Appendix A

LIQUID FUELS

Introduction

The existing liquid fuel component of the energy transport, storage, and distribution (TS&D) infrastructure is enormously complex. Table A-1 shows both the scale and diversity of that system. This component of the Quadrennial Energy Review (QER) provides an integrated assessment of the emerging threats, risks, and opportunities within this infrastructure. It includes a characterization of the developmental history and current state of these systems, as well as a description of their vulnerabilities and limitations in terms of present and future liquid fuels supply and demand, age and condition, cost, and environmental and safety risks. It also describes some of the increasing interdependencies between the liquid fuels TS&D and infrastructure of other energy sectors, as well as emerging competitive forces for specific modes of liquids transport.

Table A-1. Summary of U.S. Liquid Fuels TS&D Infrastructure[1]

Infrastructure Type	Summary
Oil/Petroleum Products	
Oil refineries	142 total refineries
	139 operating, 3 idle
	2014 total atmospheric distillation capacity of 17,924 thousand barrels per day[i]
Crude oil pipelines	60,160 miles of crude oil pipelines
Oil product pipelines	63,518 miles of oil product pipelines
Oil rail terminals	113 terminals
	upload capacity: 2 million barrels per day
Oil ports	334 crude and petroleum product ports
Waterborne transport	4,500 inland tank barges
	275 coastal tank barges and articulated tank barges
	192 lock systems
Storage terminals	1,414 crude (520,932 thousand barrels working capacity)[a] and product (1,049,334 thousand barrels working capacity)[b, ii] terminals
Petroleum reserves	Strategic Petroleum Reserve: 691 million barrels
	Northeast Heating Oil Reserve: 1 million barrels
Alternative Fuels	
Alternative fuels production facilities	269 existing or proposed ethanol plants; capacity: 15,600 million gallons per year
	134 biodiesel plants; capacity: greater than 954 million gallons per year
Alternative fuel transportation	89 CSX East Coast rail ethanol terminals
	27 CSX rail-uploading facilities[c]
	About 300,000 carloads per year

The liquid fuels infrastructure is comprised of a diverse set of components for the transport, storage, and refining of the Nation's petroleum supplies.

[a] Crude oil storage capacity is equal to U.S. total refinery working storage capacity plus crude tank farm working storage capacity (excluding the Strategic Petroleum Reserve) as of September 30, 2014.

[b] Petroleum product storage capacity is equal to refinery, bulk terminal, and product pipeline working storage capacity of motor gasoline, distillate fuel oil, kerosene and kerosene-type jet fuel, residual oil, asphalt and road oil, oxygenates and renewable fuels (except fuel ethanol), other hydrocarbons, unfinished oils, aviation gasoline, aviation gasoline blending components, special naphthas, lubricants, petrochemical feedstocks, wax, and miscellaneous products as of September 30, 2014.

[c] All seven Class I railroads transport ethanol, but only CSX makes terminal and uploading facility data specific to the transport of ethanol publicly available.

[i] U.S. Energy Information Administration. "2014 Refinery Capacity Report." Table 1. http://www.eia.gov/petroleum/refinerycapacity/. Accessed January 28, 2015.

[ii] U.S. Energy Information Administration. "Working and Net Available Shell Storage Capacity." Table 1. November 2014. http://www.eia.gov/petroleum/storagecapacity/storagecapacity.pdf. Accessed January 28, 2015.

This appendix to the QER is organized in the following manner. First is a summary of the changes seen in supplies of crude oil, natural gas liquids (NGL), and biofuels. This is followed by a discussion on the major components of the TS&D infrastructure, including recent changes in operations, infrastructure build-out, and corresponding problems that have been identified. Next, the regional resilience of liquid fuels TS&D systems is explored by highlighting potential sector-specific vulnerabilities. Last, the appendix addresses environmental issues stemming from liquid fuels TS&D, including air emissions and spill safety.

Highlights

The United States has achieved unprecedented oil production growth since 2008. This oil production growth has enabled the United States to act as a stabilizing factor in the world market by offsetting large sustained supply outages in the Middle East and North Africa and, later, contributing to a supply surplus that has reduced oil prices to levels not seen since March 2009. These developments have enhanced U.S. energy and economic security.

As a result of U.S. production growth, the network of oil distribution ("the midstream") has changed dramatically. Pipeline flows have been reversed to accommodate the transport of increasing production in the North to refining centers along the Gulf Coast. Multiple midstream transport modes—including pipelines, rail, and barges—are moving oil from new producing regions to refineries throughout the United States.

Despite the impressive response that the U.S. midstream has made to accommodate significantly changed patterns of oil supply and demand, a number of problems have received attention. Historically, chokepoints have caused significant liquid fuel price differentials. For example, from 2011 through 2013, West Texas Intermediate oil prices declined sharply relative to Brent because there was not sufficient transport capacity to move oil in the Midcontinent to the Gulf Coast. West Texas Intermediate, priced at Cushing, Oklahoma, became a landlocked oil while Brent, priced at marine terminals, was and remains an international oil price marker. Concerns also include rail traffic congestion and the potential impact of crude-by-rail shipments on other rail freight traffic, public safety implications of concerns due to crude-by-rail derailments, and the conditions of U.S. ship channels and inland waterways.

Canadian oil production has also affected the U.S. supply picture. Canadian heavy oil has substituted for declining Mexican and Venezuelan heavy oil imports to the United States, which Gulf Coast refineries have relied upon in recent years.

The Strategic Petroleum Reserve's ability to offset future energy supply disruptions has been adversely affected by domestic and global oil market developments coupled with the need for upgrades. Changes in the U.S. midstream (for example, competing commercial demands and pipeline reversals) and lower U.S. dependence on imported oil have created challenges to effectively distributing oil from the reserve. This diminishes the capacity of the Strategic Petroleum Reserve to protect the U.S. economy from severe economic harm in the event of a global supply emergency and associated oil price spike.

In addition, over the last 10 years, there have been three hurricanes that affected the Nation's petroleum product supplies. During events in 2005 and 2008, up to 5 million barrels per day of petroleum product supply was disrupted. In response to the 2005 hurricanes, 30.0 million barrels of crude oil from the Strategic Petroleum Reserve were offered to the market and 20.8 million barrels were ultimately sold; it took 20 days for the first oil to move. In addition, the most severe impact of the 2005 and 2008 hurricanes was not the relatively brief suspension of Gulf of Mexico oil drilling, but was the damage to Gulf Coast refineries. These damages caused product supply interruptions of 153 million barrels (Katrina/Rita in 2005) and 103 million barrels (Gustav/Ike in 2008) over the 2 months to 3 months following the first landfall.[a] Emergency reserves of crude oil were of relatively little benefit to offset lost refinery capacity, and no emergency Strategic Petroleum Reserve release was undertaken in the aftermath of the 2008 hurricanes.

Natural gas liquid production has increased significantly, enabling expansion of domestic chemical manufacturing and opportunities for exports. From January through August 2014, U.S. ethane production was more than 1.0 million barrels per day and propane production was more than 1.2 million barrels per day, despite declines in refinery production.

[a] Department of Energy, Office of Fossil Energy and Office of Policy and International Affairs. "Refined Petroleum Product Reserve, Assessment of Energy Security Needs, Costs and Benefits." September 2011.

Highlights (continued)

While ethanol production is substantially greater by volume than biodiesel production, ethanol growth has begun to stagnate in the last few years. Most U.S. ethanol is produced from corn; very little is produced from cellulosic sources. Biodiesel, by contrast, is now slowly growing in production.

Building and repairing infrastructure that lasts several decades requires consideration of resilience in the context of climate change and extreme weather, which is already impacting the energy sector. Projections suggest that threats will continue to increase in severity and frequency in the coming decades. Liquid fuels infrastructure is relatively more exposed to storm surge than other energy sectors, primarily due to its high density in the Gulf Coast region, which also is a region with relatively rapid land subsidence. With less than 2 feet of additional sea-level rise, the number of refineries exposed to inundation by storm surge caused by Category 1 storms is projected to increase from 6 to 10.

Changing Supply Profile for Liquid Fuels

Oil

Responding to projected declines in domestic oil production has been a feature of U.S. energy policy since 1973, influenced by the Arab Oil Embargo of 1973. U.S. crude oil production peaked in 1970 and then began, with some exceptions (like development of the North Slope and offshore Gulf of Mexico), a steady decline until 2008 (e.g., U.S. oil production dropped from 5.8 million barrels per day (bbl/d) in 2000 to 5.1 million bbl/d in 2008).

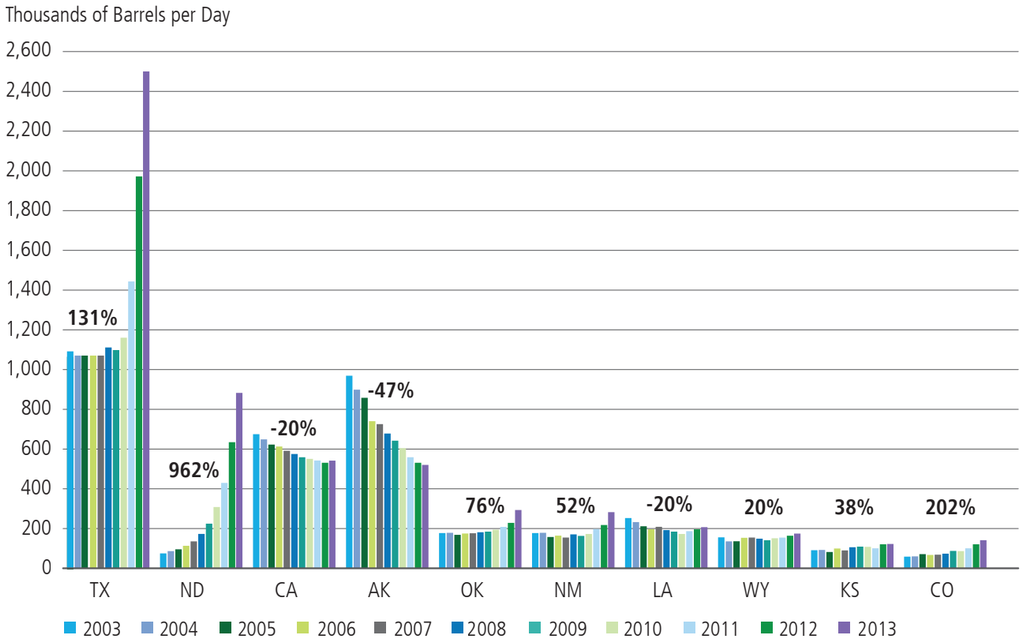
Since 2008, however, U.S. oil production—including lease condensate[b]—climbed to more than 8.6 million bbl/d in August 2014, mostly due to the development of tight oil plays in North Dakota, Texas, and elsewhere.[2] In 2013, the United States achieved the largest annual increase of oil production in world history by adding almost 1.225 million bbl/d of production, resulting in a liquid fuels daily production rate of 12.340 million barrels (bbl).[3] In early 2014, the United States became the world's largest producer of liquid fuels (including crude oil, NGL, and biofuels), overtaking Saudi Arabia. U.S. crude production in April 2014 was 8.4 million bbl/d, with two states—Texas and North Dakota—accounting for about half of this total.[4] Texas more than doubled production from 2010 to 2013, and in April 2014, production topped 3 million bbl/d[5] for the first time since the late 1970s.[6] North Dakota nearly tripled production from 2010 to 2013, and production broke 1 million bbl/d for the first time in history in April 2014.[7]

[b] Lease condensates are light liquid hydrocarbons recovered from lease separators or field facilities at associated and non-associated natural gas wells (mostly pentanes and heavier hydrocarbons). Condensate generally is crude oil with an American Petroleum Institute gravity of 50 or greater.

Between 2008 and 2013, about 3.2 million bbl/d of new crude oil production (a more than a 40-percent increase) was added to North American oil production despite continuing production declines in Alaska. Figure A-1 shows the oil production changes in major U.S. producing states between 2003 and 2012.

Most of the incremental U.S. production since 2009—about 4 million bbl/d—comes from significant improvements in drilling and production methods (horizontal drilling and hydraulic fracturing) applied to oil-bearing shales in Texas (Eagle Ford and the Permian Basin) and North Dakota (Bakken), with Bakken production beginning as early as 2000. Most of this shale oil is light[c] sweet[d] crude—that is, low-sulfur crude that requires simpler refining to produce gasoline and other refined products.

Figure A-1. U.S. Crude Oil Production by State, 2003–2012 (thousand barrels per day; percentages are changes from 2003–2012)[8]



On a state-by-state basis, U.S. crude oil production has grown at drastically different rates, led by developments in Texas and North Dakota. Other major producing states—including California, Alaska, and Louisiana—have had declining production rates.

The revolution in U.S. oil production associated with hydraulic fracturing and advances in horizontal drilling, coupled with increased production from Canada, has shifted the patterns of crude oil transport within the United States. Largely, this transport system was configured to move crude oil north from the Gulf of Mexico to refineries in the interior; refineries on the coasts received much of their oil from overseas by tanker and (for West Coast refineries) from Alaska and some local production. New production sources in Canada and shale plays (especially the Bakken Shale in North Dakota and Eagle Ford in southeast Texas) require new transport facilities. Up to this point, the transport system has adapted primarily by large expansions in rail shipments and major pipeline modifications (e.g., reversals in flow direction, repurposing of natural gas pipelines), with major investments in new pipelines in the works. The oil production shifts also have changed the types of crude flowing into the transport system (e.g., Bakken production is light sweet crude and Canadian oil sands production is heavy crude).

Canada produced more than 4.00 million bbl/d of petroleum and other liquid fuels in 2013, an increase of more than 0.93 million bbl/d from a decade ago. The majority of this growth stems from increased production from Canada's oil sands in Alberta.[9] Oil sands crude is heavy oil, requiring refineries with coking capacity (e.g., high-pressure/high-temperature reactors that thermally crack the crude into lighter products).

The North American shale and oil sands revolutions have drastically changed the locations from which the United States is importing its oil. New U.S. and Canadian oil production has reduced U.S. refiners' dependence on imported crudes from the Middle East and Africa. U.S. crude oil imports from outside the Northern hemisphere have dropped to less than 40 percent of total crude imports.[e] The recent reforms of Mexico's energy laws and markets likely will increase its oil and gas production and further add to North American supplies. New patterns of oil trade have changed U.S. refiners' need for transportation and distribution infrastructure. Increasing domestic production of light crudes also has changed the economics of refinery crude slates and could affect the profitability of recent capital investments made by some refineries to process heavy crude. Because transportation constraints can cause inland crude prices to become disconnected from international crude prices, some U.S. inland refiners have enjoyed discounted crude prices and high margins. Due to advantageous natural gas prices, highly complex refineries, limited refinery capacity in Latin American, and closures of European refineries, the Gulf Coast refining hub has become a major source of competitively priced refined products for export to Latin America and Europe.

Shifts in supply and demand are having large-scale and wide-ranging impacts on many parts of the liquid fuels TS&D infrastructure (pipelines, rail, waterborne, refineries, and storage). The specific components of the infrastructure are discussed in the infrastructure sections that follow.

[c] The "heaviness" of crude oil is determined by the American Petroleum Institute (API) gravity. Light crude typically has an API gravity above 38 degrees and heavy crudes typically are labeled as crudes with an API gravity of 22 degrees or below. Crudes with an API gravity between 22 degrees and 38 degrees typically are classified as intermediate crudes. Source: Energy Information Administration. "Petroleum & Other Liquids: Definitions, Sources and Explanatory Notes." 2014. www.eia.gov/dnav/pet/tbldefs/pet_pri_wco_tbldef2.asp. Accessed October 23, 2014.

[d] Crude is classified as sweet or sour depending on sulfur content. Crude oils with low sulfur content are classified as sweet crude and crude with high sulfur content is classified as sour.

[e] The fraction of crude imports from outside the Americas peaked at 86 percent in 1978 and has been declining ever since; as of 2014, it is currently less than 40 percent. Source: Energy Information Administration. "U.S. Net Imports by Country, Crude Oil." www.eia.gov/dnav/pet/pet_move_neti_a_epc0_IMN_mbblpd_m.htm.

Production Profile Differences in Tight Oil versus Conventional Oil Formations

Tight oil production from unconventional formations is different from conventional oil extraction in a number of ways. In general, conventional wells are easier to produce because hydrocarbons targeted for recovery are in geologic zones that are both numerous and porous (such as naturally occurring carbonates, siltstones, and sandstone). In addition, production in conventional formations typically requires only modest levels of well stimulation techniques and generally covers a sizeable area of production. Conversely, tight oil production in unconventional formations like shale plays is much more difficult because individual wells focus on smaller areas, are more resource and energy intensive (from drilling to cementing and casing of pipes, to water and chemical use in well stimulation), and require many more wells per unit of production.

Among the challenges tight oil producers face, the leading ones tend to revolve around formation depth (typically, shale formation target zones lie several thousand feet below the Earth's surface); variability in energy content of targeted source rock (e.g., 'sweet spots' versus non-economic); and low porosity of the formation, requiring intense well stimulation to drive the oil molecules up from the pay zone to the surface. However, with successive technological breakthroughs in horizontal and directional drilling, well stimulation through advanced hydraulic fracturing techniques, and seismic detection tools and techniques, tight oil is now economically recoverable and represents a growing share of U.S. oil production.[f] For example, according to Energy Information Administration statistics, from 2010 until the second half of 2013, U.S. tight oil production grew from less than 1 million barrels per day to more than 3.5 million barrels per day.[g]

According to IHS, the average rate of decline from a shale oil well ranges from 50 percent to 80 percent following initial production in the first year. For shale gas wells, the steep rate of decline in the first year also is the norm and in approximately the same range (50 percent to 75 percent).[h] Sustaining these high production levels requires constant drilling and many new wells. For example, the International Energy Agency estimated that a tight oil production level of 1 million barrels per day in the Bakken demands approximately 2,500 new wells be drilled per year. Conversely, the International Energy Agency projects that producing an equivalent amount of oil per day in a conventional field in Southern Iraq would require only 60 wells per year.[i] The difference in production profiles between a tight oil and conventional well is shown in Figure A-2.

This rapid expansion of tight oil production requires significant infrastructure investment and build-out, especially in areas outside of the oil patch (such as North Dakota's Bakken play in the Williston Basin that is newer to such widespread development). Unfortunately, tight oil wells in several parts of the country are not adjacent to existing gathering lines and/or gas treatment plants. Construction of gathering lines and treatment plants require substantial lead times, often because producers must first obtain rights of way or easements. In some areas, regulator capacity to respond to such growth in requests has been strained. In the absence of such infrastructure, many tight oil producers cannot afford to wait for it to arrive and have therefore opted to flare associated gas. This mainly is because the crude oil being extracted concurrently has been far more valuable, economically speaking, than the natural gas being flared. Flaring also may be employed for safety purposes; for example, if an explosion or power outage occurs. Another factor leading to flaring decisions might include producer concerns that facilities sized to capture the first few months of early production may end up being too large for the volume of hydrocarbons being recovered as shale wells vary in terms of productivity. Related to this concern is the fact that committing to a facility size in advance of well testing can raise a producer's risk profile substantially.[j]

[f] Canadian Association of Petroleum Producers. "Conventional & Unconventional." http://www.capp.ca/canadaIndustry/naturalGas/Conventional-Unconventional/Pages/default.aspx. Accessed February 11, 2015.

[g] Energy Information Administration. "Annual Energy Outlook 2014, Issues in Focus—U.S. tight oil production: Alternative supply projections and an overview of EIA's analysis of well-level data aggregated to the county level." April 7, 2014. http://www.eia.gov/forecasts/aeo/tight_oil.cfm. Accessed February 3, 2015.

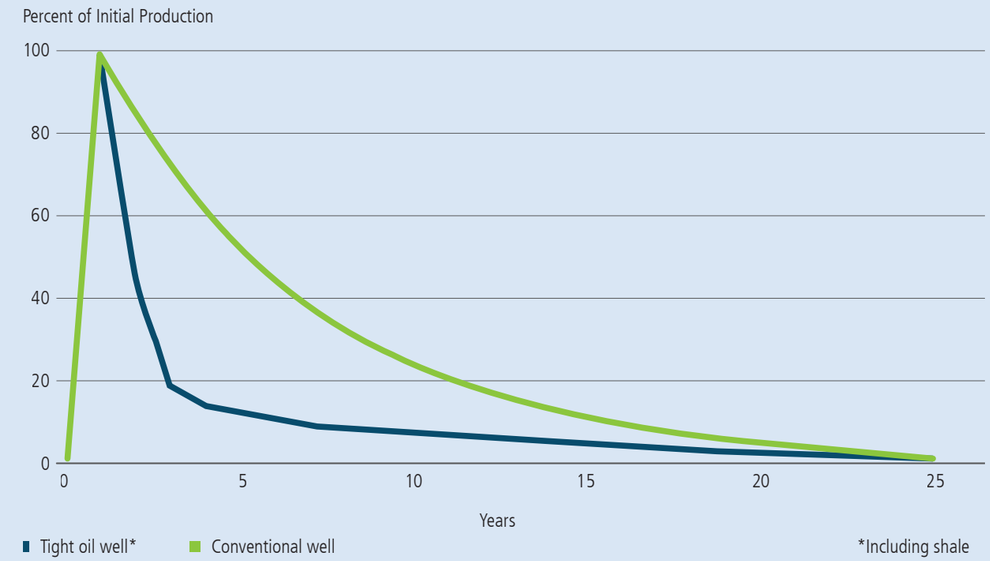
[h] Wiley, D. "The Questionable Staying Power of the U.S. Shale Boom." June 2, 2014. http://oilprice.com/Energy/Energy-General/The-Questionable-Staying-Power-Of-The-U.S.-Shale-Boom.html.

[i] The Economist. "Saudi America: The Benefits of Shale Oil are Bigger than many Americans Realise." February 15, 2014. http://www.economist.com/node/21596553/print.

[j] Quadrennial Energy Review Analysis: Department of Energy, Office of Energy Policy and Systems Analysis. "QER Public Stakeholder Meeting: Infrastructure Constraints in the Bakken." Memo. August 8, 2014. http://energy.gov/sites/prod/files/2014/08/f18/FINAL-%20BAKKEN%20BRIEFING%20MEMO_8%208.14.pdf.

Production Profile Differences in Tight Oil versus Conventional Oil Formations (continued)

Figure A-2. Production Curves for Tight Oil and Conventional Wells[k]



Typically, tight oil wells experience different production profiles than conventional wells. The difference in production profile over the lifetime of the well affects the timing of oil field infrastructure construction.

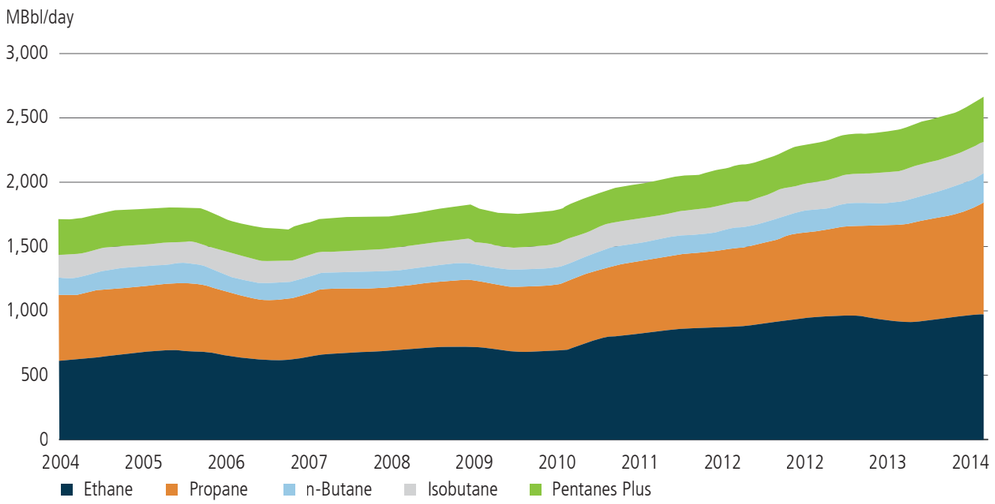
[k] The Economist. "Saudi America: The Benefits of Shale Oil are Bigger than many Americans Realise." February 15, 2014. http://www.economist.com/node/21596553/print.

Natural Gas Liquids

NGL include ethane, propane, butane, isobutane, and pentanes (natural gasoline) extracted from a wet natural gas stream or produced at a refinery or chemical facility. There are many uses for NGL, spanning nearly all sectors of the economy. NGL are used as inputs for petrochemical plants, burned for space heating and cooking, and blended into vehicle fuel. Because of their market value, NGL provide an incentive to drill in liquids-rich natural gas plays with significant NGL content.

Oil and natural gas production contribute to the supply of NGL. However, much of the recent growth in NGL has been from natural gas production (wet plays), referred to as natural gas plant liquids when extracted from natural gas at a processing plant. NGL production from refineries has remained relatively flat since 2004, while production from the wet natural gas stream has increased.[10] Historical production of natural gas plant liquids is shown in Figure A-3.

Figure A-3. U.S. Gas Plant NGL Production by Product (12-month rolling average)[11]



The large growth in NGL production can be attributed to natural gas processing plants, as hydrocarbon gas liquids production at refineries has remained relatively unchanged since 2008.

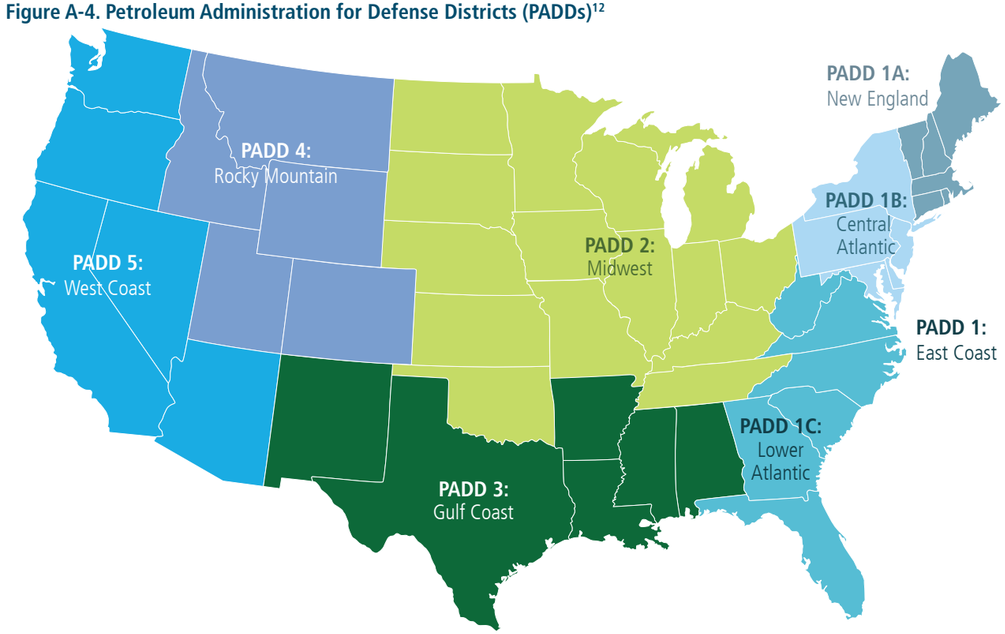
Natural gas plant liquids infrastructure involves natural gas gathering pipelines, natural gas processing plants, NGL pipelines, fractionation centers, truck and railroad transport, cargo ships (barges, pressurized/refrigerated tankers), and storage. The natural gas gathering system transports raw natural gas and NGL to a natural gas processing plant where NGL and impurities are removed. Mixed NGL are then transported by dedicated pipeline (or other method) to fractionation centers, which split the mixed NGL into the individual chemical constituents. The pure components are then transported to their demand locations (chemical manufacturing facilities, home heating distribution terminals, etc.).

NGL Prices

Spot prices of NGL are related to natural gas, crude oil, and petroleum product prices (gasoline). Spot prices of individual NGL components have experienced different trends (see Figure A-5). Ethane prices have dropped since a high in August 2008, and toward the end of 2014, they were near or below natural gas prices on an energy equivalent basis. The price of propane fell following the warm winter of 2011-2012 due to reduced home heating demand and elevated stocks. The propane price rebounded in 2013 because of a large wet corn harvest[l] that severely depleted Petroleum Administration for Defense District (PADD) II inventories. The Conway, Kansas, price—which delivers to PADD II—shows even larger propane price spikes over that period than at Mont Belvieu, Texas. In January 2014, spot propane prices in the United States hit record levels due to multiple factors that include colder-than-normal weather, high fall 2013 process needs for farmers, transportation bottlenecks, the state of inventories, and higher export levels. On average, butane prices have decreased since 2011.

PADDs are common classifications of regions in the United States. These divisions are shown in Figure A-4.

Figure A-4. Petroleum Administration for Defense Districts (PADDs)[12]

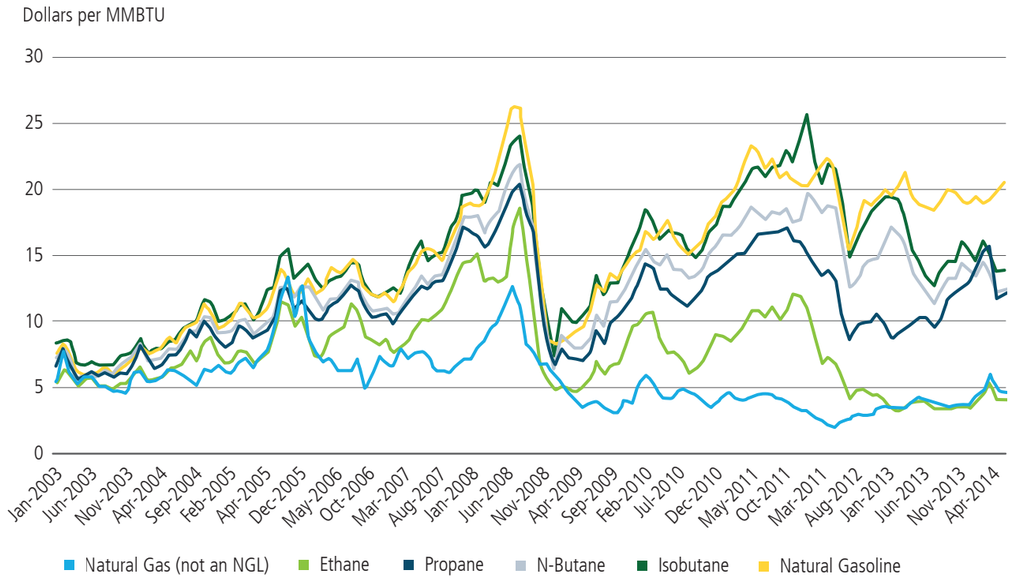


Initially created during World War II, PADDs are still in use today for data collection on petroleum production and transfer within the United States.

[l] Propane is used as a fuel for crop-drying machines.

NGL prices traditionally range between natural gas and motor gasoline spot prices on an energy content basis. Since 2009, heavier NGL products (butanes and natural gasoline) have correlated with crude oil prices and lighter NGL products (such as ethane) generally have correlated with natural gas prices.[13]

Figure A-5. Comparison of Select Hydrocarbon Gas Liquids, Petroleum, and Natural Gas Spot Prices, 2000–2014[14]



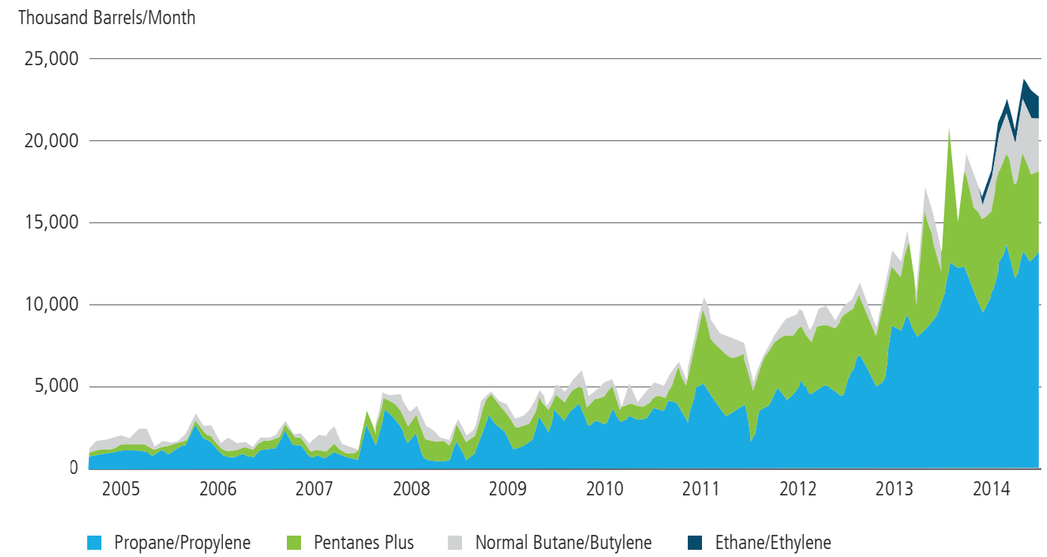
Note: NGL prices represent monthly averages of daily spot prices for products at Mont Belvieu, Texas. Natural gas price represents the monthly average of daily spot prices for natural gas at Henry Hub in Erath, Louisiana.

Daily spot prices of NGL have decoupled from crude oil in the past decade and in some cases have become more responsive to supply and demand variables specific to particular end uses.

NGL Exports

The NGL market is balanced using storage and exports. With the recent increase in levels of NGL production and a comparatively small amount of available storage, a large portion of production is exported if local demand is not sufficient or accessible. U.S. exports, primarily of propane/propylene, have increased significantly in the last 5 years (shown in Figure A-6). U.S. propane exports are now around 25 percent of total domestic production from gas processers and refiners. Ethane exports to Canada proceed by pipeline; tanker exports are expected to begin in 2015 from Marcus Hook, Pennsylvania,[15] followed by exports from the U.S. Gulf Coast.[16] With announcements of foreign import terminal upgrades and the development of a dedicated ethane carrier fleet, ethane exports are expected to increase, primarily to India and Europe for use as a petrochemical feedstock. Natural gasoline exports primarily are to Canada for use as diluent for movements of heavy western Canadian crude.[17]

Figure A-6. U.S. Hydrocarbon Gas Liquid Exports[18, m]



Since 2009, U.S. hydrocarbon gas liquid exports have risen substantially due to increased domestic production and wide international price spreads.

[m] Hydrocarbon gas liquids include natural gas processing plant liquids and both paraffin and olefin liquefied refinery gases—ethane/ethylene, propane/propylene, normal butane/butylene, isobutene/isobutylene, and natural gasoline.

NGL Infrastructure Build-Out

IHS forecasts that direct capital investments for pipelines, storage, and processing capacity for NGL will continue from 2014 to 2025 (see Table A-2).[19] Under the high production scenario in which NGL supply is assumed to be 20 percent higher than in the base case (as is the supply of crude oil and natural gas), direct capital investments are projected to rise by a smaller 15 percent due to the assumption of a slight overbuild in the NGL processing and transportation capacity under the base case.

Table A-2. IHS-Projected Direct Capital Investments, 2014–2025[20]

	Base Case	High Case	Difference
NGL & LPG Processing	$15 billion	$17 billion	15%
NGL & LPG Pipelines	$21 billion	$24 billion	13%
NGL & LPG Storage Rail	$12 billion	$14 billion	12%
NGL & LPG Marine	$3 billion	$4 billion	32%
TOTAL DCI	$51 billion	$ 59 billion	15%

Driven by increased value of NGL extraction, NGL processing and TS&D investments are projected to continue through 2025.

Driven by increased value of NGL extraction, investments in natural gas processing increased from $2.0 billion to $7.5 billion from 2010 to 2013. The large increase in NGL availability at natural gas processing plants has prompted subsequent expansions in NGL fractionation capacity. Mont Belvieu, Texas—the long-established hub for U.S. NGL fractionation—has increased fractionation capacity by approximately 1 million bbl/d in 2012 and 2013 with investments of around $4.5 billion per year.[21] Because of the shifting locations of natural gas plant liquids production, expansions of NGL infrastructure have also occurred—and are projected to continue—in other regions of the United States. Natural gas plant field production of NGL in PADD I increased from 42 thousand bbl/d in January 2012 to 237 thousand bbl/d in October 2014.[22] While the production level in PADD I is smaller than PADDs II and III, PADD I has experienced an unprecedented level of growth that is projected to continue through 2020.[23] To handle this increasing production of NGL, Houston, Pennsylvania, will emerge as an NGL fractionation hub, growing from 16 facilities in 2014 to around 25 facilities over the next decade.[24]

As processing and fractionation capacity is expanded to handle NGL production, takeaway capacity of NGL pipelines also will need to increase to connect NGL to markets. ICF International projects that almost 700 miles per year in new NGL transmission line will need to be built from 2011 through 2035.[25] Until NGL demand from the petrochemical industry catches up with increased supply, it is likely that NGL exports will increase.[26]

NGL and the Ethane Value Chain

After production, wet gas is first processed to separate NGL from methane. The NGL are then fractionated and sold to different markets. Processors may sometimes separate only the propane, butanes (normal butane and isobutane), and natural gasoline and "reject" the ethane, keeping it with the methane as dry natural gas. Ethane rejection may occur because the price of ethane is below the extraction cost, contractual obligations, British thermal unit content specifications, or other reasons. Based on reported heat contents of commercial natural gas, a significant volume of ethane appears to be rejected. The uncertainty of the amount of rejection largely is due to unknown levels of other chemicals in the commercial gas, such as nitrogen, that affect the heat content value. The Energy Information Administration (EIA) currently is developing techniques for estimating ethane rejection levels. If a large amount of ethane is being rejected, as ethane demand grows (petrochemical and exports) and the price of ethane increases and clears its lifting cost, additional pipeline and fractionator investments likely will occur, and ethane production growth will match demand growth without significant supply/demand imbalance.

The increased supply of ethane has decreased its market price relative to other petrochemical feedstocks.[27] The price spread between ethane and propane (a competing petrochemical feedstock) was large from mid-2013 to mid-2014.[28] However, the propane petrochemical margin[n] was slightly higher than ethane's toward the end of 2014 and into early January 2015.[29] The primary driver of investment in the ethane value chain is the opportunity to take advantage of ethane's price advantage relative to other petrochemical feedstocks in the international market. While demand for ethane has increased, prices have remained low as supply continues to increase. Midstream ethane infrastructure investment includes natural gas processing plants, some types of fractionation facilities, and pipelines. Downstream infrastructure includes steam crackers and petrochemical processers that produce consumer goods, ethane exports by pipeline to Canada or Mexico, and waterborne export terminals (currently Marcus Hook and Houston Ship Channel).[30] Midstream investments to extract ethane instead of rejecting it are contingent upon the existence of downstream demand and the ability of producers and project owners to obtain long-term contracts to reduce project risk. These contracts exist between participants across the ethane value chain.[31]

Currently, midstream infrastructure has been coming online as downstream demand warrants. Construction of the Appalachia to Texas, Aegis, Vantage, and Mariner system pipelines, as well as the Utica to Ontario Pipeline Access (e.g., UTOPIA) project, show that midstream infrastructure is expanding in response to an increase in supply. Kinder Morgan Cochin's UTOPIA project will transport ethane and ethane-propane mixtures from Harrison County, Ohio, to Windsor, Ontario.[32] This pipeline provides an important link for Utica liquids to reach petrochemical markets. Downstream infrastructure projects, such as export terminals, may lead to additional midstream infrastructure investments. The very low price of ethane has even led to discussions about export to the Caribbean for power production. For example, according to RBN Energy, American Ethane Co. is considering ethane exports to Jamaica for both industrial and electric power use.[33]

Current domestic demand for ethane is being fully met with domestic production; increasing ethane extraction will require growing domestic demand or access to international markets, where it has a significant cost advantage over other petrochemical feedstocks. U.S. petrochemical demand for ethane is projected to increase significantly, and new ethane export terminals are planned for the Houston Ship Channel (i.e., Enterprise Products); the Port of Louisiana (i.e., American Ethane); and Marcus Hook, Pennsylvania. Once the ethane reaches the coast, it is either exported directly to international markets or used as a chemical feedstock (e.g., in a steam cracker to produce ethylene), where it is used domestically to manufacture other downstream products or exported.[34]

[n] The petrochemical margin is an approximation of the value of specific NGL used in olefin crackers, including raw material costs and by-product credits.

Natural Gas Liquids in Domestic Manufacturing

Increased ethane production may lead to increased domestic industrial and manufacturing activity to take advantage of the low-cost feedstock. Ethylene crackers are among the first facilities to announce expansions due to suppressed ethane prices and the relative ease of feed-slate switching. Investments in steam crackers near the Marcellus and Utica plays will signal opportunities for increased downstream industrial development in the region. For example, the proposed Ascent petrochemical complex in West Virginia will manufacture downstream polyethylene products, enabled by the construction of a local ethylene cracker. The significant increase in ethane supply in the region means that this proposed, local ethane demand can be met while ethane also is exported to international markets (either directly or after conversion to intermediate or end products).[o] The availability of low-priced and abundant natural gas liquids also will impact many other chemicals beyond ethylene and polyethylene. Many downstream intermediate and end-product chemical supply chains (including alkenes, alcohols, polymers, resins, and fertilizers) will experience complicated cost effects due to changes in natural gas liquids price and supply.[p]

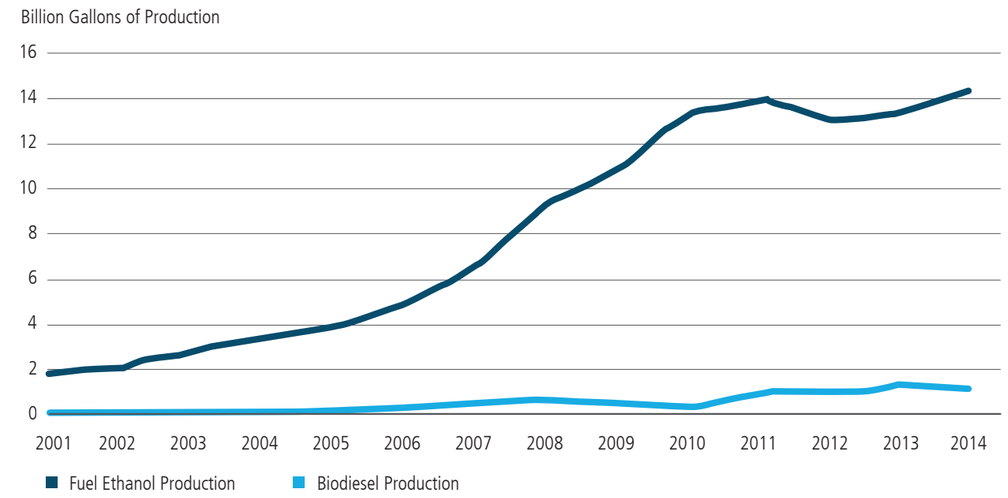
[o] Fasullo, P. and K.V. Hull. "US Hydrocarbon Exports—Part 2: NGLs." En*Vantage Inc. and RBN Energy, LLC. October 17, 2014.

[p] DeRosa, S. and D. Allen. "Impact of Natural Gas and Natural Gas Liquids Supplies on the United States Chemical Manufacturing Industry: Production Cost Effects and Identification of Bottleneck Intermediates." ACS Sustainable Chemistry & Engineering. January 30, 2015. http://pubs.acs.org/doi/full/10.1021/sc500649k. Accessed January 2015.

Biofuels

Ethanol production increased in the late 1970s as a cost-effective fuel extender in gasoline. However, the petroleum price collapse that occurred in the 1980s removed its economic competitiveness. Renewed interest in ethanol as an oxygenate additive for reformulated gasoline was introduced in the 1990s to help lower emissions. Additionally, lower-cost petroleum-derived oxygenate, methyl tertiary-butyl ether, gained the majority of the market share. In 2004, the reformulated gasoline oxygenate standard was replaced with a Renewable Fuel Standard (RFS) to mitigate water quality concerns with the use of methyl tertiary-butyl ether when underground gasoline tanks leaked fuel into water supplies. Substantial increases in the use of ethanol resulted over the last decade, driven by the RFS (see Figure A-7). The RFS requires a minimum volume of renewable fuels to be blended into U.S. transportation fuels. Currently, the predominant method of complying with this requirement is by blending ethanol into gasoline. By 2012, ethanol accounted for nearly 10 percent of U.S. gasoline demand by volume.[35] Ethanol production is now pushing against the blend wall. The blend wall refers to the maximum amount of ethanol that can be used in gasoline (10 percent, often referred to as E10) and still legally used in all gasoline-powered vehicles and equipment. The Environmental Protection Agency (EPA) established a maximum ethanol blending percentage in gasoline to address vehicle emissions and operability concerns with legacy vehicles and engines. The other available market opportunity for ethanol as a transportation fuel is E85 (85 percent ethanol and 15 percent gasoline). However, E85 can only be used in flexible fuel vehicles, which are designed to operate on E85. Recently, EPA also certified E15 (15 percent ethanol and 85 percent gasoline) as a legal fuel that could be used in light-duty vehicles manufactured in model year 2001 or newer. However, the production and consumption of E85 and E15 has not seen significant market growth to date.

Figure A-7. Yearly Ethanol and Biodiesel Production, 2001–2014[36]



Fuel ethanol production increased significantly from 2002 to 2010 and has stayed between 12 billion gallons and 14 billion gallons per year since 2010. Biodiesel production has grown slightly during this period, but has remained near or below 1 billion gallons per year.

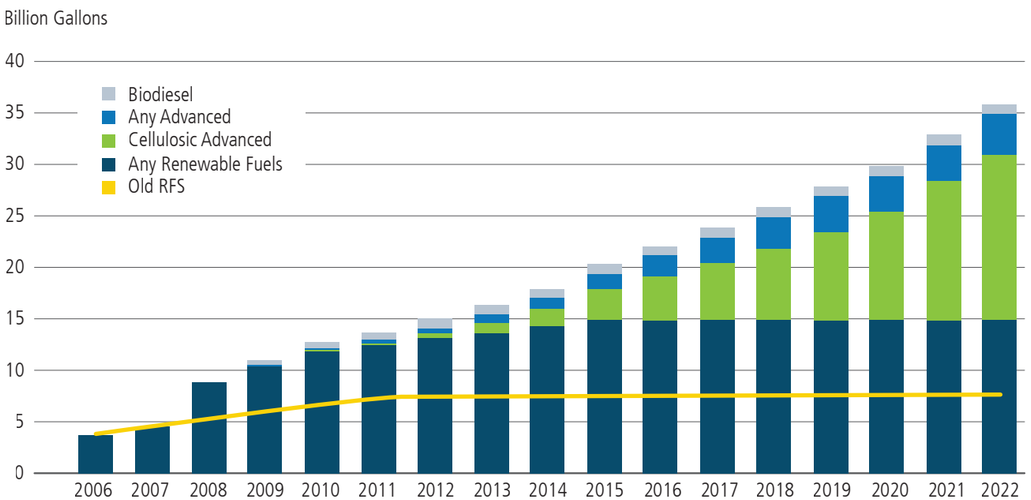
The amount of ethanol produced in the United States in 2013 was approximately 13.3 billion gallons (or 0.87 million bbl/d), which is about 10 percent of the fuel pool. In 2014, production was 0.94 million bbl/d.[37] While ethanol production is substantially greater by volume than biodiesel production, ethanol growth has begun to plateau in the last few years. Most U.S. ethanol is produced from corn; very little is produced from cellulosic sources. Meanwhile, biodiesel continues to grow in production, albeit from a smaller base.

The RFS program, which is administered by EPA, was established by Congress in the Energy Policy Act of 2005 (EPAct 2005). In 2007, the RFS was expanded significantly with passage of the Energy Independence and Security Act (EISA). Congress's primary objectives for the RFS program were to increase U.S. energy security and decrease greenhouse gas (GHG) emissions from transportation fuel by replacing an increasing amount of petroleum-based transportation fuel with renewable fuels and requiring an increasing percentage of these renewable fuels to result in significantly lower lifecycle GHG emissions than 2005 petroleum fuels. EISA established volume targets for renewable fuel, reaching a total of 36 billion gallons by 2022, including 21 billion gallons of advanced biofuels.

EISA requires EPA to publish annual standards for four different categories of renewable fuels: cellulosic, biomass-based diesel, advanced, and total (as prescribed in EISA). Figure A-8 presents the mandated RFS requirements for each year, as established in EPAct 2005 and revised in EISA 2007. These standards apply to refiners and importers of gasoline and diesel fuels. For each category of renewable fuels, EISA specifies lifecycle GHG reduction requirements and annual volume targets. For the advanced biofuel category, which must reduce lifecycle GHG emissions by at least 50 percent as compared to baseline petroleum fuels, those targets grow rapidly as a share of total renewable fuels from 13 percent in 2006 to nearly 60 percent by 2022. EISA also provides EPA with waiver authority for biofuel standards, based on the availability of required biofuels. Since cellulosic biofuels were not produced when EISA was enacted (2007), EPA is required to

assess commercial cellulosic biofuel production capacity each year and, taking account of estimated cellulosic biofuel production capacity, set the cellulosic standards prior to each compliance year. Consequently, EPA's rules for implementing the RFS for 2010 through 2013 have used the waiver authority for cellulosic biofuel to promulgate requirements for cellulosic biofuels closer to actual production levels, which were only a fraction of the levels mandated by the statute and shown in Figure A-8.

Figure A-8. EISA 2007 and EPAct 2005 Renewable Fuel Mandates[38]



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Biodiesel	0	0	0	0.5	0.65	0.8	1	1	1	1	1	1	1	1	1	1	1
Any Advanced	0	0	0	0.1	0.2	0.3	0.5	0.75	1	1.5	2	2.5	3	3.5	3.5	3.5	4
Cellulosic Advanced					0.1	0.25	0.5	1	1.75	3	4.25	5.5	7	8.5	10.5	13.5	16
Any Renewable Fuels	4	4.7	9	10.5	12	12.5	13.2	13.8	14.4	15	15	15	15	15	15	15	15
Old RFS	4	4.7	5.4	6.1	6.8	7.4	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5

The RFS is designed to introduce an increasing level of renewable fuels through 2022.

The age of ethanol production facilities is not an infrastructure issue of concern. Ethanol production grew rapidly over the last 15 years, and the age of ethanol plants is relatively low (see Table A-3). Almost half of the installed ethanol production capacity has come online after the passage of EISA in December 2007.

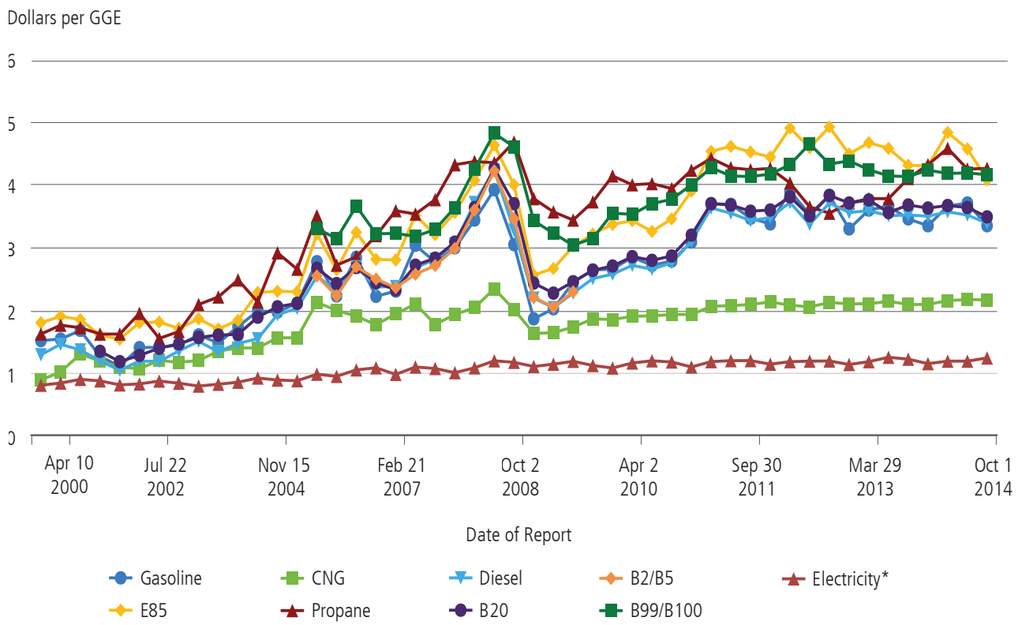
Table A-3. Ethanol Capacity by Vintage[39]

Date	Installed Production Capacity (Mgal/yr)	Capacity Under Construction (Mgal/yr)	Total Capacity (Mgal/yr)	Total Installed Plants	Plants Under Construction/ Expansion	States with Plants
1/99	1,702	77	1,779	50	5	17
1/00	1,749	92	1,840	54	6	17
1/01	1,923	84	2,007	56	5	18
1/02	2,347	391	2,738	61	13	19
1/03	2,707	483	3,190	68	13	19
1/04	3,101	598	3,699	72	15	19
1/05	3,644	754	4,398	81	16	18
1/06	4,336	1,981	6,317	95	31	20
1/07	5,493	6,130	11,623	110	76	21
1/08	7,888	5,536	13,424	139	61	21
1/09	12,475	2,066	14,541	170	24	26
1/10	13,028	1,432	14,460	189	15	26
1/11	14,071	560	14,631	204	10	29
1/12	14,907	140	15,047	209	2	29
1/13	14,837	50	14,887	211	2	28
1/14	14,880	167	15,047	210	7	28

Ethanol production capacity has grown rapidly since passage of EISA 2007. Construction of new facilities has increased the resiliency of U.S. ethanol production.

In general, the operating costs of many alternative fuels are more expensive than gasoline and diesel on a gasoline equivalent basis. Compressed natural gas and electricity are the exceptions and can compete on a cost basis with gasoline when gasoline is above $2 per gallon or $1 per gallon, respectively (see Figure A-9). Because ethanol is used as a low-level blend in gasoline, its price is linked to gasoline prices—ethanol prices move up and down with the gasoline market. Ethanol supplies octane and is a fuel extender in the gasoline pool. While ethanol costs are linked to feedstock prices and manufacturing costs, the market price tracks with the fuels it is blended into. For instance, when gasoline prices are very high, ethanol plants are profitable; when gasoline prices are very low, ethanol plants can become unprofitable if ethanol feedstock prices are not correspondingly low.

Figure A-9. Average Retail Prices of Transportation Fuels in the United States[40]



Between 2000 and 2012, alternative fuel retail prices generally have tracked the price of gasoline, with the exception of compressed natural gas and electricity.

Primarily, ethanol production is located in the Midwest where most of the corn feedstocks are grown. However, because ethanol is blended, large amounts of ethanol are transported from production to consumption areas. The main transportation infrastructure issue for ethanol is related to its chemical properties. Ethanol is not shipped through petroleum product pipelines because it interacts with water and can degrade specs for petroleum fuels that would follow in the pipeline. Additionally, ethanol product volumes have not reached a level to support the construction of dedicated ethanol pipelines from the Midwest to consumption markets in the other regions of the United States.[q] One pipeline in Florida ships small amounts of ethanol because the operator has control over all of the products on the pipeline and can more easily mitigate potential water contamination issues. Biofuels move from production plants to blending or distribution centers almost exclusively via truck and rail, with a small amount by barge. Ethanol deliveries typically occur by rail, which accounts for around 70 percent of ethanol transport.[41] Biodiesel transport, which faces similar issues as ethanol, primarily is shipped by tank car—either by rail or truck. Small amounts of biodiesel are shipped via pipeline, but these shipments are limited (primarily to avoid possible contamination of jet fuel batches also shipped by pipeline because jet fuel by law may not contain any amount of traditional biodiesel).

Two methods to bring infrastructure-compatible biofuels to market with relatively minor modifications to the existing gasoline and diesel production and delivery infrastructure include upstream biofuels pathways and drop-in fuels. "Upstream" biofuel pathways involve blending into the petroleum product supply chain; pyrolysis oil and algal oil are introduced at the refinery, and renewable diesel fuel, ethanol, and Fischer-Tropsch biofuels are blended with refinery output products.[42]

[q] A $4-billion ethanol pipeline project from Midwest to Northeast was considered by Poet and Magellan Midstream Partners, but it was abandoned in 2012 after it became clear that the project was not economically feasible.

The Department of Energy (DOE) has active research programs on drop-in fuels, and small amounts are already entering commercial markets. Jet fuel and diesel are primary targets for drop-in fuels given the challenges of electrifying airplanes and other large vehicles. Most production is in the pilot/demonstration phase, but commercial flights have flown with 50-50 biofuel blends in Europe and the United States starting in 2011. These still have a large price differential to overcome; the September 15, 2014, spot price for a gallon of jet fuel was $2.73, while the Navy paid about $15.00 per gallon of 50-50 biofuel blend for its Great Green Fleet test in 2012.[43]

Ethanol transportation by rail and barge has experienced increased competition with other commodities. Potential future issues could be the number of rail tank cars, depending on the phase-in timing of the new Department of Transportation (DOT) Specification 117 tank car standards.[44] The primary focus on rail safety has centered on the DOT-111 railcar. DOT-111s are non-pressurized tank cars designed to carry a wide range of products, including hazardous and nonhazardous materials, such as ethanol, crude oil, and petroleum products. Out of the entire fleet (335,000 active tank cars) used to transport crude oil, ethanol, and other liquid petroleum products, approximately 92,000 are DOT-111s. Rail infrastructure components are discussed in greater detail later in this appendix.

Alternative Fuels Infrastructure[r]

According to the 2013 National Academies report, "Transitions to Alternative Vehicles and Fuels,"[s] the benefits of a successful transition to clean alternative fuels for light-duty vehicles would exceed the costs by approximately an order of magnitude. In addition to reduced emissions of greenhouse gases, local air pollutants, and petroleum use, the transition also is likely to produce fuel savings for motorists and create a greater diversity of vehicle choices for consumers. At present, U.S. alternative fuels refueling infrastructure is inadequate to induce and sustain a transition to low-greenhouse gas, non-petroleum energy for transportation vehicles. Compared to approximately 150,000 public gasoline stations, the availability of alternative energy refueling stations in September 2014 was as follows: electric recharging, 8,551; propane, 2,686; E85, 2,401; compressed natural gas, 752; liquefied natural gas, 62; biodiesel, 292; and hydrogen, 12.

Deploying adequate refueling infrastructure is challenging because during the early years of a transition the refueling network necessary to support adequate alternative fuel vehicle sales growth will be underutilized. Volatile oil prices pose an additional challenge. As a result, business models for the earliest alternative refueling stations are likely to bear significant market risks. Past experience with alternative fuels policies has shown that investors are reluctant to build infrastructure before a market for alternative fuels has been established. Even so, the required annual infrastructure investments are small relative to annual expenditures on fuel for motor vehicles.

In response to this challenge, vehicle manufacturers, fuel suppliers, and retailers have developed innovative business models. One manufacturer is bundling free fuel with the lease of a hydrogen fuel cell vehicle; another is providing a nationwide network of fast-charging stations to battery electric vehicle purchasers; and another is providing capital to a startup company that will build and operate hydrogen refueling stations. Employers are providing free charging to attract and retain employees. An equipment supplier has developed a turnkey compressed natural gas refueling "station in a box" to make it easier for fleets to choose compressed natural gas. Public policy support for alternative refueling infrastructure includes capital grants and operating cost subsidies, streamlining codes, and permitting Internet applications that locate alternative fuel stations or help car buyers decide if an alternative fuel vehicle is best for them.

[r] Quadrennial Energy Review Analysis: Greene, D. et al. "Alternative Transportation Refueling Infrastructure in the U.S. 2014: Status and Challenges." UT-Knoxville: Howard H. Baker Jr. Center for Public Policy. January 2015. http://energy.gov/epsa/qer-document-library.

[s] National Research Council. "Transitions to Alternative Vehicles and Fuels." The National Academies Press. 2013.

Alternative Fuels Infrastructure (continued)

The impressive progress of alternative fuel and vehicle technologies over the past two decades suggests that more than one alternative fuel technology will be able to achieve mass market acceptance. Nevertheless, it is still not clear which technologies will succeed. Because the time constants for major changes in the transportation energy system are on the order of decades, the co-evolution of alternative fuel vehicles and infrastructure markets will necessarily involve experimentation, learning, adaptation, and persistence. There are likely to be both successes and failures along the way. The uncertainty inherent in the transition process is especially challenging for public policy. Because of the urgent need to mitigate climate change and strengthen energy security, a portfolio of alternative fuel infrastructures should be supported by stimulating innovative business models and supporting public policies. Further action by both the private sector and at the Federal level is necessary for alternative refueling infrastructure.

TS&D Infrastructure

As crude oil production patterns have shifted, domestic TS&D infrastructure also has undergone substantial change. Crude oil and refined product pipelines, rail, waterways, refineries, customer storage, strategic reserves, and the electricity dependence of these components are discussed in the sections that follow.

Pipelines

Pipelines have been and continue to be the dominant carrier of crude oil transported within the United States. There are more than 120,000 miles of refined product and crude oil pipelines in the United States (see Table A-4),[45] delivering more than 14 billion bbl of crude oil and petroleum products each year. Approximately 52 percent of the petroleum transported by pipelines is crude oil, and 47 percent is in the form of refined products, each with its own dedicated pipeline network.[46]

There are an estimated 30,000 miles to 40,000 miles of crude oil gathering lines, primarily in the Gulf of Mexico, Alaska, Texas, Oklahoma, Louisiana, Wyoming, and North Dakota, with small systems in a number of other oil producing states.[47] These small lines gather the oil from many wells, both onshore and offshore, and connect to larger crude oil pipelines. Crude oil pipelines include a few large cross-country pipelines—typically 8 inches to 24 inches in diameter, but ranging up to the 48-inch-diameter Trans-Alaska Pipeline System—that bring crude oil from producing areas to refineries or intermodal connection points. There are approximately 57,000 miles of crude oil pipelines in the United States, with some crossing boundaries with Canada.[48]

Table A-4. Annual Pipeline Mileage for Moving Hazardous Liquids, 2004–2012[49, t, u]

Year	Pipe Total	Petroleum/ Refined Products	Crude Oil	Highly Volatile Liquids[i]	CO_2 or Other[ii]	Fuel-Grade Ethanol
2004	166,669	62,391	49,264	51,794	3,221	
2005	166,760	62,899	48,732	51,284	3,846	
2006	166,719	61,905	48,453	52,533	3,827	
2007	169,846	62,091	49,488	54,382	3,884	
2008	173,789	61,599	50,963	57,024	4,203	
2009	175,965	61,803	52,737	57,233	4,192	
2010	182,072	64,787	54,729	57,980	4,560	16
2011	183,385	64,117	56,102	58,599	4,550	16
2012	185,637	64,038	57,068	59,861	4,655	16

Crude oil pipeline mileage has grown every year from 2004 through 2012, while refined product pipeline mileage has remained relatively constant, with some years experiencing a decrease in mileage.

Hundreds of miles of subsea gathering lines and pipelines connect drilling and production platforms in the Gulf of Mexico to oil and gas collection points and to onshore storage terminals. This area also is traversed by shipping channels that serve major ports and refining regions along the Gulf Coast. Several major pipelines, with a combined capacity of 4.35 million bbl/d, supply crude oil from the Gulf of Mexico to PADD III.[50]

In addition to crude oil pipelines, as of early 2014, there were approximately 95,000 miles of pipelines that carry refined petroleum products—such as gasoline, jet fuel, home heating oil, and diesel fuel—to large fuel terminals or distribution centers, where they are typically loaded into tanker trucks for transport to the final point of sale.[51] Multi-product pipelines normally are used to transport two or more different products in sequence.

Crude oil and multi-product pipeline networks also include pump stations, which keep oil flowing at rates of 1 meter per second to 6 meters per second. "Pipeline expansion" projects often entail the uprating of pumping capacity and only minimal, if any, alteration or extension to the pipe itself. Other ways to increase utilization of the system include reversing flow directions to accommodate new points of origin or converting natural gas pipelines into oil pipelines.

In 2012, transmission pipelines moved an estimated 7.5 billion bbl of crude oil and 6.7 billion bbl of products, reflecting an increase of 6 percent and 2 percent, respectively, between 2009 and 2012 (see Table A-5).

[t] Highly volatile liquids are hazardous liquids that form a vapor cloud when released to the atmosphere and have a vapor pressure exceeding 276 kilopascal at 37.8°C (100°F). Examples include ethane, ethylene, propane, propylene, butylene, and anhydrous ammonia (NH3). Source: Department of Transportation, Pipeline and Hazardous Materials Administration Form 7000-1.1.

[u] Carbon dioxide (CO_2) is defined as a fluid consisting of more than 90 percent CO_2 molecules compressed to a supercritical state. Source: Department of Transportation, Pipeline and Hazardous Materials Administration Form 7000-1.1.

Table A-5. Crude and Petroleum Product Delivered by U.S. Transmission Pipeline (billions of barrels)[52]

Year	Crude	Product	Total
2009	6.96	6.56	13.52
2010	7.15 (2.8%)	6.39 (-2.6%)	13.54 (0.2%)
2011	7.03 (-1.6%)	6.54 (2.3%)	13.57 (0.3%)
2012	7.47 (6.3%)	6.67 (1.9%)	14.14 (4.2%)

Between 2009 and 2012, there have been moderate increases in the quantities of crude oil and product shipped in U.S. transmission pipelines.

Shifting Pipeline Flows

Historically, the town of Cushing, Oklahoma, has served as the North American Mid-Continent hub for distributing crude oils from west Texas production or imported into the U.S. Gulf Coast and then shipped north via pipeline. Until recently, U.S. oil pipeline construction and system configuration roughly mirrored this flow pattern, facilitating the movement of crude to U.S. refineries throughout the Midwest. Under the new supply landscape, industry decision makers have had to reconsider how to efficiently and economically move oil to various hubs, refineries, and ports from the new producing regions. In some of these regions, infrastructure could be relatively underdeveloped and/or pipeline capacity could be insufficient to keep pace with current extraction rates.

Pipeline companies have responded to the new oil transport demands, primarily with extensive modifications to existing pipelines (e.g., reversals in flow direction, repurposing of natural gas pipelines) and some limited numbers of new pipelines. Typically, new pipelines are less feasible because of the need to secure long-term commitments from shippers for investments. Such commitments have become difficult to obtain because producers now have the option of using rail shipping, which only requires short-term contracts and provides the flexibility to move to alternative markets if market conditions shift.[53] Still, some major investments in new pipelines are under consideration. The increase in Texas and North Dakota oil production has required significant changes to the U.S. midstream, including pipeline reversals, as well as new pipelines or expansions of existing systems. Although there are also rail movements of oil from Alberta to coastal refineries, rail movement is more expensive with estimates of $15 per bbl from Bakken to the East Coast, $12 per bbl to the Gulf Coast, and $9 per bbl to the Northwest, contrasting with cost estimates of $5 per bbl for pipeline movements when such routes are available. Such bottlenecks have led to a modified oil pipeline network in the United States and Canada, including changing pipeline flow direction, conversion from gas line to crude lines, and new construction projects.

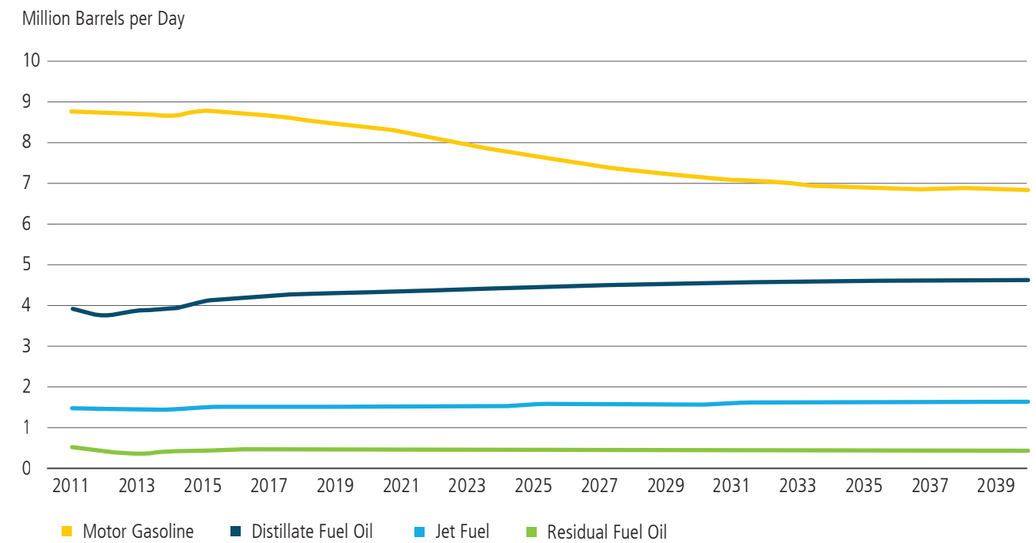
New pipeline connections to the Permian Basin have opened in the last year, and volumes of Permian and Eagle Ford petroleum can now flow to the Gulf Coast refineries. Other new pipelines are planned to open or expand access to crude from Bakken and Alberta, respectively. Collectively, supplies from the U.S. interior and Canada have been rising while imports from the rest of the world have been declining.

Pipeline Investments

Due to the extensive restructuring of domestic crude oil flow patterns, investments in U.S. crude oil pipelines increased from $1.6 billion in 2010 to $6.6 billion in 2013.[54] After an investment boom in 2013, the Oil and Gas Journal estimates a decline in U.S. pipeline expenditures in 2014. Spending for crude oil and product pipelines is expected to total $9.2 billion in 2014, a 42-percent decrease in capital outlays from 2013. As a comparison, 2014 spending for gas pipelines and compressor stations also is projected to slip from 2013 levels (down 60 percent from 2013 to $3.7 billion). Despite the decline in pipeline spending, capital spending on other modes of midstream transportation for crude oil and products is expected to increase 53 percent from 2013 to 2014.[55]

Forward-looking scenarios indicate midstream build-out and investment in line with historic levels. As an investment class, pipeline infrastructure generally is considered to be a long-term investment with relatively low risk and low return. The stable, predictable returns that these projects offer are attractive to certain entities, such as institutional investors,[v] particularly given current low interest rate conditions.

Figure A-10. Forecast Consumption of Four Major Fuels, 2011–2040[56]



Motor gasoline consumption is projected to decline from 2016 to 2040.

Rail

According to the Federal Railroad Administration, the freight rail industry includes 140,000 rail miles operated by 7 Class I railroads (systems with annual operating revenues of $467.1 million or more in 2013[w]), 21 regional railroads, and 510 local railroads.[57] Since the 1980s, the freight rail industry in the United States has consolidated as the number of major railroads has declined.

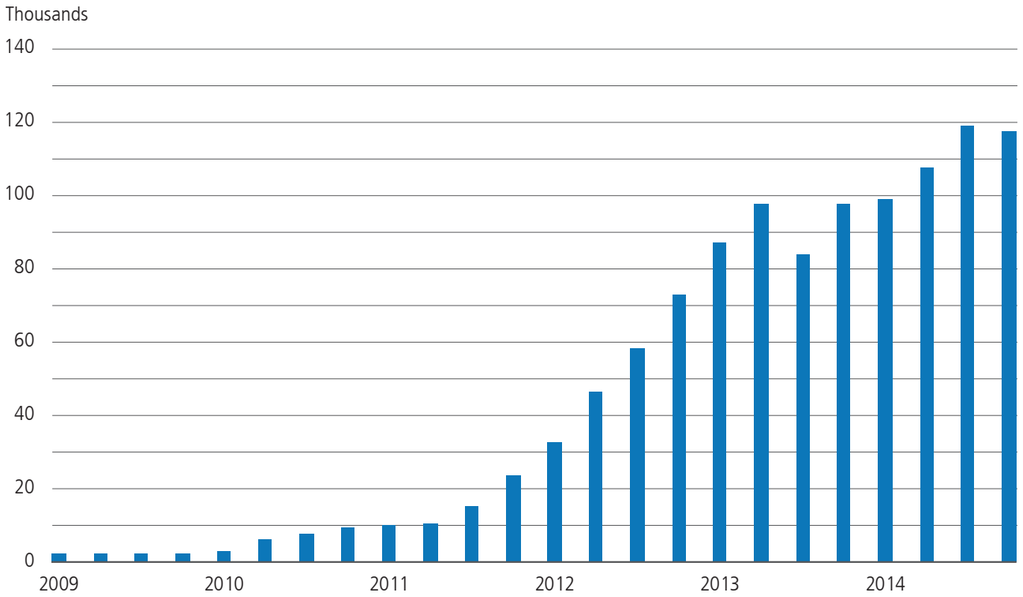
As the domestic oil production boom has outstripped the ability of pipeline developers and regulators to site new infrastructure, it has opened up a market for rail transport. In 2009, roughly 10,800 carloads of crude oil originated on U.S. Class I railroads.[58] By the end of 2014, the volume of rail shipments had grown to more than 493,000 originated carloads of crude oil[59]—an increase of roughly 4,400 percent in 5 years (see Figure A-11). The EIA estimates that, on average, over 1,022,000 bbl of domestic and Canadian crude were

[v] For example, global total capital for all mutual fund and institutional investors is estimated at approximately $80 trillion, with approximately $20 trillion for U.S. pension funds alone. Although only a fraction of this investment is applicable to the infrastructure asset class, that fraction dwarfs estimates of total required energy investment. Sources: Climate Policy Initiative. "The Challenge of Institutional Investment in Renewable Energy." 2013.; CERES. "Investing in the Clean Trillion." 2014.; and AECOM. "Fostering a Larger Private-Sector Role in the United States." 2013.

[w] Class I railroads are defined as those railroads with annual operating revenues (after being adjusted to compensate for inflation by a railroad revenue deflator formula) of more than $250 million. The $467.1 million figure represents this inflation-adjusted value for 2013.

moved in the United States by rail per day in 2014.[60] While the rapid rate of growth did slow in 2014, the first half of 2014 had the highest number of carloads for any previous 6-month period.[61] The total number of carloads of rail transport dedicated to petroleum and petroleum products is still small compared to that for other commodities. During the first quarter of 2014, crude oil accounted for 1.6 percent of U.S. originated carloads;[62] although, the share of revenue is higher. From 2005 to 2013, rail rate increases were 2.8 times higher than both inflation and truck rate increases.[63]

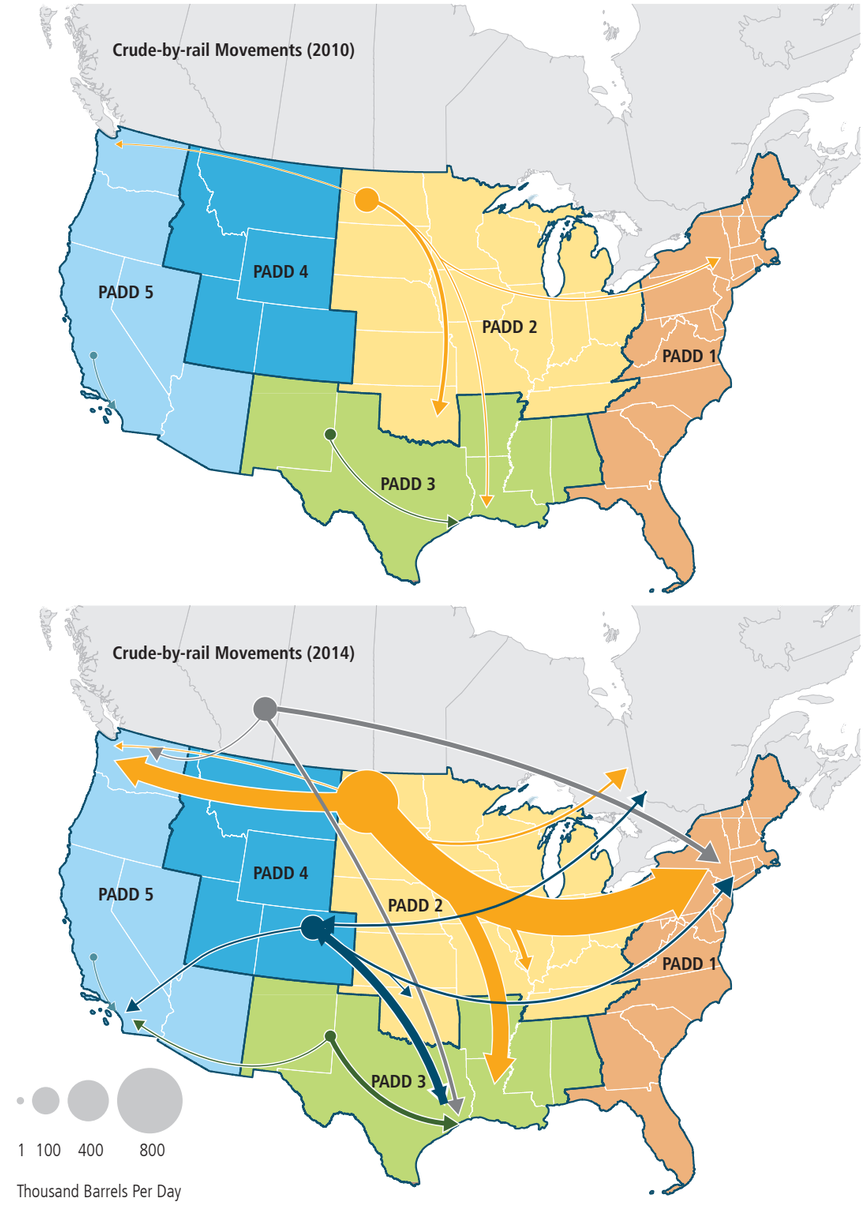
Figure A-11. Originated Class I Railcars of U.S. Crude Oil (2009–2014, Quarterly)[64]



The rapid increase in crude by rail is a function of the growth in new oil production, particularly in North Dakota, as well as limited pipeline capacity for moving this oil to refiners on the East and West Coasts.

While crude shipments have grown in the United States as a whole, the increase primarily has been a regional story (see Figure A-12). U.S. refining capacity is concentrated in traditional crude oil production areas (Texas and Oklahoma), or on the coasts where crude oil transported by tanker is readily accessible (California, Washington, the Northeast, and the Gulf of Mexico). In areas that currently lack adequate pipeline access, railroads have filled a niche in the oil transportation market.

Figure A-12. Crude by Rail Movements in 2010 and 2014[65]

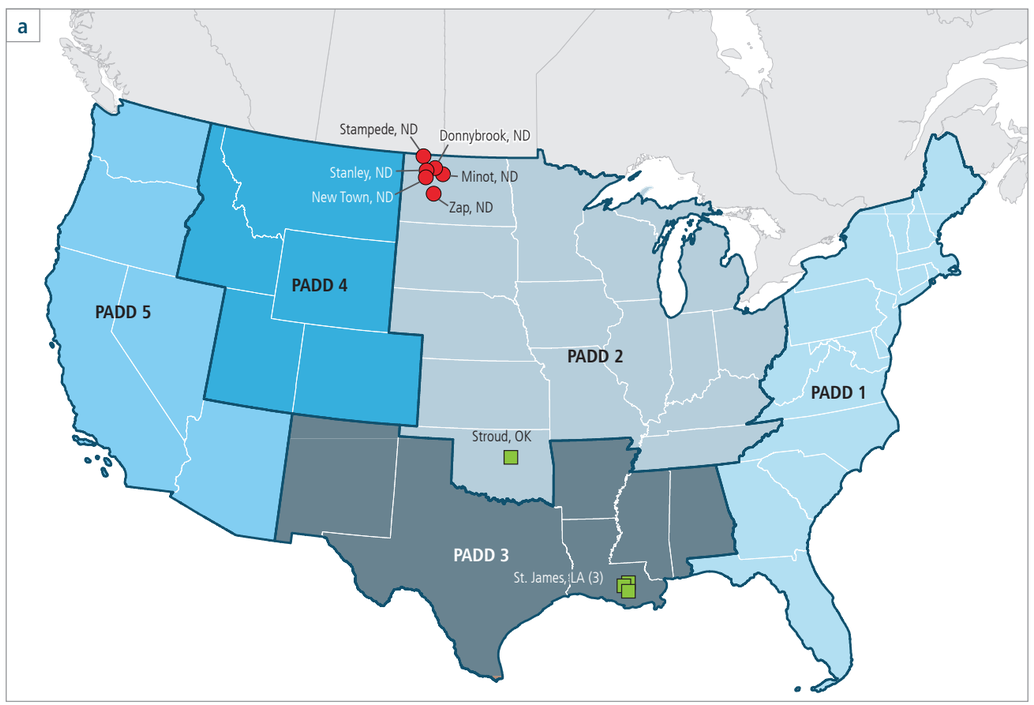


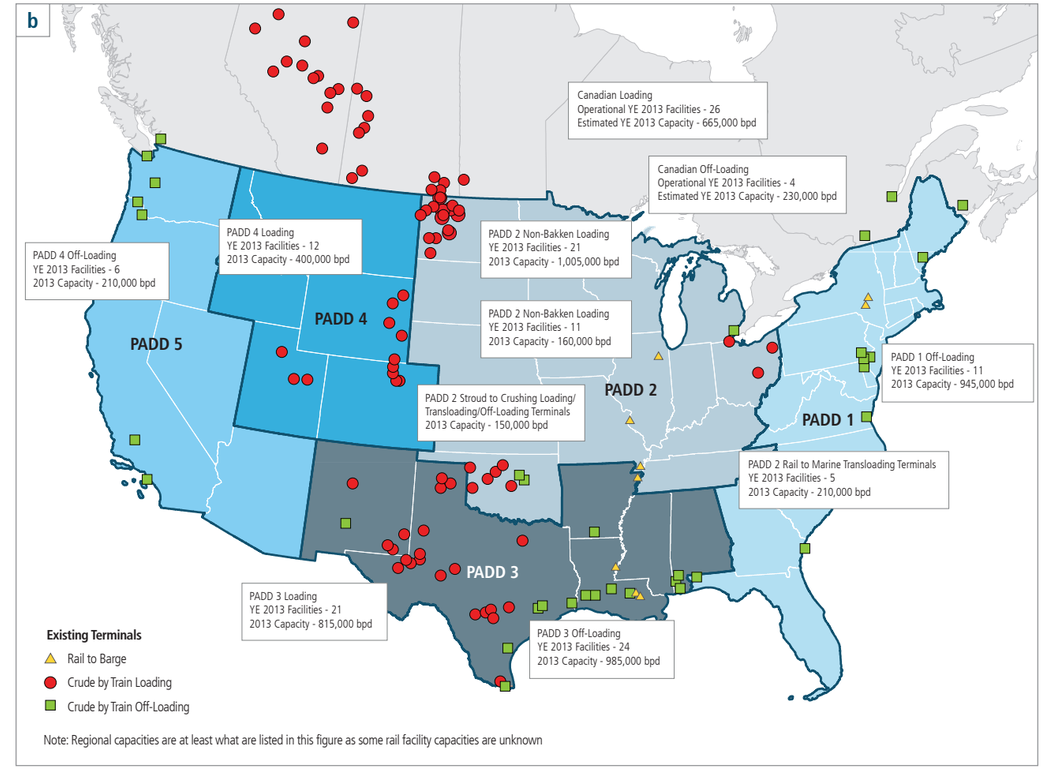
In 2010, the Williston Basin in North Dakota (PADD II) was the primary origin of 55,000 bbl/d of shipments. In 2012, the total volume shipments more than tripled, most of which went from PADD II to PADD III as rail substituted for a lack of available pipeline capacity to carry crude to Gulf Coast refineries. In 2013, shipment volumed nearly doubled, as Bakken crude from PADD II was shipped to coastal refineries. In 2014, growth in shipments started to slow, with Bakken crude (PADD II) making up 70 percent of crude-by-rail volumes and Niobrara crude (PADD IV) growing in importance as the second-largest origin for rail shipments.

From the Bakken field in North Dakota and Montana, as of mid-2014, rail accounts for more than 70 percent of total oil shipments and 100 percent of Bakken-to-West Coast deliveries (to Washington and California). BNSF is the biggest mover of oil by rail, transporting one-third of Bakken production. The percentage of total deliveries fluctuates and will decrease as new pipeline capacity comes online.

In addition to the increase in carloads of crude, construction of loading and offloading facilities has increased. This growth has been localized to producing regions and regions with refining capacity (see Figure A-13). Due to highly condensed supply locations, issues such as greater rail traffic, competition for access, and resulting congestion have emerged in certain areas that have seen rapid production increases (e.g., Bakken crude by rail out of the Williston Basin). Requirements for infrastructure expansion to deliver crude oil out of the Williston Basin to the East and West Coast refineries will be met by rail shipments for the foreseeable future because pipeline projects will likely not be economically feasible or may face local opposition for rights of way through more heavily populated areas. At the same time, new rail offloading terminals in the West Coast area may also face constraints. Figure A-13 displays expansion of the rail loading and offloading facilities in the United States and Canada, most of which were added since 2010.

Figure A-13. Crude Oil by Train-Loading and Offloading and Rail-to-Barge Facilities for 2010 (a) and 2013 (b)[66]





In 2010, the United States and Canada had six rail-loading facilities for crude oil and four offloading facilities. By year-end 2013, crude oil by rail capacity had grown to include 65 loading facilities in PADDs II, III, and IV. Rail-to-barge facilities also increased.

The expansion of crude oil transport infrastructure is entirely dependent upon expected production. DOE analysis of the infrastructure requirements relied on the expected crude oil production from EIA's 2014 Annual Energy Outlook Reference case and High Resource case projections.[67] Commercial pipeline projects proposed over the near term, along with rail-loading and offloading facilities, will have sufficient capacity to move the increased crude oil production.

Rail is constrained by the number of specialized tank cars available for oil transport. Some estimates in 2014 cited a 50,000-car (or 18-month) backlog in orders.[68, 69] Possible constraints in the capacity of loading and unloading terminals also present challenges for moving oil by rail.

Information on rail constraints is difficult to obtain because much data on rail transport is proprietary. The continuing decline in coal traffic has also opened up capacity on some lines, and large investments to expand capacity, improve efficiency, manage traffic, and make safety improvements now allow rail to carry more capacity than before. Even with additional capacity, because of the locations of rail traffic growth, constraints do exist in some areas.

Crude by rail from the Bakken, coal from the Powder River Basin, and agricultural products are competing for limited rail capacity moving out of the same part of the country. While the movement of crude out of the Bakken may only be one factor in general rail competition issues, the large volume of crude shipments has exacerbated the problem in a number of areas. There is a Federal interest in ensuring open, competitive markets and in preventing monopolistic behaviors and the potential negative consequences on consumers. It is also the stated rail policy of the United States to ensure effective competition in rail service, to establish that service at reasonable rates, and to prohibit predatory pricing and practices and avoid undue concentrations of market power.[70]

To address the issue of market power, but motivated primarily by the financial struggles of U.S. railroads in a heavily regulated, economically inefficient environment, Congress passed the Staggers Rail Act in 1980. The Staggers Act has been successful in improving the financial health of the railroads, which have become more efficient by eliminating excess capacity and redundancy and streamlining operations. In the last three decades (from 1980 to 2011), the number of ton-miles transported by rail has doubled, while Class I revenues per ton-mile have declined almost 40 percent in real terms.[71, 72]

This is not the case for all commodities on all routes. According to the Department of Agriculture, "Even though a recession started in December 2007, railroads continued to raise rail rates, partly to support record railroad capital investments and higher costs. Average real rail rates per ton-mile for all commodities increased 36 percent between 2004 and 2011. Real rail costs adjusted for railroad productivity increased 29 percent during the same period. This indicates that most of the increase in rail rates was due to increased rail cost, but the increased rail rates also contributed to record rail profits. In comparison, real truck rates have increased 27 percent since 2004."[73] Protecting rail consumers from service disruptions is another prime factor in passage of the Staggers Act; a more streamlined rail system with limited excess capacity can, however, become overburdened when demand spikes, as it did in 2013 to 2014, which can leave shippers vulnerable to service deficiencies.

Rail Safety

Rail safety has become a key issue as rail transport of liquid fuels has grown. Several high-profile crude-by-rail accidents occurred since 2013, the most devastating of which killed 47 people in Lac-Mégantic, Quebec. Others, such as those in Aliceville, Alabama; Casselton, North Dakota; Lynchburg, Virginia; and Mount Carbon, West Virginia, resulted in significant environmental and property damage after tank cars derailed, ruptured, and the oil caught fire. Similar accidents involving ethanol rail shipments also have raised concerns about the safety of rail tank cars and the shipping of these flammable hazardous commodities across the United States. These accidents have highlighted the need for additional monitoring, enforcement, inspection, and setting of new tank car safety design requirements.[74]

To address these safety concerns, DOT published a final rulemaking in 2015 to enhance rail tank car standards and operational controls for high-hazard flammable trains and a proposed rulemaking in 2014 to propose development of oil spill response plans for high-hazard flammable trains.[75] In addition, in 2014, the Pipeline and Hazardous Materials Safety Administration released a data summary that detailed the agency's testing and sampling program (Operation Classification) for Bakken crude oil. The summary stressed the importance of proper classification of hazardous materials.[76] Specifically, the results of the sampling and analysis would be used to determine the potential volatility of crude oils predominantly shipped by rail compared with other domestic crude oils. New regulations at the state and Federal[77] levels have been proposed or established to accomplish the following:

- Improve railroad operations to make derailment of crude oil trains less likely.
- Improve the integrity of crude oil tank cars.
- Improve the classification of the crude oil being shipped.
- Improve field processing of crude oil to reduce the volatility of crude oil that will be shipped.

Notably, North Dakota has instituted temperature and pressure requirements on field-conditioning equipment in its Bakken and Three Fork formations that will reduce some of the volatile components contained in the crude oil produced from these fields, for purposes of improving the safety of rail transportation of that crude.

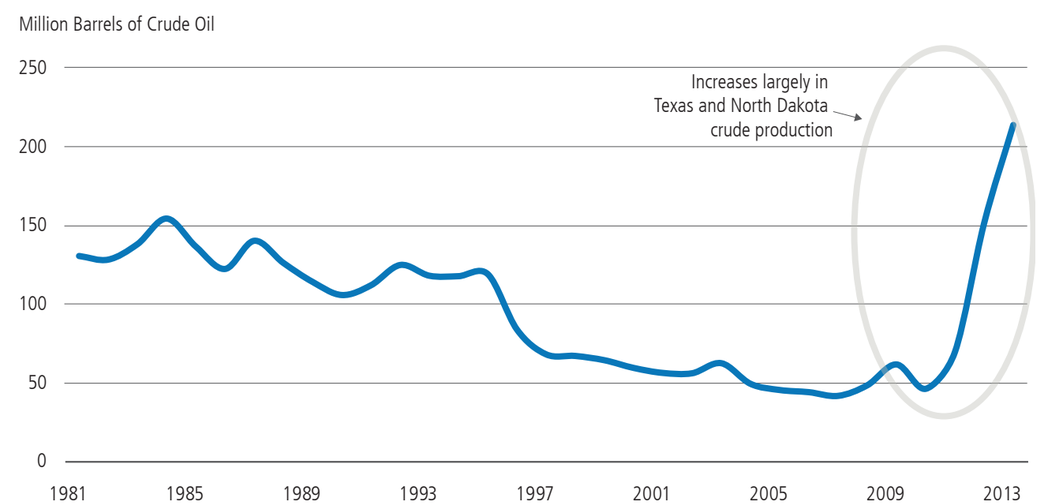
Should derailments of crude oil unit trains occur, with more robust tank cars, the consequences of the derailments should be reduced. While all modes of travel have inherent risk that cannot be reduced to zero, these measures are expected to improve crude-by-rail safety.

Waterways

Inland barges were used to transport oil on Pennsylvania's Allegheny River as early as 1861.[78] In the following decades, pipelines, tankers, and railroads overtook inland barges as the preferred method of moving oil as international imports rose and pipeline capacity increased. For similar reasons, coastal shipping between U.S. ports declined over the years.

Recently, however, utilization of barges for petroleum transport has risen dramatically, as shown by the sharp increase in refinery receipts by barge from 46 million bbl of domestic crude in 2010 to 214 million bbl in 2013 (see Figure A-14). Despite a decrease in oil imports, barge deliveries of foreign crude have risen by more than 60 percent since 2011.[79] The main factor is the boom in the production of shale oil from the Bakken and Eagle Ford plays, which has exceeded pipeline capacity and necessitated the use of other modes of transport to avoid severe discounting of crude. According to analysis by BB&T Capital, "In less than 2 years, crude-by-barge pricing has increased three-fold and now nearly one-third of the inland fleet is moving oil and about 15 percent of the coastal fleet is transporting crude. . . Just a few years ago, crude-by-barge was essentially nonexistent and today it has become one of the largest commodities moved by the barge industry."[80]

Figure A-14. Annual Refinery Receipts of Domestic Crude Oil by Barge[81]



Refinery receipts of crude oil by barge have increased by more than 300 percent since 2010, reflecting a larger trend of increased crude-by-barge traffic in the United States.

In terms of capacity, one river barge has a capacity of 10,000 bbl to 30,000 bbl of oil. Typically, two or three river barges are connected in a single tow, providing similar capacity to a unit train. Articulated tug-barges (ATBs) are coastal tank barges designed for open sea transport and can have a capacity between 50,000 bbl and 185,000 bbl. New ATBs have been designed with a capacity of up to 340,000 bbl, which is similar to the capacity of some coastal oil tankers; although, ATBs are "slower, less fuel efficient, and more restricted by sea conditions"[82] than coastal oil tankers. Larger tankers designed to move Alaska oil to refineries on the West Coast have capacities of 800,000 bbl to more than 1 million bbl. Despite the limitations of ATBs, there are instances where they possess an economic advantage over tankers, as "U.S. Coast Guard regulations allow ATBs to sail with one-third to one-half the crew required on a tanker."[83] EIA data show that domestic crude received at refineries by tanker has been relatively flat, while foreign crude received at refineries by tankers (at a much bigger volume compared to domestic crude) has declined in recent years. Historically, refinery receipts of crude oil by barge have been predominantly foreign crude; however, in 2012 and 2013, domestic crude receipts by barge were higher than receipts of foreign crude by barge.[84]

Coastal movement of oil also has risen in recent years. Many refineries traditionally receive crude from overseas by tanker and thus are located near the coastline with access to dock facilities. A recent Congressional Research Service report[85] states that, though circuitous compared to rail, tankers could also play a bigger role in moving domestic (Bakken) oil to East or West Coast refineries in the future. Significant amounts of Bakken oil are already transported to Gulf Coast refineries by pipeline, railroad, barge, or combinations of these modes. Tankers also could participate in such multi-modal transports and extend shipments of Bakken crude to either East or West Coast refineries. Tankers also could provide the last leg of moving Bakken oil to Northeastern refineries after the oil has been railed to the Great Lakes ports. However, the economic viability of these routes—in particular, routes involving domestic coastal transport in general—is heavily influenced by the Jones Act.[86, x]

With respect to crude moved by inland waterways, the main mechanism is intermodal, whereby railroads transfer oil to barges typically for the last leg of the trip to refineries. Locations where railroads transfer crude oil to barges include St. Louis and Hayti, Missouri; Osceola, Arkansas; Hennepin, Illinois; Albany, New York; Yorktown, Virginia; and Anacortes and Vancouver, Washington. In addition, crude produced in the Eagle Ford in Texas, which is located near ports, is being moved along the Gulf Coast area by barge or ship.[87] Major transport routes for crude oil are shown in Figure A-15.

[x] The Jones Act, Section 27 of the Merchant Marine Act of 1920 (Public Law No. 66-261), codified at 46 U.S.C. § 50101 *et seq*. (2006), regulates maritime commerce in U.S. waters and between U.S. ports. It requires that all commercial shipping between U.S. ports must be performed by U.S.-flag ships constructed in the United States, wholly owned by U.S. citizens, and crewed by U.S. citizens and U.S. permanent residents. Source: Energy Information Administration. "Potential Impacts of Reductions in Refinery Activity on Northeast Petroleum Product Markets." May 2012.

Figure A-15. Coastal and Inland Waterborne Transport Routes for Oil[88]

Coastal and inland waterborne energy transport routes converge in the Gulf Coast region, largely between Corpus Christi, Texas, and the coasts of Mississippi and Alabama. In this region, barges on the Mississippi River connect inland production and pipeline terminals to Gulf Coast refineries and key ports. Coastal waterways also connect the Gulf Coast region's refineries to major demand centers in the Northeast and international refined product markets. Within the Gulf Coast region, waterways such as the Houston Ship Channel and Sabine Pass are heavily trafficked due to the high concentration of refineries that they connect to the larger coastal and inland waterway system.

Some areas of concern with the increase in barge use include the following:[89]

- **The Mississippi River** and its tributaries provide a route to the Gulf Coast, regional refineries, and key ports, including New Orleans. There are times, though, when a portion of the river may be closed to traffic. If sections of the river are shutdown or traffic is limited, barge shipments will be severely disrupted. At certain times of the year, parts of the river or its tributaries are unnavigable due to flooding and drought, and the river has occasionally been closed to traffic because of Gulf hurricanes, upstream flooding, accidents, and oil spills. A large number of locks control the flow of water and traffic on the Mississippi River. Each of these locks can be a chokepoint, as any malfunctions will cause delays and congestion that affects the transport of refined products and crude oil, as well as other commercial uses of the river.

- **Sabine Pass** is a coastal port channel connecting Sabine Lake to the Gulf of Mexico. Its importance comes from the access it provides to and from the Gulf for major crude oil and product facilities at a cluster of ports—Port Arthur, Nederland, and Beaumont, Texas. As the Port Arthur area becomes important to the oil and gas industry, the Sabine Pass will likely experience greater use. The Army Corps of Engineers (USACE) recently completed a study on proposed channel improvements, which Congress authorized in the Water Resources and Development Act of 2014, and is working with the ports to update the supporting economic analysis.

- **The Houston Ship Channel** is already one of the most trafficked waterways in the United States and serves the second largest port in the Nation by tonnage. Houston has a large number of refineries and petrochemical facilities and receives crude through several pipelines, railroads, tankers, and barges. The channel is 52 miles long and connects downtown Houston and its refinery row to Galveston Bay and the Gulf of Mexico. About 8 percent of U.S. refining capacity is located along the channel. Hundreds of ships transit the channel daily, and traffic may increase in the coming years. Gulf ports generally silt in more quickly due to geographic differences and thus require much more maintenance dredging than many ports on the East Coast or West Coast. USACE recently deepened and widened this channel and has started a study to determine whether further improvements are warranted based on the current and expected traffic levels.
- In terms of imports, the **Louisiana Offshore Oil Port (LOOP)** and its associated storage sites are among the most important pieces of infrastructure in the Nation. LOOP is the only port that can handle offloading Ultra Large Crude Carriers and Very Large Crude Carriers. In addition to handling imports, LOOP has been used in recent years to offload Eagle Ford crude transferred by barge. LOOP further connects to pipelines, which gather oil produced in the Gulf of Mexico. From LOOP, crude can be fed into the pipeline system for transfer to storage facilities at Clovelly and St. James and moved to refineries in the Gulf region, sent by way of the Capline pipeline to the Midwest, or sent to the Strategic Petroleum Reserve (SPR) storage site at Bayou Choctaw by the Red Stick Pipeline. Reduced imports have reduced volumes of oil handled by LOOP. Nonetheless, with the Nation being more than 30 percent oil import dependent, LOOP remains critical infrastructure.

Waterways and Ports Infrastructure Opportunities

These relatively recent and rapid increases in energy-related demands for waterborne transport have brought a new focus on the Nation's ports and related infrastructure. DOT's "Beyond Traffic 2045" report[90] concludes that "Looking to the future, several critical trends will have a major impact on the performance of marine links in our transportation systems. They include:

- Increasing imports and exports and containerized freight will lead to greater congestion on America's coastal and inland ports.
- Investment in ports, harbors, and waterways will be essential to meet the demand of increased trade and competition."

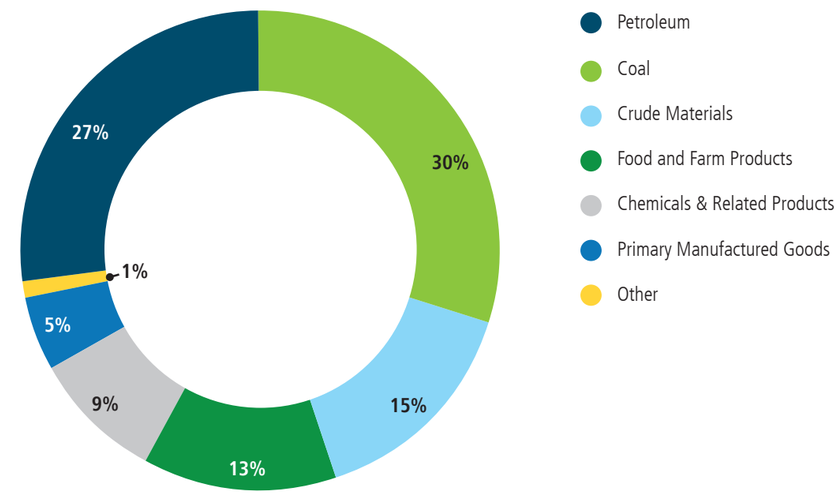
Funding mechanisms for maintaining or improving coastal ports, inland waterways, and related infrastructure is a shared responsibility. The available funding sources depend in part on the nature of the investment and the type of infrastructure involved.[91]

Under current law, the Federal Government is authorized to pay all operations and maintenance costs for inland waterways and generally for half the cost of the construction, replacement, rehabilitation, and expansion of locks and dams on these waterways. The other half is paid for with an excise tax on diesel fuel used on the 27 fuel-taxed inland waterways, which in effect is deposited in the Inland Waterways Trust Fund.[92]

The Federal Government is authorized to pay 100 percent of the cost of eligible operations and maintenance at coastal ports for all work at depths up to 50 feet. For channels at coastal ports, the Federal Government provides a 50 percent to 90 percent cost share for new construction (this varies by channel depth needs and contributions by sponsors).[93] There are two port channel systems in use or under construction that exceed 50 feet depth—Los Angeles/Long Beach and Seattle/Tacoma—both of which have limited needs for maintenance dredging. Additional ports have been authorized to depths greater than 50 feet and may require non-Federal maintenance dredging expenditure, but construction has not yet begun.

The largest categories of tons of commodities shipped on U.S. inland waterways are coal and petroleum (by tonnage). Together, these energy commodities were 56 percent of goods transported on inland waterways in 2012 (see Figure A-16).[94] In addition, a significant proportion of chemicals and crude materials shipped on inland waterways are energy related.

Figure A-16. Inland Waterborne Shipments by Commodity, 2012 (by weight)[95]

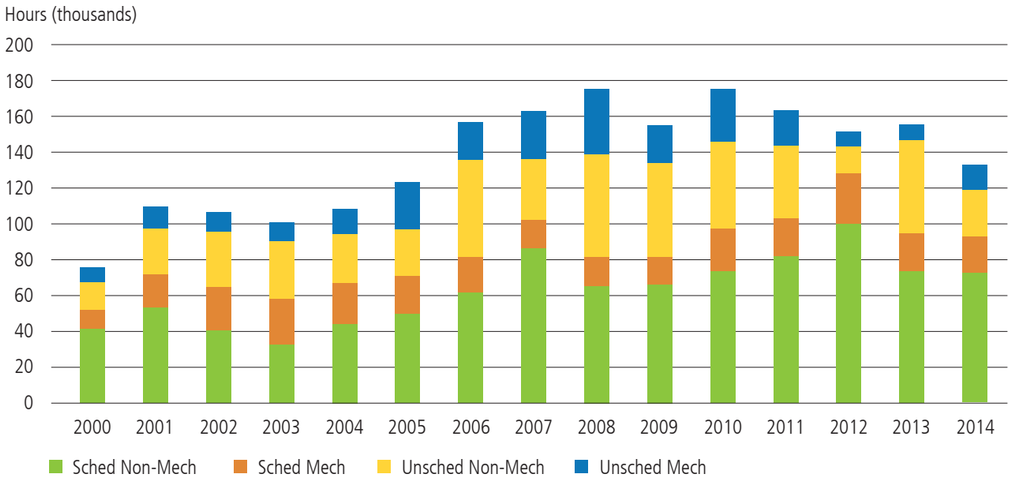


Energy commodities are the dominant commodity group in U.S. cargo traffic. In 2012, crude oil, refined petroleum products, and coal were 56 percent of all shipments by weight on inland U.S. waterways. Energy commodities were a similarly large portion of all domestic and international waterborne shipments in the United States.

Inland locks and dams are a critical component of the Nation's inland waterways. More than 55 percent of the navigation lock chambers were built in the 1960s or earlier, yet almost half of the overall tonnage moving on the inland system passes through them.[96] According to a joint Department of Agriculture/DOT study, "Although aging, the locks and dams on the river system are generally reliable. As locks age, however, repairs and maintenance becomes more extensive and expensive."[97] USACE gives priority to the structures that support the most commercial traffic and invests heavily in their maintenance and periodic rehabilitation. Maintaining the locks and dams of the inland waterways is becoming more costly over time, due primarily to two factors—the condition of some of the components and the cost increases in the broader economy.

The Administration has made progress in reducing time losses from lock closures in recent years. Due in part to Federal investment, the number of main lock chamber closures on high and moderate commercial use waterways (those that carry at least 1 billion ton-miles of traffic annually) due to preventable mechanical breakdowns and failures lasting longer than 1 day and lasting longer than 1 week has decreased significantly since fiscal year (FY) 2010. Non-mechanical failures—such as weather, drought, floods, ice, and current conditions—also create unscheduled lock outages, so impacts from climate change may play a role in inland waterway availability in the future.

Figure A-17. Hours of Lock Unavailability on U.S. Inland Waterways, 2000–2014[98]



Progress in reversing the trend of increasing outages due to unscheduled mechanical breakdown must continue for the inland waterways to remain a reliable and affordable transportation option for shippers.

A typical round trip from New Orleans to the Upper Midwest and back on the inland waterways can take up to 30 days. Although shippers expect to encounter occasional delays due to weather- and equipment-related conditions, according to USACE, "Shippers recognize that the inland waterways are a low-cost method of transportation...they will encounter a delay on some trips due to a weather or equipment related conditions but they remain uneasy about the reliability of this system, noting observed trends in availability. To the extent that system outages disrupt waterborne service, shippers and carriers will experience additional, sometimes unexpected, costs."[99] In spite of these risks, shippers move roughly 600 million tons of cargo annually on the inland waterways.

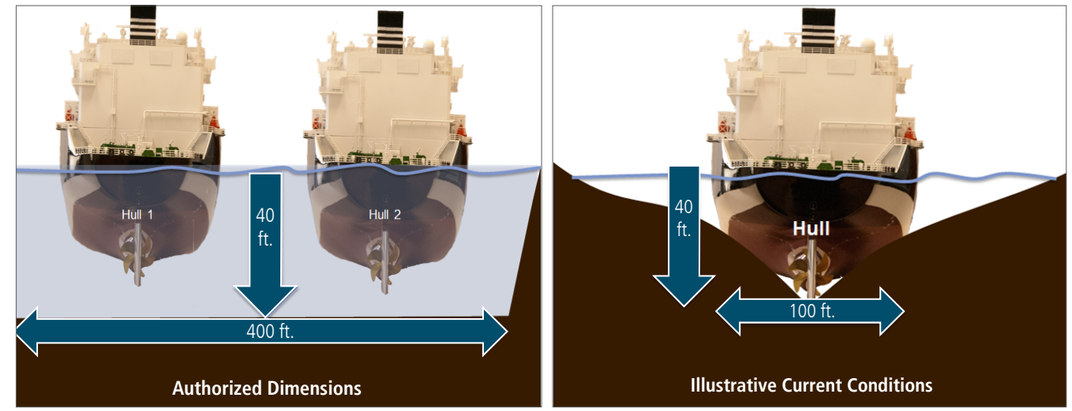
On the principal inland waters, which carry 90 percent of the traffic, additional capital investment beyond current funding levels will be needed to maintain the current level of performance. To address this concern, the Administration has proposed legislation to reform the way the Federal Government finances capital investment on these waterways.[100] Funding for water infrastructure is split between Federal and non-Federal sponsors, presenting an opportunity for additional Federal and private sector investment to accommodate new needs due to the changing domestic energy landscape that are not reflected in current project plans.

On November 12, 2014, Vice President Biden issued a call to action for greater investment in U.S. port facilities, noting, "We are investing less than 1 percent of our gross domestic product in transportation infrastructure... ranking 28th in the world among advanced nations. That is simply unacceptable...we need to do everything we can to ensure that the whole infrastructure system is connected, especially to our ports."

Large ports generally are able to successfully handle today's levels of cargo at the current funding levels for harbor maintenance and related work; although, as noted, port traffic is expected to grow over the next decades. However, some carriers may need to proceed more slowly due to hazards, or to light load their vessels, or offload some cargo to smaller vessels. Depending on the channel conditions, tankers or other vessels may encounter arrival or departure delays (e.g., until another ship has moved through that section of the channel, or until high tide) or restrictions that reduce the recommended vessel draft (which can affect how much cargo some ships can hold).

An example can be found in Louisiana's Calcasieu Ship Channel, which provides access to the Port of Lake Charles—the 13th largest deep sea port in the Nation and an important maritime hub for the U.S. energy natural gas export terminals. In 1968, USACE deepened and otherwise improved the Calcasieu River and Pass to the current authorized Federal dimensions of the channel, which are 400 feet wide and 40 feet deep. USACE dredges the most critical reaches of the channel annually, but shoaling reduces the channel to less than authorized dimensions (see Figure A-18). To help address reduced depths and channel narrowing, which reduces the efficiency of commercial operations, the Calcasieu River and Pass Federal navigation project received $27.7 million of FY 2015 operation and maintenance funds, which will allow USACE to dredge the most vital portions of the channel to optimize safety and efficiency.

Figure A-18. Calcasieu River Ship Channel, Illustration (not to scale) of Authorized Dimensions and Example Conditions Where Shoaling Occurs[101]



This figure is an illustrative example of design dimensions of the Calcasieu Ship Channel authorized in 1968 (left) and a depiction of where shoaling occurs and its impacts on efficiency of shipping (right). This figure is not representative of the entire channel.

Another example of the role of maintenance dredging is the main channel of the lower Mississippi River between Baton Rouge and the Gulf of Mexico. In 2011, shoaling in some areas led those who are responsible for vessel operation to place restrictions on certain parts of the river, until USACE addressed the concern by performing additional maintenance dredging.[102]

USACE is working to develop better analytical tools to help determine the appropriate spending level for harbor maintenance and related work at coastal ports, based on the economic and safety return, as well as a comparison with other potential uses of available funds. The sufficiency of a channel for commercial navigation depends upon the economic and safety return from an additional potential increment of maintenance work, which in turn is a function of actual traffic utilization patterns, the condition of the channel, and other factors.

The 10 port systems where coal, crude oil, and petroleum products make up the largest share of shipments are shown in Table A-6.

Table A-6. Top 10 Port Systems by Total Energy Commodity Shipments (2013, millions of short tons)[103]

Port Channel System	Crude and Petroleum Products	Coal	Total Energy	Energy as a Percent of Shipments
Lower Mississippi (LA)	161	47	208	48
Houston/Galveston (TX)	200	3	203	69
Beaumont/Port Arthur (TX)	115	0	115	89
Port of NY/NJ	80	<1	80	59
Delaware River	62	0	62	82
Corpus Christi (TX)	58	0	58	77
Port of Virginia	2	50	52	66
Lake Charles (LA)	49	0	50	88
LA and Long Beach (CA)	46	2	47	33
Huntington - Tristate (WV)	8	32	41	87

Energy shipment is concentrated on the Gulf Coast, but half of the 10 ports moving the most energy commodities are found elsewhere in the United States. The inland waterways are also important to the shipment of energy commodities to and from coastal ports.

Waterways and Ports—Federal Funding Mechanisms

The recent Water Resources Reform and Development Act of 2014 (Public Law 113-121), which was signed into law by President Obama on June 10, 2014, contains new funding avenues for water infrastructure projects, including a loan program for water infrastructure and supporting water infrastructure development and funding by the private sector.

Two navigation-related Federal trust funds—the Inland Waterways Trust Fund (IWTF) and the Harbor Maintenance Trust Fund (HMTF)—are used for construction and maintenance of federally owned and authorized waterways. DOT's Transportation Investment Generating Economic Recovery (TIGER) program, initiated under the American Recovery and Reinvestment Act of 2009, is designed to fund multi-modal, multi-jurisdictional projects not eligible for funding through traditional DOT programs. These three programs highlight funding mechanisms for waterways-related infrastructure:

IWTF pays a share of the construction and rehabilitation costs for inland and intracoastal waterways. Funding is derived from the General Treasury and, until recently, a $0.20 per gallon fuel tax on commercial towing by tugboats on certain of the inland waterways. An increase to $0.29 per gallon was authorized in December 2014 and took effect after March 31, 2015.

HMTF pays for harbor maintenance and related work at coastal ports. HMTF revenues are generated by a 0.125-percent *ad valorem tax* on cargo and passenger shipping. In FY 2014, 92 percent of the revenue came from imported cargo, 7 percent came from domestic shipping, and 1 percent came from passenger travel.[104]

TIGER is a competitive grant program that funds state and local transportation projects across the United States. TIGER can fund port and freight rail projects, which play a critical role in the United States' ability to move freight, including energy commodities and equipment, but which are not eligible for any other sources of Federal funds. It can provide capital funding directly to any public entity, including municipalities, counties, port authorities, tribal governments, and municipal planning organizations. TIGER's broad eligibility criteria make it ideal for multi-modal, multi-jurisdictional projects like landside-connecting infrastructure for ports and waterways, which can be difficult to fund under state block grants. The TIGER program has funded a number of improvements to port connector infrastructure, including a new access road for the Port of Seattle and its associated rail yards. Since 2009, Congress has dedicated $4.2 billion for TIGER projects, which address national freight rail bottlenecks; reduce truck traffic; improve air quality; and reduce other port, rail, and road and freight congestion. However, TIGER currently is oversubscribed; in its most recent funding round, only 72 of 797 eligible applications were funded, and 15 times the available $600 million was requested.

Pipeline, Rail, and Waterway Data

Gaps exist in the data collected by various Federal agencies regarding both shared (e.g., rail and inland waterways) and dedicated energy infrastructures (e.g., pipelines), as well as the energy products and other commodities moved on them. In conducting research for the Quadrennial Energy Review, staff encountered repeated instances in which the information needed for a particular analysis was not collected, was held and protected by the private sector, or was dated and prior to the current energy boom.

Federal agencies share responsibility for oversight of some modes and some infrastructures. The Army Corps of Engineers and Coast Guard maintain data about, respectively, (1) freight moved by barge and other vessels along the inland waterway, the Great Lakes, and coastal traffic; and (2) freight and vessels traveling through the Nation's ports. Depending on the database, the amount of crude oil moving might be documented relying on just what moves in the ports, rivers, and canals, or it might include product moved on railroads and highways as part of a "waterborne" total.

The Energy Information Administration has authority to collect energy information. Other Federal agencies have limited authorities and/or hesitancy to use authorities to make data public. The Surface Transportation Board has no jurisdiction over any rail freight moved under contract (which includes most crude oil) and therefore relies on the private sector for a stratified sample of carload waybills[y] for all U.S. rail traffic submitted by those rail carriers terminating 4,500 or more revenue carloads annually.

Even when the data is collected, there are often long lags between commodity movements and publication of data. These gaps hinder objective analysis across commodity types and transport modes, at least with regard to several topic areas in a comprehensive review of components of a national energy policy.

[y] A waybill is "a shipping document prepared by a carrier at the point of origin showing the point of origin, destination, route, shipper, consignee, description of shipment, weight, charges, and other data necessary to rate, ship, and settle." Source: CSX. "Railroad Dictionary." Waybill. www.csx.com/index.cfm/about-csx/company-overview/railroad-dictionary/?i=W. Accessed January 30, 2015.

Waterborne Vessels, U.S. Shipbuilding, and the Jones Act

The Jones Act, Section 27 of the Merchant Marine Act of 1920 (Public Law No. 66-261), codified at 46 U.S.C. § 50101 *et seq*. (2006), regulates maritime commerce in U.S. waters and between U.S. ports. It requires that all commercial shipping between U.S. ports must be performed by U.S.-flag ships constructed in the United States, wholly owned by U.S. citizens, and crewed by U.S. citizens and U.S. permanent residents.[105] Jones Act shipping costs are higher than equivalent international rates for the same distance. For instance, crude oil transportation costs from the Gulf Coast to the East Coast are almost double the costs for Gulf Coast to eastern Canada or Europe transportation.[106]

Historically, East Coast refineries have been supplied by waterborne imports; a large fraction of which have been premium-priced light sweet crude oils. Very recently, East Coast refiners have begun to arrange for delivery of discounted Bakken and Canadian sweet crude oils by rail. Estimated deliveries of Bakken crude oil averaged 266 thousand bbl/d in 2013 and have continued to climb. Consequently, light sweet crude imports declined from 670 thousand bbl/d in 2010 to 380 thousand bbl/d in 2013; they were less than 200 thousand bbl/d in the first quarter of 2014.

Today, the Jones Act ensures higher levels of waterborne freight safety due to the more stringent safety inspection and certification regime that exists for U.S.-flagged waterborne vessels.[107] The current Jones Act-compliant fleet consists of 86 seagoing barges (50 bbl to 300,000 bbl), 31 "handysize" product tankers (300,000 bbl),[z] and 11 Aframax or Suezmax crude oil tankers (800 bbl to 1,300,000 bbl). The latter categories are Jones Act eligible.[108] Another 30 seagoing oil and/or product vessels are either under construction or on order at domestic shipyards.[109] All 11 Aframax and Suezmax tankers are used to ship Alaska crude to West Coast and Alaskan refineries, while the smaller handysize tankers and seagoing barges are used for shipping throughout the Gulf and from the Gulf to Florida.[110]

The changing geography and volumes of domestic oil production are increasing demand for Jones Act-eligible vessels, while the number and aggregate capacity of U.S.-flagged tankers has decreased significantly since the early 1980s. Demand for seagoing vessels to move oil produced in Texas and Louisiana have diverted shipping capacity away from moving gasoline into Florida, causing increased and more volatile gasoline prices in the state.[111] Lack of U.S.-flagged tanker availability to move product from the Gulf to the Northeast causes refineries to rely on imports and domestic Bakken oil that requires more costly rail transportation.[112]

Perhaps the largest challenge for increasing the fleet of U.S.-flagged ships is the high costs associated with domestic manufacturing and operations. It costs roughly three to four times more to manufacture ships in the United States than higher-volume shipyards in Korea, China, and Japan, and about three times as much to operate on domestic routes than a foreign-flagged ship.[113] No LNG tankers have been built in the United States in the past 30 years.

It is true that American shipyards are experiencing a "boom" in recent construction orders, building patrol boats, tugs, barges of all sizes, ferries, and other vessels. In 2012 alone, U.S. shipbuilders delivered 1,260 vessels and also have seen a spike in recent orders for large ocean-going vessels. Fifteen containerships and tankers are on order or already under construction in U.S. shipyards. The Maritime Administration has noted that U.S. shipyards are experiencing the greatest volume of shipbuilding activity in more than three decades.

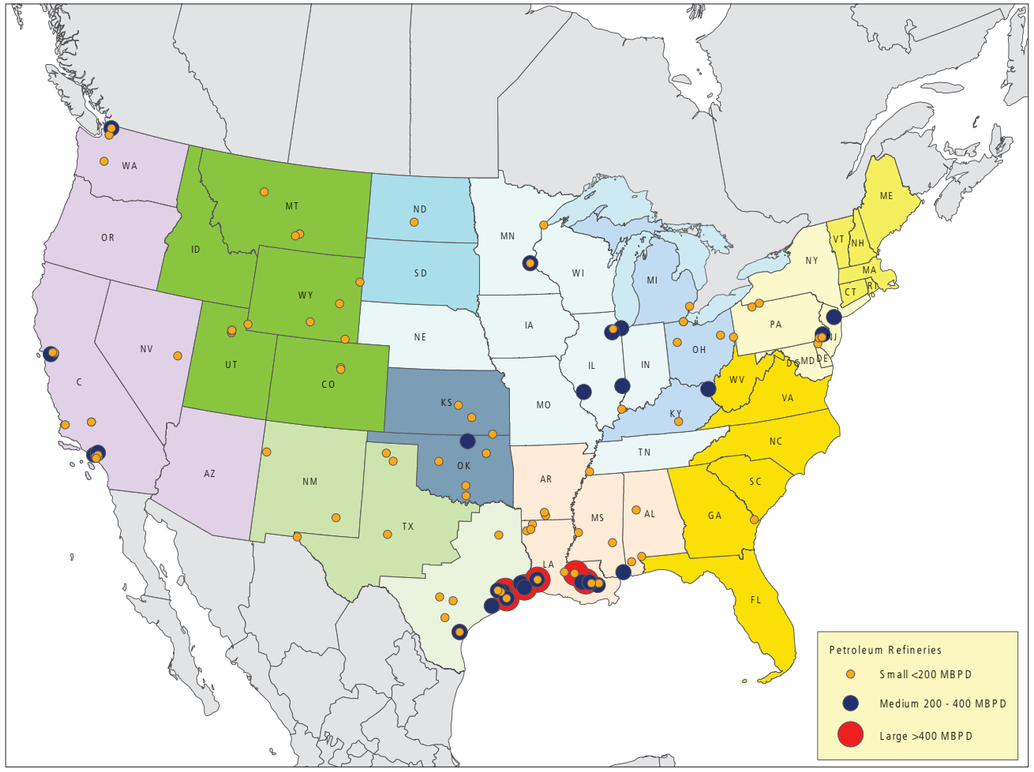
[z] Handysize refers to a dry bulk carrier or an oil tanker with a capacity between 15,000 deadweight tons and 35,000 deadweight tons. Sometimes they are used to refer to vessels with deadweight tons of up to 60,000, thus including Handymax and Supramax vessels under its category. These vessels also have shallower draught in comparison to larger Supramax, Panamax, and Chinamax ships, which allows them to operate in most ports and terminals across the world. Due to their small dimensions, handysize ships can serve ports and terminals of all sizes, even ports with length and draught restrictions. As they are fitted with on-deck cranes, they also can serve ports lacking transshipment infrastructure. As a result, handysize vessels make up the majority of bulk carriers over 10,000 deadweight tons. Source: Maritime-Connector. "Handysize." maritime-connector.com/wiki/handysize/. Accessed January 14, 2015.

An understanding of the history of the decline of the U.S. commercial shipbuilding capacity is instructive. Until 1981, the United States' national policy was to actively support its merchant marine fleet and the Nation's domestic shipbuilding industry.[114] In 1981, operating and construction differential subsidies were halted under the theory that U.S. shipbuilding capacity would be supported by construction of naval vessels. A subsequent decline in construction of naval vessels had the effect of diminishing the capacity for domestic shipbuilding. Despite accounting for about 20 percent of the global seaborne trade, the Unites States now builds less than 1 percent of the world's merchant vessels. Aside from lost commercial opportunity, some observers believe that reliance on foreign shipyards could have implications for U.S. energy security. For example, the United States' ability to conduct a major drawdown from the SPR in the case of global energy supply disruption now relies on waivers of the Jones Act due to the lack of Jones Act ships. It is important to better understand possible energy vulnerabilities associated with the overall decline in U.S. shipbuilding, as well as the competitiveness opportunities associated with enhancing domestic energy shipbuilding.

Refineries

U.S. petroleum refineries are some of the most sophisticated in the world, supplying consumers and industry with 19.8 million bbl/d of petroleum products—or 832 million gallons per day—as of January 23, 2015,[115] while undergoing continual upgrades to improve efficiency, product quality, feedstock utilization, and environmental performance. Domestic refining provides 90 percent of the Nation's gasoline and ultra-low-sulfur diesel supply. The United States also houses roughly 20 percent of the global refining capacity, more than any other country.[116] Currently, 57 companies own and operate the 142 refineries in the United States (see Figure A-19), and 15 of these companies account for 14.305 million bbl/d of operable capacity—an 80-percent share of available refining capacity. Most major refinery infrastructure has been in service since the 1950s. Since the 1980s, the number of refineries has dropped significantly while capacity has increased. Since the late 1970s, no new refineries have been built in the United States. However, because of increased Bakken production, two small new greenfield refineries (operating capacity of approximately 20,000 bbl/d) are planned for construction in North Dakota, while two existing refineries are adding capacity to process stranded Bakken crude.

Figure A-19. Geographic Location of U.S. Refineries (state colors show PADD and sub-PADD divisions)[117]

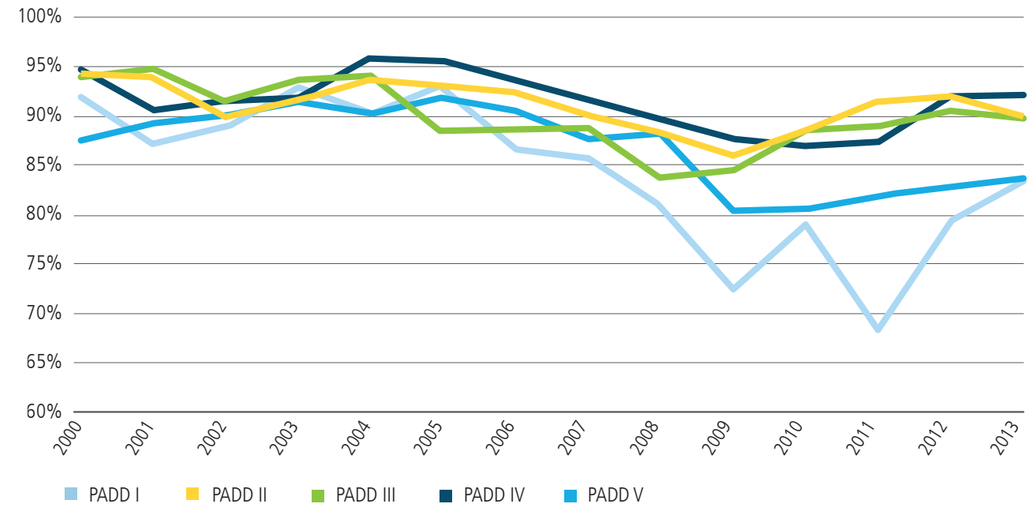


Apart from clusters of refining capacity near major urban centers on the West Coast and Mid-Atlantic/Northeast, the majority of U.S. refining capacity exists in the Gulf Coast or is connected to the Mississippi River system.

The Texas and Louisiana Gulf Coast within PADD III represents the most highly concentrated refining region in the United States. This area houses 47 refineries with a combined operable capacity of 8,477 thousand bbl/d, or 47.5 percent of total operable U.S. refining capacity. Since 2009, East Coast refineries (PADD I) have faced low margins, high crude acquisition costs, and stiff competition from European gasoline imports, and several refineries have been idled and closed. In 2013, in response to increased Bakken crude supplies to the East Coast via rail, rail terminals were built and refineries were reopened, and the downward trend in East Coast refining capacity was reversed.

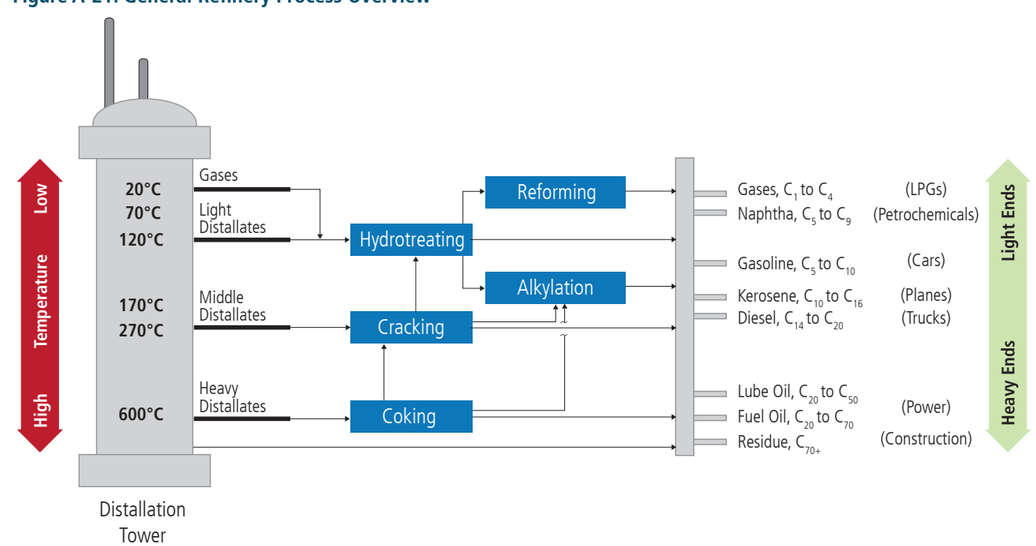
To meet the global demand for petroleum, refineries are running at their highest utilization rates in 6 years (see Figure A-20). Products like distillates are the desired transportation fuel in most foreign countries (not gasoline), and kerosene and residual oil are the predominant exports for jet fuel, power generation, and construction. From 1993 to 2000, refinery gasoline yields averaged around 45 percent, distillates around 22 percent, and all other products accounted for the remaining 33 percent. In 1999, distillate yields began increasing and are now at 30 percent. Figure A-21 provides an overview of a general refinery process. A 42-gallon bbl of oil, refined today, would produce about 19 gallons of gasoline, 13 gallons of distillate, and 8 gallons of other products. Throughout the 1990s, U.S. refiners produced enough distillate to meet domestic demand while importing gasoline to cover increasing demand. In 1999, distillate yields began increasing, and now the United States exports both.

Figure A-20. Refining Capacity Utilization by PADD[118]



Although refineries in PADDs II, III, and IV have maintained high levels of utilization in the past decade, often operating well above 90 percent, refinery utilization in PADDs I and V has fallen below 85 percent or more. These developments reflect ongoing dependence on Gulf Coast and interior refineries in light of imports from Canada, Mexico, and other countries and domestic production from the Bakken and Eagle Ford fields.

Figure A-21. General Refinery Process Overview[119]



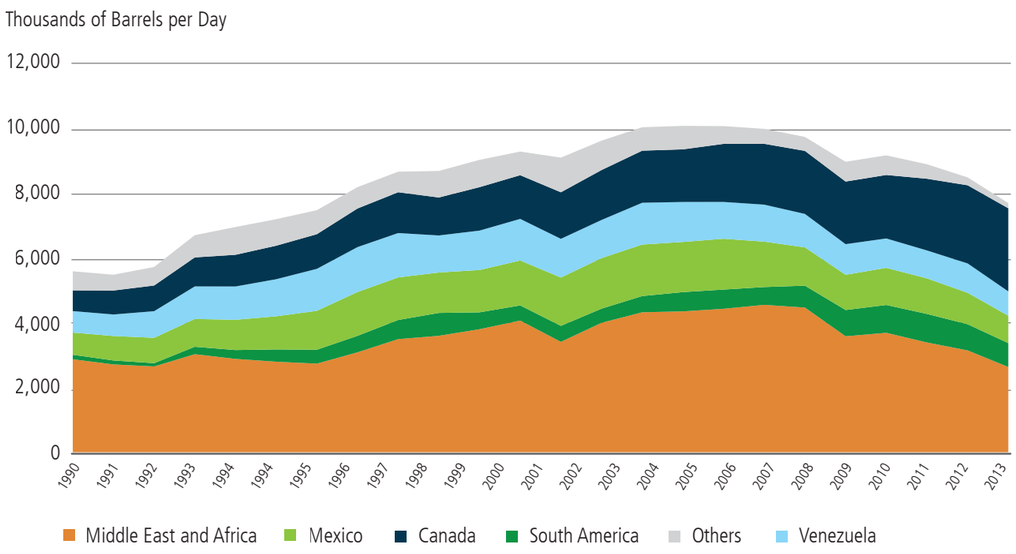
The refining process converts crude oil into a range of products.

Receipts of foreign crude oil began increasing in the 1980s and peaked in 2005 when the United States had net imports of more than 10 million bbl/d of petroleum. At this time, the quality of imported crude to the United States was primarily medium to heavy sour. Most Gulf Coast refiners upgraded their facilities in the late 1990s, adding coking units, hydrocrackers, and shorter distillation columns to process medium to heavy crude mixes. Consequently, the majority of U.S. refineries are not configured for the multitude of light crude produced from shale today without blending in heavier crude mixes. Reconfiguring plants to process higher volumes of light sweet crudes requires capital and downtime for construction.

PADD II mostly processes heavy Canadian crude. As the historic locus for most U.S. seaborne crude oil imports, PADD III refineries are designed primarily to process heavier imported crude oils. PADD IV processes both Canadian and domestic crude, and PADD V processes approximately 50 percent foreign crude (mostly from the Middle East and Central and South America).

Gross crude imports to the United States have been on the decline since 2009, totaling 7.72 million bbl/d in 2013 (see Figure A-22). PADD III experienced a significant decline in imported crude, while PADD II saw moderate increases from Canada. These trends are both attributed to the convenient supply of inexpensive North American crude. Bakken and Eagle Ford crudes are flooding PADD III markets via unprecedented rail and barge shipping routes and a complete reconfiguration of U.S. crude pipeline infrastructure, displacing requirements for some imports. Canadian crudes have flooded PADD II and are becoming more accessible to PADDs I, IV, and V as new pipeline projects and rail facilities become increasingly integrated into existing infrastructure networks. The United States imports the majority of its crude across the Atlantic from the Middle East or Africa, across the Gulf of Mexico from Mexico and Venezuela, or from Canada. Excluding Canada, imports from other regions of the globe have all declined in recent years.

Figure A-22. U.S. Crude Oil Imports by Region of Origin[120]



Imports of foreign oil have declined since 2005 except for imports from Canada. The decline in imports reflects both the simultaneous increase in domestic U.S. production, coupled with an increase in heavy crude/bitumen production from Canada, as well as increasing end-use efficiencies and marginal declines in vehicle miles traveled.

Refinery Investments

The U.S. refining industry experienced a relatively large and sustained investment period from 2005 to 2010, driven by investment to produce cleaner fuels, reduce criteria emissions, process a larger slate of heavy crudes, produce a greater proportion of middle distillates, and improve process safety standards. Several large investment decisions were made during the relatively high refining margin period from 2005 to 2007. Since about 2010, U.S. demand for refined petroleum products has not increased as predicted; rather, demand has decreased, curtailing the need for additional large-scale investment in U.S. refining capacity. As a result, calculated, non-sustaining capital investment in refining has decreased from $7.5 billion in 2010 to slightly less than $3.0 billion in 2013 (see Table A-7).[121]

Table A-7. Recent Direct Capital Investments for Refineries and Refined Product Infrastructure[122]

2010	2011	2012	2013
$7.5 billion	$4.5 billion	$3 billion	$2.9 billion

Direct capital investments in refineries and refined product infrastructure have decreased since 2010.

In the future, IHS does not project much more direct capital investment going toward U.S. refining compared to refinery investments seen over the previous decade (see Table A-8).[123] ICF International did not cover refineries in its 2014 midstream infrastructure study, but has indicated to DOE that it does not foresee much investment going into the refinery industry moving forward. Substantial new investment in refineries' distillation capacity is not likely in the future, partially due to the lack of demand growth for refined products in the United States (see Table A-8). Investments will continue to enable refineries to adapt to changing crude slates and delivery infrastructure and to enable the increased export of high-valued products. The impact of changing crude qualities and the effects of crude oil export policies on refineries is discussed in the U.S. Tight Oil Congestion section.

Table A-8. Forecast of Direct Capital Investment for Refineries/Refined Product Infrastructure, 2014–2025[124]

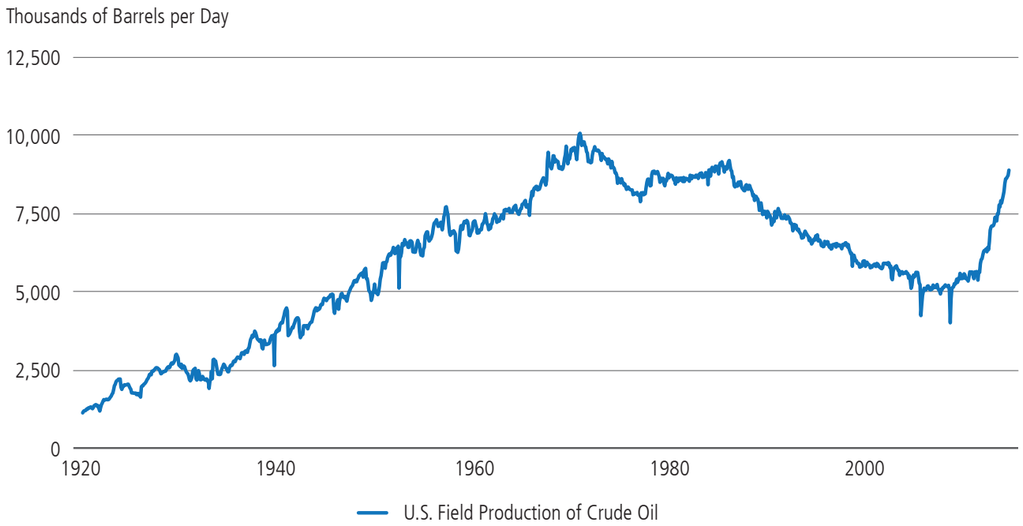
	Base Case	High Case	Difference
Refineries	$19.1 billion	$19.1 billion	0%
Refined Product Pipelines	$2.0 billion	$2.0 billion	0%
Refined Product Storage	$2.1 billion	$2.1 billion	0%
Refined Product Marine	$1.9 billion	$1.9 billion	0%

IHS forecasts that direct capital investments into refineries and refined product infrastructure through 2025 will not vary much by underlying resource assumption (base case versus high case) and will not be much more than investments seen over the previous decade.

Investment is likely to continue as U.S. refineries continue to adjust their refinery operations and infrastructure configuration to take advantage of changing American crude supply in terms of volume, quality, and associated delivery infrastructure. As domestic crude oil has expanded in the United States, refiners have been processing a larger share of domestic crude relative to imported crude to meet domestic and export product demand. As a consequence, imports of crude oil—particularly light sweet crude oil—have declined.

U.S. tight oil production has a relatively high API gravity compared to most crude oil used by U.S. refineries. Tight oil production, primarily from the Bakken region in North Dakota and Eagle Ford and Permian regions in Texas, has increased domestic crude production by more than 4 million bbl/d since 2008.[125, 126] The rapid growth of U.S. light tight oil production is likely to continue.[127] Crude oils from these regions have a particular high content of naphtha boiling range hydrocarbons, which primarily are used as gasoline feedstock and to a lesser extent in the U.S. market as a petrochemical feedstock.

Figure A-23. U.S. Field Production of Crude Oil[128]



U.S. crude oil production has increased significantly since 2008.

Increasing light crude production affects refinery economics in complex ways. Several domestic refineries—particularly those in the Gulf Coast—have been configured to process an increasing share of heavy crude oils. Investments in heavy crude processing capabilities were made over the past two decades as the supply of heavy crudes increased. Because heavy oil supply increased at a greater rate than the demand for these crudes, the price differential between heavy and light crudes increased. As such, refiners could produce fuels and other product from heavy crudes at a lower cost. This encouraged investments in coking and other residuum processing units at refineries to process the heavy crudes. The high coking capacity in the Gulf Coast, combined with price discounts for heavy oil and low process energy and hydrogen costs, have contributed to higher corporate profits and growing petroleum product exports. Now, however, with the increasing availability of light crudes, the price differentials between light and heavy crudes have diminished somewhat, reducing the value of such investments.

The economics of the product slates also have favored Gulf Coast refineries using heavy crudes. In the past, gasoline production was the primary economic driver for refinery investments in the United States, as gasoline demand grew at a greater rate than demand for other petroleum products. However, demand for diesel and distillate fuels has been growing worldwide at a greater rate than refinery capacity to produce these fuels. Additionally, U.S. demand for gasoline has been declining and is expected to continue to decline because of higher gasoline prices, increased fuel vehicle efficiency standards, and the blending of renewable fuels into gasoline. With the price of diesel fuel (domestically and internationally) generally being higher than gasoline, refiners have been shifting production from gasoline to diesel fuel—a trend that favors Gulf Coast refineries that can process heavier crudes.

Notwithstanding the drivers of past investment in processing facilities for heavier crudes, more recently, the significant new domestic production of crude oil from the Eagle Ford and Bakken plays has resulted in U.S. refiners planning expansions to enable processing of a larger percentage of light crude at their existing facilities. These investments primarily are for the crude distillation tower, auxiliary equipment, and downstream processing units to enable a larger share of the lighter distillation products that result from these crudes. Additionally, some refiners and other non-refining midstream infrastructure companies are investing in simple crude oil distillation facilities (splitters and crude stabilizers) to enable lighter crudes to be minimally processed into finished petroleum products and unfinished oils[aa] in order to enable exports of a part of these crude streams to foreign markets. Some of these investments in splitters and crude stabilizers have been at separate locations from refineries, closer to areas of production for these lighter crudes.

[aa] Unfinished oils are petroleum product streams derived from crude oil—which includes naphthas and lighter oils, light and heavy gas oils, and residuum—that require additional processing to produce a finished product.

Refinery Investment and the Environment

Fuel combustion and fugitive and vented air emissions from the petroleum sector result in significant air emissions, including carbon dioxide (CO_2), particulate matter, volatile organic compounds, and roughly 5 percent of industrial sources of hazardous air pollutant releases in 2013, according to the Toxics Release Inventory.[ab, ac] In 2012, onsite emissions of CO_2 from petroleum refineries accounted for more than 30 percent of CO_2 emissions from U.S. manufacturing[ad] and 4 percent of total CO_2 emissions from fossil energy combustion.[ae] From 1990 through 2013, U.S. refiners invested approximately $149 billion in environmental improvements.[af] In terms of water use, annual water consumption by these petroleum refineries in 2005 was approximately 474 billion gallons.[ag] By way of comparison, this is nearly one-third of the approximately 1,570 billion gallons of total water consumption by electric power generation in 2008.[ah]

The environmental impacts of petroleum refining and the use of refined products have resulted in a number of environmental laws and regulations. Some of the most significant statutes are those that focus on altering the formulation of products (mostly fuels) to reduce air emissions generated by their use. These often require substantial changes in refinery processes, along with large capital investments. Additionally, a number of Federal and state regulations focus on reducing refinery process emissions to air, land, and water. The combination of regulations to reformulate fuels and those aimed at reducing emissions from refinery operations make petroleum refining one of the most heavily regulated industries in the United States. A proposed rule (Proposed Petroleum Refinery Sector Risk and Technology Review and New Source Performance Standards) was published

[ab] Environmental Protection Agency. "TRI National Analysis 2013." p. 21. January 2015. http://www2.epa.gov/sites/production/files/2015-01/documents/2013-tri-national-analysis-complete_1.pdf. Accessed February 11, 2015.

[ac] Major toxic air pollutants released from petroleum refineries include hexane, toluene, xylene, benzene, and other known or suspected carcinogens.

[ad] Energetics Incorporated. "U.S. Manufacturing Energy Use and Greenhouse Gas Emissions Analysis." November 2012. http://energy.gov/sites/prod/files/2013/11/f4/energy_use_and_loss_and_emissions.pdf. Accessed February 11, 2015.

[ae] Total 2012 CO_2 emissions from fossil fuels for energy consumption equaled 5,232 million metric tons (Source: Energy Information Administration. "Table 12.1 Carbon Dioxide Emissions from Energy Consumption by Source." http://www.eia.gov/totalenergy/data/monthly/pdf/sec12_3.pdf. Accessed February 12, 2015.). Total onsite CO_2 emissions from petroleum refineries equaled 210 million metric tons (Source: Energetics Incorporated. "U.S. Manufacturing Energy Use and Greenhouse Gas Emissions Analysis." p. 37. November 2012. http://energy.gov/sites/prod/files/2013/11/f4/energy_use_and_loss_and_emissions.pdf. Accessed February 11, 2015.), giving 4 percent of total fossil fuel energy combustion emissions.

[af] American Petroleum Institute. "Environmental Expenditures by the U.S. Oil and Natural Gas Industry." 2014. http://www.api.org/~/media/files/publications/environmental-expenditures-2014.pdf. Accessed February 2, 2015.

[ag] Based on daily refinery water use of 1.3 billion gallons in: Argonne National Laboratory. "Baseline and Projected Water Demand Data for Energy and Competing Water Use Sectors." November 2008. https://www.acs.org/content/dam/acsorg/policy/acsonthehill/briefings/energywaternexus/11-08-anl-water-demand-for-energy-competing-sectors.pdf. Accessed February 11, 2015.

[ah] Averyt, K. et al. "Water use for electricity in the United States: an analysis of reported and calculated water use information for 2008." Environmental Research Letters. 8(1). 2013.

Refinery Investment and the Environment (continued)

in the Federal Register for public comment on June 30, 2014.[ai] Additional emission controls are being proposed for storage tanks, flares, and coking units. The Environmental Protection Agency is also proposing fence-line air quality monitoring to ensure that standards are being met and neighboring communities are not being exposed to unintended emissions. If the final rule is identical to the proposed rule and fully implemented (i.e., 3 years from the promulgation of the final rule), the Environmental Protection Agency estimates that these and other provisions will result in a reduction of 5,600 tons per year of toxic air pollutants and 52,000 tons per year of volatile organic compounds.[aj]

[ai] This rulemaking is under consent decree with Air Alliance Houston and several other litigants. The consent decree requires the EPA Administrator to sign the final rule no later than June 16, 2015.

[aj] Environmental Protection Agency. "Fact Sheet: Proposed Petroleum Refinery Sector Risk and Technology Review and New Source Performance Standards." 2014. http://www.epa.gov/airtoxics/petrefine/20140515factsheet.pdf. Accessed February 25, 2015.

Refinery Security/Physical Threats

Due to much of the liquid fuels (and natural gas) pipeline infrastructure being underground, it is not highly susceptible to malicious physical attack. Damage from an isolated small-scale event could be quickly repaired with minimal impact on stocks and supplies. However, larger facilities, like refineries, do have some vulnerability to intentional physical attack. Much of the critical TS&D infrastructure in PADD IB—including oil and gas production, ports and terminals, processing, and refining facilities—is geographically concentrated, visible, and potentially accessible from major and ancillary transportation routes, making it vulnerable to intentional damage.[129] Results from a Department of Homeland Security (DHS) survey of critical infrastructure energy facilities showed that approximately 74 percent of energy sites have uncontrolled parking where a vehicle can get within 400 feet of the facility without having to pass through any type of access control points.[ak]

Increasing standoff distance is an effective way to mitigate potential consequences from certain types of threats. Other measures include fencing, barriers, access control points, and security personnel. Barriers can be used to help *control standoff distances* from the facility. Notably, less than 50 percent of the energy facilities have barriers in place; only 26 percent of the facilities with high-speed avenues of approach have K-rated barriers for high-speed avenues of approach, and even fewer sites have K-rated fencing and gates. Of the about 50 percent of facilities that have barriers in place, the *weakest* barrier was the data captured for each surveyed facility. Table A-9 shows types of barriers used to enforce standoff.

[ak] DOE's Office of Energy Policy and Systems Analysis requested that Argonne National Laboratory's Infrastructure Assurance Center conduct an analysis of the protection and resilience information collected through DHS's Enhanced Critical Infrastructure Program Initiative, which conducts facility site visits and surveys. The primary objective of this analysis was to identify gaps in preparedness and rapid recovery measures for surveyed energy facilities. The analysis was conducted on 273 energy facilities (170 electricity, 45 liquid fuels, and 15 natural gas) using data collected from January 2011 through September 2014.

Table A-9. Standoff Barrier Types[al]

Barrier Type to Enforce Standoff	Percent of Surveyed Energy Facilities w/ Barrier Type
Bollards, Planters, or Rocks	43
Jersey Barrier/Wall	32
Spike System/Tire Shredders	0
Guard Rails	4
Maritime or Water Deployed	6
Earthen Berm	4
Natural Barriers	11

A wide array of protective techniques can be used at energy facilities.

Fencing and gates can also *control standoff distances* to the facility. Ninety-three percent of facilities have some kind of fencing. Similar to the data collection for barriers, the questions about fences and gates focus on the weakest sections of the fencing and gates at the facility. Highlights with regard to fencing and gates are as follows:

- All of the energy facilities have fencing completely surrounding significant areas and assets.
- Only 64 percent of the facilities have fencing around the entire facility.
- Approximately 93 percent of the sites have chain-link fencing.

The DHS critical infrastructure survey also assessed the existence of security forces[am] at facilities. The prevalence of security forces is highly dependent on the energy subsector. One-hundred percent of refineries surveyed and about 90 percent of city gate facilities had a security force, but almost no (about 5 percent) crude or petroleum product transport facilities had a security force.

Some energy sites are inside buildings. Of the energy sites surveyed that indicated they are inside a building, approximately 68 percent have ground floor windows (i.e., less than 18 feet from the ground). Only 19 percent of those sites have protective measures on those windows.[an] Additionally, of the energy sites surveyed that have air-handling systems with outside air intakes, only 41 percent have their external air intakes located greater than 30 feet above ground or roof mounted.

[al] DOE's Office of Energy Policy and Systems Analysis requested that Argonne National Laboratory's Infrastructure Assurance Center conduct an analysis of the protection and resilience information collected through DHS's Enhanced Critical Infrastructure Program Initiative, which conducts facility site visits and surveys. The primary objective of this analysis was to identify gaps in preparedness and rapid recovery measures for surveyed energy facilities. The analysis was conducted on 273 energy facilities (170 electricity, 45 liquid fuels, and 15 natural gas) using data collected from January 2011 through September 2014.

[am] In the DHS survey, a security force is defined as a special group of employees or contractors with unique and sole duties to provide security. It does not include general employees who are trained in security awareness to observe and report security issues.

[an] Protective measures for windows include blast/safety film, blast curtains, bullet-proof glass, laminated glass, wire-reinforced glass, and thermally tempered glass.

Tertiary (Customer) Storage of Heating Fuels

The major fuels used for space heating vary by region and include natural gas, heating oil, electricity, and propane. Heating oil and propane are unique because they can be stored by customers at their households (i.e., tertiary storage).

The 2013-2014 fall and winter fuel markets for propane encountered severe shortages across much of the country. For a relatively short but impactful time period, market dynamics produced supply disruptions and price spikes, negatively impacting the 5.7 million households that rely on propane as a heating fuel, in addition to agricultural consumers.[130] Many factors contributed to the propane crisis, but despite record levels of U.S. propane production, TS&D infrastructure was unable to supply the required amount of propane to markets in the Midwest. As seen by the spike in PADD I propane price during January–February 2014, tight propane markets in the Midwest significantly impact prices in other regions of the country.[131]

The Administration took a series of actions to respond to the changes in TS&D infrastructure for propane that was a contributing factor to the shortages in 2013–2014. EIA added capability to monitor propane inventories on a more granular, state-by-state basis, greatly enhancing the ability of industry, consumers, and policymakers to monitor possible shortages or distribution issues. Because propane storage in customer tanks can provide an additional margin of supply security, the Federal Government helped support public education campaigns to encourage consumers to fill their propane storage early for the 2014-2015 winter season. As of January 2015, propane inventories were above the 5-year average, and the experience of the 2013-2104 season was not repeated in the 2014-2015 season.

More than 6 million households use heating oil as their primary space heating fuel; more households use heating oil than propane as their primary space heating fuel.[132] Retail home heating oil prices are linked to crude oil prices, so consumers are susceptible to swings in home heating costs if crude oil prices increase. Additionally, Europe is a competing market for Northeast heating oil, as both are served by Atlantic Basin suppliers. Coinciding extreme winter weather between the two regions will stress the market.[133] Since the summer of 2012, distillate inventories in the United States remain at the low end of the previous 5-year range. Due to this decrease in primary storage utilization, secondary and tertiary storage is now more important as a mechanism for consumers to protect themselves against supply disruptions and resulting price spikes.[134] Even with the current reserves provided by the Northeast Home Heating Oil Reserve, supply disruptions at ports may lead to distribution shortages within 5 days and immediate retail price spikes.[135]

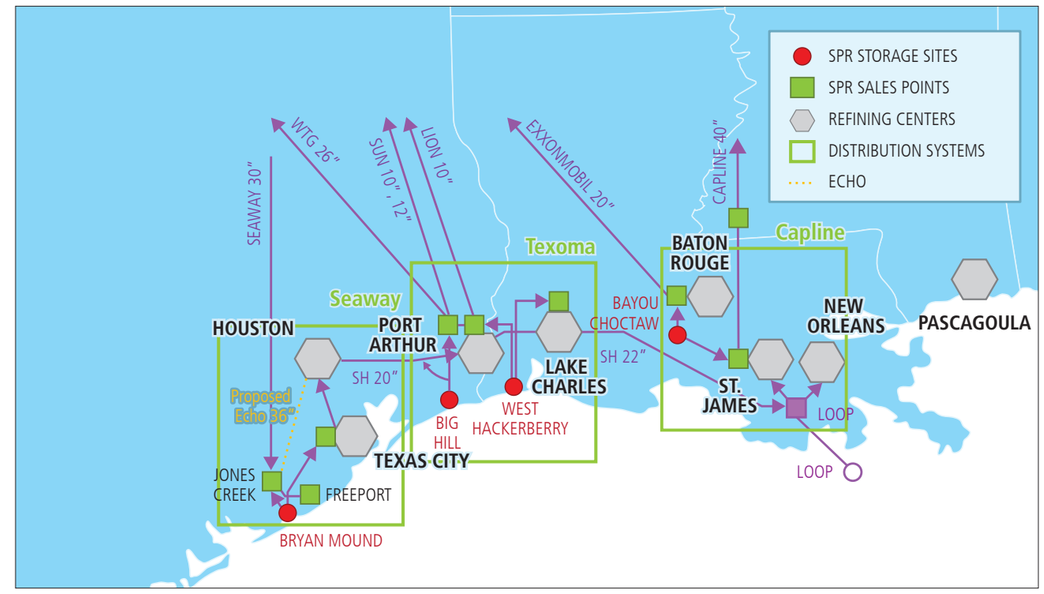
Strategic Oil Stocks for International Oil Supply Disruptions

The SPR was authorized by the Energy Policy and Conservation Act (EPCA)—as amended (42 U.S.C. § 6201 *et seq.*)—which was enacted on December 22, 1975 (Public Law 94-163). The SPR serves as an essential energy security response for the United States. The reserve provides a national insurance policy against critical petroleum supply interruptions due to global events, natural disasters, and terrorist actions. In addition, it is a deterrent to oil-based threats from other nations, and the reserve also serves to satisfy the obligation of the United States to hold 90 days of strategic stocks (both commercial and government-owned) as a condition of membership in the International Energy Agency (IEA).

The SPR currently operates and maintains four major oil storage facilities in the Gulf Coast region of the United States (see Figure A-24). All of the crude oil stored in SPR facilities is in 62 large underground caverns that have been solution-mined from naturally occurring salt domes in Texas and Louisiana. Salt dome storage technology provides maximum security and safety for the Nation's stockpile of crude oil and is also the lowest-cost technology for large-scale petroleum-storage projects. The average operations cost for FY 2013 was $0.221/bbl for management, staffing, operations and maintenance, and security. This cost is substantially less than industry storage costs and most foreign petroleum oil reserves.

The SPR oil storage facilities are grouped into three geographical distribution systems in the Gulf Coast: Seaway, Texoma, and Capline. Each system has access to one or more major refining centers, interstate crude oil pipelines, and marine terminals for crude oil distribution. The locations of the SPR storage sites and their respective distribution systems are shown in Figure A-24.

Figure A-24. SPR Storage Facilities and Proximate Distribution Infrastructure[136]

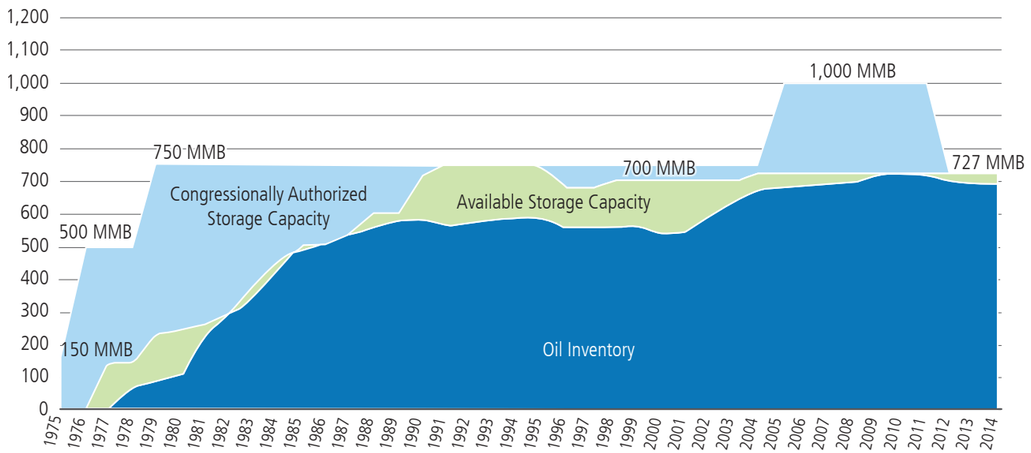


Each SPR storage and sale point has access to major refining centers, interstate crude oil pipelines, and marine terminals.

While the SPR owns and operates its own storage, as well as some pipeline and marine infrastructure, it depends almost entirely on privately owned and operated infrastructure for a majority of the distribution of crude oil. The first emergency drawdown occurred during the 1991 Persian Gulf War. In coordination with the initiation of military operations, 17.3 million bbl were sold to 13 companies. In the aftermath of Hurricane Katrina in 2005, 11 million bbl were released as part of an IEA-coordinated action in response to petroleum product shortages in the United States. The 2005 drawdown was designed to offset international product releases, as the United States did not have any strategic petroleum product reserves. Since 2005, there have been two more drawdowns: the IEA Libya Collective Action in 2011 (30 million bbl) and the 2014 Test Sale (5 million bbl).[137]

Figure A-25 shows the authorized and available storage capacity, as well as the crude oil inventory of the reserve over time. The acquisition of oil for the reserve occurred using a combination of direct purchase and oil received as in-kind royalties from production on Federal lands (referred to as royalty in kind).

Figure A-25. SPR Capacity and Inventory History (million barrels)[138]



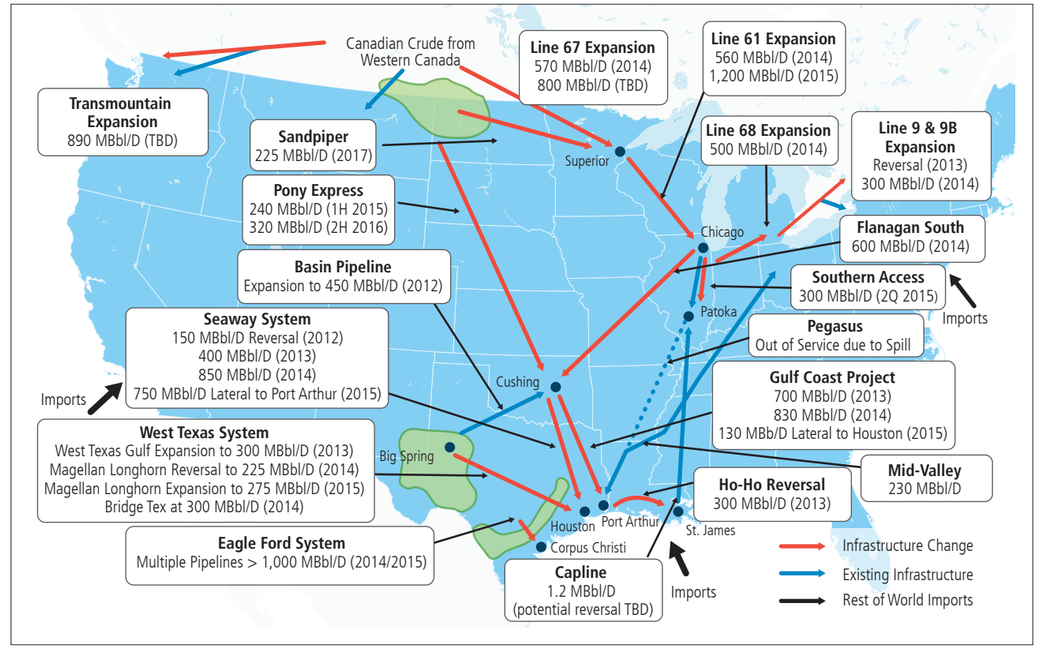
The SPR reached near-full capacity in the early 2000s at approximately 727 million bbl.

Outlook for the SPR

In recent years, the changing geography of U.S. oil production has led to major changes in the domestic oil and natural gas pipeline system. These new patterns of oil supply and demand among U.S. oil producers and refineries, along with associated changes in the U.S. midstream, have reduced the ability of the SPR to distribute *incremental* volumes of oil during possible future oil supply interruptions. Moving SPR oil to Midwest refineries—a historical pattern—would be of no value during a petroleum supply disruption since non-Canadian imports and Gulf Coast supplies into this refining complex have essentially disappeared. The U.S. pipeline distribution system, along with other modes of oil transport, is instead moving large volumes of oil to the Gulf Coast, especially from U.S. tight oil plays and Canada.[ao] This new geography of U.S. oil production and energy exports has also increased commercial traffic at U.S. Gulf Coast marine loading facilities.

[ao] For example, the SPR's distribution capacity has been affected by reversals of the Seaway and Ho-Ho pipelines. New pipeline capacity has been built to move oil stored at the Cushing, Oklahoma, terminal to the Gulf Coast, or to bypass Cushing by shipping oil from new tight oil plays directly to Gulf Coast refineries.

Figure A-26. Highlighted Pipeline Reversals and Expansions Accommodating Increased Domestic and Canadian Supply (completed and planned as of February 2015)[139]



Changes in the crude oil pipeline distribution network and marine terminal congestion have impacted the SPR in distributing its vast reserve of oil.

While the SPR can commandeer dock space at certain leased locations, doing so might cause a corresponding reduction in commercial traffic. The changing patterns of U.S. oil imports[ap] mean that the location of an international oil supply disruption can affect the disposition of an SPR oil auction and the capacity of the SPR to deliver oil to its customers. If the SPR cannot load oil onto barges and tankers without disrupting commercial shipments, SPR sales could be offset by a corresponding *decrease* in domestic crude oil shipments or exports of domestically produced petroleum products.[aq] For all of these reasons—the evolution of global oil markets, the participation of the United States in those markets, the changed geography and volume of U.S. oil supplies, reduced oil imports, and the congestion of commercial facilities in the SPR's distribution region—an effective SPR release will increasingly depend on the ability to load *incremental* SPR oil onto barges and tankers.[140]

[ap] Besides the disappearance of non-Canadian imports to Midcontinent refineries, Gulf Coast refineries are using more heavy oil from Latin America and less oil from the Middle East, while West Coast and East Coast refiners continue to import Middle Eastern and other light/medium grade crudes.

[aq] The maximum distribution rate during an oil supply interruption depends on the location of the oil-exporting nation(s) that has (have) been disrupted, the type of oil that has been disrupted, and whether the United States imports oil from that nation (and, if so, how much and to what refining region). Additionally, due to increased U.S. tight oil production, the three SPR distribution systems will, in the future, rely more on marine distribution of SPR oil than inland pipelines. The pipeline network will remain important, though, especially for disruptions of oil that the Gulf Coast refineries rely on (such as oil from Venezuela, Mexico, or Columbia). Supply disruptions from these sources may result in less congestion for moving SPR oil on its pipeline system.

The SPR is an important insurance policy for the U.S. economy in the event of serious oil supply disruptions and the associated price increases in domestic petroleum and petroleum products. Sharp increases in fuel prices and declines in gross domestic product growth have consistently followed previous oil supply disruptions. In spite of the changes in the U.S. oil profile, the U.S. economy will remain vulnerable to future international oil supply disruptions without the protection afforded by the SPR.[141]

The SPR was established by EPCA, which authorized the President to release the SPR upon finding that a "severe energy supply interruption" exists. EPCA defines a severe energy supply interruption as a reduction of energy supplies of sufficient scope and duration to cause a severe increase in the price of petroleum products that would have an adverse impact on the national economy. U.S. and global oil markets have evolved since the 1970s, changing the environment in which the SPR operates. When the SPR was established, U.S. oil production was in decline, oil price and allocation controls separated the U.S. oil market from the rest of the world, and a truly global commodity market for oil, as we know it today, did not exist. EPCA's 1970s-era goal was focused on avoiding "national energy supply shortages"—a loss of supply to U.S. refineries—rather than on the impacts of an overall disruption of global oil markets—a less important concern given the existence of domestic price controls that aimed to separate domestic and foreign prices.

Regardless of the levels of U.S. oil imports, in today's global oil markets, a severe global market disruption would have the same effect on domestic petroleum product prices whether or not U.S. refineries import crude oil from the disrupted countries.[ar, 142] This indicates that EPCA's definition of a "severe energy supply interruption" needs to include an additional criterion focused specifically on disruptions in the global oil market, regardless of whether they resulted in a loss of oil imports to the United States.

Another change that would increase the effectiveness of the SPR involves the adequacy of the anticipatory authorities in EPCA, which articulate the process and criteria for an SPR release *before* domestic petroleum price increases. In 1990, Section 161(h) was added to authorize an SPR release in anticipation of a severe increase of petroleum product prices; that authority is limited to a release of no more than 30 million bbl of oil and for no more than 60 days. In today's fast-moving and globalized energy markets, the President should not have to wait until higher fuel prices have already damaged the U.S. economy before the SPR can be used without restrictions. The authority to anticipate an economy-damaging price increase as a result of a severe energy supply interruption should be added to the President's broader Section 161(d) release authorities to more closely conform to other EPCA goals of preventing "a severe increase in the price of petroleum products" that "is likely to cause an adverse impact on the national economy."

In the event of a serious international oil supply disruption, offsetting a significant share of lost supplies with SPR oil, in concert with other countries that hold strategic reserves, would help reduce the sharp increase of international oil prices that would otherwise occur. When SPR oil is sold to domestic refineries, foreign oil shipments that would have been processed by U.S. refineries are freed up for use elsewhere, effectively increasing global oil supplies. The more oil the SPR is able to distribute to U.S. coastal refineries (inland refineries are now well supplied by domestic production and Canadian imports), the more oil will be added to global markets. This will mitigate the increase in international and domestic fuel prices and reduce harm to the U.S. economy. These diversions of foreign oil that would have been used by U.S. refineries are illustrated by the 2011 Libyan Collective Action.[as] At that time, the United States imported about 1 million bbl/d of oil from Nigeria. As a result of the June 2011 SPR release, significant Nigerian supplies were redirected to foreign refineries. The SPR oil sold to domestic refineries caused a corresponding *increase* of oil into the global market.

[ar] Domestic petroleum product prices are determined by international oil prices.

[as] In June 2011, the United States, as part of an IEA "Collective Action," released 30 million bbl of SPR oil in response to the loss of Libyan oil production as a result of the Libyan civil war (February 2011) and subsequent loss of Libyan oil exports.

This is why in today's global oil market, where U.S. petroleum product prices are tied to international prices, the SPR could help protect the U.S. economy if it helped to minimize an international oil price spike that would otherwise follow a serious oil supply outage. An SPR release could limit or prevent an oil price spike by quickly replacing lost oil supplies in order to keep the international oil market in balance at the prevailing prices prior to the disruption. The volume of SPR oil needed to offset lost supplies would also depend on the *timely* release of other strategic stocks.[at]

Domestic Petroleum Product Supplies and Emergencies

The Nation's liquid fuel system is diverse, robust, and resilient. Nevertheless, its infrastructure has vulnerabilities. These vulnerabilities are determined by the types of natural disasters that can occur in a region, as well as by the types of infrastructure within the region. Regions can have supply vulnerabilities if they are dependent on fuel supplies from outside the region (see Table A-10).

Table A-10. 2013 Product Supply and Demand Balance by PADD (thousand barrel per day)[143]

	PADD I	PADD II	PADD III	PADD IV	PADD V
Demand	**4,218**	**3,699**	**2,468**	**569**	**2,361**
Local Supply	**976**	**3,881**	**7,321**	**536**	**2,237**
Imports	730	10	44	1	72
Exports	117	47	1,497	0	209
			Balance = (Local Supply + Imports) – (Demand + Exports)		
Balance	(2,629)	145	3,400	(31)	(260)

An imbalance in the local supply and demand for petroleum products in some PADDs increases the vulnerability of PADDs to supply disruptions originating in other regions.

The Gulf Coast region is home to more than 50 percent of the Nation's refining capacity. Damage to liquid fuels infrastructure in this region can lead to significant impacts on much of the rest of the country, as the Gulf supplies oil products to the Northeast, Midwest, Mid-Atlantic, and South Atlantic regions.[144] Many U.S. regions are vulnerable to severe weather in the Gulf of Mexico or other threats to infrastructure in the Gulf of Mexico or on the Gulf Coast. Land subsidence is also a widespread issue throughout the Gulf Coast (and Mid-Atlantic coastal areas). During the past century, global sea-level rise has averaged about 1.7 millimeters per year (mm/yr), though the rate in the Gulf has been faster (at 5–10 mm/yr, in part due to subsidence).[145] Between now and 2030, the average global sea-level rise could accelerate to as much as 18 mm/yr in worst-case scenarios.[146]

Gulf Coast refineries in the path of a major hurricane typically shutdown in advance of a storm and restart after the storm has passed. While an undamaged refinery is likely to return to operation within 1 week of hurricane landfall, a severely damaged refinery might take several months to recover. Hurricanes Katrina and Rita provide examples of such impacts. The combined consequences of these two hurricanes in 2005 caused refinery outages of more than 4.5 million bbl/d. More than 20 refineries were shutdown on the worst day, representing a loss of 67 percent of the Gulf's capacity and 28 percent of national refinery capacity. While the refineries recovered,

[at] The release of emergency stocks after an oil price shock has peaked is much less effective at avoiding the economic consequences of the shock. Clayton concludes that the SPR can be effective at preventing an oil price shock, but is less effective at bringing oil prices down after they have increased. Source: Clayton, B. "Lessons Learned from the 2011 SPR Release." Council on Foreign Relations Working Paper. 2012.

the outage was still 2 million bbl/d 3 weeks after Rita's landfall and remained at 1 million bbl/d for more than 2 months. This caused a sharp, temporary increase in regional and national gasoline and diesel fuel prices.[147]

In response to these hurricanes, 30 million bbl of crude oil from the SPR were offered to the market and 20.8 million bbl were ultimately sold; it took 20 days for the first oil to move. While the IEA, in a coordinated effort, released petroleum product stocks to assist with the U.S. supply disruption, these supplies were not easily distributed to the Southeast region; truck deliveries to the Southeast region were made hundreds of miles from ports on the Atlantic Coast.

Similar petroleum product outages occurred in 2008 as a result of Hurricanes Gustav and Ike, leading to significant increases in motor fuel prices in all regions of the United States. In these instances, no SPR emergency release or IEA coordination action was taken.[au] As was apparent in 2005, the release of SPR reserves would have been of limited value to replace lost petroleum product supplies. In addition, all four SPR sites are located in the Gulf Coast region and may be exposed to hurricane damage, including inundation caused by storm surge.[148] In September 2008, for example, the Big Hill and West Hackberry sites sustained significant damage caused by Hurricane Ike.[149]

Industry has taken actions to harden Gulf Coast infrastructures after hurricanes in 2005 and 2008. Aboveground product storage tanks represent a particular vulnerability in hurricanes, as they can float off their foundations and spill product, creating environmental and supply concerns. At least four companies surveyed by DOE in 2010[150] indicated that they had "taken steps to ensure a minimum volume of product is in their storage tanks before a storm arrives." The refinery and pipeline operators interviewed for this study all confirmed that they maintain confidential hurricane preparedness plans. State public utility commissions also have responded in a variety of ways, initiating studies of and rulemakings for storm hardening. On the power side, the actions of Entergy during Hurricane Gustav in 2008 provide an example of the efforts by utilities to maintain service to customers. Entergy's use of grid sensors enabled it to identify and warn of islanding conditions[av] in order to manage their impacts on its systems in four states. Entergy's success during Gustav provides a replicable example for the effective use of technologies to manage storm impacts.[151]

In 2012, Hurricane Sandy caused numerous fuel supply and distribution problems in New York and New Jersey, involving refineries, marine terminals, petroleum product terminals, and retail service stations. As with the 2005 and 2008 hurricanes, an SPR crude oil release would have provided little remedy to the fuel supply problems. As a result of the lessons learned from Hurricane Sandy, DOE began considering the possibility of storing gasoline in a similar fashion as the ultra-low sulfur distillate stored in the Northeast Home Heating Oil Reserve. The vulnerability of the New York/New Jersey Harbor to storm surges was made clear during the event. The highly interconnected network of marine terminals was completely offline, causing fuel disruptions for emergency personnel and first responders. Additional gasoline reserves would enable states, localities, and retailers to resume operations during times of crisis. Following a secretarial finding to develop and implement emergency gasoline reserves, DOE began collaborating with the Defense Logistics Agency in March 2014 to solicit storage and begin fuel acquisition. Commercial storage contracts were awarded in early July 2014 at three locations: South Portland, Maine; Revere, Massachusetts; and Port Reading, New Jersey. Fuel deliveries were made in late July and early August.

[au] Some SPR sites sustained significant damage. While the SPR was able to conduct a test exchange of 5.4 million bbl of crude in response to requests for supplies from several refiners, it took weeks to restore SPR sites to their pre-storm levels of mission capability.

[av] Islanding is an unsafe situation for utility workers, where a distributed generator, when not appropriately monitored or understood, continues to provide power when electricity from the utility is cut off.

Electricity Interdependency

Loss of electric power (a vulnerability for liquid fuels infrastructure) and threats to electric power reliability and resilience are on the rise. Reported threats from cyber and physical attacks are increasing; however, weather-related disturbances still have had the greatest impact on service—in terms of customer hours and total number of disturbance events.[152] Most extreme weather-related disruptions can be attributed to thunderstorms, wind storms, and tornadoes.[153]

Increasingly, climate change and extreme weather are impacting the energy sector,[154] and projections suggest that most weather-related threats will continue to increase in severity and frequency in the coming decades.[155] For instance, tropical storms—the most intense of which are projected to increase under climate change—are significant contributors to grid disruptions. Extreme heat waves and wildfires can also result in grid disruptions and are projected to occur more frequently with climate change.

Most refining and processing companies' event response plans include purchasing or leasing portable generators to provide electricity to critical facilities during outages. Purchasing a typical 2-megawatt trailer-mounted generation unit may cost $1 million or more with accessories and financing.[156] For refineries and gas processing plants, these back-up generators can power lighting, communications, and facility operations essential to recovering from a disaster. Although back-up generators for these facilities cannot provide sufficient power to run refining or gas processing operations,[157] ensuring back-up power in these areas would allow for the pumping of refined products from storage in the area, thereby mitigating the impacts on consumers.

Available information suggests that a significant majority of critical energy facilities, including those in the liquid fuels and natural gas sectors, maintain some degree of onsite back-up power generation capabilities. Work conducted for DHS by Argonne National Laboratory indicated that of the critical energy infrastructure facilities surveyed since 2011, 90 percent of the facilities with an electricity dependency had back-up generation capabilities in place, but only 50 percent had procedures in place to refuel in an emergency.[aw] Furthermore, these back-up supplies are largely designed for short-term outages, with onsite fuel supplies for these generators typically providing only 6 hours to 72 hours of generation. These data suggest that many bulk energy facilities have appropriately addressed electricity dependencies through the construction and installation of back-up electricity equipment, but lack refueling plans for extended outages.

Analysis by INTEK Inc. found that back-up power has been successful, where available, in maintaining or restoring operations in pipelines, pumping stations, marine terminals, tank farms, and—importantly—retail sales points.[158] Liquid fuels distribution and retail delivery infrastructure is very dependent on electricity and particularly critical to consumers during natural disasters. During Hurricane Sandy in 2012, the lack of back-up generation at gasoline stations contributed to the inability of retail liquid fuels stations to dispense fuel to citizens, first responders, and emergency crews.[159, 160] To address this issue, states such as Florida, Louisiana, and post-Hurricane Sandy New York require select gas stations on highways or evacuation routes to have back-up generation to ensure retail operations during electricity disruptions.

[aw] DOE's Office of Energy Policy and Systems Analysis requested that Argonne National Laboratory's Infrastructure Assurance Center conduct an analysis of the protection and resilience information collected through DHS's Enhanced Critical Infrastructure Program Initiative, which conducts facility site visits and surveys. The primary objective of this analysis was to identify gaps in preparedness and rapid recovery measures for surveyed energy facilities. The analysis was conducted on 273 energy facilities (170 electricity, 45 liquid fuels, and 15 natural gas) using data collected from January 2011 through September 2014.

Liquid Fuels Infrastructure Vulnerabilities

The Nation's domestic petroleum supply infrastructure faces significant threats from a variety of hazards. These include, but are not limited to, tropical storms, tornadoes, derechos, earthquakes, landslides, droughts, floods, sea-level rise, severe winter weather, thawing permafrost, wildfires, and cyber attacks. A number of high-profile weather events that occurred during the last decade illustrate these hazards, such as Hurricane Katrina, Superstorm Sandy, the 2012 Mid-Atlantic summer derecho, and the 2014 polar vortex event, which have placed a spotlight on the vulnerabilities and resiliency of the Nation's fuel system. These events, and the energy supply disruptions they create, also demonstrate the need to mitigate the effects of such disasters. Hurricanes Katrina and Sandy damaged fuels system infrastructure, caused large production losses, and led to supply disruptions (both for refiners and consumers). The derecho and polar vortex events introduced the Nation to these lesser-known natural disasters that also caused significant disruptions to the liquid fuels system. Key hazards and their effects include the following:[161, 162]

- ***Tropical storms.*** Heavy rain and storm surge from tropical storms can flood well pads and access roads, rip oil tanks from their moorings, and damage control rooms and pump stations. The corrosive salt water that accompanies storm surge creates a serious risk for pipelines and associated equipment. High winds can damage refinery cooling towers, empty storage tanks, and overhead cabling. Typically, onshore crude production is not impacted significantly by tropical storm events. Offshore production often undergoes advanced shutdown procedures and evacuations of nonessential workers, and production is usually brought back online from a shutdown within a couple of weeks. However, major storms can severely damage or destroy offshore platforms, and subsea pipelines may be damaged when bottom currents associated with tropical storms create underwater mudslides.

  Coastal port and terminal facilities could be damaged from tropical storms; however, impacts on fuel availability due to these facility closures would be partially mitigated by drawing down inventory and trucking fuel from operating facilities in the region. Distribution terminals in the United State average about a week's worth of refined products at any given time, but it might not be possible to distribute fuel if transport routes are disrupted from the storm, or if terminals and retail gas stations are damaged or experience power outages. In previous tropical storm events, pipeline services typically are suspended in advance of landfall.

  Coastal refineries will usually shutdown ahead of a major hurricane, with operational status returning within 1–2 weeks, except for facilities that require major repairs. Some refineries generate their own power and will restore their own power systems; however, many must complement onsite generation with grid power to operate at full capacity. Approximately 2 weeks of refined products are typically in storage, which can be used to mitigate the impacts of refinery or pipeline disruptions on fuel supplies.

  Oil storage sites (tanks and underground storage), including the SPR, implement severe weather preparations ahead of tropical storms. This includes draining surface oil piping, sealing and isolating oil cavern wellheads, and filling tanks to prescribed depths to withstand wind and flood effects. Disruptions in tanker and barge traffic can present challenges for areas such as Florida, which is dependent on marine transport for fuel delivery.

- ***Tornadoes.*** Given the extreme damage tornadoes can cause to firmly rooted infrastructure, they pose a significant threat to most oil and gas infrastructure in their paths. Tornadoes can destroy nearly anything above ground, including oil and gas wells, pumping stations, terminals, tank farms, transportation infrastructure, refineries, processing plants, and pipeline manifolds. However, while tornadoes are capable of causing serious damage, their threat is mitigated by their relatively short duration and localization compared to other disasters. Tornadoes regularly destroy wells and rigs in the Great Plains region, causing extensive site damage and spills, yet the effects are isolated to those sites. Tornadoes pose a more dangerous threat to refineries and tank farms, which contain more significant production and commodity capacity.

- ***Derechos.*** Oil and gas infrastructure is primarily affected by derechos through access to power supply. Fast-moving violent thunderstorms characteristic of derechos often cause massive power outages over large areas. These outages can last for days to weeks and are exacerbated by lack of forewarning and subsequent heat waves that slow recovery. In this respect, derechos are similar to hurricanes, which can also leave large areas without power in the wake of the storm, thereby requiring coordination with unaffected regions to bring in temporary work crews. One characteristic that solidly separates derechos from other disasters is the added threat of lightning. Lightning is a common occurrence that rarely damages infrastructure; however, it poses unique challenges to the TS&D infrastructure. Over the years, lightning strikes have been known to start fires at tank farms and pipelines, and they have even caused explosions in propane tanks.[163] These are typically rare and localized events, but must be considered as part of the total impact that derechos present.

- ***Earthquakes.*** Significant ground shake can cause structural collapses, pipe breakage, and oil spills that could cause environmental damage or ignite and burn for several days. Structural damage could occur to wharf structures, loading arms, and refinery equipment, such as concrete stacks, chimneys, and cooling towers that may collapse. Older offshore production platforms could become unstable and collapse. Onshore production oil wells can suffer cracks in the wellhead or plug. In some cases, an earthquake can improve the well production in the same way fracking improves the flow of oil to the wellhead. Buried oil pipelines are also vulnerable to ground displacement, with modern steel pipelines generally being more resilient than older pipelines. Port and terminal facilities can experience shearing of transfer piping, leading to multiple spills.

- ***Landslides.*** Pipelines and water transportation routes are particularly susceptible to landslides because they are long, linear features that often traverse regions of varying geologic conditions. Large landslides can remove long sections of pipelines; consequently, recovery could entail complete replacement of a pipeline and its foundation.

- ***Droughts.*** Port facilities, refineries, and barge transport are the petroleum distribution infrastructure most vulnerable to drought. Drought can intensify concerns about both water quantity and water quality. Port facilities, particularly in the Great Lakes, may experience debilitating changes in water level associated with drought. Refineries consume water for processing and also make water withdrawals for cooling. Barge transport, especially important in the Mississippi watershed, can be disrupted if water levels are too low.

- ***Floods.*** Low-lying equipment, such as pump stations, control rooms, oil tanks, and well pads, are vulnerable to flooding. If flooded, pump stations will shutdown system operations until the water recedes, affecting nearby product terminals. Refineries could shutdown from flooding or associated power outages. Barge and tanker traffic may be disrupted by high water conditions. Additionally, if port and terminal facilities are flooded and shutdown, barge shipments that require loading or unloading at the terminals would be delayed. Flooding may also disrupt rail and truck transport of petroleum products, as floodwaters can wash out railroads and roads, degrade rail tracks and road foundations, and damage bridges.

- ***Sea-level rise.*** Low-lying coastal petroleum supply infrastructure is exposed to inundation from sea–level-rise-enhanced storm surge**.** The incremental effect of higher sea levels depends on the location or track of any given storm and the type of infrastructure in question. Up to 34 oil refineries constituting 7.7 percent of U.S. refining capacity are currently exposed to storm surge inundation from Category 3 hurricanes; sea-level rise is expected to increase the portion of exposed refining capacity to 8.8 percent.[164] Petroleum pipeline pumping stations and oil and gas pipeline facilities display similar patterns of exposure.

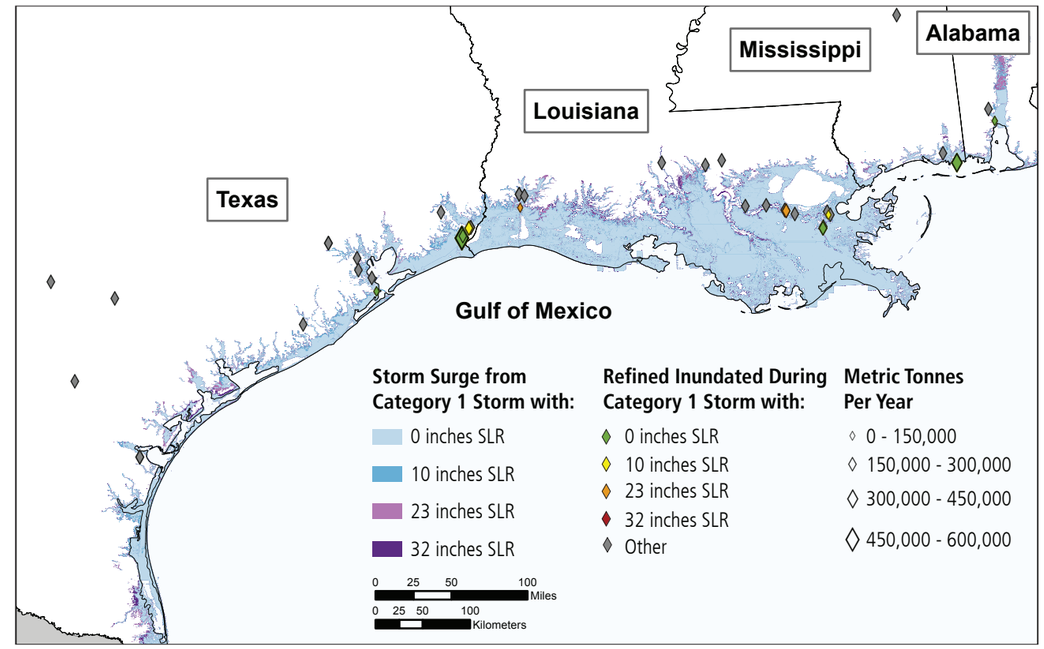
- ***Severe winter weather.*** Cold waves can have several impacts on the fuels supply infrastructure, ranging from equipment malfunction to transportation disruption. As with most natural disasters, power loss remains one of the primary disrupting factors. Ice storms and blizzards can easily take down power lines and trees, while the road conditions make it more difficult for power to be restored. Oil and gas production can be hampered from the extraction stage, particularly in areas not used to or prepared for cold weather. Drilling occurs all over the world—from the Arctic to the Equator—and therefore requires different approaches for different climates. Wells in the Permian Basin have equipment to deal with extreme heat, while drilling teams at Prudhoe Bay, Alaska, maintain equipment to prevent constant freezing. Therefore, when cold temperatures and weather move into an area like the Permian Basin, they can cause serious disruptions.
- ***Permafrost thaw.*** In the Arctic, thawing permafrost causes ground subsidence and disturbances to soil stability that can affect pipeline structural support or impinge directly on pipelines themselves.
- ***Wildfires.*** Uncontrolled wildfires can cause serious damage to all structures and pose a special risk to oil and gas infrastructure because they necessarily contain highly flammable substances. Refineries have experienced fires in the past, which have caused severe injuries and damage. Outside of the clear risks associated with fire, wildfires also can cause power outages, affect local natural gas distribution, create road and rail obstruction, and cause areas to be unsafe for humans through smoke and ash deposits.
- ***Cyber attack.*** Refineries and pipelines are dependent on cyber components for operations. A cyber attack could result in losing control of critical operations, which could cause a process shutdown and damage to a refinery or pipeline. However, the petroleum infrastructure is fairly dispersed, limiting the impacts of a cyber attack. Cyber components are not considered necessary for extracting crude from onshore wells, and fuel product distribution from storage terminals to tank vessels, rail cars, or tank trucks is substantially less reliant on cyber controls.[165]

Climate change is intensifying many natural hazards and thus compounding the Nation's petroleum supply vulnerabilities. The average global temperature has risen 1.4 degrees Fahrenheit in the past century and is predicted to rise further in the coming decades. Rising global temperatures are contributing to sea-level rise, exposing coastal cities and infrastructure to greater risk of inundation during hurricanes and tsunamis. Rising temperatures also have contributed to melting permafrost, an increase in the frequency and intensity of extreme weather events, creating more frequent heat waves, more intense precipitation events, and more severe droughts in some regions. The observed frequency of Category 4 and 5 hurricanes in the North Atlantic Basin has increased.[166] Moreover, the National Climate Assessment projects with "medium confidence" that hurricane intensity will increase in the future, which, in combination with sea-level rise, will result in more extensive inundation and damage to infrastructure when tropical storms make landfall.[167]

Building and repairing infrastructure that lasts several decades requires consideration of resilience in the context of those changes. Land subsidence is also a widespread issue throughout the Gulf Coast (and Mid-Atlantic coastal areas). During the past century, global sea-level rise has averaged about 1.7 mm/yr, though the rate in the Gulf has been faster (at 5–10 mm/yr, in part due to subsidence).[168] Between now and 2030, the average global sea-level rise could accelerate to as much as 18 mm/yr in worst-case scenarios.[169] Due to land subsidence, rising sea levels, more intense precipitation, and the potential for more intense hurricanes in the future, coastal infrastructure in the Atlantic and Gulf Coast is increasingly exposed to erosion, flooding, inundation, damage caused by high winds,[170] and storm surge.[171]

Recent DOE analysis[172] that looked at the effects of climate change on infrastructure exposure to storm surge and sea-level rise found that liquid fuels infrastructure is relatively more exposed to storm surge than other energy sectors, primarily due to its high density in the Gulf Coast region. For example, 100 percent of SPR facilities are currently exposed to storm surge caused by Category 5 storms. With less than 2 feet of additional sea-level rise, Figure A-27 illustrates that the number of Gulf Coast refineries exposed to inundation by storm surge caused by Category 1 storms is estimated to increase from 6 to 10. The study also found that an increase in hurricane intensities in a warmer climate would increase the exposure of infrastructure to storm surge and sea-level rise.

Figure A-27. Oil Refineries on the Gulf Coast Exposed to Storm Surge under Different Sea-Level Rise Scenarios[173, 174, ax]



Sea-level rise increases the vulnerability of refineries to inundation caused by Category 1 hurricane storm surge. Future vulnerabilities correspond with a high-end sea-level rise scenario of 10 inches in 2030, 23 inches in 2050, and 32 inches in 2060; baseline vulnerability corresponds with sea levels in the year 1992.

In addition to natural hazards, the U.S. fuels infrastructure faces vulnerabilities due to physical human threats, chokepoints, and interdependencies within and between the various systems. Potential vulnerabilities in the system related to acts of terrorism are a growing area of concern. Although there have been no high-profile incidents of terror attacks on domestic petroleum supply infrastructure, it is considered a potential prime target because of its economic and security importance to the Nation. Another facet of vulnerability is the age of the Nation's petroleum infrastructure. All currently active refineries were built before 1976, and subsequent capacity growth in the last four decades has stemmed from numerous refinery expansions. Transportation infrastructure also presents vulnerabilities, as nearly 56 percent of hazardous liquid pipelines were built before 1970.[175] In terms of waterborne transport, most of the locks conducting barge and vessel traffic flow on U.S. waterways are over 50 years old, and much-needed maintenance generally has been delayed or deferred.[176, 177]

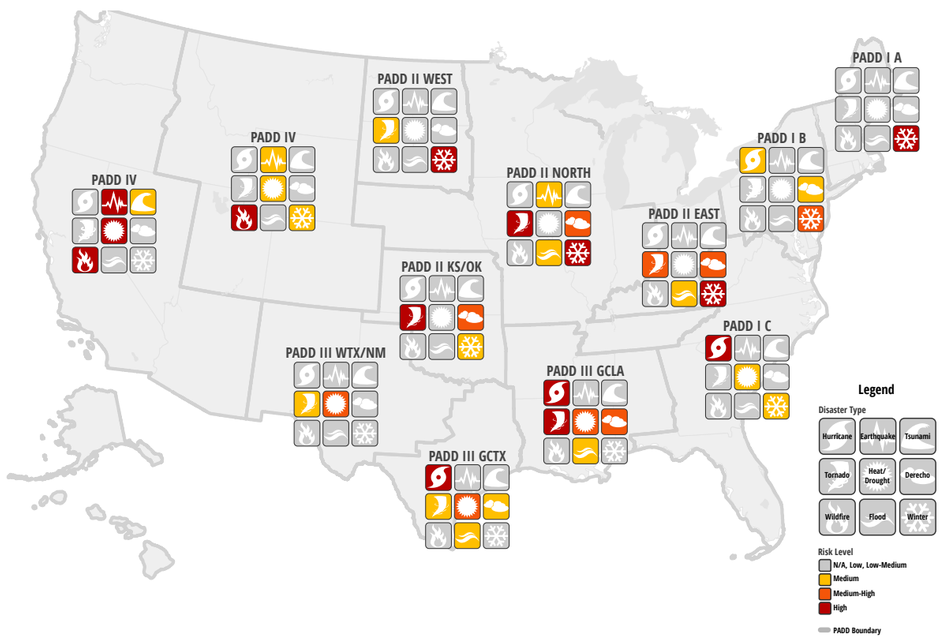
[ax] Areas inundated by hurricane storm surge do not account for local land subsidence, which will further increase the exposure of infrastructure in this region.

Regional Fuel Resilience[ay]

Threats to the Nation's oil and refined products infrastructure vary by region. For example, hurricanes, earthquakes, tsunamis, and tornadoes comprise highly dangerous, region-specific events (as depicted in Figure A-28). Hurricanes affect nearly the entire Gulf Coast and East Coast, and they occasionally affect the West Coast. Earthquakes primarily occur in the western United States, and there are pockets of serious seismic hazards in the central United States along the Mississippi River in the Tennessee Valley Region and in coastal South Carolina. Tsunamis often are associated with seismic activity and therefore pose a particular threat to the West Coast. Tornadoes traditionally are associated with "Tornado Alley" in the Great Plains region, yet also occur frequently throughout the Southeast and Midwest. The Northeast also is susceptible to extreme winter weather, which can cause demand for heating fuels to outstrip local supply and cause major pipeline congestion.

Natural disasters do not necessarily pose a significant threat to liquid fuels TS&D. Each discrete PADD and sub-PADD is vulnerable to a wide variety of potential natural disasters and threats. In most cases, however, only a few of these threats occur with sufficient frequency or intensity as to merit major concern (as shown in Figure A-28). Regional resiliency entails the ability of a region to absorb a supply or TS&D disruption with limited impact to consumer fuel consumption, whether the cause is a natural disaster (local or not), expected or unexpected offline infrastructure, or other event. The major vulnerabilities of liquid fuels TS&D to natural disasters and other potential interruptions are discussed by PADD and sub-PADD in this section.

Figure A-28. Major Natural Disaster Hazard Regions in the Continental United States[178]



Major natural disasters in the United States are region specific, impacting regional energy infrastructure in different ways.

[ay] Parts of this section rely on Quadrennial Energy Review Analysis: INTEK Inc. "United States Fuel Resiliency: U.S. Fuels Supply Infrastructure (Vol 1–3)." September 2014. http://energy.gov/epsa/qer-document-library.

PADD I

PADD I alone accounts for 32 percent of U.S. fuels demand. Of this, 52 percent is consumed in Sub-PADDs IA and IB, which include the major cities of Boston; New York; Philadelphia; Pittsburgh; Baltimore; and Washington, D.C. More than 70 percent of this demand is supplied by PADD III refiners or imports.

Northeast (Sub-PADD IA)

Sub-PADD IA—the New England States of Connecticut, Rhode Island, Massachusetts, New Hampshire, Vermont, and Maine—is subject to long, harsh winters; coastal storms and hurricanes; coastal flooding; sudden and intense squalls; and derechos. Because New England lacks indigenous fuels production, its fuels are largely supplied by other regions, as well as by foreign imports. The region relies on its ports, marine terminals, rail, and highway systems to receive and distribute fuels, and it is highly reliant on the fuels supply and infrastructure of Sub-PADD IB, Sub-PADD IC, and PADD III.

Boston Harbor is the largest seaport in New England. It includes refined petroleum product import and storage terminals, as well as a LNG terminal. In 2012, Boston Harbor received approximately 196,000 bbl/d of refined petroleum products,[179] or 27 percent of New England's delivered petroleum consumption.[180] Analysis conducted by Sandia National Laboratories indicates that Boston Harbor disruptions would affect petroleum product availability in Boston and the greater New England area, causing temporary market shortages and price spikes. Given limited petroleum product pipeline infrastructure in New England, potential shortages resulting from a disruption in Boston Harbor would require imports to be made up by increasing waterborne shipments to other ports (e.g., New York City; Providence, Rhode Island; Portland, Maine; and New Haven, Connecticut), and then shipping the fuels by truck or rail to the affected area, as available transportation capacity permits.[181]

Mid-Atlantic (Sub-PADD IB)

Sub-PADD IB—Virginia, West Virginia, Maryland, Pennsylvania, Delaware, New Jersey, and New York—also is susceptible to hurricanes, winter weather, coastal flooding, and derechos, which can impact critical TS&D infrastructure. Any disruption of Linden, New Jersey, or New York Harbor infrastructure, system interconnections, or associated power or communication systems could disrupt the distribution of fuel stocks, largely by barge and tanker, to terminals in New England.

The Linden, New Jersey, and New York Harbor areas—including the Colonial and Buckeye systems—and the Arthur Kill and Kill Van Kull waterways, as well as all of the marine and storage terminals that serve them, were shutdown and severely damaged by storm surge, rainfall and associated flooding, and power loss during and after Hurricane Sandy, curtailing product movements to the Northeast.

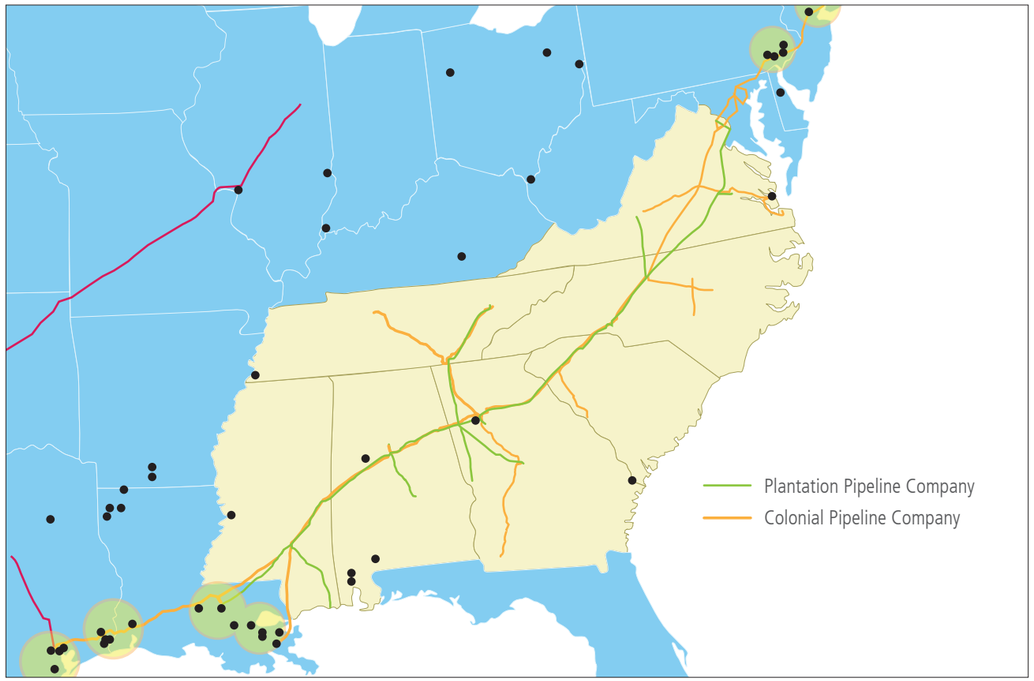
Post-Hurricane Sandy, DOE developed a 1 million bbl Northeast Regional Petroleum Product Reserve, in addition to the 1 million bbl Northeast Home Heating Oil Reserve. The State of New York subsequently established an additional 3 million gallon (71,500 bbl) gasoline reserve near Manhattan on Long Island. The combined stocks in these new reserves are still insufficient to satisfy the 1.3 million bbl/d fuels demand of the Northeast region for more than a few days in the event of a significant interruption caused by a hurricane or other event. Further, while the sites for these reserves were carefully selected, they too could be susceptible to interruption, depending on the path and intensity of a hurricane and its storm surge.

The impact of a Mid-Atlantic hurricane on consumer fuel availability was modeled by Sandia National Laboratories. A hypothetical hurricane event can be shown to reduce fuel consumption to near zero in areas surrounding landfall due to power outages. Areas of the Mid-Atlantic that receive product only from ports and not pipelines will experience greater shortages because, while both infrastructure components would experience electric power outages, ports are expected to be down longer than pipelines.[182]

Southeast (Sub-PADD IC)

The Southeastern states (Sub-PADD IC)—Florida, Georgia, South Carolina, and North Carolina—have no refining capacity. Coastal areas of these states are supplied by waterborne deliveries, and Florida is heavily dependent on receiving water shipments of refined products. The interior portions of Georgia, South Carolina, North Carolina, and Virginia rely on refined products that are supplied from PADD III by two pipelines: Colonial and Plantation (see Figure A-29). A major hurricane or other disruptive event in PADD III could interrupt fuels supply to the Southeast for as much as 14 days or more. Stocks in storage at bulk terminals and distribution centers can provide less than 3 to 5 days of supply.[183] Over the past century, sea levels have increased by as much as 3–6 mm/yr in the Atlantic Coast-South region.[184]

Figure A-29. Southeast Regional Dependency on PADD III and Product Pipelines[185]



Sub-PADD IC has no refining capacity and nearly is totally reliant on refined products that are supplied from PADD III by two pipelines: Colonial and Plantation.

Midwest (PADD II)

PADD II comprises the majority of the central portion of the United States, extending west from Ohio to Nebraska and from the southern border of Tennessee all the way to the Canadian border. It includes 15 of the lower 48 states. Extreme weather events of greatest concern for petroleum supply in this region include tornadoes, inland flooding, and shifts in the polar vortex. Energy infrastructure in the region may also be vulnerable to earthquakes in the New Madrid Seismic Zone (NMSZ), which runs through Missouri, Arkansas, Tennessee, Kentucky, and Illinois.

Overall, PADD II is reliant on external sources for about two-thirds of its crude oil and natural gas demand, but is a net producer and exporter of refined products to other PADDs and markets. PADD II produces crude oil in the Bakken and several other formations. It receives crude via pipeline from Canada, Colorado (PADD IV), New Mexico, and Louisiana (PADD III). There are two major pipeline junctions at Patoka, Illinois, and Cushing, Oklahoma. Cushing has several major pipelines, including Seaway, which send crude to the Gulf Coast refineries. PADD II also receives products. The Explorer and TEPPCO pipelines bring products north from the Gulf and distribute them throughout the central and eastern portions of the PADD. Products also are received along Canadian pipelines into Michigan.

A large portion of the crude produced in the Bakken area of North Dakota is shipped via rail to refineries outside of the PADD. Major destinations include the East Coast, West Coast, and Gulf Coast. In addition to these shipments, products are sent from northern PADD II refineries into Montana.

PADD II receives natural gas from Canada, Colorado (PADD IV), New Mexico, Texas, Louisiana (PADD III), and the Appalachia (PADD I). Several pipelines run through eastern PADD II and supply gas to PADD I. Conway, Kansas, contains the largest propane storage facility and the origin for pipelines that transport propane throughout central portion of PADD II.

Sub-PADD II East and North

Sub-PADD II East includes the eastern oil and gas producing States of Michigan, Ohio, and Kentucky. Sub-PADD II North includes the central Midwest States of Illinois, Indiana, Iowa, Minnesota, Missouri, Nebraska, Tennessee, and Wisconsin, among which Illinois and Indiana are oil and gas producers. While generally immune to coastal threats such as hurricanes and tsunamis, these areas are susceptible to a broad range of other natural disasters, including tornadoes, derechos, flooding, and shifts in the polar vortex.

Earthquake risk extends from western Tennessee northwards toward southern Illinois. NMSZ near St. Louis, Missouri, also poses earthquake risk. An earthquake in the NMSZ would be expected to severely damage the Memphis refinery and disrupt several crude oil and refined product pipelines that pass through the NMSZ to link the Gulf Coast to the Midwest. In those areas, significant consequences would include near-zero availability of fuel in the directly affected areas, with fuel shortages potentially lasting 60 days or more and disruption of barge traffic on the Mississippi River eliminating normal fuel supplies to Memphis. An earthquake in the NMSZ would have relatively little effect on overall U.S. fuel supplies, with fuel shortages that are only severe in areas directly affected by the earthquake and areas served by the disrupted refined product pipelines.[186]

This region includes several major population centers and markets for natural gas and refined products, the largest of which is the Chicago area. The Patoka area in southern Illinois is a major market hub and interconnect point for crude oil pipelines originating in Canada; from the Cushing, Oklahoma, oil market hub; from Sub-PADD II Kansas/Oklahoma; and from the PADD III Gulf Coast area. The Mississippi River flows through the sub-PADD and serves as a major route for waterborne transit of oil and refined products to Midwest refiners, storage terminals, and end-use markets. As such, this area is indirectly vulnerable to Gulf Coast hurricanes and other natural disasters and threats in those areas.

Petroleum pipeline reversals are limiting flows of crude oil from the Gulf of Mexico region to PADD II refiners, reducing supply resiliency. For example, Capline only can provide about 500 thousand bbl/d from SPR or Gulf of Mexico producers in the event of a disruption of crude supply from other sources.

Refined product stocks in storage in the region average 5 days to 7 days of demand. Local refineries with excess capacity could increase utilization to offset loss of products, but would need sufficient crude stocks. Tennessee and Kentucky markets could be impacted by shutdowns of Colonial or Plantation pipelines if local demand exceeds stocks in storage and the production capacity of the refinery in Memphis, Tennessee.

Sub-PADDs II North and East are large producers of ethanol, which is supplied to blenders and distributors by truck and rail. Heat waves, droughts, and flooding could result in shortage of corn/crop supplies for ethanol production. However, multiple sources and excess supply within the PADD provide resilience in the ethanol supply to fuel blenders and distributors. Stocks in storage average 5 days to 15 days of demand, and because of the inherent flexibility of ethanol transportation methods, additional ethanol can be obtained by rail and truck from Sub-PADD II Kansas/Oklahoma if necessary.

A number of changes to the midstream propane infrastructure in the United States have stressed the ability of the system to provide propane during the winter heating months. One refined products line of the Enterprise TEPPCO system has been reversed, reducing south to north product capacity. Also, Kinder Morgan's Cochin pipeline, which originally delivered propane to the Midwest, is now shipping light condensate from the United States to Alberta, Canada. Currently, there are no projects underway to add additional propane service.

ICF International (on behalf of the Propane Education & Research Council) conducted an analysis of the impact of the Cochin pipeline reversal on consumer propane markets in the Midwest. The reduction in transmission capacity into the region has decreased the ability of the midstream propane infrastructure to adequately supply propane to the Midwest for home heating during high-demand winter months.[187]

As an alternative to building new pipeline capacity that would only be utilized during the winter months, utilization of tertiary propane storage can significantly contribute to meeting demand with little additional investment. Existing tertiary propane storage in the United States is estimated to be nearly 800 million gallons,[188] while demand peaks at approximately 70 million gallons per day in the winter and is reduced by more than half in the summer.[189] Maintaining a sizeable volume of propane already in the market area before the winter can help consumers meet their needs while reducing strains on delivery infrastructure during the winter.[190, 191, 192] Increased off-season filling also offers a significant impact on reducing peak season demand because of the large amount of tertiary storage available. ICF International found that consumer propane tanks are about 50 percent to 60 percent full at the start of the heating season. An increase in summer fill capacity utilization of just 5 percent would make up for nearly 1 month of supply that has been lost due to the Cochin pipeline reversal.[193]

To increase the resiliency of the propane system after the loss of the Cochin pipeline, the Propane Education & Research Council undertook a national advertising campaign from September 8–November 23, 2014, to reassure contract customers and spur will-call customers to lock in supplies for winter. Materials also were prepared to assist propane marketers. During the duration of the advertising campaign, propane sales in some states increased compared to last year, and 7 percent more propane was odorized between August and October 2014 than for previous years.[194] Encouraging customers to fill their storage before the winter has enabled more efficient utilization of the existing propane infrastructure, offsetting the need for additional winter pipeline capacity. Importantly, consumers also will benefit from decreased prices, as summer propane prices will usually be lower than winter propane prices.[195]

Sub-PADD II Kansas and Oklahoma

Liquid fuels TS&D infrastructure in Kansas and Oklahoma includes eight small refineries (each less than 200 thousand bbl/d), which provides geographic distribution and some resilience for refined product availability. Local stocks in storage total 5 days to 7 days, which likely is sufficient to meet demand until repairs can be made in the event of a minor disruption.[196]

The region's TS&D infrastructure is susceptible to winter weather and shifts in the polar vortex, inland flooding, and heat waves. These extreme weather events may damage electrical infrastructure, leading to power outages at refineries and along pipelines. Inland flooding may also damage pipeline infrastructure via flood-borne debris or inundation of pipeline pumping stations,[197] damage or washout roads and railroads,[198] and inundate transport facilities and refineries.[199] However, the major threat to TS&D infrastructure in this oil and gas region is the number, frequency, and intensity of tornadoes. With more than 80 million bbl of crude oil storage capacity and numerous pipeline interconnections, a direct hit from a major tornado in the Cushing, Oklahoma, area could cause extensive infrastructure damage with potentially significant crude oil loss, leading to market impacts. While new crude oil pipelines, crude by rail, lower volumes stored, and changing flow patterns may dampen these impacts, a major tornado strike and damage or fire at Cushing could cause loss of stocks, infrastructure, and connectivity. The Seaway pipeline reversal now limits the options for SPR deliverability to PADD II Kansas/Oklahoma refineries.

Sub-PADD II West

Sub-PADD II West—comprised of North Dakota and South Dakota—is notable because of its emerging role as a major producer of light sweet oil from the Bakken and Three Forks shale oil plays. Sub-PADD II West is a net exporter of crude oil to other PADDs. Only one refinery is operational in North Dakota. However, two new refineries are under construction to produce diesel and distillates for the local market and diluent for heavy crude oil. The completion of these two refineries will increase refined product resiliency in the region. Military bases in the sub-PADD maintain limited stocks.

A major natural threat to TS&D infrastructure in North Dakota and South Dakota is severe winter weather, potentially exacerbated by the polar vortex phenomenon. Excessive cold, wind, heavy snows, and ice associated with winter conditions can result in power loss to crude oil terminals, pipelines, and refineries; malfunctions of instrumentation, controls, and communications; and disruption of road, rail, and other transportation infrastructure. This region also is susceptible to severe storms and floods; counties in the Bakken region of North Dakota have experienced some of the highest numbers of disaster declarations in the country. Inland flooding could inundate energy infrastructure in the region, expose and damage pipelines, and impair travel on roads and railroads.[200]

PADD III

PADD III—which includes the States of Alabama, Mississippi, Arkansas, Louisiana, Texas, and New Mexico, as well as the Federal offshore Gulf of Mexico—is the largest oil and gas producing, refining, and processing region in the United States. Its refineries are the recipients of the majority of crude oil produced in the United States and the source of most of the refined products received and consumed in the eastern and southern regions of the United States. PADD III also is a major source of refined products to the Midwest, the southern Rocky Mountain states, the Southwestern states, and southern California.

Crude oil is brought into the Gulf Coast region via the Longhorn, Seaway, Ho-Ho, and other pipelines. Rail is used to bring crude from the Bakken and other sources into hubs in St. James, Louisiana, and Port Arthur, Texas. Barges are used to bring crude oil, produced in the Eagle Ford, from Corpus Christi, Texas, to other destinations along the Gulf Coast. In addition, tankers and other marine vessels carry large volumes of foreign imports into the region.

Pipelines are used to transport refined products to markets in the East Coast and Northeast (via the Colonial and Plantation), as well as the Midwest (via the Explorer and TEPPCO). PADD III also contains one of the major propane storage hubs at Mont Belvieu, Texas. Pipelines owned by Enterprise transport propane to markets in the Southeast and Mid-Atlantic. Barges and other vessels are used to carry products to markets along the East Coast and West Coast.

Sub-PADD III Gulf Coast

The Gulf Coast portion of PADD III is susceptible to a wide variety of natural hazards, including hurricanes, tornadoes, coastal flooding, derechos, and even earthquakes. The most frequent, severe, and impactful of these hazards on oil and gas TS&D infrastructure are Gulf Coast hurricanes.

Hurricanes can interrupt oil and gas production in the Gulf of Mexico and onshore; damage rigs and platforms; shutdown crude and product pipelines; down gas processing and oil refining facilities; cause wind damage to structures and systems; knock out electric power to populations and critical infrastructure; and cause coastal flooding of ports, terminals, refineries, and storage facilities due to their storm surge and torrential rains. Surface road and rail transportation and waterborne transport in the Gulf, major ports and seaways, and the critical Mississippi River can all be damaged or curtailed. Some climate models indicate that the most intense tropical storms (Category 4 and 5 hurricanes) will occur more frequently as temperatures increase, and the impact of associated storm surge may be amplified by accelerating sea-level rise, rendering more infrastructures vulnerable to coastal flooding.[201] During the past century, land subsidence in the Gulf Coast region has caused relative sea levels to rise by 5–10 mm/yr, which is more than the twice the global average. The highest rates of land subsidence within the Gulf Coast region are estimated to be in the vicinity of the Mississippi River Delta.[202]

Power outages resulting from a large Gulf Coast hurricane would create near-zero availability of fuel for approximately 7 days along the portion of the coast where the hurricane makes landfall. Lesser shortages would extend inland along the storm path, especially if the storm path travels along a pipeline corridor. It is likely that the fuel shortages will occur in two stages. In the immediate aftermath of the hurricane, widespread electric-power outages would cause fuel shortages because most pipelines and distribution systems require electric power. After power is restored, refined product storage in the area would be released to relieve shortages. However, extended refinery outages would cause fuel shortages to increase again in certain corridors. Longer-term shortages could peak about 1 month after the hurricane makes landfall, but even at the peak, some simulations indicate that consumption would be reduced by less than 10 percent below normal rates.[203] Shipments of refined products out of the Gulf ports also would be disrupted. Most of these shipments are destined for ports in Florida and the East Coast, so fuel shortages could occur in those areas too, but any such shortages likely would be insignificant because other sources of supply are available to those areas.

Sub-PADD III West Texas and New Mexico

This sub-PADD differs greatly from PADD III Gulf Coast. It is a major producer of oil and natural gas, but has limited refining capacity and infrastructure. PADD III West Texas/New Mexico supplies crude oil from the Permian Basin and Eagle Ford areas to PADD III refineries, as well as to the oil market hub in Cushing, Oklahoma. A refinery in El Paso supplies products to key markets in Phoenix and Tucson, Arizona. PADD III West Texas/New Mexico also produces and supplies gas to the Nation's transmission system, sending it east to Texas and eastern markets and west to Arizona and California. Outside the path and reach of most Gulf Coast hurricanes, the major vulnerability is to wildfires, drought, tornadoes, and—perhaps—earthquakes. Wildfires and drought may cause damage to production wellheads, gathering systems, pipelines, or controls. Drought may limit water supplies for some oil and gas exploration, production, and refining operations, reducing production. Tornadoes can cause loss of power, wind damage, and structural damage (due to flying debris) to rigs and platforms; gathering systems; refineries; crude oil storage terminals; refined product storage and distribution terminals; gas processing plants; compression stations; interconnects; and surface transportation infrastructure, including roads, bridges, rail lines, and river crossings.

In this sub-PADD, there is no crude oil dependence due to local production. The TEPPCO products pipeline is a critical source of products to Abilene, Texas. Refined products easily can be provided from the PADD III Gulf Coast area. Exports of refined products to Arizona could be interrupted by a disruption affecting the El Paso refinery or Kinder Morgan's SFPP East Line between El Paso, Texas, and Tucson and Phoenix, Arizona.

Rocky Mountains (PADD IV)

PADD IV is comprised of the Rocky Mountain States of Colorado, Idaho, Montana, Utah, and Wyoming. Of these states, Colorado, Utah, and Wyoming are significant producers of natural gas, as well as producers and refiners of crude oil. The flows of crude oil, refined products, and natural gas in and out of PADD IV reflect the rugged topography of the region, as well as geographic separation of producing areas from the more populous demand centers.

Canadian crude oil supplies refineries in the Guernsey, Wyoming, area. Refined products from PADD II North also supply markets in Montana and Wyoming. Products from Guernsey, Wyoming, flow to Utah and northern Colorado, while products from the Utah refineries flow to markets in Nevada and Washington.

The northern location and mountainous terrain of PADD IV subjects it to cold winters, significant snowfall, and icy conditions that can result in flooding during periods of thaw. Warm summers and arid conditions make some areas prone to drought, and wildfires are common. PADD IV straddles the Continental Divide, making it vulnerable to earthquakes; although, activity tends to be of low frequency and intensity.

About one-quarter of oil supplied to PADD IV refineries (in Colorado, Wyoming, and Utah) is heavy synthetic crude supplied via Canadian pipelines or from PADD II. The rest is produced locally in Colorado, Utah, and Wyoming. Crude oil stocks in storage average nearly 30 days of supply, which is sufficient to offset any likely disruption.

Ninety percent of refined products are supplied by PADD IV refiners, with the balance being supplied by PADD II refiners. Approximately 50 percent of jet fuel is supplied by pipelines or rail from PADD II. Some areas receive fuels from outside the PADD via the Phillips 66 and NuStar pipelines from Amarillo, Texas, to Denver, Colorado. Product stocks in storage average 6 days to 7 days, which is sufficient to meet any likely disruption in PADD IV.[204] Additional products could be supplied from PADD III via pipeline, rail, or tanker trucks.

In the result of a disabled refinery in PADD IV, fuel shortages are minimal compared to simulations of disruptions in other PADDs. Increased production at other refineries in the region to compensate in part for the lost refining capacity is sufficient to limit fuel shortages to only several percent of normal consumption in surrounding areas. The local area around a hypothetical disabled refinery may experience a slightly higher decrease in fuel consumption for an extended period of time until the specific refinery can be brought back online.[205]

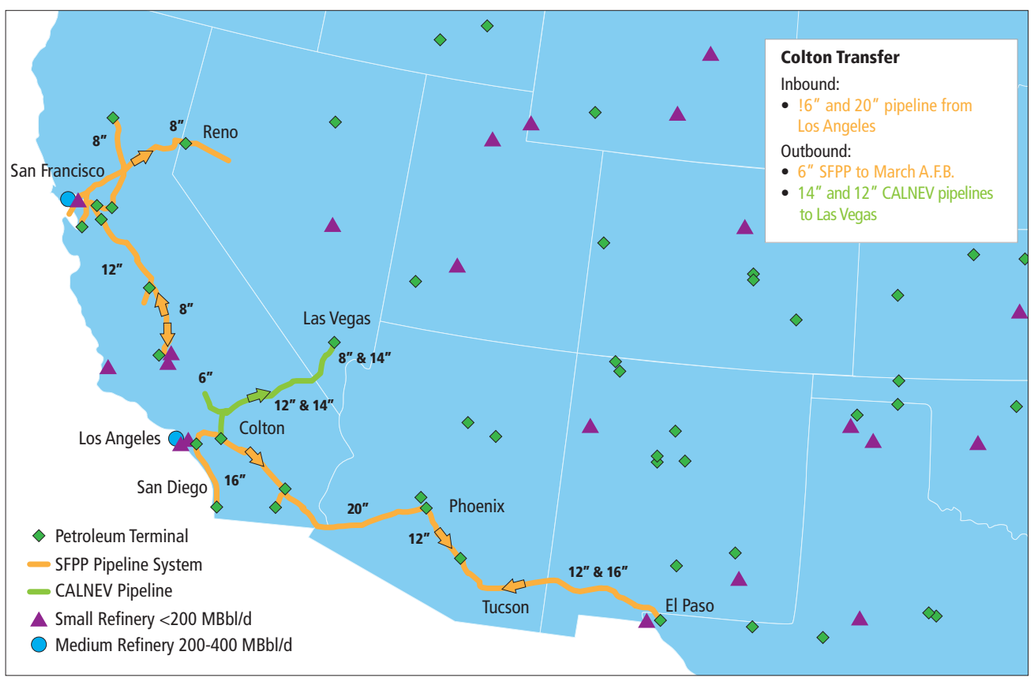
West Coast (PADD V)

The Western States of Arizona, California, Nevada, Oregon, Washington, Alaska, and Hawaii are susceptible to earthquakes, wildfires, drought, and flooding. Earthquakes may damage TS&D infrastructure, and wildfires may damage electrical infrastructure in the region, resulting in power outages that could disrupt petroleum supplies. The region increasingly depends on receiving shipments of liquid fuels via marine vessel from other regions, including Alaska. Flooding could impact fuel supply to the region by damaging terminals, refineries, and transport infrastructure.

PADD V depends on crude oil imports from South America and the Middle East for more than one-third of its refinery demand, much of which travels through the Panama Canal to reach West Coast ports (Alaska and Hawaii refineries partially supply those self-contained markets). Most of PADD V refined products demand is met by local refineries.

Washington and Oregon can rely on alternative sources of crude and refined products from Canada in the event of a supply disruption. However, the California markets of San Francisco and Los Angeles are far less resilient. Further, Reno, Nevada, depends on product pipelines from the San Francisco area, and Phoenix, Arizona, and Las Vegas, Nevada, depend on products supplied by pipelines from southern California. Numerous major airports, nine air force bases, and several naval bases rely on southern California refiners and imports for fuels, posing strategic resiliency concerns (see Figure A-30).

Figure A-30. PADD V Crude Oil and Product Movements Dependency[206]



Two main import and refinery centers in California serve multiple demand points, limiting the refined products resiliency of the region.

The major concern in PADD V is that there are few alternative sources of oil or refined products to meet major market demands in the event of a major earthquake or other supply disruption. Consequently, resilience depends on stocks in storage being sufficient to meet market requirements until disrupted infrastructure can be restored.

Terminals at Colton, California, store products for shipment from southern California to the Phoenix and Las Vegas areas, as well as critical military facilities. While a major supply disruption could be offset by SPR crude shipments (non-ultra large crude carrier) via the Panama Canal to southern California refineries, it could take as much as 21 days for SPR crude to reach California refineries via this route. Current regional product storage (approximately 10 days) is insufficient to mitigate a significant interruption of supply to critical markets and military bases in California, Arizona, and Nevada. If the Panama Canal closure is the source of crude supply loss, SPR crude would require up to 50 days to be delivered by seaborne vessels around South America (Jones Act waivers would be required in this case).

An earthquake affecting southern California would impact liquid fuels infrastructure that serves southern California and cities to the east. Fuel consumption in Los Angeles primarily would be limited by lack of electric power at distribution terminals. However, fuel in San Diego, California, other parts of southern California, Las Vegas, Nevada, and Phoenix, Arizona, would experience a severe decrease in consumption due to damaged refined product pipelines that are in close proximity to the Southern San Andreas Fault.[207]

An earthquake caused by a rupture along the Hayward fault east of San Francisco, California, primarily would affect refined product pipelines that cross the fault to carry transportation fuels from refineries in the North Bay Area to consumers. In the event that these pipelines are damaged, fuel consumption in San Francisco would be reduced significantly. Other cities to the east that receive fuel from San Francisco refineries will feel minimal impacts in some scenarios (less than a 5 percent decrease in consumption).[208]

Domestic Petroleum Product Chokepoints

The Colonial and Plantation pipelines follow parallel routes from the Gulf Coast through the Southeast and into the Mid-Atlantic, with the Plantation terminating in northern Virginia and the Colonial terminating in Linden, New Jersey. Both pipelines are the primary suppliers of products to the Southeast, and Colonial is of critical importance to the Northeast because it feeds into the Buckeye system at the Intra Harbor Transfer at New York Harbor. If these pipelines go offline, all of PADD I would face a serious supply shortage.

The Arthur Kill and Kill Van Kull are two waterways separating Staten Island, New York, from New Jersey. Both waterways also contain a large number of petroleum terminals along their banks. These waterways were exposed as product chokepoints during Hurricane Sandy when the terminals were flooded and petroleum spilled into the river. Immediately following Sandy, both waterways were closed or heavily restricted for more than 1 week due to the spill and debris. Their closure exacerbated the fuel shortages facing New York and New Jersey.

Federal Responsibilities for Energy Infrastructure Resilience

Title II of the Homeland Security Act of 2002, as amended, details DHS's responsibilities for critical infrastructure protection. The foundation for Federal resilience efforts is the National Infrastructure Protection Plan 2013; this lays out how government and the private sector should and can coordinate to manage risks and achieve security and resilience goals.

In February 2013, the President further strengthened and broadened the United States' national position on critical infrastructure resilience by issuing Presidential Policy Directive-21, *Critical Infrastructure Security and Resilience*. The directive applies to all critical infrastructures, but calls out energy infrastructures as being *uniquely* critical due to the enabling functions they provide across all other critical infrastructures.

This document goes on to define resilience as "the ability to prepare for and adapt to changing conditions and withstand and recover rapidly from disruptions. Resilience includes the ability to withstand and recover from deliberate attacks, accidents, or naturally occurring threats or incidents." Threats may include natural or human-made hazards, such as hurricanes or physical threats. Consequences, as stated in Presidential Policy Directive-21, reflect social welfare. They go beyond the ability of a system to operate and address the vitality of national safety, prosperity, and well-being.

As part of the President's National Preparedness Policy, the National Response Framework serves as a guide to an all-hazards response and establishes a foundation for Federal Government coordination with state, local, and tribal governments and the private sector during incidents.

DOE is the lead agency for implementing National Response Framework Emergency Support Function #12 – Energy. This entails coordinating assistance to government and private sector stakeholders to reestablish energy systems, providing technical expertise, and sharing information on energy system damage and reestablishment efforts. Responsibility for resiliency of privately held energy infrastructure lies mostly with the state public utility commissions, but also with Federal regulators such as the Federal Energy Regulatory Commission/North American Electric Reliability Corporation, the Nuclear Regulatory Commission, the Pipeline and Hazardous Materials Safety Administration, and more. Responsibility for resiliency of publicly held energy infrastructure projects lies with the agencies that own and operate them, which are scattered across the Federal and state governments.

For a detailed description of Federal responsibilities for energy infrastructure resilience, see Appendix D.

Environmental Impacts

Air Emissions

Major air quality concerns arise in the vicinity of ports and rail yards, where the density of vehicles and increasingly frequent problems with congestion lead to high concentrations of pollutants and greater risks to nearby urban communities. Vehicles transporting energy as freight that are within the scope of the QER include locomotives, truck, and marine vessels, from which emissions primarily are due to diesel engine combustion of diesel fuel and residual fuel oil (in the case of marine engines). Health effects from short-term exposures to diesel exhaust, a likely carcinogen, include premature mortality, increased hospital admissions, and heart and lung diseases.[209]

Communities living in close proximities to rail yards[210] and ports[211] are exposed to significantly higher concentrations of diesel particulate matter, including fine particulate matter, which is harmful to public health. Research also has found that low-income households and minority populations are overrepresented in the aggregate affected population compared with the overall U.S. population, often by a factor of 2 or 3.[212] In 2013, an estimated 33 million people in the United States lived in counties with air quality concentrations above the National Ambient Air Quality Standards level for fine particulate matter.[213]

Oil Spills

Pipeline ruptures from small (less than 50 bbl) to large (greater than 1,000 bbl) volumes can occur at any point along the pipeline system, including construction sites, operations and maintenance facilities, and within the pipeline right of way.[214] Spills can affect soils and vegetation in agricultural and natural areas, terrestrial and aquatic wildlife, and water resources. Both small and large volume spills have the potential to significantly impact agriculture and other economic and social assets.[215]

Pipeline ruptures are becoming less common despite an increase in the number of miles of pipelines in use. The average number of pipeline ruptures per year decreased from about 190 per year to 150 per year between 2002 and 2012, with small releases accounting for between half and one-third of the total number of incidents.[216] Similar trends are taking place in Canada. For example, the Alberta Energy and Utilities Board reported that pipelines in Canada saw an average of 66 ruptures per year between 1990 and 1995 compared to an average of 24 ruptures per year between 2000 and 2005.[217] Despite reductions in spill rates, older pipelines remain more vulnerable due to corrosion and fatigue, outdated technology, and incomplete records.[218] Equipment failure (valves) and incorrect operations (tanks) are common causes for releases.[219] Spills also can occur during inspection activities and routine maintenance.[220] Interpreting the pipeline spill statistics is complicated by the fact that smaller spill incidents are frequently not reported, which causes a bias toward larger spill sizes and lower spill frequencies.[221]

Due to economic pressure and lack of pipeline capacity, petroleum products are increasingly being transported by alternative methods, particularly rail.[222] However, it is challenging to compare marine, rail, truck, and pipeline spill statistics due to several data limitations and inherent differences between modes. For example, there is large interannual variability in the volume of reported releases of crude oil from marine and rail vessels; for rail, it ranges from less than 5 bbl per year to more than 25,000 bbl per year—with the increase in shipments of crude by rail, there has been a concomitant increase in oil releases from this mode.[223] In terms of recorded impacts relevant to the environment and public health, the simplest comparative metrics are total reported incidents and volumes of spills. In general, available data indicate that releases from pipelines are relatively more significant than spills from rail transport, and the total oil spilled by pipelines is greater than that from other sources. Between 2004 and 2013, pipelines spilled an average of 63,069 bbl per year of oil.[224] In comparison, the average annual oil spill rate for rail (1,431 bbl per year for 1998 to 2007),[225] truck (9,181 bbl per year for 1998 to 2007),[226] and marine vessel (including tankers and barges, 9,593 bbl per year for 2001 to 2011)[227] were all considerably lower. This comparison is dominated by the fact that each mode transports different total volumes of energy product over different average distances, with pipelines carrying far larger volumes than other modes. Better data on barrels spilled per barrel-miles moved would improve our ability to compare spill statistics across modes on a common basis. This is particularly important for assessing how relative risks are changing during this dynamic period of growing domestic production of crude oil and shifting patterns of energy transport.

The environmental effects of any spill will depend on the vulnerability of the region where the spill takes place and the ease of response. Rail and marine spills result in the spill of a relatively small volume (typically aboveground), although pipeline spills can go undetected for relatively long periods of time and result in higher spill volumes (typically underground). For example, one of the largest inland oil spills in U.S. history occurred in North Dakota in 2013 when 865,000 gallons of crude were released from a pipeline rupture.[228] This spill affected 7 acres in a relatively remote part of the state, and remediation will require constant work for more than 2 years.[229]

In certain areas, the risk of seismic damage to energy transmission infrastructure, including pipelines, is an important consideration to avoid significant environmental damage. The benefits of such planning were demonstrated during the 2002 magnitude 7.9 Denali Fault Earthquake. Since the Trans-Alaska Oil Pipeline crossed the Denali Fault, engineers understood the seismic risks and, in preparation, the pipeline was carefully designed to accommodate this risk and did not break despite 19.5 feet of lateral movement during the quake.[230] The savings from avoiding a pipeline rupture and the associated repair and environmental cleanup were estimated to be over $100 million.[231] However, other high-risk areas for seismic activity have not yet made similar accommodations. A scenario analysis by the U.S. Geological Survey estimated that a magnitude 7.9 earthquake along the southern San Andreas Fault could cause very substantial damage to energy infrastructure, including pipelines.[232]

Arctic Energy Region

Arctic region energy infrastructure has already seen impacts from climate change. In 2013, DOE released the report, "U.S. Energy Sector Vulnerabilities to Climate Change and Extreme Weather," which describes some of the potential impacts due to sea ice recession, permafrost thaw and associated subsidence, and other climate and weather impacts.[233] The changing conditions affect energy exploration, development, and infrastructure for both potentially increased access to resources and more unpredictable work seasons and transportation conditions.

The United States has assumed the chairmanship of the Arctic Council and is proposing collaborative initiatives—including scientific research, national/regional security measures, trade policies, and others—for the council to implement. As transmission and storage facilities and vessels are employed increasingly to access Arctic energy resources, safety and spill and leak prevention standards or regulations also will need to be tailored to the region given its changing climate and harsh conditions. Additionally, increasing the amount of onsite renewable generation in remote areas will contribute to decreased fuel distribution needs.

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