

7.1.2 Equipment Durability/Reliability

According to a recent DOE assessment, “fuel cells have not yet demonstrated a level of durability comparable to the incumbent technologies in the main application areas of transportation and stationary power generation” (DOE Fuel Cell Technologies Office, 2017). This assessment is based on long-term testing programs and on current fuel cell technology’s ability to meet real-world operational conditions and duty cycles over expected equipment application lifetimes including fuel impurities, cold weather starting and operation, humidity, and load cycles. Of course, it should be stated that in these cases fuel cell technologies are being compared with mature and market-proven technologies such as diesel engines. Ultimately, for fuel cell applications at ports, extended in-use testing may be necessary in actual port operations with rapidly changing duty cycles, humid-salty air, and ambient industrial air pollution to fully demonstrate fuel cell reliability and potential performance detrioration.

In a recent study NREL presented long-term durability data based on laboratory testing of fuel cells from 23 domestic and international fuel cell developers across multiple applications including forklifts and stationary prime and back-up power (Blenkey, 2019). On average, none of the systems met DOE’s target metric for accumulated operational hours before 10 percent voltage degradation. DOE uses the 10 percent voltage degradation metric as an indicator of service life degradation, although it is not necessarily an end of useful life indicator. For example, DOE estimates that the 5,000-hour durability target with less than 10 percent degradation for automotive fuel cells is equivalent to about 150,000 miles of actual driving (DOE Fuel Cell Technologies Office, 2017). (It should be noted that DOE ultimately established an 8,000-hour durability target associated with 150,000 miles of driving under a lower average speed drive cycle.) While the average NREL operational data for each application did not meet the DOE targets, it should be pointed out that some individual back-up power units did meet the target.

For applications with rapid cycling and frequent starts and stops such as nonroad vehicle applications, meeting durability requirements is typically challenging. Higher fuel cell catalyst loadings can improve long-term durability but at the expense of higher capital costs. BOP components are also a source of fuel cell durability issues in PEMFCs. For example, about 90 percent of automotive fuel cell systems failures and forced outages are due to BOP-related issues, including air blowers, compressors, and hydrogen fuel leaks (DOE Fuel Cell Technologies Office, 2017) (Eudy & Post, 2018). For low temperature fuel cells like PEMFCs, additional research is needed for improving designs for more effective water management and operation below freezing temperatures.

Fuel cells for stationary power systems must meet durability limits upwards of 60,000 hours to be competitive with traditional diesel-fueled stationary power systems in some markets (DOE Fuel Cell Technologies Office, 2017). SOFCs have demonstrated durability levels over 25,000 hours. As discussed above, the high operating temperatures and thermal cycling of high temperature fuel cells (SOFC, MCFC, and PAFC) in stationary power applications place additional long-term stress on a variety of fuel cell stack components. About 90 percent of CHP fuel cell system failures and forced outages are due to BOP-related issues. Start-up and shutdown durations and energy use under varied ambient conditions require improvement for high temperature fuel cell types.

7.1.3 Equipment Power and Duty Cycle Performance

The power and duty cycle requirements of some port-related equipment applications are significant in terms of maximum torque and power levels and durations spent at these levels. Fuel cell power plants must be capable of meeting these duty cycle demands to be viable alternatives to their diesel-fueled counterparts in these applications.

The modularity and scalability of fuel cells enables their broad application in equipment ranging from kW to MW power requirements. Necessary equipment power levels are achieved by combining multiples of the same module. This is beneficial to manufacturers as well in terms of increasing production volumes of the same module in order to lower per unit costs. Toyota is a good example of a manufacturer taking advantage of this modularity. Toyota is currently producing the Mirai light duty fuel cell-powered sedan which utilizes a 114-kW PEMFC stack. Toyota is also using multiple Mirai fuel cell stacks in parallel for other applications including a pre-commercial drayage truck developed with Kenworth for a demonstration in California as well as its Sora transit bus in Japan (Tajitsu & Shiraki, 2018). Further, Toyota bases its forklift fuel cell powerplant on the Mirai sedan's powerplant, using the same fuel cells but different stack structure (370 total cells for the Mirai and 82 total cells for the forklift) (Schreffler, 2019).

For high power, heavy duty vehicle manufacturers are developing pre-commercial hybrid systems ranging from fuel cell dominant to fuel cell range extender platforms. Similar modular approaches are being taken for meeting the power demands in these applications. Table 41 illustrates the average power requirements and fuel cell power system approach for one manufacturer of fuel cell hybrid container handlers for three types of duty cycles (Nieuwland, 2017).

Table 41. Typical Fuel Cell Power Requirements and Range Extender Design for Various Container Handler Duty Cycles

Duty Cycle*	Average Power Requirement (kW)	Fuel Cell Range Extender Power
#1	55-70	1x50 kW/2x30kW
#2	70-85	2x30kW/3x30kW
#3	85-110	3x30kW/2x50kW

*Duty cycle based on load monitoring at Port of LA

7.1.4 Equipment Operational Hours/Range

For effective utilization in port applications, fuel cell-powered equipment should have equivalent or greater operational capacity (hours) or driving range compared with diesel-fueled equipment. For port applications such as forklifts, yard tractors, and container handlers, operational capacity or driving range is important for port operational efficiency and productivity so that equipment does not have to be frequently refueled/recharged during shift work.

One of the benefits of fuel cell systems is that they are on average two times more energy efficient than diesel engines. However, while hydrogen has excellent gravimetric (mass) energy density compared with diesel fuel, as a gas under ambient conditions it exhibits poor volumetric energy density. To improve its volumetric energy density in storage systems, hydrogen is compressed to high pressures (typically 350-700 bar for vehicles/equipment storage) or liquefied at temperatures below its boiling point of -423°F (-253°C). Hydrogen has a gravimetric energy density of about 120 MJ/kg compared to diesel fuel with about 43 MJ/kg (U.S. Department of Energy, 2019). However, the volumetric energy density of hydrogen ranges from about 3MJ/L as a gas at 350 bar pressure to 4 MJ/L as a gas at 700 bar, and 9 MJ/L as a liquid. This compares with diesel fuel at about 38 MJ/L. Thus, on an equivalent volume basis, diesel fuel provides 4-12 times more energy depending on how the hydrogen is stored on a vehicle or piece of equipment. For this reason, hydrogen fuel cell vehicles and equipment require larger volume storage systems than comparable diesel vehicles and equipment even with their increased energy efficiencies. For stationary power applications, hydrogen storage volume and weight concerns are generally less of an issue for most sites.

The issue of hydrogen storage volume can be exacerbated in heavy-duty vehicles and equipment such as used at ports which have high fuel consumption, payload weight requirements, and limited space for hydrogen fuel storage. Hydrogen stored at high pressures require high pressure storage cylinders that add to the overall weight of the vehicles or equipment potentially limiting viable payload and increasing fuel consumption. The fuel storage volume and weight issue become even more challenging for fuel cell hybrid platforms that incorporate both fuel cells and large battery packs for meeting peak power and onboard energy storage specifications.

As a near-term solution, manufacturers are developing higher pressure hydrogen fuel dispensing and onboard storage systems. However, these systems have higher capital costs, and compressing hydrogen to higher pressures increases dispensing station operating costs. Further, higher storage pressures increase fuel temperatures during refueling resulting in lower refueling volume efficiency and lower final tank storage pressures (and thus energy densities) once the fuel tanks cool down. As a longer-term solution (U.S. Department of Energy, 2019), researchers are investigating cryo-compressed hydrogen dispensing and storage. Cryo-compressed hydrogen involves the generation of compressed hydrogen gas from liquid hydrogen using a cryogenic compressor. The cryo-compressed hydrogen gas is stored in heaviliy insulated pressure vessels. The cryo-compressed gas has much higher densities at lower storage pressures than compressed hydrogen gas. Cryo-compressed hydrogen storage offers potential improved performance compared to traditional high pressure hydrogen storage both in terms of vehicle storage volume and weight, especially for larger vehicles.

In summary, most hydrogen fuel cell vehicles and equipment have comparable to slightly less operational range than their diesel-fueled counterparts. This is accomplished by employing larger volume tanks, increasing gaseous hydrogen storage pressures or liquid hydrogen product tanks, and/or using hybrid range extender platforms that incorporate battery packs in addition to hydrogen storage. Cryo-compressed hydrogen storage holds promise for higher hydrogen storage densities and corresponding improved operational range, but these systems are still in the research phase.

7.1.5 Equipment Maintenance/Serviceability

Another factor in the commercial viability of fuel cell-powered port equipment is their ability to be reasonably maintained and serviced. In theory, the maintenance for fuel cell-based drivetrains should be equivalent or even less than that of comparable diesel engine drivetrains since the former are less mechanically complex and rely on low-maintenance electric propulsion components such as electric motors. While this has generally been born out for scheduled maintenance protocols for limited commercial and pre-commercial fuel cell vehicles and equipment, the generally pre-commercial status of fuel cell systems has resulted in higher vehicle and equipment downtimes due to unscheduled maintenance. These occurrences result not only from fuel cell stack-related issues but also BOP failures, indicating further development work is necessary for comparable reliability to diesel-powered versions. In addition, many fuel cell platforms are hybrid systems incorporating advanced batteries and power electronics for meeting duty cycle requirements. Spare parts and supplies for low production volume fuel cell vehicles and equipment has been challenging for some applications. To counter this in the fuel cell transit bus application, North American manufacturers are incorporating fuel cell platforms into traditional bus platforms (Eudy & Post, 2018). This approach allows greater availability of parts and lower fuel cell bus part costs, as well as affords fleet mechanics with greater bus serviceability. This approach is likely to be followed for other fuel cell applications as well. However, additional training on fuel cell system maintenance, diagnostics, and repair is required for fleet applications. Also, new maintenance and diagnostic equipment for fuel cell systems may need to be purchased by fleets.

7.1.6 Hydrogen Fuel Price

Hydrogen fuel price remains a limiting market factor for fuel cell-powered equipment. Currently, hydrogen fuel can be obtained in most areas of the country from established hydrogen production facilities and gas supply companies that currently serve U.S. petroleum product refineries and fertilizer industries.

California by far has the most established infrastructure for supporting hydrogen fuel use in fuel cell vehicles and equipment. According to CARB's 2019 Annual Hydrogen Evaluation (California Air Resources Board, 2019), the state has 41 existing retail hydrogen refueling stations and an additional 24 planned stations to serve over 5,900 registered light duty fuel cell vehicles in the state. In a December 2015 study, the California Energy Commission (CEC) reported retail hydrogen prices of between $12.85-16.49/kg of hydrogen dispensed for 700 bar pressure refueling, with an average price of $13.99/kg. Refueling at 350 bar pressures were about $2/kg lower due to less required compressor operation at these the lower pressure (McKinney, 2015).

The CEC also reported delivered hydrogen costs for gaseous and liquid hydrogen to multiple California-located stations (McKinney, 2015). For gaseous hydrogen, the average delivered hydrogen cost via gaseous hydrogen tube trailer to 180 kg/day stations was about $8/kg. For liquid hydrogen, the average delivered hydrogen cost via liquid hydrogen tank truck or trailer to 350 kg/day stations was about $9–10/kg. Other sources have reported similar delivered hydrogen costs to refueling sites. Sandia National Laboratories reported that industrial gas companies could provide liquid hydrogen at $6.35-7.40/kg to support the SF BREEZE marine vessel's 1,600 kg/day hydrogen consumption (Pratt & Klebanoff, Feasibility of the SF-BREEZE: A Zero-Emission, Hydrogen Fuel Cell, High-Speed Passenger Ferry, 2016). NREL reported an average delivered gaseous hydrogen cost of about $8/kg for a multitude of forklift fleets in its 2013 study, although the range of delivered hydrogen costs reported was $5-22/kg (Ramsden, 2013).

The CEC also reported projected retail prices through year 2025 assuming production volume and economies of scale improvements in the market (McKinney, 2015). Study results projected an average retail hydrogen price of $11.11/kg in year 2025. The CEC study also predicted an average gaseous hydrogen delivered cost via truck transport to retail stations of about $7.64/kg by year 2025 assuming increased production and greater economies of scale for hydrogen production and transport/delivery.

The DOE's Fuel Cell Technologies Office estimates the current cost of hydrogen, delivery, and dispensing at about $13-16/kg at today's low production volumes (Satyapal, 2018). Through additional research and development to lower refueling station capital costs, increase station efficiency and outputs, and improve hydrogen production and transport technologies, DOE targets a cost of hydrogen production, delivery, and dispensing at $7/kg by 2025. DOE's long-term target for the cost of hydrogen production and delivery is less than $4/kg for a fully mature hydrogen market; the target for hydrogen production costs is about $2/kg and the target for the cost of hydrogen delivery and dispensing is $2/kg.

Table 42 below lists DOE's hydrogen cost estimates and targets for low-volume, high-volume, and long-term timeframes. The Table also contextualizes these costs on the basis of DGE efficiency (Satyapal, 2018). The hydrogen cost on a DGE basis places them on an equivalent energy basis with diesel fuel, while the efficiency adjusted price basis further accounts for the energy efficiency improvement of fuel cells (assuming about twice more efficient on average). The DGE efficiency adjusted cost values for hydrogen can be compared favorably with the EIA's forecasted (as of the end of calendar year 2019) average retail low sulfur diesel price of $3.33/gallon in 2020 and $3.76/gallon in 2030.

Table 20. DOE Estimated Retail Hydrogen Price Projections Compared with Retail Diesel Price

Hydrogen Cost	Hydrogen Cost – DGE Basis	Efficiency Adjusted Cost Basis	EIA Forecasted 2020 Average Diesel Fuel Price
DOE Estimate – Current Low-Volume Production			$3.33/gal
$13 - 16/kg H_2	$15.12 - 18.60/DGE H_2	$7.55 - 9.30 /DGE Adj	
DOE Estimate – Future High-Volume Production			
$5 -10/kg H_2	$5.81 – 11.62/DGE H_2	$2.91 - 5.81/DGE Adj	

Hydrogen Cost	Hydrogen Cost – DGE Basis	Efficiency Adjusted Cost Basis	EIA Forecasted 2020 Average Diesel Fuel Price
DOE Long-term Target			
< \$4/kg H_2	\$4.65/DGE H_2	\$2.32/DGE Adj	

7.2 Future Potential Hydrogen Fuel Supply and Demand

The flexibility of hydrogen production across a variety of feedstocks and processes allows for opportunities in ramping up production volumes quickly for meeting future hydrogen demand, including demand for fuel cell vehicles and equipment. Similarly, the extensive networks of natural gas pipelines and electricity transmission and distribution infrastructure in the U.S. may be able to support both centralized and distributed approaches to hydrogen production using SMR and electrolysis processes. Furthermore, the projected lower long-term costs of natural gas and electricity and the anticipated growth in renewable energy electricity generation collectively support lower costs for hydrogen production at high-volume demand levels.

Figures 20 and 21 list EIA forecasts for both natural gas and electricity prices through 2050 (U.S. Energy Information Administration, 2020) (Nieuwland, 2017). The projected reference case price of natural gas shows a modest increase through 2050 depending on natural gas and oil resources available and future processing technology assumptions, while the reference case electricity price is relatively flat through 2050 as lower generation costs are offset by high distribution and transmission costs. Generation costs decrease in the future due to lower investment costs resulting from lower cost installed capacity and lower operating costs from more efficient generator technologies and renewable energy. Higher transmission and distribution costs over that time result from the replacement of older infrastructure as well as upgrades necessary for integrating renewable energy capacity. Figure 22 illustrates the impact of renewable energy electricity generation in the future as traditional coal and nuclear generation capacity is retired in favor of solar and wind generation and lower cost natural gas generation (U.S. Energy Information Administration, 2020).

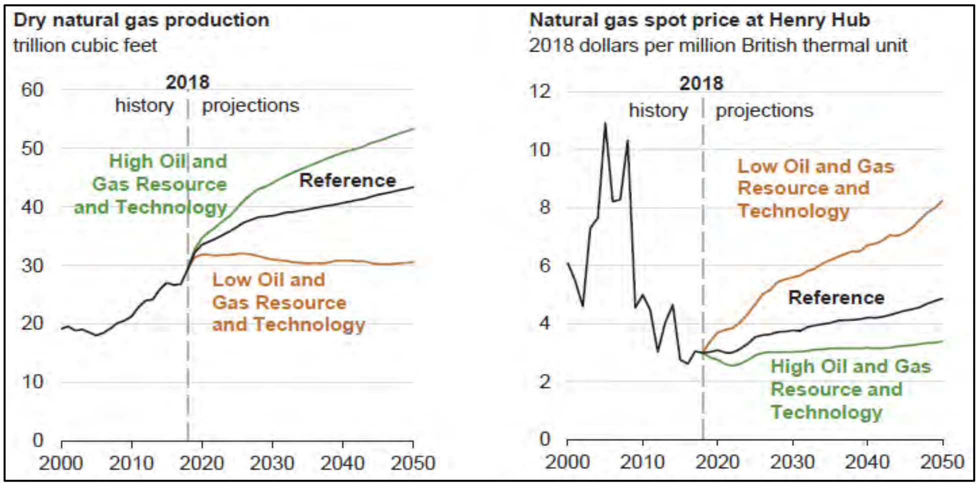

Figure 10. Natural Gas Consumption and Price Projections

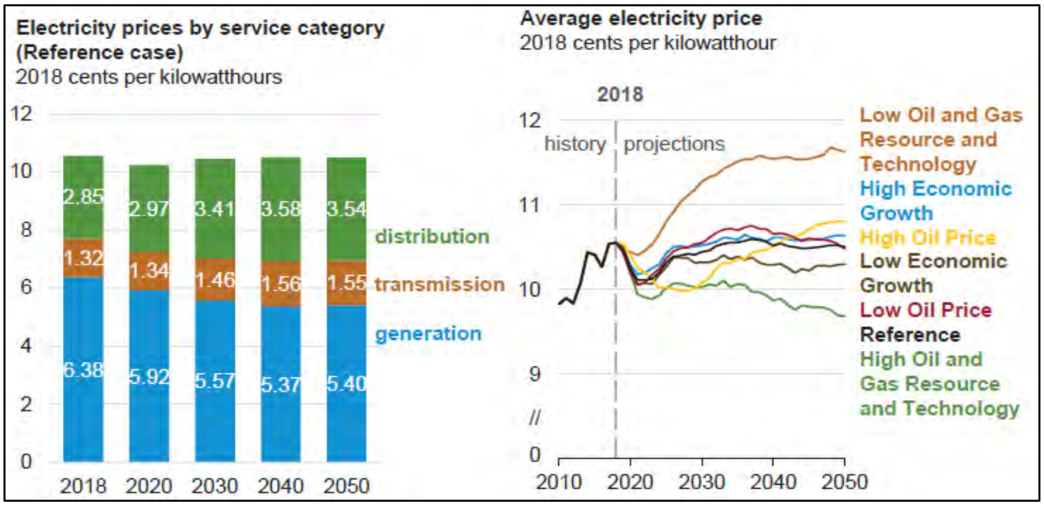

Figure 11. Electricity Price Projections

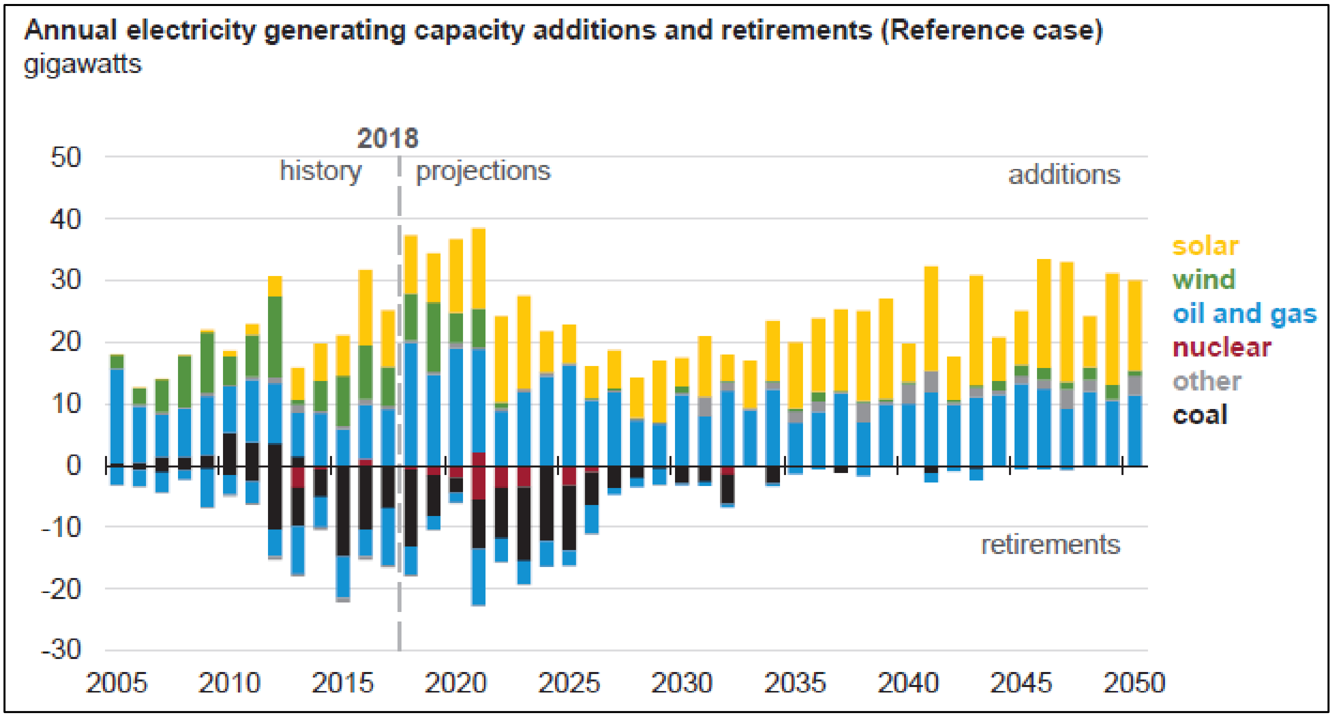

Figure 12. Projected Annual Electricity Generation Capacity (GW) Additions/Retirements (Reference Case)

Future hydrogen demand will be comprised of both existing capacity and emerging markets. Recent NREL[24] and ANL research under DOE's H2@Scale initiative (Ruth, Jadun, & Elgowainy, 2019) (Elgowainy, Hydrogen Demand Analysis for H2@Scale, 2019) has determined the total technical potential hydrogen demand[25] at about 166 million metric tons per year by 2050, as provided in Table 43. This is more than a sixteen-fold increase over current annual market levels of around 10 million metric tons. Hydrogen demand for the U.S. refinery and chemical industry is anticipated to grow to about eight million metric tons per year by 2030 and remain at that level through 2050. Annual hydrogen demand for ammonia production could increase to four million metric tons as domestic fertilizer production increases over time. Significant synthetic fuel and biofuel markets are expected to develop, fed by increasing production from natural gas production wells, ethanol plants, and ammonia plants. The increasing use of direct reduction iron (DRI) technology in electric arc furnace steel production could require about 12 million metric tons per year, while hydrogen demand for natural gas pipeline injection (5 –15 percent hydrogen by volume) is forecasted to increase to ten million metric tons annually. NREL also estimated annual hydrogen demand for transportation at about 86 million metric tons, and for seasonal electricity storage at 28 million metric tons.

NREL assessed the economic hydrogen demand potential[26] for five separate future scenarios accounting for hydrogen pricing impacts (Ruth, Jadun, & Elgowainy, 2019). The five scenarios, listed in Table 44, vary according to natural gas price assumptions based on EIA Annual Energy Outlook forecasts, and use of natural gas SMR, nuclear power for high temperature electrolysis, curtailed electricity for low temperature electrolysis, and available biomass gasification (Ruth, Jadun, & Elgowainy, 2019).

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[24] A final report update for the cited NREL research is anticipated in year 2020.

[25] Defined as market and resource potential that is constrained by existing end-uses, real-world geography, and system performance, but not constrained by economics.

[26] Subset of the technical demand potential where hydrogen is less expensive than other options that can supply the end use.

Table 43. Future Technical Potential Hydrogen Demand by Market Sector

Future Hydrogen Market	Technical Potential Hydrogen Demand (million metric ton/yr)
Refinery/Chemical Industries	8
Ammonia	4
Synthetic Fuels	14
Biofuels	4
Metal/Steel Production	12
Natural Gas Pipeline Injection	10
Light Duty Vehicles	57
Other Transport	29
Seasonal Electricity Storage	28
Total	166

Table 44. NREL Hydrogen Demand Economic Potential Scenarios

Scenario Element	Economic Potential Scenarios				
	Business as Usual	Low NG Resource	Improved Electrolysis	Available Biomass Resource	Low Cost Electrolysis
Natural Gas Prices	AEO 2017 Reference	AEO 2017 Low Oil and Gas Resource/Technology			
Availability of NG SMR	Hydrogen from SMR for non-ammonia production capped at three times current levels (23 million metric ton/yr Hydrogen production from SMR estimated future ammonia production capped at five million metric ton/yr				
Nuclear Hydrogen	20 percent of current nuclear plants available at $\$25/\mathrm{MWh}_e$ equivalent				
LT-Electrolysis Capital Costs	$400/kW		$200/Kw		$100/Kw
Curtailed Electricity	Available at Retail price		Available between retail and wholesale prices		Available at wholesale price
Biomass	Not available		Available		Not available
Metals Demand	Must compete with existing technologies		Markets are willing to pay premium for metals refined using hydrogen		

For each scenario, NREL developed national hydrogen demand curves. Market acceptable hydrogen prices ranges from over $3/kg for traditional refinery and ammonia production demand to about $1/kg for future electricity storage. NREL then developed hydrogen supply curves for the five scenarios. The supply curves were developed by aggregating supply curves from multiple production sources and estimating delivery and storage costs. Supply curve pricing ranges from less than $1/kg to close to $3.50/kg across the five scenarios.

Each scenario's hydrogen demand curve was then compared to determine the economic equilibrium point for each scenario, that is, the quantity in which the demand and supply prices are equal. Equilibrium is the natural end point for market dynamics and thus predictive of future market response to these scenarios.

Table 45 lists the equilibrium point results for each scenario (Ruth, Jadun, & Elgowainy, 2019). Overall results from NREL's work indicate future hydrogen market prices of $2.00–2.30/kg across the scenarios for the production volumes indicated, all of which are lower than DOE's targeted hydrogen cost of $4/kg. In general, natural gas SMR comprises a significant portion of hydrogen supply except in the Low-Cost Electrolysis scenario in which low temperature electrolysis becomes economically dominant.

The current status of low and high temperature electrolytic systems for hydrogen production points to the potential for heavy use of these technologies in the future. There are a number of alkaline-, proton exchange membrane-, and high temperature-based electrolyzers either available today, soon to be available, or in demonstration today (E4tech, 2018).

Table 45. Economic Potential Hydrogen Demand Equilibrium Point Results by Scenario

Scenario Parameter	Business as Usual	Low NG Resource	Improved Electrolysis	Available Biomass Resource	Low Cost Electrolysis
Hydrogen Equilibrium Price ($/kg)	2.20	2.30	2.30	2.20	2.00
Annual Hydrogen Demand/Supply (million MT)	31	14	17	36	48

Alkaline-based systems are most established in the marketplace, with a variety of manufacturer products, including systems for central plant production.

NREL also analyzed the U.S. regional hydrogen demand and supply locations under the Low-Cost Electrolysis scenario. NREL determined that hydrogen demand locations tended to be located along the coasts in major population centers, while centralized hydrogen production centers were co-located with major wind and solar resources in the middle of the country. This would necessitate the need for regional and long-distance transport of hydrogen from the production centers to the end use locations. Since gaseous pipelines are the lowest cost method for transporting quantities of hydrogen of over ten tons per day at distances greater than 60 miles, regional and interstate pipelines may prove economical in the long-term for serving mature hydrogen markets (Penev & Hunter, 2018).

7.3 Future Fuel Cell Equipment Market Penetration

The following provides market penetration estimates for port fuel cell equipment applications for the 2020-2050 timeframe. Estimates were derived according to various future market assumptions and employing an “S-curve” market penetration methodology. In deriving market penetration estimates, it was assumed that current research and development efforts would address fuel cell costs and durability issues as well as decrease hydrogen fuel production, transport, and dispensing costs in the future. Estimates also accounted for future market competitiveness and conditions. The following port equipment are addressed: forklifts, yard tractors, cargo handlers, switcher locomotives, marine propulsion and auxiliary power, and stationary power generators. Note: This effort is one way to do this analysis. The results, although detailed and specific, should not be used to gleam any definitive relationships or conclusions.

7.3.1 Fuel Cell Forklifts

The Occupational Safety and Health Administration (OSHA) Class IV-V forklift segments are generally representative of the forklifts used at ports. The majority of fuel cell forklift sales to date are in the class I-III segment represent lighter weight forklifts used primarily in warehouses. The Class IV-V forklift segment is comprised of heavier forklift products powered by internal combustion engines with cushion or pneumatic tires. Forklift market sales data was obtained for purposes of this analysis from a report by the Industrial Truck Association (Industrial Truck Association, 2017).

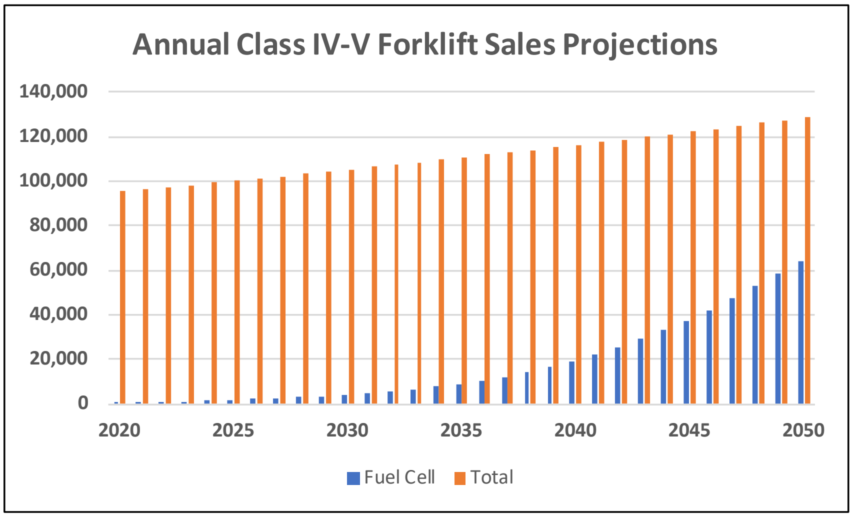

Figure 13. Estimated Annual Class IV-V Fuel Cell Forklift U.S. Market Penetration

Figure 23 provides the estimated market penetration for the Class IV-V forklifts which are more highly utilized in port applications. Class IV-V fuel cell forklifts are still pre-commercial today, as opposed to Class I-III fuel cell forklifts. In addition, the Class IV-V market segment will remain very competitive in the future with diesel, natural gas, liquified petroleum gas (LPG), and emerging all-electric systems. A relatively stable natural gas liquids market in the future should support the economics of natural gas and LPG forklifts. The Class IV-V fuel cell forklift market should benefit from actions taken to grow the on-highway light and medium duty fuel cell vehicle markets as it develops both from fuel cell system cost reduction as well as local and regional fuel supplies. For these reasons, the Class IV-V fuel cell forklift market penetration is estimated at about 45 percent in 2050, or 56,000 units per year.

Primary Market Penetration Assumptions for Class IV-V Fuel Cell Forklifts

- Competitive market with diesel, natural gas, propane, and emerging electric forklifts.
- Assume forklift market share of one percent in 2020.
- Fuel cell forklifts will benefit from on-road light and medium/heavy duty fuel cell vehicle market development.
- Generally low future natural gas liquids prices will help natural gas and propane markets.
- Class IV-V forklift market will develop more slowly, in concert with on-road medium/heavy duty vehicle market.
- Additional research and development work needed for forklift applications.

7.3.2 Fuel Cell Cargo Handling Equipment

Cargo handling equipment constitutes yard tractors, reach stackers, and heavy-duty lift trucks. Annual sales data from the Port Equipment Manufacturers Association was obtained for estimating future sales forecasts (Port Equipment Manufacturers, 2018). Figure 24 provides the estimated annual fuel cell cargo handling equipment market penetrations.

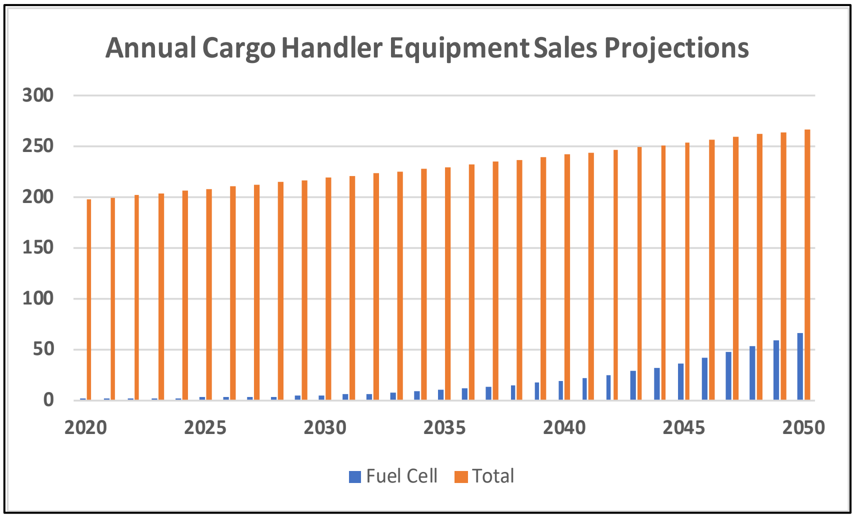

Figure 14. Estimated Annual Fuel Cell Cargo Handling Equipment Market Penetration

Note that total fuel cell market penetration in 2050 is estimated at about 25 percent, or 66 units per year. In general, fuel cell platforms for these applications are in the early prototype stage and still require further development. Average duty cycles for this equipment require high power and significant operational range. Most of the fuel cell platforms to date are incorporate both fuel cells and onboard batteries to meet power demands, and hydrogen storage to meet range requirements. Optimal platform development is still ongoing, and thus pre-commercial incremental capital costs are currently very high. Fuel cell development and costs for these applications should benefit from commercial progress made in fuel cell transit bus and heavy truck markets.

Primary Market Penetration Assumptions for Fuel Cell Cargo Handlers

- Competitive market with diesel and diesel hybrid cargo handlers.
- Only limited prototype platforms produced as of 2020. Assume fuel cell less than one percent in 2020.
- Fuel cell cargo handler equipment will benefit from on-road and nonroad fuel cell heavy vehicles/equipment development.
- Considerable research and development work needed for cargo handler applications.
- Hybrid platforms likely to be developed including fuel cell and battery systems.
- High incremental costs compared with diesel platforms will impact market penetration.
- Battery technology continually improving resulting in the development of competitive diesel hybrid platforms.

7.3.3 Fuel Cell Switcher Locomotives

Figure 25 provides market penetration estimates for fuel cell switcher locomotives. A 2016 study by the California Air Resource Board on freight locomotives formed the basis for annual sales predictions for switcher locomotives (California Air Resources Board, 2016). As provided in the Figure, fuel cell market penetration for switcher locomotives is estimated at about 15 percent in 2050. However, more recently, there has been increased development of fuel cell switcher locomotives and line haul locomotives. Costs for previous prototypes were very high but cost levels can be Expected to lower as technology advances. Recent developments may advance fuel cell locomotive deployment well beyond what is projected here.

High hydrogen fuel volumes are necessary to support fuel cell switcher locomotives which can be a limiting factor in some regions of the country in the near-term. The annual market for switcher locomotives is also limited, and so cost improvements due to economies of scale are not likely. However, some benefits from commercial fuel cell production for other markets could assist in this regard. Government funding assistance may be warranted to offset the high incremental cost of fuel cell switcher locomotives to jumpstart the market for port applications and others.

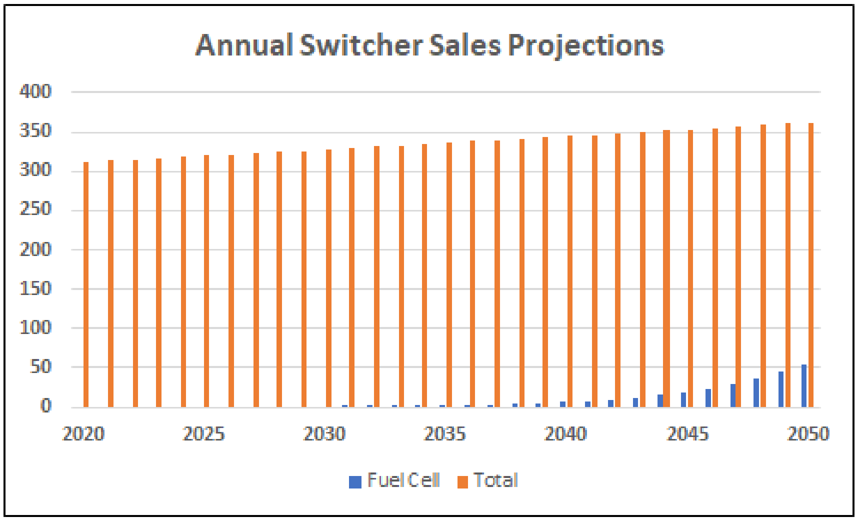

Figure 15. Estimated Annual Fuel Cell Switcher Locomotive Market Penetration

Primary Market Penetration Assumptions for Fuel Cell Switcher Locomotives

- Recent fuel cell switcher research and development
- Primary market competitor are diesel hybrid platforms.
- Hybrid platforms likely incorporating fuel cells and battery systems.
- Necessary hydrogen fuel volumes likely limiting early market development.
- cost of fuel cell switcher prototypes will slow market penetration until hydrogen fuel markets developed and hydrogen prices come down.
- Future market penetration at ports may benefits from other fuel cell port equipment introduction.
- I limited annual market for new switcher locomotives will slow fuel cell switcher market penetration without economies of scale cost benefits for high volume production.

7.3.4 Fuel Cell Marine Propulsion and Power

For purposes of this report, fuel cell marine propulsion applications are defined as harbor craft such as passenger cruise boats, ferry boats, tugboats, and push boats. Data from the Institute for Water Resources U.S. Army Corps of Engineers were used for representing U.S. sales for these applications (U.S. Army Corps of Engineers, 2017). Figure 26 provides the estimated market penetration for fuel cell harbor craft of this type. Market penetration is estimated at about 25 percent in 2050, or about 26 vessels per year.

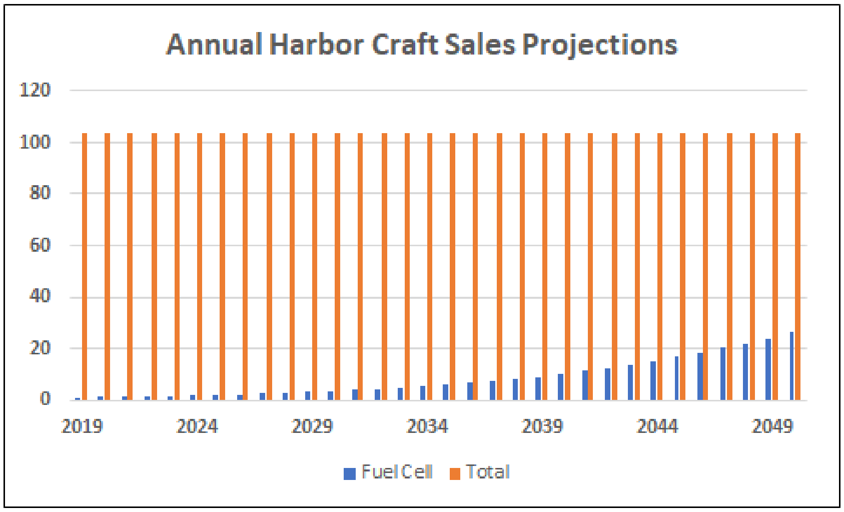

Figure 16. Estimated Annual Fuel Cell Harbor Craft Market Penetration

There has been recent fuel cell propulsion prototype development in harbor craft applications both in the U.S. and Europe, and prototypes are expected to be in service in the next couple of years. In terms of power and energy use requirements in these applications, the primary competitor is likely to be diesel and diesel hybrids, although natural gas engines and biofuels might be competitive in certain markets. Limiting factors for market penetration include very high incremental costs and large fuel volumes that could be problematic to supply in certain regions in early markets. Again, early government funding assistance for marine vessel fuel cell applciations may be warranted to create momentum in the marketplace.

Primary Market Penetration Assumptions for Fuel Cell Harbor Craft

- Only the Sea Change ferry in California and European harbor craft fuel cell vessel prototypes as of 2021.
- No significant market competition other than diesel and diesel hybrid.
- Prototype costs are a limiting factor for early market penetration.
- Necessary hydrogen fuel volumes likely limiting early market development.
- Overall limited annual market for new harbor craft will slow fuel cell market penetration; no economies of scale cost benefits for high volume production.
- Market penetration established once regional fuel supply established.

7.3.5 Fuel Cell Power Generator Systems

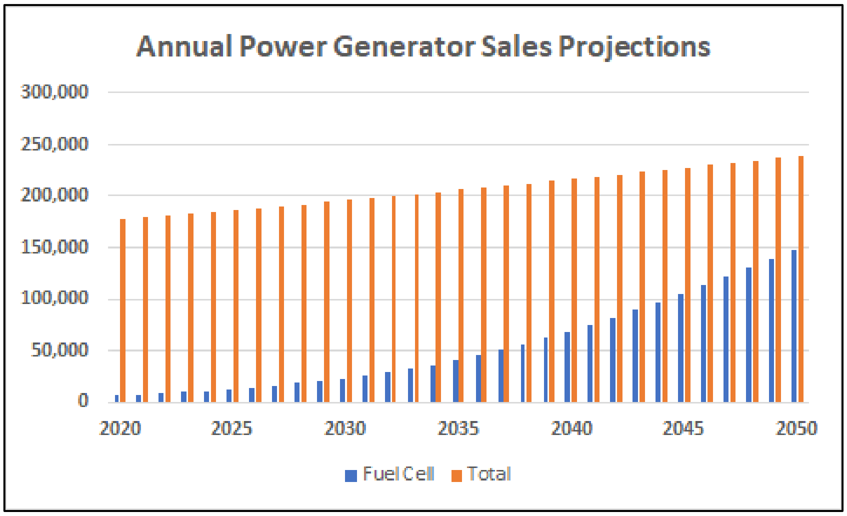

Figure 17. Estimated Annual Fuel Cell Generator Market Penetration

As noted above, stationary power systems have been one of the more successful applications for fuel cell technology to date, with fuel cell systems offered across a range of power levels incorporating different types of fuel cells (E4tech, 2018). As a means of assessing fuel cell market penetration in this segment, representative diesel generator sales data was obtained across the 10 to 6,000 kW power range (Pratt & Chan, Maritime Fuel Cell Generator Project, 2017). Fuel cell market penetration estimates were then derived for power generator sales segment and are shown in Figure 27. Fuel cell market penetration in 2050 is estimated at about 60 percent, or about 148,000 units per year. This assumed over one percent market share currently, and no significant future competition except for diesel engines.

Primary Market Penetration Assumptions for Fuel Cell Power Generators

- Fuel cell power generators about three percent share in 2019.
- No significant market competition other than diesel.
- Fuel cell generator costs on downward trend over last decade.
- Some fuel cell units could run on cheap natural gas or propane until hydrogen is available or cheaper.

Fuel cell system costs for stationary power systems have decreased significantly over the last decade and should continue to decline as systems and balance of plant components are improved. The fuel cell market will likely be slanted towards high power levels as they are cheaper on a per kW basis and the ease of diesel fuel supplies for lower power units will probably be preferred unless hydrogen is being used for other applications on site. Depending on the fuel cell type used, fuel cell generators can also run on hydrogen or natural gas, providing flexibility to some facilities for using the cheapest available fuel.

8. Areas of Uncertainty

8.1 Uncertainty in the Economics and Emissions Analysis

An analysis of the costs and emissions associated with fuel cell equipment revealed several areas of uncertainty:

8.1.1 Economics

- Current hydrogen fuel prices for fuel cell vehicles and equipment vary regionally, but generally range between $13 to $16 per kg. However, these prices correspond with low-volume production, transport, and dispensing. Applying these hydrogen prices in the economics analysis skews the results against fuel cell competitiveness. However, using a Figure more representative of high-volume production poses additional risk, as the high-volume price would be based on speculative market conditions. In response to fuel pricing uncertainties, guidance from the DOE and the national laboratories on future market conditions and fuel pricing promotes the use of more economically viable fuel pricing projections for forecasting fuel cell implementation at ports and other sectors.
- There is some uncertainty in using regional hydrogen fuel feedstock resources as the basis for forecasting centralized plant locations and resultant fuel transport distances to port locations. Additional analysis of water restrictions, competing markets, economic conditions, plant siting restrictions, and other factors would decrease uncertainty in this approach.
- Fuel cell system costing for some equipment applications are based on pre-commercial designs, making comparisons between fuel cell and diesel markets more difficult. Pre-commercial costs are nearly always higher than baseline equipment costs because of the low manufacturing volumes. However, this skews the estimate, making capital costs appear higher than normal, and consequently reducing their applicability in economic comparisons between equipment types. In addition, pre-commercial capital costs are difficult to use in forward pricing scenarios.
- Similar to equipment capital costs, maintenance costs based on in-use performance of pre-commercial designs provide potentially unrepresentative cost estimates at best, and erroneous cost estimates at worst.

8.1.2 Emissions

- Portions of the emission analysis were completed using port equipment inventory information. There were a limited number of inventories available for analysis, which limited this data’s veracity in representing the broader port equipment market.
- The use of models and equipment emission factors has inherent uncertainties for estimating emissions for ports or other types of facilities.

8.2 Current Barriers to the Fuel Cell Implementation at Ports

- High fuel cell equipment costs and hydrogen fuel prices weaken the business case for fuel cells.
- Although fuel system costs have become more competitive with regards to reduced catalyst content and improved design, estimated balance of plant (BOP) costs account for 50 percent of fuel cell costs.
- The lack of hydrogen production volume, long transport distances and high refueling station costs drive hydrogen fuel prices upwards.
- The rapid growth of the electric vehicle market has usurped interest and curbed potential investment in fuel cell equipment in many regions.

- The durability/reliability, performance and operational range associated with some fuel cell port equipment have not been fully realized in the marketplace. Demonstrating the advantages of fuel cell technology is necessary to increase the industry's market share.

8.3 Potential Areas for Future Work

- Additional research should focus on lifecycle emission analysis on the various components of the equipment cycle. Future collaborative efforts with ANL staff could support lifecycle emission research.
- Additional forecasts of hydrogen pricing for high-volume production, transport and dispensing through 2050 would benefit port analytical and decision-making efforts considering future implementation of fuel cell equipment.
- Similarly, forecasts of fuel cell system and equipment costs at varying volumes of production are vital to understanding the economic viability of fuel cell equipment in current and future market conditions.

9. Summary and Conclusions

9.1 Study Overview and Scope

This study involved a comprehensive evaluation of fuel cell technology and its applications in port equipment for replacing comparable diesel-fueled equipment. The study was intended to provide EPA with a more thorough understanding of fuel cell applications within the port environment and their potential impacts on equipment operation, performance, emissions, and cost.

The specific research areas covered in the study and presented in this report include:

- Fuel Cell Types and Characteristics
- Fuel Cell Market Status
- Fuel Cell Applications and Characteristics for Ports
- Fuel Cell Fuel Supply Infrastructure
- Port Fuel Cell Equipment, Infrastructure, and Fuel Costs
- Hydrogen Fuel Cell Lifecycle Emissions
- Future Hydrogen and Fuel Cell Market Penetration

A summary of key findings in these areas is provided below.

9.2 Summary of Key Findings

9.2.1 Fuel Cell Types and Characteristics

Fuel cells are characterized according to their electrolyte type. There are five primary types of fuel cells that are currently on the market and/or under further development. These include:

- Polymer Electrolyte Membrane, or PEMFCs
- Alkaline, or AFCs
- Phosphoric Acid, or PAFCs
- Molten Carbonate, or MCFCs
- Solid Oxide, or SOFCs

Table 46 provides a summary of common characteristics for these fuel cell types. Low temperature fuel cells include PEMFC and AFCs, while MCFCs and SOFCs are considered high temperature fuel cells (U.S. Department of Energy Fuel Cell Technologies Office, 2019). The fuel cells with the highest efficiencies are PEMFCs, AFCs, and SOFCs. The high temperature fuel cells tend to have greater tolerance for air and fuel impurities, but all fuel cell types require high purity fuels to limit catalyst poisoning. Fuel quality is a key aspect of fuel cell maintenance.

Table 21. Common Fuel Cell Type Characteristics

Fuel Cell Type	Common Electrolyte	Operating Temp/ Electrical Efficiency (LHV)	Common Applications	Current Challenges
PEMFC	Water- or mineral-based acidic polymer	140 – 212°F/60%	On-road vehicles, mobile nonroad equipment, mobile power supplies, stationary power sources	Expensive catalysts; CO and sulfur poisoning
AFC	Aqueous solution containing potassium hydroxide in a porous matrix	158 – 212°F/60%	Distributed generation and remote stationary power	Electrolyte management; CO_2 poisoning
PAFC	Phosphoric acid in a porous matrix or polymer membrane	302 – 392°F/40%	Stationary power and DG generation including CHP	Expensive catalysts; long-start up time; CO and CO_2 poisoning
MCFC	Molten lithium, sodium, and potassium carbonates in a porous matrix	1,112 – 1,292°F/50%	Large stationary power generation including CHP	High temperature corrosion; long start-up time; low power density
SOFC	Zirconium oxide stabilized with yttrium oxide	932 – 1,832°F/60%	Stationary power including CHP, small portable power, CHP, automotive auxiliary power systems	High temperature corrosion; long start-up time; limited number of shutdowns

9.2.2 Fuel Cell Market Status

Worldwide fuel cell markets have emerged for a variety of stationary power and transportation applications (E4tech, 2018). Transportation applications and stationary power applications made up a combined total of about 69,000 fuel cell shipments in 2018 and over 800 MW shipped capacity. As shown in Figure 28, Asia is the largest fuel cell market accounting for almost 75 percent of total worldwide fuel cell shipments in 2018. Much of the Asian market (over half of the fuel cells shipped in 2018) can be attributed to the fuel cell demand for residential CHP applications under the Japanese Ene-Farm program. North America accounted for only about 13 percent of market shipments in 2018, but about 52 percent of total MW capacity. PEMFCs are dominant in the marketplace with about 58 percent of total worldwide fuel cell shipments, and SOFCs were second with about 36 percent. PEMFCs are being applied across both stationary and transportation applications, while SOFCs have been relegated to stationary applications, including CHP.

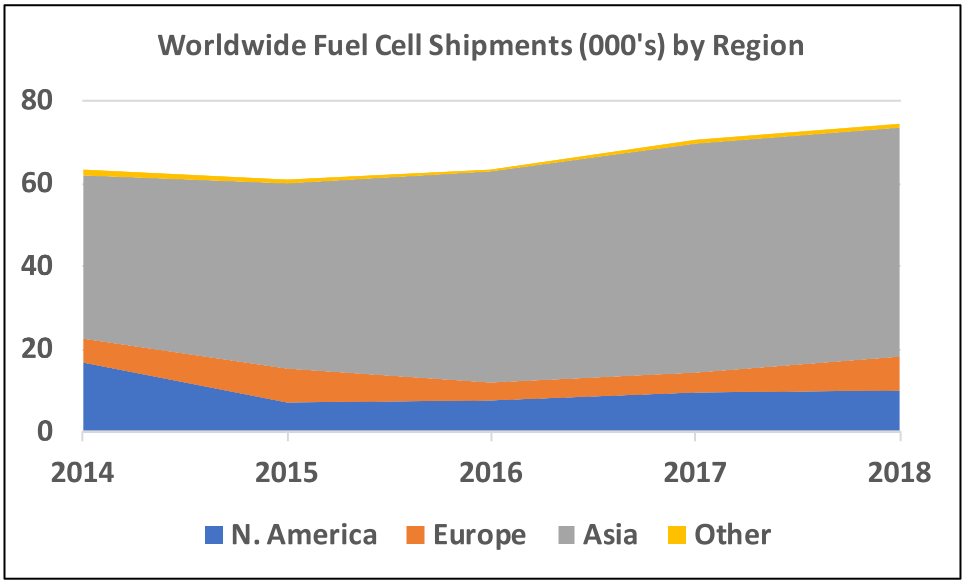

Figure 18. Worldwide Fuel Cell Market Status in 2018

9.2.3 Fuel Cell Equipment Applications and Characteristics for Ports

There is considerable potential for the application of fuel cell technology in port applications including on-highway vehicles, nonroad vehicles, rail, marine and stationary power applications. Many of these applications are part of current or planned formal demonstrations of pre-commercial and commercial fuel cell equipment.

Table 47 lists typical port equipment applications, the most common fuel cell types for these applications and their commercial status. As noted in the table, PEMFCs are the primary technology used in the port-related equipment listed. Additional market details for each port fuel cell equipment application are listed below.

Table 47. Typical Diesel-Fueled Equipment Characteristics Used at Port Facilities and Common Fuel Cell Replacements

Diesel Equipment Type	Common Fuel Cell Types	Estimated Fuel Cell Equipment Commercial Status*	Application Summary
Forklift	PEMFC	TRL 7 Class IV, V and higher	Commercially available for Classes I, II and III; pre-commercial demonstration for Classes IV, V and higher.
Yard Tractor	PEMFC	TRL 7	Pre-commercial demonstrations.
Cargo Handlers	PEMFC	TRL 7	Pre-commercial demonstrations.
Switcher Locomotives	PEMFC	TRL 6-7	Pre-commercial switcher and line haul demonstrations are on-going. Recent domestic and international pre-commercial passenger train demonstrations are advancing technology.
Harbor Craft			Both domestic and international pre-commercial demonstrations for propulsion and onboard power.
Propulsion	PEMFC	TRL 7	
Auxiliary	PEMFC, SOFC	TRL 7	
Power Generator	PEMFC, AFC, PAFC, MCFC, SOFC	TRL 9	Commercially available in 5 kilowatt (kW) - 10 megawatt (MW) capacities for stationary, back-up, and portable power applications.

*Based on the DOE Technology Readiness Level (TRL) Scale

Forklifts

- As of early 2018, the DOE estimated that almost 22,000 Class I to III fuel cell forklifts have been deployed in the U.S. In these classes, forklifts are successfully competing with all-electric forklifts (DOE Hydrogen and Fuel Cells Program , 2018).
- For Class IV and higher forklifts, pre-commercial fuel cell versions are being demonstrated or planned for development.

Yard Tractors and Cargo Handlers (e.g., Top Loaders)

- Pre-commercial fuel cell yard tractors have been developed and are being demonstrated at present.
- Platforms have typically been “hybrid” platforms, incorporating both fuel cells and battery packs on an electric motor drivetrain. Depending on the platform, the fuel can be used as a range extender to charge the battery pack or may provide primary propulsion power.
- Most platforms incorporate energy recovery systems that capture a portion of energy typically lost from braking to recharge onboard battery packs and increase overall operational range. Some cargo handler platform energy recovery systems capture normally lost energy from braking and lowering loads.

Switcher Locomotives

- Pre-commercial fuel cell switcher and line haul locomotives are being developed and demonstrated in service.
- “Hydrorail” developments, both internationally and in the U.S., involving hydrogen fuel cell passenger train locomotives may stimulate new efforts in fuel cell locomotive applications, especially given their potential to improve local air quality.

Marine Propulsion and Auxiliary Power

- A study by SNL determined that most marine vessel types can be viable applications for propulsion or power, except for vessels requiring multi-MW power capacities and associated impractical, large hydrogen storage volumes.
- Internationally, fuel cell system research has focused on lower power and shorter-range harbor craft vessels such as passenger ferries, inland cruise boats and push/tow boats.
- In 2022, A U.S. industry consortium began conducting sea trails of a hydrogen fuel cell-powered passenger ferry for deployment in the California Bay Area.

Power Generator

- A range of commercial fuel cell stationary power systems from kW to MW power levels are available.
- According to the HARC (Hydrogen Analysis Resource Center , 2019), 580 active stationary power installations have been deployed across the country. As of September 2018, the vast majority (81 percent) of installations were SOFCs.

9.2.4 Fuel Cell Fuel Supply Infrastructure

Current annual U.S. hydrogen production stands at about 10 million metric tons for supporting its primary markets of petroleum refining and fertilizer production. While the supply infrastructure in terms of production plants, regional pipelines, and terminal storage are well-established for serving these two current sectors, the same cannot be stated for future hydrogen fuel cell markets. Currently, fuel cell equipment users must generally work through equipment manufacturers to secure a local supply of high-quality hydrogen from an industrial gas supply company. To meet future hydrogen demand for widescale fuel cell equipment use, including port users, a significant expansion of existing production, storage, and distribution infrastructure is necessary.

9.2.4.1 Hydrogen Production Processes

A vast variety of hydrogen production processes are currently available or under development. These include SMR, partial oxidation of natural gas, gasification of biomass or coal feedstocks, water electrolysis using electricity, biomass-to-liquids (ethanol) followed by reformation, microbial biomass conversion (or dark fermentation), and ammonia cracking. SMR using natural gas feedstock is by far the most prominent hydrogen production process and currently produces about 95 percent of hydrogen supplies today (Ogden, 2018). The remaining 5 percent of current hydrogen production results from by-product production from refinery and chemical plant processing such as hydrocracking plants and chemical plants. Smaller SMR plants are also available for local or onsite hydrogen production. Water electrolysis is also a common hydrogen production process. Electrolyzers typically incorporate polymer electrolyte membrane or alkaline electrolytes and are available as small plants for onsite installation and have been demonstrated at port facilities.

Table 48 summarizes the feedstock, energy use, and water consumption requirements for various thermochemical and electrolytic hydrogen production processes (Mehmeti, 2018). Several processes have significant water consumption requirements, which may impact plant locations in the U.S. under water use restrictions. In addition, high electricity consumption is required for many of the processes, especially the electrolytic processes. Electrical power for the electrolysis process is generally grid-based, so the sources of grid electricity can significantly affect both electrolyzer economics and its lifecycle emissions. For this reason, current research is being conducted on electrolyzers principally powered by onsite renewable energy sources such as wind and solar.

Table 48. Feedstock, Water, and Electricity Requirements for Hydrogen Production Processes

Type/Conversion Pathway	Thermo-Chemical				Electrolysis	
	Steam Methane Reforming	Coal Gasification	Biomass Gasification	Biomass Reformation	Proton Exchange Membrane	Solid Oxide Electrolysis
Natural Gas (MJ/kg H_2)	165	---	6.228	---	---	50.76
Coal (kg/kg H_2)	---	7.8	---	---	---	---
Biomass (kg/kg H_2)	---	---	13.5	6.54	---	---
Electricity (kWh/kg H_2)	1.11	1.72	0.98	0.49	54.6	36.14
Water (kg/kg H_2)	21.869	2.91	305.5	30.96	18.04	9.1

9.2.4.2 Hydrogen Storage and Transport Technologies

Following large-scale production, hydrogen is typically stored in bulk storage tanks before transport to regional or local end use markets. Bulk hydrogen storage is either as a gaseous or liquid product. In gaseous form, hydrogen storage is typically pressurized to 2,500–5,000 psi and stored in large cylindrical steel storage tanks. In liquid form, hydrogen must be cooled to below its boiling point of -423°F using a liquefaction process, and then stored in insulated, cryogenic storage cylinders.

In terms of transport, hydrogen can be moved via a variety of modes depending on distance and hydrogen product type (gaseous or liquid). Currently, there is over 1,600 miles of hydrogen pipeline in the U.S. (U.S. Drive Partnership, November 2017). Most of this existing pipeline is in California, Louisiana, and Texas for supporting large-scale hydrogen production for the petroleum refining industry. Pipelines are the most economical means of transporting gaseous hydrogen long distances (over 1,000 miles). Regional and local hydrogen distribution from production to terminal storage and/or to the end use site via truck transport is very common today for either as gaseous or liquid product. Although less common, liquid hydrogen can be transported long distances via rail car, ship, and barge.

Once hydrogen product arrives onsite as gaseous or liquid product it can be stored locally until ready for use. Stationary power fuel cell applications can typically be fed gaseous hydrogen directly. For mobile fuel cell equipment, gaseous hydrogen would typically be boosted in pressure before dispensing to increase the stored hydrogen energy density onboard the equipment. Most commercial dispensing systems can provide hydrogen gas at either 350 bar (5,000 psi) or 700 bar (10,000 psi) pressures.

As with most fuel energy carriers, there are safety considerations for the storage, handling, and dispensing of hydrogen fuel product. Hydrogen has significantly different fuel properties than diesel fuel and should be handled differently to mitigate potential fire and exposure risks. While diesel fuel is a low volatility fuel at ambient conditions, hydrogen is gas at ambient condition that can readily mix with air. Hydrogen has much wider flammability limits and burns almost invisibly. Enclosed facilities that store or maintain hydrogen fuel cell equipment must be properly designed for hydrogen gas releases and leaks. Liquid hydrogen product, which is cryogenic, should be handled with care to prevent personal exposure to fuel spills or uninsulated dispensing equipment which could result in severe frost bite.

9.2.4.3 *Future Potential Hydrogen Production and Delivery Pathways*

Future hydrogen delivery from production to end use will likely follow two pathways: Centralized and Distributed Pathways. Centralized pathways involve large-scale hydrogen production (50,000–500,000 kg/day) for serving regional or even national end use markets depending on plant location. Hydrogen product is transported via pipeline, truck, or rail to end use markets. For distributed pathways, hydrogen is produced locally or onsite to support specific end users. Hydrogen product carriers such as natural gas or water are transported to the site to be used as feedstocks in small scale (less than 1,500 kg/day) SMR or electrolytic hydrogen production processes. The choice between centralized and distributed hydrogen production will depend on availability and proximity to feedstocks and process energy sources, size of regional or local markets, and hydrogen production process efficiency, costs, and market, environmental, socioeconomic impacts. While centralized and distributed plant sizes may be most common in early hydrogen market development, production facilities between the 1,500 and 50,000 kg/day size may also arise for meeting regional hydrogen markets (U.S. Drive Partnership, November 2017), potentially growing into centralized plants serving broader geographical regions.

Table 49 provides an estimated implementation timeline for various centralized and distributed hydrogen pathways based on DOE program information (DOE Fuel Cell Technologies Office, 2019). The near and mid-term hydrogen production candidates for centralized pathways include natural gas reforming, biomass and coal gasification, renewable energy supported electrolysis, and high temperature electrolysis using nuclear or renewable energy. While hydrogen by-product production from hydrocracking and chlorine production plants are also commercially available, these processes are more likely to support market demand rather than serve as full-scale centralized plants. The most promising distributed pathways at this time include natural gas reforming, electric grid-based electrolysis, bio-derived liquids reforming (ethanol), and microbial biomass conversion.

Table 49. Implementation Timeframes for Centralized and Distributed Hydrogen Pathways

2020 - 2030 Timeframe	2030 - 2040 Timeframe	2040+ Timeframe
	Centralized Pathways	
NG SMR (500,000 kg/day plants)	Biomass Gasification (100,000 kg/day plants)	High Temperature Electrolysis (500,000 kg/day plants)
	Electrolysis - Wind/Solar (50,000 – 100,000 kg/day plants)	
	Coal Gasification (500,000 kg/day plants)	
	Distributed Pathways	
NG SMR (1,500 kg/day plants)	Bio-derived Liquids Reforming (1,500 kg/day plants)	Microbial Biomass Conversion (1,500 kg/day plants)
Grid-based Electrolysis (1,500 kg/day plants)		

While each of the centralized pathways has significant potential for serving future hydrogen markets, some of these options are more likely to be regionally rather than nationally significant. In terms of distributed pathways, the existing natural gas pipeline system would support the use of natural gas as a viable hydrogen carrier source for onsite hydrogen production, and small-scale SMR plants are already commercially available. Water electrolysis is the second most used hydrogen production process behind SMR and small-scale water electrolysis plants are commercially available now. While the water distribution system in the U.S. is ubiquitous and port locations are thusly well-served, the water requirements for small-scale electrolysis are higher than other distributed production processes which may be a limiting factor in some jurisdictions.

It should be noted too that there are non-hydrogen fuel sources that can be used directly by some types of fuel cells. These fuels include natural gas, ammonia, and methanol. For example, natural gas, which can be delivered onsite via pipeline, can be used in MCFCs and SOFCs in stationary power applications. Methanol, a widely distributed chemical in the U.S., can be used in DMFCs which are specialized PEMFCs. DMFCs are currently used extensively in portable power applications but could also be adapted to other stationary power applications. Ammonia is also a widely used chemical in the U.S. and thus supported by an expansive distribution system, especially in the agricultural and pharmaceutical industries. Ammonia can generally be used directly in AFCs, AMFCs, and SOFCs, but further research is needed before these applications are commercialized.

9.2.5 Port Fuel Cell Equipment, Infrastructure, and Fuel Costs

9.2.5.1 Refueling Station Capital and Operating Costs

A review of several recent studies of hydrogen station economics determined that station capital costs on a per kg dispensed basis are higher for smaller capacity stations than for larger stations. In addition, there is a large difference in station capital costs on a per kg dispensed basis between the stations associated with centralized versus distributed delivery. From a station operating cost standpoint, centralized production served stations generally have lower costs than distributed served stations for the same hydrogen dispensed capacity. The onsite grid-electrolysis stations exhibited the highest operating costs due primarily to their intensive electricity usage.

9.2.5.2 Dispensed Hydrogen Price

The final cost to the end user for dispensed hydrogen ($/kg) must account for all production and delivery pathway elements. This is especially important for centralized production pathways that include costs for production and transport to the site on top of amortized costs for station capital cost recovery and operations.

Levelized pathways costs were compiled from several studies and placed on a kg produced or transported basis. Final dispensed hydrogen costs were then estimated by summing the pathway costs with the station capital and operating costs on a kg delivered basis. Based on a ten-year station lifetime, centralized pathway levelized dispensed fuel costs ranged from about $4.98–$9.84 per kg, while those for distributed pathways ranged from $5.43–$12.28 per kg for station capacities ranging from 100–1,000 kg/day. These costs dovetail well with DOE long-term projected hydrogen cost of less than $4/kg assuming high-volume production (Satyapal, 2018).

9.2.6 Port Fuel Cell Equipment Costs by Port Application

Port fuel cell equipment cost estimates were derived for the following types of port equipment: forklifts, yard tractors, cargo handlers (top loaders), switcher locomotives, marine vessels, and power generators. Incremental pricing between fuel cell and comparable diesel-fueled equipment was based on available cost information and projections and typical equipment operating characteristics and anticipated lifetimes. Results for the assessment of capital and annual maintenance costs are provided in Table 50 for years 2020 and 2030. Diesel fuel costs represent EIA projections (except for the switcher locomotive case, which is based on Surface Transportation Board figures), while hydrogen pricing is based on DOE projected near-term and long-term cost estimates. Note that the costs for all the port fuel cell equipment are higher than those of comparable diesel equipment in 2020 and 2030. In 2030, annual operating savings are generated for some fuel cell equipment as a result of its higher fuel efficiency and the lower hydrogen pricing. As a result of these savings, reasonable capital payback is possible for fuel cell forklift, yard tractor, cargo handler, and generator applications in 2030. Thus, ports could realize significant economic benefit from the implementation of fuel cell equipment as future fuel cell costs decrease with improved designs and higher-volume manufacturing, and hydrogen fuel pricing drops due to higher-volume production.

Table 50. Fuel Cell Equipment Capital and Operating Cost Results

Comparative Cost Parameter	Forklift	Yard Tractor	Cargo Handler	Switcher Locomotive	Ferry Boat	Generator
Assumed Useful Lifetime	10	12	12	20	20	10
Assumed Utilization (Hr/yr)	1,500	1,600	2,000	1,500	2,800	3,000
Year 2020						
Assumed Hydrogen Price ($/kg)	13.00	13.00	13.00	13.00	11.64	13.00
Assumed Diesel Price ($/gal)	3.33	3.33	3.33	2.07	3.33	3.33
Incremental Capital Cost ($)	39,194	115,000	142,578	1,922,543	5,566,000	212,000
Annual Operating Savings ($)	-8,494	-15,484	-53,817	-316,261	-5,038,704	-32,975
Estimated Simple Payback (Yrs)	None	None	None	None	None	None
Year 2030						
Assumed Hydrogen Price ($/kg)	5.00	5.00	5.00	5.00	4.40	5.00
Assumed Diesel Price ($/gal)	3.76	3.76	3.76	2.34	3.76	3.76
Incremental Capital Cost ($)	16,214	48,614	77,494	1,922,536	1,117,764	52,225
Annual Operating Savings ($)	2,227	8,515	33,804	-53,165	-887,027	6,839
Estimated Simple Payback (Yrs)	7.3	5.7	2.3	None	None	7.6

9.2.7 Hydrogen Fuel Cell Lifecycle Emissions

A comprehensive illustrative lifecycle emissions assessment was completed for port fuel cell equipment by estimating WTP and PTW emission components relative to low sulfur (15 ppm) diesel. WTP emissions analyses were conducted using ANL's 2019 GREET model. In general, the analysis determined that hydrogen production and transport pathways are more energy and water use intensive than that for diesel fuel. Criteria pollutant and GHG emissions from the hydrogen pathways generally correlated with energy use and fossil energy fractions. Thus, centralized and distributed SMR and grid-based electrolysis produced the highest criteria pollutant and GHG emissions. The centralized and distributed solar-based electrolysis generally produced the lowest criteria pollutant and GHG emissions. Further, an analysis of electricity generation sources for serving the distributed grid-based electrolysis indicated that electricity mixes with high fossil energy (especially coal) and low renewable energy produce much higher WTP emissions than electricity generated from low fossil energy and high renewable energy mixes. This means that WTP results from grid-based electrolysis are very dependent on the region of the country and its electricity generation sources.

In terms of PTW emissions, fuel cell equipment offers a distinct advantage over comparable diesel equipment across all criteria pollutants, air toxics, and GHG emissions as fuel cell emit only water vapor and heat.

Final WTW emission results were derived by combining the respective WTP and PTW emission components of fuel cell and diesel equipment, respectively. The increased fuel efficiencies of fuel cell equipment relative to diesel equipment were considered in deriving the WTW results. (Port fuel cell equipment applications were estimated to be 1.4-2.5 times more efficiency than comparable diesel equipment.) Table 51 lists directional results for each of the port equipment and the hydrogen fuel pathways relative to low sulfur diesel. A green "+" indicates an emission reduction, while a red "-" signifies an emissions increase. Overall, WTW emissions were seen across pollutants and hydrogen pathways. Significant reductions were seen for VOC and NO_x

Table 22. WTP Emission Reduction Summary for Port Fuel Cell Equipment Relative to Diesel Equipment

Equipment Type	Hydrogen Fuel Pathway	WTW Emission Reductions Relative to Diesel-Fueled Equipment (g/kg H_2								
		VOC	CO	NO_x	PM_{10}	$PM_{2.5}$	SO_2	CO_2	CH_4	N_2O
Yard Tractor	Centralized NG SMR	+	+	+	+	+	-	+	+	-
	Centralized Biomass Gasification	+	+	+	+	+	-	+	+	+
	Centralized Electrolysis Solar	+	+	+	+	+	+	+	+	+
	Distributed NG SMR	+	+	+	+	+	-	+	-	-
	Distributed Electrolysis Solar	+	+	+	+	+	+	+	+	+
	Distributed Electrolysis Grid (US Avg)	+	-	+	-	-	-	+	-	-
	Distributed Electrolysis Grid (Hi Coal)	+	+	+	-	-	-	-	-	-
	Distributed Electrolysis Grid (Lo Coal)	+	-	+	-	-	+	+	+	+
Forklift	Centralized NG SMR	+	+	+	+	+	-	+	+	-
	Centralized Biomass Gasification	+	+	+	+	+	-	+	+	+
	Centralized Electrolysis Solar	+	+	+	+	+	+	+	+	+
	Distributed NG SMR	+	+	+	+	+	-	+	-	-
	Distributed Electrolysis Solar	+	+	+	+	+	+	+	+	+
	Distributed Electrolysis Grid (US Avg)	+	+	+	-	+	-	+	+	+
	Distributed Electrolysis Grid (Hi Coal)	+	+	+	-	+	-	-	-	-
	Distributed Electrolysis Grid (Lo Coal)	+	+	+	-	+	+	+	+	+
Cargo Handler (Top Loader)	Centralized NG SMR	+	+	+	+	+	-	+	+	-
	Centralized Biomass Gasification	+	+	+	+	+	-	+	+	+
	Centralized Electrolysis Solar	+	+	+	+	+	+	+	+	+
	Distributed NG SMR	+	+	+	+	+	-	+	-	-
	Distributed Electrolysis Solar	+	+	+	+	+	+	+	+	+
	Distributed Electrolysis Grid (US Avg)	+	-	+	-	+	-	+	-	-
	Distributed Electrolysis Grid (Hi Coal)	+	+	+	-	-	-	-	-	-
	Distributed Electrolysis Grid (Lo Coal)	+	-	+	-	-	+	+	+	+
Assist Tugboat	Centralized NG SMR	+	+	+	+	+	-	+	-	+
	Centralized Biomass Gasification	+	+	+	+	+	-	+	+	+
	Centralized Electrolysis Solar	+	+	+	+	+	-	+	+	+
	Distributed NG SMR	+	+	+	+	+	-	+	-	+
	Distributed Electrolysis Solar	+	+	+	+	+	+	+	+	+
	Distributed Electrolysis Grid (US Avg)	+	+	+	+	+	-	-	-	+
	Distributed Electrolysis Grid (Hi Coal)	+	+	+	+	+	-	-	-	-
	Distributed Electrolysis Grid (Lo Coal)	+	+	+	+	+	-	+	+	+
Ferry	Centralized NG SMR	+	+	+	+	+	-	+	-	+
	Centralized Biomass Gasification	+	+	+	+	+	-	+	+	+
	Centralized Electrolysis Solar	+	+	+	+	+	-	+	+	+
	Distributed NG SMR	+	+	+	+	+	-	+	-	+
	Distributed Electrolysis Solar	+	+	+	+	+	+	+	+	+
	Distributed Electrolysis Grid (US Avg)	+	+	+	+	+	-	-	-	+
	Distributed Electrolysis Grid (Hi Coal)	+	+	+	-	+	-	-	-	-
	Distributed Electrolysis Grid (Lo Coal)	+	+	+	-	+	-	+	+	+
Harbor Tugboat	Centralized NG SMR	+	+	+	+	+	-	+	-	+
	Centralized Biomass Gasification	+	+	+	+	+	-	+	+	+
	Centralized Electrolysis Solar	+	+	+	+	+	-	+	+	+
	Distributed NG SMR	+	+	+	+	+	-	+	-	+
	Distributed Electrolysis Solar	+	+	+	+	+	+	+	+	+
	Distributed Electrolysis Grid (US Avg)	+	+	+	+	+	-	-	-	+
	Distributed Electrolysis Grid (Hi Coal)	+	+	+	-	+	-	-	-	-
	Distributed Electrolysis Grid (Lo Coal)	+	+	+	-	+	-	+	+	+
Switcher Locomotive	Centralized NG SMR	+	+	+	+	+	-	+	-	+
	Centralized Biomass Gasification	+	+	+	+	+	-	+	+	+
	Centralized Electrolysis Solar	+	+	+	+	+	-	+	+	+
	Distributed NG SMR	+	+	+	+	+	-	+	-	-
	Distributed Electrolysis Solar	+	+	+	+	+	+	+	+	+
	Distributed Electrolysis Grid (US Avg)	+	+	+	+	+	-	-	-	-
	Distributed Electrolysis Grid (Hi Coal)	+	+	+	+	+	-	-	-	-
	Distributed Electrolysis Grid (Lo Coal)	+	+	+	+	+	-	+	+	+
Stationary Generator	Centralized NG SMR	+	+	+	+	+	-	+	-	+
	Centralized Biomass Gasification	+	+	+	+	+	-	+	+	+
	Centralized Electrolysis Solar	+	+	+	+	+	-	+	+	+
	Distributed NG SMR	+	+	+	+	+	-	+	-	-
	Distributed Electrolysis Solar	+	+	+	+	+	+	+	+	+
	Distributed Electrolysis Grid (US Avg)	+	+	+	+	+	-	+	-	-
	Distributed Electrolysis Grid (Hi Coal)	+	+	+	+	+	-	-	-	-
	Distributed Electrolysis Grid (Lo Coal)	+	+	+	+	+	+	+	+	+

emissions for all port equipment and hydrogen fuel pathways. CO, PM_{10}, and $PM_{2.5}$ emission reductions were achieved for most hydrogen pathways and equipment except for grid-based electrolysis. CO_2 emissions reductions were observed for all hydrogen fuel pathways, with the exception of high coal/low renewables grid-based electrolysis and U.S. average generation grid-based electrolysis for some equipment applications. CH_4, N_2O emissions were mixed across pathways and port applications, with lower emissions generally being achieved with biomass gasification, solar-based electrolysis, and low coal/high renewables electrolysis pathways.

Only SO_2 emissions were higher for many port fuel equipment and hydrogen fuel pathways except for solar-based electrolysis and low coal/high renewables generation grid-based electrolysis. Overall, the solar-based electrolysis pathway achieved the best emissions among the centralized and distributed pathway cases. The performance of distributed grid-based electrolysis is highly dependent on regional electricity generation mix. Ports with electricity generated from fossil (especially) coal and low renewable resource generation will produce higher WTW emissions for the grid-based electrolysis compared to regions with low fossil energy and high renewable resources. Further, the WTW emission results were dictated by specific assumptions for both WTP and PTW estimates.

9.2.8 Future Hydrogen and Fuel Cell Market Penetration

9.2.8.1 Primary Factors for Future Fuel Cell Commercial Viability and Competitiveness

Various factors were identified as impactful on the future market viability of fuel cells in ports and other sector applications. These factors included:

- **Equipment capital cost** – Current fuel cell system costs are higher than comparable diesel powerplants. Much of this cost variance is low-volume manufacturing. Fuel cell system costs are expected to decrease in the near- to mid-term as fuel cell designs improve and manufacturing volumes increase.
- **Required emission reductions** – For ports with high future emission reduction targets, fuel cell equipment can help meet future emission inventory goals.
- **Equipment durability/reliability** – Fuel cell durability and reliability across equipment applications have improved considerably, including port equipment. The DOE expects fuel cell systems will meet targets (that is, 5,000 hours for mobile applications and 80,000 hours for SOFC stationary applications) within the next two to four years.
- **Equipment power/duty cycle performan**ce – The general scalability of fuel cells should allow fuel cell systems to meet most demanding power and duty cycle requirements for port equipment.
- **Equipment operational hours/range** – For most port equipment, operational ranges for fuel cell-powered equipment are like those of diesel-fueled equipment. For some port equipment such as top loaders and marine propulsion, hybrid fuel cell battery systems and improved hydrogen storage systems are under development to assist in meeting specific operational requirements.
- **Equipment maintenance/serviceability** – While scheduled maintenance for fuel cell systems is generally less frequent than comparable diesel equipment, pre-commercial systems have exhibited higher rates of unscheduled maintenance. As pre-commercial fuel cell systems continue to develop, unscheduled maintenance episodes are anticipated to decrease.
- **Hydrogen fuel price** – Fuel price is a limiting factor for fuel cell equipment market growth. Dispensed hydrogen market prices are currently about \$13-16/kg in many areas of the country (or about \$7.55-9.30/DGE when adjusted for the energy content and higher fuel efficiency of hydrogen) (Satyapal, 2018).

DOE expects hydrogen costs to decrease to about $2.91-5.81/DGE efficiency adjusted in 2025, and to less than $2.32/DGE efficiency adjusted in the long-term. These future hydrogen prices compare favorably with EIA diesel fuel price forecast of $4.05/gallon in 2045 (U.S. Energy Information Administration, 2020).

9.2.8.2 Future Potential Hydrogen Fuel Supply and Demand

Future hydrogen demand will be comprised of both existing capacity and emerging markets. Recent NREL and ANL research under DOE’s H2@Scale initiative determined the total technical potential hydrogen demand at about 166 million metric tons per year by 2050, a sixteen-fold increase over current annual hydrogen productions levels.

9.2.8.3 Future Fuel Cell Equipment Market Penetration Estimates

Market penetration estimates for port fuel cell equipment applications were estimated for the 2020-2050 timeframe based on future market assumptions and employing an S-curve market penetration methodology. As provided in Figure 29, high fuel cell market penetration was estimated for new purchases of generators and forklifts based on their current status in the market and anticipated competitiveness in future markets.

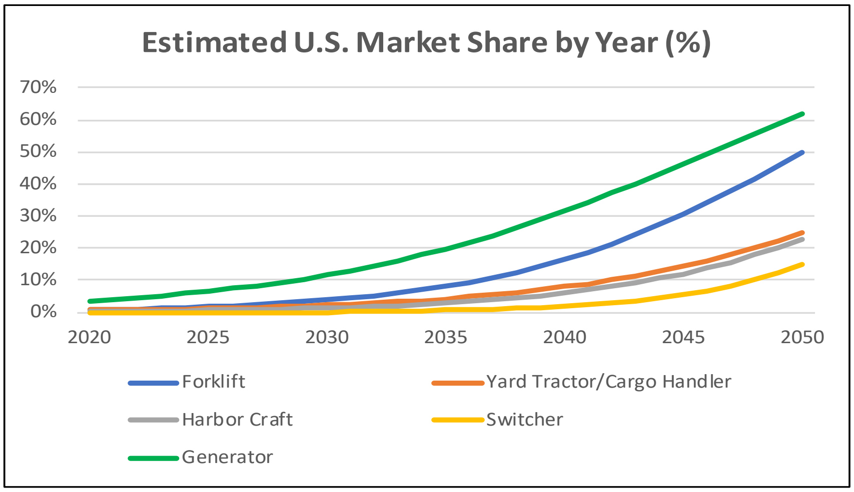

Figure 29. Estimated Port Fuel Cell Equipment Market Penetration (2020-2050)

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Appendix A-
Summary of Recent Fuel Cell Equipment Demonstrations and Deployments at U.S. Ports

Table A-1. Recent Fuel Cell Demonstrations and Deployments at U.S. Ports

Project Name (Port Location)	Port Application	Fuel Cell Manufacturer/Type	Installation Date/ Planned Date	FC Design and Operational Information
Alcatraz Island National Park Ferry Boat Embarkation Dock, San Francisco, California	Portable fuel cell-powered mobile light tower for ferry boat embarkment dock	Plug Power/PEM	Fall 2016	The 1,100 W fuel cell in the Luxfer-GTM Technologies Zero-Set Lite uses hydrogen fuel and provides up to 36 hours of continuous LED lighting. The Zero-Set Lite provided critical working light for a scheduled overnight barge exchange operation at Alcatraz Island National Park. The project was undertaken by Alcatraz Cruises, Alcatraz Island's official National Park Service ferry service concessioner. Ferry boat embarkment dock serves about 5,000 visitors per day.
Zero Emission Cargo Transportation Program (ZECT II program) (Ports of Long Beach and Los Angeles/San Pedro Bay Ports)	Drayage truck	1. BAE/Ballard/Kenworth – Electric with PEM FC range extended drayage truck 2. Hydrogenics/Siemens – Electric with PEM FC range extended drayage truck 3. Transpower/Hydrogenics/Navistar – Electric with PEM FC range extended drayage truck 4. U.S. Hybrid/US FuelCell/International – Electric with PEM FC range extended drayage truck	The demonstration phase of this project is expected to start by Q1 2018 with at least two trucks, one each from TransPower and US Hybrid. The project is set be completed by Q3 2019 and the commercialization of these truck technologies can be expected after 2019.	BAE/CTE – Ballard Fuel cell range extended drayage truck; 100 kWh Lithium technology batteries; Auxiliary Power Unit (Range Extender) is 100 kW Fuel Cell providing power to charge batteries; 30 kg Onboard hydrogen fuel storage system. BAE plans to build and install a FC APUs on one fully integrated truck systems for drayage service demonstration. BAE anticipates that the 30 kg of hydrogen (25 kg usable) will provide approximately 110 to 120 miles of range between re-fueling. Hydrogenics/Siemens - will develop a hydrogen fuel cell drayage truck powered by their latest advanced fuel cell drive technology (Celerity Plus fuel cell power system) and Siemens' ELFA electric drivetrain, customized for heavy duty vehicle applications. The proposed fuel cell drayage truck is designed to be capable of delivering over 150 miles of zero emission operation with 10-15 minutes fast refueling of hydrogen. TransPower – Plug-in electric Fuel cell range extended drayage truck - Battery energy storage 120kWh; gaseous storage, fuel cell; TransPower plans to build and install FC APUs on two fully integrated truck systems for drayage service demonstration. The proposed project will result in the manufacturing and deployment of two demonstration trucks, one with a

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				30-kW fuel cell and one with a 60-kW fuel cell, enabling a direct comparison of both variants. The higher power output of the 60 kW systems is expected to be better suited for trucks carrying heavy loads over longer distances that might exceed the average power capacity of the 30 kW systems. The system will store 25-30 kg of hydrogen onboard based on an estimated 7.37 miles per kg fuel economy. TransPower's system also includes a bi-directional J1772-compliant charger that can recharge the vehicle batteries or provide power export U.S. Hybrid – Plug-in electric Fuel cell range extended drayage truck; UTC Pure Motion 80 (80kW) fuel cell; 26kWhr battery system; expected range 150-200 miles; 20kg @ 350bar; 6.6kW on-board charger; US Hybrid plans to build and install FC APUs on two fully integrated truck systems for drayage service demonstration. The proposed technology will provide a 150-200 mile range between refueling. Each truck will carry approximately 20 kg of hydrogen storage at 350 bar with an estimated fueling time of less than 10 minutes. These advanced technology trucks will operate along major drayage truck corridors including the Terminal Island Freeway, a primary corridor for port cargo travelling between Port of Los Angeles and Port of Long Beach terminals and the Intermodal Container Transfer Facility, a near-dock rail facility.
FAST TRACK Fuel Cell Truck Project (Ports of Los Angeles and San Diego)	Drayage truck	GTI/Loop Energy/Transpower/Peterbilt – Loop's FC-REX fuel cell	Loop fuel cell range extenders will be integrated by TransPower into two Peterbilt 579 truck gliders in early 2019. Following on-highway testing by	Canada-based Loop Energy's heavy-duty fuel cell range extender will power two new zero-emission hybrid-electric Class 8 drayage trucks that will operate for a one-year period as part of a FAST TRACK Fuel Cell Truck Project in southern California. The Loop-powered, long-haul trucks will work in demanding road operations, towing up to 80,000 pounds of freight throughout the San Diego and Los Angeles regions. The hybrid-configured trucks will

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			Peterbilt, the trucks are scheduled to enter daily operational service in California in the second quarter of 2019.	incorporate a range of technologies including Loop's FC-REX fuel cell range extender, TransPower's latest "T-NMC" energy storage technology that is built around batteries provided by Nissan, and battery-electric drive systems supplied by TransPower, to extend the operating range of Peterbilt trucks beyond 200 miles without the need for refueling or recharging.
Commercialization of POLB Off-Road Technology (C-PORT) Demonstration Project (Port of Long Beach)	Yard Tractor	Kalmar Transpower/Loop Energy	2019	The POLB C-PORT project is to: 1) design, develop and demonstrate three battery electric top handlers at the Long Beach Container and SSA Marine Terminals; 2) design, develop and demonstrate one battery electric and one hydrogen fuel cell yard tractor at the Long Beach Container Terminal; and 3) install electric charging and hydrogen fueling infrastructure to support operation of these vehicles in revenue service for a minimum of six months at Long Beach Container Terminal Pier E. It is anticipated that up to three vehicle original equipment manufacturers and three technology vendors will be involved in this project. The project will also feature a unique, head-to-head comparison of hydrogen fuel cell vs. battery-electric technology in yard trucks.
Demonstration of Zero-Emission Technologies for Freight Operations at Ports (Port of Los Angeles)	Top Loader	Nuvera PEM Fuel Cell Hyster Yale Group	---	The project team, led by the Center for Transportation and the Environment, will build an electric top loader with wireless inductive charging and a 90-kW fuel cell range extender for demonstration at the Port of Los Angeles. The electric top loader with a fuel cell range extender will be developed, integrated, and built by Hyster Yale Group, with the fuel cell engine provided by Nuvera and wireless charging provided by WAVE. The vertical integration of zero-emission equipment by a major OEM provides a clear path towards commercialization and represents the commitment of the OEMs to develop and commercialize advanced technologies that are necessary to meet California's air quality and climate goals.

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Hydrogenics Advanced Fuel Cell Vehicle Technology Demonstration for Drayage Truck (Ports of Los Angeles and Long Beach)	Drayage truck	Hydrogenics Corp CelerityPlus™ hydrogen PEM fuel cell	---	For the project, "Advanced Fuel Cell Vehicle Technology Demonstration for Drayage Truck," Hydrogenics, with the technical support of Siemens, will integrate its advanced CelerityPlus^{TM} fuel cell drive system into a Class 8 drayage truck. Total Transportation Services, Inc. (TTSI) will demonstrate the Hydrogen fuel cell-powered drayage trucks on the Alameda Corridor as well as in the ports of Long Beach and Los Angeles.
Hydrogen Fuel Cell Passenger Ferry Boat (Port of San Francisco)	Passenger Ferry Boat	Hydrogenics PEM fuel cell BAE Systems Hexagon Composites	Mid-2020 planned	The catamaran ferry boat is powered by dual 300 kW electric motors using independent electric drivetrains from BAE Systems. Power is generated by three 120 kW of Hydrogenics proton exchange membrane fuel cells and two 50 kWh Li-ion battery packs. Hydrogen tanks from Hexagon Composites, will be installed on the upper deck, and contain enough hydrogen to go up to two days between refuelings. The ferry''s cruise speed is estimated to be 21 knots. In 2022, All American Marine, Inc. (AAM) and the vessel owner SWITCH Maritime (SWITCH)began conducting sea trials of the vessel "Sea Change", a 70-foot, 75-passenger zero-emissions, hydrogen fuel cell-powered, electric-drive ferry that will operate in the California Bay Area.
Fuel Cell Drayage Truck and Intelligent Transportation Systems Demonstration (Ports of LA/Long Beach) **(ZECT I)** **SCAQMD Project ID: VSS115**	Drayage Trucks	Kenworth/General Motors, Toyota, AirProducts	Project start date: Oct. 2012 Project end date: Sept. 2017	Project involving fuel cell electric vehicles (FCEVs) for the drayage industry, supporting hydrogen infrastructure, as well as the next iteration of geofencing technologies that will maximize emissions reductions from near-zero emission vehicle technologies in disadvantaged communities (DACs). These vehicles will support the Ports of LA and Long Beach and include fuel cell electric (Kenworth-General Motors and US Hybrid-Dongfeng) trucks, state-of-the-art renewable hydrogen infrastructure (Toyota), and plug-in diesel hybrid electric with ITS (Volvo Group North America with University of California-Riverside). Project includes a confirmed end-user fleet which has

Project Name (Port Location)	Port Application	Fuel Cell Manufacturer/Type	Installation Date/ Planned Date	FC Design and Operational Information
				routes in DACs within the state, as well as a partnership with the National Renewable Energy Laboratory for data collection. The goals of the fuel cell and ITS technology development are to reduce criteria and greenhouse gas emissions, protect public health, and reduce dependence on fossil fuels.
"Project Portal" Experiment (Port of Long Beach/Los Angeles) **"Project Portal" 2.0 (Port of Long Beach/Los Angeles)**	Drayage truck	Toyota/Kenworth	"Alpha" truck - April 2017 "Beta" truck – Fall 2018	Since mid-2017, Toyota has been testing a prototype Class 8 tractor powered by hydrogen fuel cell technology, in drayage service. Toyota is using the same proton exchange member fuel cell (PEMFC) technology that it has already commercially deployed in its Mirai fuel cell passenger cars. The Kenworth Class 8 tractor used by Toyota in the project incorporates two Mirai PEMFC stacks in parallel (totaling about 230 kW of peak power output), hybridized with a small battery pack (about 12 kWhr). Under the initial Project Portal effort, Toyota has been testing its first prototype PEMFC truck in local drayage service, from Toyota's Port of Long Beach facility. The Toyota Alpha truck has logged more than 10,000 miles. In mid-2018, Toyota launched a second "Beta" model, which reportedly offers longer range (increased from 200 to 300 miles), and other improvements. Notably, Toyota's apparent ultimate plan is to sell this heavy-duty PEMFC drive system to Class 8 truck OEMs (rather than to become a Class 8 OEM itself).
Zero-Emission Freight "Shore to Store" Project (Port of Los Angeles)	Drayage truck	Toyota, Kenworth, Ballard Power Systems, and Shell	ZANZEFF projects must be completed by April 2021	ZANZEFF funds are supporting the development of hydrogen fuel cell technology. The Zero-Emission Freight "Shore to Store" project involves a hydrogen fuel-cell-electric technology framework for freight facilities to structure operations for goods movement. As part of the plan, the partners will collaborate to develop and deploy 10 hydrogen fuel cell Class 8 trucks, develop two hydrogen fueling stations, and increase zero-emission technology use in off-road applications.

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				• Ten new zero-emissions hydrogen fuel-cell-electric Class 8 on-highway trucks on the Kenworth T680 platform will be developed through a collaboration between Kenworth and Toyota to move cargo from the Los Angeles ports throughout the Los Angeles basin, as well as ultimately to inland locations such as Riverside County, the Port of Hueneme, and eventually to Merced. The trucks will be operated by Toyota Logistics Services (4), United Parcel Services (3), Total Transportation Services Inc. (2), and Southern Counties Express (1). • Two new large capacity heavy-duty hydrogen fueling stations will be developed by Shell in Wilmington and Ontario, California. The new stations will join three additional stations located at Toyota facilities around Los Angeles to form an integrated, five-station heavy-duty hydrogen fueling network. Together, they will provide multiple sources of hydrogen throughout the region, including over 1 ton of 100% renewable hydrogen per day at the heavy-duty station to be operated by Shell, enabling zero-emissions freight transport. Stations supplied by Air Liquide at Toyota Logistics Services in Long Beach and Toyota Technical Center in Gardena will serve as important research and development locations.
Renewable H_2 Production & Fueling Station (Joint Base Pearl Harbor-Hickam)	Refueling for ground fuel cell vehicles	---	First installed in 2006 as mobile storage and refueling unit, with more established station in 2013	JBPHH H_2 Station Capacity Upgrades: • 65 kg/day PEM Electrolyzer • 270 kg H_2 storage • Dual compressors and dispensers for 350 bar and 700 bar vehicle refueling
Naval Submarine Base New London Fuel Cell	Stationary power generation	FuelCell Energy Inc. molten carbonate fuel cell	July 2018	The project involves the installation of two FuelCell Energy SureSource 4000™ power plants at the U.S. Navy Submarine Base in Groton, CT for the long-term supply of 7.4 megawatts of power. The highly efficient fuel cell power generation project minimizes

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				carbon output while providing continuous power to the strategic military base. The U.S. Navy continues to purchase power from CMEEC and Groton Utilities, who in turn purchases the power from FuelCell Energy under a 20-year power purchase agreement. This pay-as-you-go structure enables CMEEC and the Navy to avoid a direct investment in owning the power plant which will be operated and maintained by FCE. By generating 7.4 MW of clean, efficient power, the fuel cell park will meet a majority of the average daily energy needs of Submarine Base New London. Any excess power will be exported to the Groton Utilities distribution system.
Maritime Hydrogen Fuel Cell Project (Port of Honolulu)	Portable power generation	Hydrogenics Corp proton exchange membrane fuel cell	August 2015	Hydrogenics Corp. designed and manufactured a containerized 100-kilowatt hydrogen fuel cell unit, which includes the fuel cell engine, a hydrogen storage system, and power-conversion equipment. The unit fits inside a 20-foot shipping container and consist of four 30 kW fuel cells, a hydrogen storage system, and power-conversion equipment. The unit has an outward appearance and functionality similar to maritime diesel generators that are currently in use. The system contains 72 kg of hydrogen at 350 bar and has a rated power of 100 kW, 240 VAC 3-phase, which can be divided among 10 plugs to power up to 10 reefer containers at a time. The design of the generator was reviewed by the US Coast Guard, American Bureau of Shipping, and the Hydrogen Safety Panel to ensure safety and compliance with regulations.
Integrated Algal Flow-Way, Digester, and Fuel Cell Demonstration Project (Port of Baltimore)	Onsite process power	Atrex Energy solid oxide fuel cell	2017	A 500 W-fuel cell (Atrex Energy ARP500) was purchased for the demonstration project. The biogas being converted to electricity by the fuel cell was constrained by the algal flow-way size and the biogas production rate from site-grown algae. The lowest wattage of a commercially available fuel cell was 500 W at the time of the RFPs in spring 2017; therefore, a

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				greater percentage of supplemental gas was needed to continuously power the fuel cell than anticipated. As an operational adjustment, the demonstration project team decided to collect and store biogas in the external biogas storage bags until enough biogas was available to run the fuel cell for at least 5 to 7 days at a time, allowing for the testing of up to 35% biogas in the fuel mix to the fuel cell. This demonstration project successfully validated the ability to couple an algal flow-way, digester, biogas conditioning and compression unit, and fuel cell into an integrated system producing electricity from algae grown on site. The demonstration project team designed and operated an integrated system to convert algae—already being grown on an algal flow-way to remove nutrients from a nutrient-rich surface water—into biogas for fuel to a fuel cell. This demonstration project showed that electricity could be produced using a non-fossil fuel energy source and, thereby, could reduce air emissions. With financial support and project oversight from MARAD and MDOT MPA, the demonstration project answered many questions on the feasibility and success potential of coupling independent units into a system that could produce electricity from site-grown algae. Several design and operational uncertainties were answered, and others identified during the design, start-up, and operations of the system.
Naval Submarine Base New London Fuel Cell	Combined Heat and Power	FuelCell Energy Inc. molten carbonate fuel cell	2010	Two 300-kilowatt DFC300 fuel-cell plants were installed next to the existing power plant on the base to provide reliable electricity. LOGANEnergy installed and operated two power plants. These units will provide base load electricity, with byproduct heat being used to preheat boiler water.

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Zero Emissions for California Ports (ZECAP) (Port of Los Angeles)	Yard Tractors	Ballard Power Systems PEM fuel cell	Installation in 2019 and a 12-month operating period is planned for the project, beginning in March 2020.	85kW FCveloCity HD PEM fuel cell modules. BAE Systems electric drive integrated within its HDS200 HybriDrive Propulsion System.
Toyota Renewable Energy Fuel-cell Power Plant and Hydrogen Fueling Station (Port of Long Beach)	Combined heat and power and hydrogen refueling station	Toyota and FuelCell Energy	Construction anticipated to start late 2018 and be completed in 18 months.	The Tri-Gen facility will be the first megawatt-sized molten carbonate fuel cell power generation plant in the world. Using 100 percent renewables, the plant will utilize agricultural waste to generate the water and hydrogen required to support the logistics of the project trucks and electricity for use in the Port of Long Beach. The 2.3 MW powerplant will provide the following benefits: 1. Electricity- enough to power the terminal - and sell power back to the grid 2. Water- a byproduct of the power plant- will be used to wash cars at the terminal 3. Heat-another by-product- will generate necessary heat for the facility. 4. Hydrogen- fueling the power plant - will also be used to fuel the Toyota Mirai as well as trucks operating at the terminal.
Comparison of Battery Electric and FC Electric Yard Trucks (Port of Long Beach)	Yard trucks	LOOP Energy National Heavy-Duty Truck Group	August 2017	Two main elements: First, demonstrate three battery-electric top handlers with collaboration between BYD and Taylor Machine Works. Second, perform a head-to-head comparison of a battery electric yard truck and a fuel cell yard. The battery electric yard truck will be developed by TransPower and Kalmar, and the fuel cell yard truck will be developed by LOOP Energy and China National Heavy-Duty Truck Group. All the equipment will be demonstrated at the Port of Long Beach at two different terminals.
Toyota "Tri-Gen" Facility for Logistics	Stationary power generation EV charging, and	FuelCell Energy	2020	2.35 MW power plant, with power and hydrogen production produced from agri-bio-waste conversion (manure).

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Operations (Port of Los Angeles)	onsite production of hydrogen refueling station			Hydrogen refueling station, producing 1.2 tons of hydrogen per day. The electricity will be used to power Toyota Logistic Services' (TLS) operations at the Long Beach Port, making it the first Toyota facility in North America source all its power from renewable sources.