OCS Study
BOEM 2022-076

Atlantic Fact Book Update: Onshore Infrastructure to Support Oil and Gas Development in the Atlantic OCS Region

US Department of the Interior
Bureau of Ocean Energy Management
New Orleans Office

BOEM Bureau of Ocean Energy Management | ESP Environmental Studies Program

AUTHENTICATED U.S. GOVERNMENT INFORMATION GPO

OCS Study
BOEM 2022-076

Atlantic Fact Book Update: Onshore Infrastructure to Support Oil and Gas Development in the Atlantic OCS Region

Authors

D. E. Dismukes

November 2022

Prepared under BOEM Obligation
140M0119C008
by
Acadian Consulting Group
5800 One Perkins Place Dr.
Suite 5-F
Baton Rouge, Louisiana 70808

Published by

US Department of the Interior
Bureau of Ocean Energy Management
New Orleans Office

DISCLAIMER

Study concept, oversight, and funding were provided by the US Department of the Interior, Bureau of Ocean Energy Management (BOEM), Environmental Studies Program, Washington, DC, under Contract Number 140M0119C0008 with Acadian Consulting Group (Baton Rouge, Louisiana). This report has been technically reviewed by BOEM, and it has been approved for publication. The views and conclusions contained in this document are those of the authors and should not be interpreted as representing the opinions or policies of the US Government, nor does mention of trade names or commercial products constitute endorsement or recommendation for use.

REPORT AVAILABILITY

To download a PDF file of this report, go to the US Department of the Interior, Bureau of Ocean Energy Management Data and Information Systems webpage (http://www.boem.gov/Environmental-Studies-EnvData/), click on the link for the Environmental Studies Program Information System (ESPIS), and search on 2022-076. The report is also available at the National Technical Reports Library at https://ntrl.ntis.gov/NTRL/.

CITATION

Dismukes D (Acadian Consulting Group, Baton Rouge, LA). 2022. Atlantic Fact Book update: onshore oil and gas infrastructure to support development in the Atlantic Outer Continental Shelf region. New Orleans (LA): US Department of the Interior, Bureau of Ocean Energy Management. 528 p. Contract No.: 140M0119C0008. Report No.: BOEM 2022-076.

ABSTRACT

This report examines the wide range of energy infrastructure assets that would be required if the Outer Continental Shelf (OCS) of the Atlantic region were opened to oil and gas production. It is a snapshot in time using the most up-to-date information available as of December 2019 and does not include any data related to the temporary impacts of the ongoing COVID-19 pandemic. The report does not explore any testable hypotheses or other complex research questions, but merely describes, examines, and outlines the nature of a variety of different, yet important, energy infrastructure assets and their current status within the Atlantic region. This report examines these infrastructure assets' recent development trends and their outlook given ongoing and expected offshore oil and natural gas exploration and production (E&P) activities.

This report examines twelve major energy infrastructure categories significant to development in the Atlantic OCS region, including: platform fabrication and shipyards; port facilities; support and heliport facilities; oil spill response; oil field waste disposal; pipe coating yards; natural gas processing and storage; liquefied natural gas (LNG) facilities; refineries; petrochemical facilities; electric power infrastructure; and intermodal transportation.

The report identifies and describes each type of onshore infrastructure that would potentially support OCS oil and gas projects in the Atlantic region. This includes an examination of the infrastructure, its unique features and how it is related to the oil and gas industry. Each type of infrastructure is inventoried and analyzed. A summary of the infrastructure type locations, operations, and capacities is provided. A list of existing facilities with descriptive statistics is provided in an accompanying project database. A discussion of potential infrastructure responses is included within each chapter, including a review of changes or additions to existing infrastructure to adapt to new development trends.

For purposes of this fact book, the Atlantic impact region is defined as the states along the East coast of the US from Maine, south to Florida. The states included, from north to south, are: Maine, New Hampshire, Connecticut, Rhode Island, New York, Pennsylvania, New Jersey, Delaware, Maryland, Pennsylvania, Virginia, North Carolina, South Carolina, Georgia, and Florida.

Contents

Contents **5**

List of Figures **10**

List of Tables **18**

Summary **20**

1. ....Introduction **21**

1.1 Overview 21

1.2 Data, Sources, and Methods Used to Evaluate Supporting Infrastructure 22

2. ....Platform Fabrication and Shipyards **24**

2.1 Description of the Industry and Services Provided 24

2.1.1 Overview of Platform Fabrication 24

2.1.2 Overview of Shipyards 25

2.2 Typical Facility Characteristics 26

2.2.1 Platform Fabrication 26

2.2.2 Shipyards 34

2.3 Geographic Distribution 36

2.3.1 Platform Fabrication 36

2.3.2 Shipyards 37

2.4 Scope of Economic Contribution to Regional Economy 41

2.5 Current Trends 47

2.5.1 Regulatory Changes 47

2.5.2 Trends 48

2.6 Outlook 56

2.6.1 Platform Fabrication 56

2.6.2 Shipyards 57

2.6.3 Factors Impacting East Coast Development 59

3. ....Ports **66**

3.1 Description of the Industry and Services Provided 66

3.2 Typical Facility Characteristics 67

3.3 Geographic Distribution 72

3.4 Scope of Economic Contribution to Regional Economy 74

3.5 Current Trends 92

3.5.1 Dredging of Shipping Channels 92

3.5.2 Declining Domestic Waterborne Commerce 94

3.6 Current Outlook 96

3.6.1 Offshore wind Development and Production 96

3.6.2 Automation 101

3.6.3 Continued Dredging of Shipping Channels 102

3.6.4 Factors Impacting Atlantic Coast Development 103

4. ....Support and Heliport Facilities **105**

4.1 Description of the Industry and Services Provided 105

4.2 Typical Facility Characteristics 106

4.2.1 General Support Facilities 106

4.2.2 Repair and Maintenance Yards 106

4.2.3 Supply Bases 107

4.2.4 Heliports 107

4.2.5 Crew Services 108

4.2.6 Offshore Support Vessels 109

4.2.7 Existing Infrastructure in the Atlantic Region 111

4.3 Geographic Distribution 116
4.3.1 Heliports 116
4.3.2 Other Support Facilities 119
4.4 Scope of Economic Contribution to Regional Economy 121
4.5 Current Trends 121
4.5.1 Trends 121
4.5.2 Outlook 122
4.5.3 Regulatory Changes 123
4.6 Current Outlook 124
4.6.1 Factors Impacting East Coast Development 124
5. ....Oil Spill Response 126
5.1 Description of the Industry and Services Provided 126
5.1.1 Federal Oversight 126
5.1.2 Historical Oil Spills 128
5.2 Typical Facility Characteristics 129
5.2.1 Contingency Planning 130
5.2.2 Common Remediation Methods 132
5.3 Geographic Distribution 138
5.4 Scope of Economic Contribution to Regional Economy 139
5.5 Current Trends 146
5.5.1 Decline in Frequency and Magnitude of Oil Spills 146
5.6 Current Outlook 150
5.6.1 Factors impacting East Coast Development 150
6. ....Oil Field Waste Disposal 151
6.1 Description of the Industry and Services Provided 151
6.2 Typical Facility Characteristics 152
6.2.1 Waste Minimization 152
6.2.2 Reuse and/or Recycle 154
6.3 Geographic Distribution 158
6.4 Current Trends 159
6.4.1 Environmental Impacts 160
6.4.2 Regulatory Changes 162
6.5 Current Outlook 165
6.5.1 Environmental Outlook 165
6.5.2 Offshore Wind 166
7 .....Pipe Coating 167
7.1 Description of the Industry and Services Provided 167
7.2 Typical Facility Characteristics 167
7.2.1 Coatings 168
7.2.2 Cathodic Protection 169
7.3 Geographic Distribution 170
7.4 Scope of Economic Contribution to Regional Economy 172
7.5 Current Trends and Outlook: Industry 173
7.5.1 Regulatory Changes 173
7.5.2 Trends 175
7.5.3 Outlook 176
7.6 Current Trends and Outlook: East Coast 176
7.6.1 Trends 176
7.6.2 Outlook 176
7.7 Factors Impacting East Coast Development 179

8. Natural Gas Processing **and Storage** **181**
8.1 Description of the Industry and Services Provided 181
8.1.1 Natural Gas Processing 181
8.1.1 Natural Gas Storage 184
8.2 Typical Facility Characteristics 185
8.2.1 Natural Gas Processing 185
8.3.2 Natural Gas Storage 187
8.3 Geographic Distribution 190
8.3.1 Natural Gas Processing 190
8.3.2 Natural Gas Storage 192
8.4 Scope of Economic Contribution to Regional Economy 193
8.4.1 Natural Gas Processing 193
8.4.2 Natural Gas Storage 200
8.5 Current Trends 206
8.5.1 Natural Gas Processing 206
8.5.1 Natural Gas Storage 209
8.5.3 Market Trends 212
8.6 Current Outlook 216
8.6.1 Factors Impacting Atlantic Coast Development 221
9. ....Liquefied Natural Gas 222
9.1 Description of the Industry and Services Provided 222
9.2 Typical Facility Characteristics 224
9.3 Geographic Distribution 230
9.4 Scope of Economic Contribution to Regional Economy 237
9.5 Current Trends 238
9.6 Current Outlook 242
9.6.1 Factors Impacting East Coast Development 246
10. Refineries 252
10.1 Description of the Industry and Services Provided 252
10.2 Typical Facility Characteristics 253
10.3 Geographic Distribution 257
10.4 Scope of Economic Contribution to Regional Economy 260
10.5 Current Trends 267
10.5.1 Capacity Flows 268
10.5.2 Regulatory Changes 270
10.5.3 Fluctuating Crude Oil and Refined Product Prices 272
10.5.4 Refined Product Demand 273
10.5.5 Alternative Fuels Standards 275
10.5.6 Exports 280
10.6 Current Outlook 281
10.6.1 Energy Export Opportunities 282
10.6.2 Emerging Transportation Technologies 283
10.6.3 Public Policies Curtailing Fossil Fuel Use 286
10.6.4 Factors Impacting East Coast Development 287
11. Petrochemical Plants 288
11.1 Description of the Industry and Services Provided 288
11.1.1 Primary Petrochemicals 289
11.1.2 Supply Chain 290
11.2 Typical Facility Characteristics 296
11.3 Geographic Distribution 297
11.3.1 Petrochemical Facilities in the Study Area 297

11.4 Scope of Economic Contribution to Regional Economy 299
11.5 Current Trends 301
11.5.1 Gross Domestic Product 301
11.5.2 Employment 303
11.5.3 Regulatory Changes 305
11.6 Current Outlook 306
11.6.1 Industry Outlook 306
11.6.2 Factors Impacting East Coast Development 306
12. ..Electric Power 309
12.1 Description of the Industry and Services Provided 309
12.2 Typical Facility Characteristics 310
12.3 Geographic Distribution 313
12.3.1 Generation 313
12.3.2 Transmission 315
12.3.3 Distribution 316
12.4 Scope of Economic Contribution to Regional Economy 319
12.5 Current Trends 324
12.5.1 Regulatory Trends 324
12.5.2 Generation and Consumption Trends 327
12.5.3 Transmission and Distribution Trends 331
12.6 Outlook 332
12.6.1 Generation and Consumption Outlook 332
12.6.2 Transmission and Distribution Outlook 334
12.6.3 Factors Impacting East Coast Development 335
13. ..Intermodal Transportation 341
13.1 Description of the Industry and Services Provided 341
13.2 Pipelines 341
13.1.2 Rail and/or Train 342
13.1.3 Trucking 342
13.1.4 Marine Ships and/or Barges 343
13.1.5 Natural Gas Market Hubs 344
13.1.6 Import and Export Terminals 346
13.2 Typical Facility Characteristics 346
13.2.1 Pipelines 346
13.2.2 Rail and/or Train 348
13.3.3 Trucking 349
13.3.4 Marine Ships and/or Barges 350
13.3.5 Natural Gas Market Hubs 353
13.3.6 Import and Export Terminals 355
13.3 Geographic Distribution 356
13.3.1 Pipelines 356
13.3.2 Rail and/or Train 359
13.3.3 Trucking 361
13.3.4 Marine Ships and/or Barges 363
13.3.5 Natural Gas Market Hubs 365
13.3.6 Import and Export Terminals 366
13.4 Scope of Economic Contribution to Regional Economy 368
13.4.1 Pipelines 368
13.4.2 Rail and/or Train 376
13.5 Current Trends 376
13.5.1 Regulatory Changes 376
13.5.2 Trends 378
13.6 Current Outlook 392

13.6.1 Factors Impacting East Coast Development 396
14. ..Conclusion 398
14.1 Fabrication Yards 398
14.2 Shipyards and Shipbuilding 398
14.3 Port Facilities 399
14.4 Support and Heliport Facilities 399
14.5 Oil Spill Response 400
14.6 Waste Management Facilities 400
14.7 Pipe-coating Yards 400
14.8 Natural Gas Processing Facilities 400
14.9 Natural Gas Storage Facilities 400
14.10 Liquified Natural Gas Facilities 401
14.11 Refineries 401
14.12 Petrochemical Facilities 401
14.13 Electric Power Infrastructure 401
14.14 Intermodal Transportation 402
References 403

List of Figures

Figure 1. Gulf Island Fabrication main yard. 26
Figure 2. Royal Dutch Shell, construction of the Appomattox drilling platform. 27
Figure 3. Drilling barge, Maersk Drilling. 28
Figure 4. Jack-up rig, Heimdal. 29
Figure 5. Submersible rig, Noble Joe Alford. 29
Figure 6. Semisubmersible rig, *Transocean Encourage*. 30
Figure 7. Drill ship, *Maersk Voyager*. 31
Figure 8. Fixed, floating, and subsea production systems. 32
Figure 9. Location of Atlantic region shipyards. 38
Figure 10. Newport News shipyard, Newport News, Virginia. 39
Figure 11. Philly Shipyard, Philadelphia, Pennsylvania. 40
Figure 12. Chesapeake Shipbuilding, Salisbury, Maryland. 40
Figure 13. Atlantic region ship and boat building employment shares, 2018. 43
Figure 14. Trends in Atlantic region ship and boat building employment, 2009-2018. 43
Figure 15. Atlantic region ship and boat building wage shares, 2018. 45
Figure 16. Trends in Atlantic region ship and boat building wages, 2009–2018. 45
Figure 17. Trends in Atlantic region ship and boat building average annual wage, 2009–2018. 47
Figure 18. Independence Hub. 50
Figure 19. Commercial shipbuilding order history (through 2004). 54
Figure 20. Atlantic OCS offshore wind leases. 61
Figure 21. Offshore wind supply chain contracts cumulative CAPEX Forecast. 63
Figure 22. *Pacific Orca* wind turbine installation vessel. 65
Figure 23. Principle commodity groups carried by water, 2007–2016. 67
Figure 24. Number of cranes at Atlantic ports. 69
Figure 25. Dry bulk terminal flow. 70
Figure 26. Container terminal flow. 71
Figure 27. Liquid bulk terminals. 72
Figure 28. Atlantic region water transportation GDP shares, 2017. 76
Figure 29. Trends in Atlantic region water transportation GDP, 1997–2017. 77
Figure 30. Atlantic region water transportation employment, 2018. 79
Figure 31. Trends in Atlantic region water transportation employment, 2009–2018. 80
Figure 32. Atlantic region water transportation wage shares, 2018. 82
Figure 33. Trends in Atlantic region water transportation wages, 2009–2018. 83
Figure 34. Trends in Atlantic region water transportation average annual wages, 2009–2018. 85
Figure 35. Atlantic region ports employment, 2018. 87
Figure 36. Trends in Atlantic region ports employment, 2009–2018. 87
Figure 37. Atlantic region ports wage shares, 2018. 89
Figure 38. Trends in Atlantic region ports wages, 2009–2018. 90

Figure 39. Trends in Atlantic region ports average annual wages, 2009–2018. 92
Figure 40. Historical growth of container vessels. 93
Figure 41. US waterborne commerce, 2008–2016. 94
Figure 42. Atlantic waterborne commerce, 2008–2016. 95
Figure 43. Atlantic waterborne commerce vs. US waterborne commerce (2008–2016). 95
Figure 44. Percentage Change in Tons Carried, (1960–2014). 96
Figure 45. State offshore wind targets (as of 2019). 97
Figure 46. Atlantic offshore wind projects and lease areas (as of 2020). 98
Figure 47. Atlantic OSW wind targets. 99
Figure 48. Automated port facilities. 101
Figure 49. Sikorsky S-92 Helicopter. 107
Figure 50. Accommodation barge with helipad. 109
Figure 51. *Pacific Harrier*: a Swire Pacific offshore platform supply vessel. 110
Figure 52. A diver secures a pipeline with a riser clamp. 112
Figure 53. Sacrificial anodes mounted on a metal jacket structure. 113
Figure 54. Lightering of the M/V *Montrose*. 114
Figure 55. *Delta Amber* after its recovery by RESOLVE Marine Group. 115
Figure 56. DelDOT Helistop. 117
Figure 57. Heliports and estimated range, North Atlantic Region. 118
Figure 58. Heliports and estimated range, Mid-Atlantic Region. 118
Figure 59. Heliports and estimated range, South Atlantic region. 119
Figure 60. Other support facilities, North and Mid-Atlantic regions. 120
Figure 61. Other support facilities, Southeast Atlantic region 120
Figure 62. The Alseamar SeaExplorer glider. 122
Figure 63. National response system concepts. 127
Figure 64. Regional response teams. 128
Figure 65. Largest oil spills affecting US waters (1969–2017). 129
Figure 66. In situ burning at the 2010 *Deepwater Horizon* spill. 132
Figure 67. In situ burning at a crude oil spill. 133
Figure 68. In situ burning at a crude oil spill. 134
Figure 69. Aerial application of dispersants, 2010 *Deepwater Horizon* spill. 135
Figure 70. Oleophilic skimmers. 136
Figure 71. Weir skimmers. 137
Figure 72. Skimmers used during the 2010 *Deepwater Horizon* spill. 137
Figure 73. Types of sorbents. 138
Figure 74. Atlantic region remediation employment shares, 2018. 141
Figure 75. Trends in Atlantic region remediation employment, 2009–2018. 142
Figure 76. Atlantic region remediation wage shares, 2018. 143
Figure 77. Trends in Atlantic region remediation wages, 2009–2018. 144
Figure 78. Trends in Atlantic region remediation average annual wages, 2009–2018. 146

Figure 79. US petroleum oil spill incidents (1995–2018). 147
Figure 80. US petroleum oil spill spilled (1995–2018). 148
Figure 81. US petroleum oil spill spilled (1995–2018). 149
Figure 82. Oil tanker spills (1970–2019). 150
Figure 83. Advanced drilling techniques. 153
Figure 84. Schlumberger coil tubing 153
Figure 85. Oil Field Waste Disposal Facilities 158
Figure 86. Water Stress Map 161
Figure 87. Pipeline coating applied at installation site. 168
Figure 88. Atlantic impact region pipe coating facilities. 170
Figure 89. Liberty coating storage yard. 171
Figure 90. Plural component spray rig. 172
Figure 91. Components of natural gas. 182
Figure 92. Natural gas production, gathering and processing. 183
Figure 93. Natural gas processing schematic. 184
Figure 94. Natural gas production and delivery. 184
Figure 95. Types of underground natural gas storage facilities. 187
Figure 96. The solution mining process. 190
Figure 97. Concentration of natural gas processing plants across the United States. 191
Figure 98. Atlantic region oil and gas extraction GDP shares, 2017. 195
Figure 99. Trends in oil and gas extraction GDP, 2010–2017. 195
Figure 100. Trends in Atlantic region oil and gas extraction employment, 2009–2018. 197
Figure 101. Trends in Atlantic region oil and gas extraction wages, 2009–2018. 198
Figure 102. Trends in the Atlantic Region oil and natural gas extraction Average Annual wages shares, 2009–2018. 200
Figure 103. Atlantic region Pipeline Transportation GDP shares, 2017. 202
Figure 104. Pipeline Transportation GDP Trend, 2010–2017. 202
Figure 105. Trends in Atlantic region pipeline transportation employment, 2009–2018. 204
Figure 106. Trends in Atlantic region pipeline transportation wages, 2009–2018. 205
Figure 107. Trends in Atlantic region pipeline transportation average annual pay, 2009–2018. 206
Figure 108. US natural gas processing plants and capacity, 2012, 2014, and 2017. 207
Figure 109. Change in US natural gas processing capacity, 2014–2017. 208
Figure 110. Natural gas volume processed, Atlantic Region and US. 208
Figure 111. Natural gas volume processed by state, 2008 compared to 2018. 209
Figure 112. US Natural gas storage working gas capacity, 2008–2018. 210
Figure 113. Atlantic states natural gas storage working gas capacity trend, 2008–2018. 212
Figure 114. NGL production trend, 2010–2019. 213
Figure 115. Chemical industry investments from shale gas, cumulative. 214
Figure 116. Trend of US export of NGLs. 214
Figure 117. Natural gas spot price and NGL composite price. 215

Figure 118. US natural gas price trends. 216
Figure 119. Dry natural gas production by type. 217
Figure 120. US natural gas demand forecast, by sector. 218
Figure 121. Initial US LNG terminals and original capacity. 223
Figure 122. LNG supply chain. 225
Figure 123. Receiving terminal: LNG gas flow. 226
Figure 124. Adriatic LNG terminal. 227
Figure 125. Buoy used for LNG regasification. 228
Figure 126. Floating storage and regasification unit at the Northeast Gateway Deepwater Port. 228
Figure 127. Floating liquefied natural gas vessel. 229
Figure 128. Shell's FLNG, *Prelude*. 230
Figure 129. Onshore US LNG facilities. 231
Figure 130. Onshore Northeastern US LNG facilities. 232
Figure 131. Existing North American LNG import terminals as of March 2020. 233
Figure 132. Everett, MA LNG terminal. 234
Figure 133. Cove Point liquid natural gas facility. 235
Figure 134. Elba Island liquid natural gas facility. 236
Figure 135. US natural gas imports as a percent of total consumption, 1990–2019. 238
Figure 136. LNG imports and natural gas price. 239
Figure 137. Total US natural gas marketed production and natural gas imports. 239
Figure 138. Existing North American LNG export terminals as of March 2020. 240
Figure 139. US natural gas reserves and exports. 241
Figure 140. LNG exports by exit point, 2019. 242
Figure 141. Total world energy growth by fuel type, 2018-2035. 243
Figure 142. Historic and projected LNG exports by top four countries, 2014–2024. 243
Figure 143. Approved North American LNG export terminals. 244
Figure 144. World CO_2 emissions by top ten countries, 2018. 245
Figure 145. Share of total world consumption by fuel type, 2018–2035. 245
Figure 146. Marcellus and Utica shale formation map. 246
Figure 147. Dry shale gas production by shale play. 247
Figure 148. Location of proposed New Jersey LNG terminal. 248
Figure 149. LNG bunkering by ship and shoreside facility. 249
Figure 150. ENSIS offshore wind installation vessel. 251
Figure 151. Products made from a barrel of crude oil (Percentage of Yield). 253
Figure 152. US Imports of Heavy Crude Oil, 2009–2018. 254
Figure 153. Distillation process and yield schematic. 255
Figure 154. Number and capacity of US refineries, as of January 1, 2019. 257
Figure 155. Study area refineries. 258
Figure 156. Regional refinery value-added (GDP) contributions, 2017. 261
Figure 157. Trends in Atlantic region refining GDP. 262

Figure 158. Atlantic region refinery employment shares, 2018. 263
Figure 159. Trends in Atlantic region refinery employment, 2009–2017. 264
Figure 160. Atlantic region refinery wage shares, 2018. 265
Figure 161. Trends in Atlantic region refining wages, 2009–2017....266
Figure 162. Trends in Atlantic region refinery average annual wages, 2009–2017....267
Figure 163. PADD 1 Refineries. 268
Figure 164. US Refineries. 269
Figure 165. Historic trends in average operable capacity (PADD 1 v. US). 270
Figure 166. Average ownership shares. 270
Figure 167. EPA regulations, sulfur fuel specifications. 271
Figure 168. Monthly crude oil spot prices. 272
Figure 169. Monthly crude oil spot and retail gasoline prices. 273
Figure 170. US Gasoline prices and demand, 2010–2019. 274
Figure 171. Price of RINs, 2010–2019. 277
Figure 172: Ethanol as a Percentage of Finished Motor Gasoline. 278
Figure 173. US fuel ethanol industry plants and production capacity. 279
Figure 174. US fuel ethanol production. 279
Figure 175: US PEV Sales, 2011–2017. 280
Figure 176. Imports compared toxports, 2000–2018. 280
Figure 177. Domestic compared to International Price Differential. 281
Figure 178: Outlook: Net Crude Exports and Imports (2020–2030). 282
Figure 179: Outlook: Net Crude Exports and Imports (2020–2050). 283
Figure 180: Outlook: Net Crude Exports. 283
Figure 181: Outlook: Electric Vehicle Sales 284
Figure 182: All-Electric Vehicle Sales (2011–2019). 285
Figure 183: Outlook: Autonomous Vehicles 286
Figure 184: Bike-sharing and scooter-sharing the US. 286
Figure 185. Petrochemical manufacturing basics. 288
Figure 186. The relationships among feedstock and primary petrochemicals. 290
Figure 187. Relationship between feedstock and the primary petrochemicals. 291
Figure 188. Relationships among the primary petrochemicals and petrochemical intermediates and derivatives. 292
Figure 189. End-use products derived from petrochemicals. 293
Figure 190. Petrochemical intermediates: polyurethane and phenolic chain. 294
Figure 191. Petrochemical intermediates: polyurethane and phenolic chain. 295
Figure 192. Petrochemical supply chain. 296
Figure 193. Petrochemical plants in Delaware, southern New Jersey, and southeastern Pennsylvania. 298
Figure 194. Petrochemical plants in Pennsylvania and northern New Jersey. 299
Figure 195. Share of national real GDP in study area for chemical manufacturing industry and total GDP, 1997–2017. 302
Figure 196. Chemical manufacturing industry real GDP for study area and United States, 1997–2017. 303

Figure 197. Share of national employment in study area for chemical manufacturing industry and in total, 1998–2018. 304
Figure 198. Chemical manufacturing industry employment for study area and United States, 1998–2018. 305
Figure 199. Point Pleasant-Utica Shale map. 307
Figure 200. Electric power generation, transmission, and distribution. 310
Figure 201. US electric power industry net generation by fuel source, 2018. 311
Figure 202. Electric transmission: high voltage transmission and low voltage distribution. 312
Figure 203. Electricity restructuring by state. 313
Figure 204. Atlantic region's share of electric generation capacity, 2018. 314
Figure 205. North Atlantic planning area capacity by state and fuel type, 2018. 314
Figure 206. Mid and South Atlantic planning area capacity by state and fuel type, 2018. 315
Figure 207. Current North American Reliability Corporation regions. 316
Figure 208. Atlantic region's energy sales and customers by utility type. 317
Figure 209. North Atlantic region energy sales by state and type of utility. 317
Figure 210. North Atlantic region energy delivery by state and type of utility. 318
Figure 211. Mid- and South Atlantic region energy sales by state and type of utility. 318
Figure 212. Mid- and South Atlantic region energy delivery by state and type of utility. 319
Figure 213. Atlantic region electric power generation employment shares, 2018. 321
Figure 214. Trends in Atlantic region electric power generation employment, 2009–2018. 321
Figure 215. Atlantic region electric power generation wage shares, 2018. 323
Figure 216. Trends in Atlantic region electric power generation wages, 2009–2018. 323
Figure 217. Atlantic region net generation, coal. 327
Figure 218. US electric power generation by fuel type. 328
Figure 219. Atlantic region net generation, natural gas. 329
Figure 220. Atlantic region net generation, wind. 330
Figure 221. Annual energy outlook, capacity additions by fuel type. 330
Figure 222. Electric power consumption by customer class. 331
Figure 223. Utility spending on electricity. 331
Figure 224. Investment in transmission infrastructure by electric utilities. 332
Figure 225. Projected electric generation capacity in the US, 2019–2050. 333
Figure 226. Proposed renewable capacity by state, 2019–2023. 333
Figure 227. Proposed transmission projects on Atlantic Coast. 335
Figure 228. Length of lines of proposed transmission projects on Atlantic Coast. 335
Figure 229. Projected natural gas supply and price, 2019–2050. 336
Figure 230. Existing state renewable energy standards, 2019. 337
Figure 231. Atlantic region net generation, solar. 338
Figure 232. Planned solar capacity by Atlantic subregion. 339
Figure 233. Atlantic Wind Connection planned route. 340
Figure 234. Movement of natural gas by pipelines. 347
Figure 235. Non-jacketed, non-pressure tank car for rail oil transport. 348

Figure 236. Features of a standard tanker truck. 349
Figure 237. Articulated tug barge. 350
Figure 238. Tanker sizes and classes. 351
Figure 239. *Knock Nevis* ULCC tanker. 352
Figure 240. Generalized market hub operational schematic. 354
Figure 241. Marine export and import terminal. 355
Figure 242. US pipeline network and shale plays. 356
Figure 243. Major liquid pipelines between the US and Canada. 357
Figure 244. Interstate and intrastate natural gas pipelines in the US. 358
Figure 245. Petroleum product flows from Gulf Coast to East Coast. 358
Figure 246. Class I railroads in the US. 359
Figure 247. CSX crude oil network. 360
Figure 248. Crude oil rail terminals in the eastern US. 361
Figure 249. Major trucking routes by volume and traffic. 362
Figure 250. Route of Interstate 95. 363
Figure 251. Navigable waterways in the US. 364
Figure 252. Marine transportation of crude oil in the US. 365
Figure 253. Natural gas and HGL hubs in the Atlantic region. 366
Figure 254. Points of entry and exit of natural gas by pipeline and ship. 367
Figure 255. Petroleum ports in the Atlantic region. 368
Figure 256. Trends in Atlantic region pipeline transportation GDP, 1997–2017. 370
Figure 257. Trends in Atlantic region pipeline employment, 2009–2018. 372
Figure 258. Trends in Atlantic region pipeline wages, 2009–2018. 374
Figure 259. Trends in Atlantic region pipeline average annual wages, 2009–2018. 376
Figure 260. Petroleum Administration for Defense Districts regions in the US. 378
Figure 261. Total crude oil receipts and shipments to and from PADD 1, 2010–2019. 380
Figure 262. Total petroleum product receipts and shipments to and from PADD 1, 2010–2019. 380
Figure 263. Natural gas flow (MMcf/d) via pipeline between US regions, 2019. 381
Figure 264. Atlantic region's natural gas inflow by pipeline, 2010–2019. 382
Figure 265. Atlantic region's natural gas outflow by pipeline, 2010–2019. 382
Figure 266. Added capacity of completed natural gas pipeline projects in the Atlantic region, 1996–2019. 383
Figure 267. Total US crude oil movements by rail and PADD 1 crude oil receipts by rail, 2010–2019. 384
Figure 268. PADD 1 crude oil receipts by transportation mode, 2010–2019. 385
Figure 269. Rail traffic by commodity tonnage, 2017. 386
Figure 270. Real average annual coal transportation costs from state to state by railroad, 2008–2018. 386
Figure 271. Tons of crude petroleum moved by mode in the US, 2012–2018. 387
Figure 272. PADD 1 and total US crude oil refinery receipts by truck, 2010–2019. 388
Figure 273. PADD 1 petroleum products received via ship from PADD 2 and PADD 3, 2019. 388
Figure 274. Transportation fuel flows from Gulf Coast to East Coast. 389
Figure 275. PADD 1 refinery crude oil receipts by source and transportation method, 2009–2018. 390

Figure 276. PADD 1 crude oil and petroleum product exports by destination, 2010–2019. 391
Figure 277. Atlantic region exports, imports, and prices, 2009–2018.....392
Figure 278. Added capacity of historical and projected Atlantic region liquid pipeline projects, 2014–2022. 393
Figure 279. Added capacity of historical and projected Atlantic region natural gas pipeline projects, 2010–2023. 394
Figure 280. Projected natural gas consumption in the Atlantic region and US, 2019–2050. 395
Figure 281. Projected East Coast natural gas and crude oil production, 2019–2050. 396
Figure 282. Wind turbine transportation. 397

List of Tables

Table 1. Atlantic region shipyards and repair yards 37
Table 2. Regional and national employment contribution, ship and boat building, 2018 42
Table 3. Regional and national wage contribution, ship and boat building, 2018 44
Table 4. Regional and national average annual wage contribution, ship and boat building, 2018 46
Table 5. Deliveries by US shipyards, by type of vessel, 2010–2014. 55
Table 6. Number of container terminals at select Atlantic ports 68
Table 7. Air draft restrictions of Atlantic ports 69
Table 8. Principle Ports in the Atlantic region (Tonnage > 5 million tons) 73
Table 9. Principle Ports in the Atlantic region (Tonnage < 5 million tons) 74
Table 10. Regional and national GDP contributions, water transportation sector, 2017 75
Table 11. Regional and national employment contribution, water transportation sector, 2018 78
Table 12. Regional and national wage contribution, water transportation sector, 2018 81
Table 13. Regional and national average annual wage contribution, water transportation, 2018 84
Table 14. Regional and national employment contribution, ports sector, 2018 86
Table 15. Regional and national wage contribution, ports sector, 2018 88
Table 16. Regional and national average annual wage contribution, ports, 2018 91
Table 17. Channel dredging along the Atlantic Coast 102
Table 18. Marine Spill Response Corporation: Atlantic region operating capabilities 139
Table 19. Regional and national employment contribution, remediation sector, 2018 140
Table 20. Regional and national wage contribution, remediation sector, 2018 142
Table 21. Regional and national average annual wage contribution, remediation, 2018 145
Table 22. Summary of US offshore requirements for drilling wastes 155
Table 23. Federal laws governing waste materials and management activities 162
Table 24. Examples of exempt and nonexempt exploration and production waste streams 164
Table 25. Atlantic impact region pipe coating facilities 171
Table 26. Miles of cast and/or wrought iron gas distribution mains in Atlantic states, 2009–2018 178
Table 27. Miles of bare steel gas distribution mains in Atlantic states, 2009–2018 178
Table 28. Characteristics of natural gas storage facilities 187
Table 29. US natural gas processing plants and capacity 192
Table 30. Underground natural storage by region, 2018 193
Table 31. Regional and national GDP contribution, and gas extraction sector, 2017 194
Table 32. Regional and national employment contribution, oil and gas extraction sector, 2018 196
Table 33. Regional and national wages contribution, oil and gas extraction sector, 2018 197
Table 34. Regional and national Average Annual Pay contribution, Oil and Gas Extraction sector, 2018 199
Table 35. Regional and national GDP contributions, pipeline transportation sector, 2017 200
Table 36. Regional and national employment contributions, Pipeline Transportation sector, 2018 203
Table 37. Regional and national wage contributions, pipeline transportation sector, 2018 204
Table 38. Regional and national average annual pay contributions, Pipeline Transportation sector, 2018 205

Table 39. US natural gas storage working gas capacity by state, 2018 211
Table 40. NGL Pipeline capacity added by region (MMBbl per day) 219
Table 41. Projected annual CAPEX by region and category, through 2035 (Million 2016 $) 220
Table 42. Estimated number of employees by LNG facility 237
Table 43. Top 20 US Container Ports (2017) and Nearby LNG Terminals 250
Table 44. Study area refineries as of January 2019 258
Table 45. Regional and national value-added (GDP) contribution, refinery sector, 2017 260
Table 46. Regional and national employment contribution, refinery sector, 2018 262
Table 47. Regional and national wages contribution, refinery sector, 2018 264
Table 48. Regional refinery and national average annual wage comparisons, 2017 266
Table 49. PADD 1 Shipments, 2014–2018 281
Table 50. Petrochemical plants in study area. 298
Table 51. National employment figures for top ten occupations in the chemical manufacturing industry as of May 2019. 300
Table 52. Median annual earnings for major occupations in the chemical manufacturing industry as of May 2019. 301
Table 53. Projected employment and output across all industries and in the chemical manufacturing industry. 306
Table 54. Regional and national employment contribution, electric power generation, 2018 320
Table 55. Regional and national wage contribution, electric power generation, 2018 322
Table 56. Regional and national average annual wage contribution, electric power generation, 2018 324
Table 57. Regional and national GDP contributions, pipeline transportation sector, 2017 369
Table 58. Regional and national employment contribution, pipeline sector, 2018 371
Table 59. Regional and national wage contribution, pipeline sector, 2018 373
Table 60. Regional and national average annual wage contribution, pipeline sector, 2018 375
Table 61. Crude oil inter-PADD pipeline movements, thousands of barrels, 2019 379
Table 62. Petroleum products inter-PADD pipeline movements, thousands of barrels, 2019 379

Summary

This fact book provides an examination of a wide range of energy infrastructure assets that would be required if the Outer Continental Shelf (OCS) of the Atlantic region were opened to offshore oil and gas exploration and production. It is a snapshot in time using the most up-to-date information available as of December 2019 and does not include any data related to the temporary impacts of the ongoing COVID-19 pandemic. The infrastructure categories examined include: platform fabrication and shipyards; port facilities; support and heliport facilities; oil spill response; oil field waste disposal; pipe coating yards; natural gas processing and storage; liquefied natural gas (LNG) facilities; refineries; petrochemical facilities; electric power infrastructure; and intermodal transportation.

A number of issues and topics have been examined for each of these sectors, including:

- A basic description of the industry and the types of services that type of infrastructure provides.
- A review of each infrastructure category's characteristics and an overview of the typical facilities in each category.[1]
- The geographical distribution of existing companies and infrastructure locations within the Atlantic region.
- The impact or scope of existing infrastructure relative to the regional Atlantic seaboard economy.
- Current industry trends associated with each infrastructure category, how those trends compare with those in the oil and gas industry, and how those trends translate into infrastructure development and maintenance in the Atlantic region.
- Current industry outlooks for each infrastructure category in general, and in the Atlantic region with an additional analysis of the potential changes in regulation and regulatory guidelines governing each industry sector.
- A discussion of factors that would impact development of each infrastructure type in the Atlantic region.
- A list of resources and data sources for each type of infrastructure.

For purposes of this fact book, the Atlantic impact region is defined as the states along the East coast of the US from Maine, south to Florida. The states included are: Maine, New Hampshire, Connecticut, Rhode Island, New York, Pennsylvania, New Jersey, Delaware, Maryland, Pennsylvania, Virginia, North Carolina, South Carolina, Georgia, and Florida.

[1] This is not a regionally specific overview, but rather a review of the types of facilities that exist within the industry.

1. Introduction

1.1 Overview

Offshore oil and activity in the US is commonly dated to 1947 when Kerr McGee, an Oklahoma independent oil and gas company, drilled the first well out of the sight of land along the Gulf of Mexico (GOM). Subsequently, activity increased dramatically, particularly in what was considered state waters as an increasing number of oil and gas operators attempted to develop what appeared to be larger scale and more profitable hydrocarbon reserves. Since that time, oil and gas exploration, development, and production has been vibrant along the GOM. In contrast, the Atlantic Outer Continental Shelf (OCS) is an untapped region with no active offshore oil and gas activities.

Over the past five years, there has been a massive development of support facilities, ports, roads, pipelines, and processing stations dedicated to supporting offshore drilling and production in the GOM. The supporting infrastructure in the GOM region is an invaluable link connecting these important energy resources with North American markets because within offshore oil and gas exploration, even a moderate disruption of any infrastructure link can have far-reaching impacts and can weaken other operations along the entire chain. The purpose of this fact book is to assist BOEM in identifying the existing onshore infrastructure resources that could support OCS oil and gas projects in the Atlantic region. Additionally, this fact book outlines the regulatory and economic considerations relevant to each type of infrastructure. The examination focuses on the 15 Atlantic coastal states that stretch from Maine to Florida.

In 2014 BOEM sponsored an earlier version of this project to address each of the above-listed issues, and this fact book is an important update on that original work. As in the previous fact book, ongoing trends and outlooks for each of the infrastructure categories and sectors have been examined. However, two new chapters have been added to this fact book (petrochemical plants and intermodal transportation) that had not been included in the previous effort.

Thus, 12 major infrastructure categories were identified for this study. These include:

- **Platform Fabrication and Shipyards:** (1) Facilities in which platforms are constructed and assembled for transportation to offshore areas. Facilities can also be used for maintenance and storage. (2) Facilities in which ships, drilling platforms, and crew boats are constructed and maintained.
- **Port Facilities:** Major maritime staging areas for movement between onshore industries and infrastructure classifications and offshore leases.
- **Support Facilities:** Facilities and services that could be used to support the offshore activities. This includes repair and maintenance yards, supply bases, crew services, and heliports.
- **Oil Spill Response:** Facilities that are capable of assisting in the response and mitigation of oil spills.
- **Oil Field Waste Disposal Facilities:** Sites that process drilling and production wastes associated with oil and gas activities.
- **Pipe Coating Yards:** Sites that condition and coat pipelines used to transport oil and gas from offshore production locations.
- **Natural Gas Processing and Storage Facilities:** Sites which process natural gas and separate its component parts for the market, and sites that store processed natural gas for use during peak periods.

- **Liquefied Natural Gas:** Facilities that take super-cooled natural gas produced in other regions of the world, and raise the temperature through various vaporization processes, to inject into regional natural gas storage and/or transportation assets. These assets can also be thought of as special natural gas import facilities.
- **Refineries:** Industrial facilities that process crude oil into numerous end-use and intermediate use products.
- **Petrochemical Plants:** Industrial facilities that intensively use oil and natural gas, and their associated by-products, for fuel and feedstock purposes.
- **Electric Power:** A collection of infrastructure assets that include those that produce electricity (generation) and transmit and distribute the electricity to households and industry along the Atlantic.
- **Intermodal Transportation:** Infrastructure that is used to transport oil and gas from offshore facilities to onshore processing sites, and ultimately to end users.

The following chapters of this fact book discuss each of these critical infrastructure areas and their relationship with offshore oil and gas activities. Each chapter outlines:

- **Description of Industry and Services Provided:** Examines the infrastructure in question and provides a description of its unique features.
- **Typical Facility Characteristics:** Discusses the industry characteristics associated with the infrastructure under examination. Typical facilities and typical firms are also discussed.
- **Geographic Distribution:** Discusses the geographic distribution associated with the infrastructure under examination.
- **Scope of Economic Contribution to Regional Economy:** Discusses the economic impact or scope of existing infrastructure relative to the regional Atlantic seaboard economy.
- **Current Trends:** Examines the current trends of infrastructure development in the Atlantic.
- **Current Outlook:** Examines the outlook of infrastructure development in the Atlantic.

1.2 Data, Sources, and Methods Used to Evaluate Supporting Infrastructure

A variety of different data sources have been used to examine energy infrastructure in the GOM region. A full list of these sources has been included in the references section. In general, the following sources have been consulted:

- Data series regularly collected by the US Department of Energy (DOE) that include refinery locations and capacities, oil and gas production, natural gas storage facilities, gas processing capabilities and electric power plants.
- Data published by the US Environmental Protection Agency (EPA) that includes locations of refineries, natural gas processing facilities, petrochemical plants and electric power plants.
- Data published by the Federal Aviation Administration (FAA) that include heliport facilities, ownership, and locations. Oil and gas production statistics collected and published by state utility and natural resource regulators like the Virginia Department of Mines Minerals and Energy.
- Industry associations like the American Association of Port Authorities; American Shipbuilding Association; the Gas Processors Association and the National Association of Pipe Coating Applicators.
- Commercial databases including Pennwell Mapsearch and IHS Energy's Major Industrial Plant Database (MIPD) that includes descriptive and location information about transportation pipelines and industrial facilities.

- Data published by Penwell's Oil & Gas Journal that include statistics on natural gas processing facilities.
- Data collected by the US Department of Transportation that includes ports, railroads, and highways.
- US Corps of Engineers data collected on the areas it regulates such as inland waterways, dredging of waterways, and concentrations of vessel traffic.
- US Geological Survey (USGS) maps; BOEM documents; and or the US Environmental Protection Agency records in order to identify latitude and longitude coordinates for each facility identified.
- News reports, trade press articles and research, independent research reports, individual company websites and press releases, and government press releases discussing or examining the status of critical energy infrastructure and their trends.

2. Platform Fabrication and Shipyards

2.1 Description of the Industry and Services Provided

This chapter examines the nature of oil platform fabrication facilities and shipbuilding manufacturing facilities which are important to offshore oil and gas exploration and production. The two industries–platform fabrication and shipbuilding–are closely related, and thus, each subsection of this chapter is divided across both sectors. Because the Atlantic region does not possess a significant footprint in such sectors, this chapter frequently references the nature of such industries along the Gulf of Mexico (GOM), where platform fabrication and shipbuilding manufacturing facilities have historically been based.

Section one of this chapter provides an overview of both industries, and section two examines the typical facility characteristics associated with both sectors. Section three of this chapter outlines the geographical distribution of manufacturing facilities, while section four examines the economic contribution of these sectors on the Atlantic region's economy. Finally, section 5 and section 6 focus on the current trends and forward-looking outlook for the sector.

2.1.1 Overview of Platform Fabrication

The early days of offshore oil and gas drilling and production began in the regions along and in the GOM. Oil and gas companies, and their locally contracted drilling crews, attempted a variety of techniques to overcome the environmental challenges of drilling in swamps, bayous, and bays, and ultimately offshore out of sight of land. The most successful methods used floating vessels or barges as a "base" or "platform" placing drilling equipment on top of the floating "platform" in order to traverse and operate over swamps, marshes, or open water. These relatively primitive methods, while functional, limited drilling to small areas over relatively shallow water and marshes that were protected from wind and wave exposure. These methods served as the base from which purpose-specific mobile drilling rigs were ultimately developed (Austin et al. 2008).

The world's first submersible oil platform, called *Giliasso*, was developed in 1933 and consisted of a barge that carried drilling equipment, a platform, and a derrick or rig. The first implementation of this design was towed and then sunk off the shore of Louisiana at a pre-determined location for use as a fixed foundation for the platform above water (Wilds et al. 1996). The development of *Giliasso* ended the task of assembling and dismantling units for every well (Davis 2002). However, new problems arose in determining how to provide support for crews and to receive supplies needed for drilling.

Giliasso's success helped spawn a number of other technological advances related to the modification of floating structures used for near-shore exploration and production activities and logistical support. Initially, drilling crews lived in piling-supported camps which were suspended over the marsh. These camps, or drilling staging areas, lacked any considerable above-ground storage space which required drilling mud to be hauled 35 miles (56 kilometers) to the drilling site (Davis 2002). When *Giliasso* was first deployed, rig workers solved the inherent storage problem by using three old grounded oil tankers and connecting them to an old steel schooner, which was used as a loading dock (Davis 2002). Eventually, a pipeline was constructed to the drilling location which ended the need for vessels to transport the oil onshore.

Starting in the 1990s, the industry began to push into deeper water depths, which led to new innovations, as this movement into deeper water also corresponds with being further away from shore. This movement into deeper water environments also led to significantly larger wells and drilling rigs, forcing fabrication yards, docks, and assembly facilities to adapt to the larger sizes and increased technological sophistication. Today, there are approximately 2,610 active leases in the GOM; 55 percent are in water depths greater than 1,000 meters and are considered “deepwater” (BOEM 2020 Feb 9).

The more recent emphasis into larger deepwater structures has also spawned a modular-based approach to fabrication. Some fabrication facilities along the GOM, for instance, specialize in constructing specific components or platform types. These yards can also team up with one another to produce required parts or individual modules. Even very large yards contract out for certain aspects of their platform projects. For example, a yard may focus on producing living quarters, decks, modules, or storage facilities. The modular based approach has created some interdependence among different yards, and yet still produces coherent and complete platforms (USDOI 2005 May 24).

2.1.2 Overview of Shipyards

In 1932 eight shipyards employed 19,000 workers along the Atlantic seaboard, all dedicated to meeting the varied needs of the federal government: Bath Iron Works (Bath, Maine); Bethlehem's Fore River Plant (Quincy, Massachusetts); Bethlehem's Union Iron Works (Sparrows Point, Maryland)); Electric Boat Co. (New London, Connecticut); Federal Shipbuilding (Kearny, New Jersey); New York Ship (Camden, New Jersey); Newport News Shipbuilding (Newport News, Virginia); and United Drydocks (Staten Island, New York) (Tyler Priest and Lajaunie 2014; Global Security c2019).

The Maritime Administration was created in 1936 by the Merchant Marine Act and was designed, in part, to assist in the organization of marine construction activity in the US The Maritime Commission that was created by this legislation began an extensive ship construction program towards the end of the 1930s that intensified with the US involvement in World War II (Lane et al. 2001). By the end of World War II, there were nine different federally owned and operated shipyards and over 130 privately-owned shipyards in the US (Global Security c2019).

The end of World War II reduced the need for extensive naval craft construction. The federal government, however, recognized that private shipyards were critical to US military and economic strength and pursued policies (such as the Jones Act) and other activities to assure private shipyard economic survival. By 1961, up to 70 percent of federal naval construction funding went to private yards (Global Security c2019). In addition, many of these Navy yards performed maintenance and repair functions. Since the 1960s, the shipbuilding industry has evolved into a group of small to medium-sized shipyards that build vessels for foreign, inland, and coastal waterway use; however, there are still some very large yards, some of which are in the GOM and Atlantic regions. The increase in offshore exploration and production activity in the GOM has helped to expand market demand and the number of customers for shipyards to serve (Austin et al. 2008).

Today, the federal government is the largest customer of the US shipbuilding industry, in large part because of the high demand for naval and marine craft. These naval ships range from large navy combatant construction (i.e., aircraft carriers, destroyers, frigates, guided missile cruisers, etc.) to noncombatant tankers, patrol ships, and smaller experimental craft used for ocean and marine life observation (USEPA 1997). Besides the US Navy, a number of other government agencies place orders for ships such as the Military Sealift Command, the Army Corps of Engineers, the US Coast Guard, the National Oceanic and Atmospheric Administration, the National Science Foundation, and the Maritime Administration (USEPA 1997). Shipyards in the Atlantic region focus almost exclusively on meeting federal government marine craft demand.

Shipyards in coastal areas make important contributions to offshore oil and gas operations since they host ship, barge, and other large vessel construction and repair activities. Marine vessels are an important and, in some instances, the primary means by which equipment and personnel are transported from onshore bases to offshore drilling and production locations. Most shipyards integrate their offshore oil and gas construction/maintenance activities with similar activities that may be conducted for towing and tugboat companies, petrochemical companies, commercial shipping companies, commercial fishing companies, passenger and cruise companies, ferry companies, and the federal government (Colton c2019).

2.2 Typical Facility Characteristics

2.2.1 Platform Fabrication

Platforms are constructed onshore at a fabrication yard or assembled from parts constructed in multiple places, and then towed to an offshore location for installation and sea-fastening. Fabrication yards perform a variety of functions including the cutting and welding of steel components, construction of living quarters and other structures, and assembling of platform components (Gulf Island Fabrication 2012). These facilities often span several hundred acres due to the construction requirements for these large offshore oil and gas-related construction projects. These fabrication yards also have considerable space requirements for the equipment and storage requirements associated with offshore facility and facility component construction. Specialized equipment and storage requirements include, but are not limited to, providing inventory for a large amount of metal pipes and beams in addition to space needed to house cranes, welding equipment, lifts, rolling mills, and sandblasting machinery. Since platform jackets are so large, vast space is also required for proper assembly.

The space needed for these fabrication and construction activities is shown in Figure 1, a picture of Gulf Island Fabrication's main yard in Houma, Louisiana. This is one of three yards owned by Gulf Island; it covers 140 acres and 2,800 linear feet (853 meters) of water frontage (Gulf Island 2012).

Figure 1. Gulf Island Fabrication main yard.

Source: (Gulf Island Fabrication c2020).

The pictures in Figure 2 emphasize the enormous size and magnitude of these fabrication yards and projects. These pictures portray the different stages of construction of Royal Dutch Shell's (Shell) *Appomattox* drilling platform. Spanning 29-stories high and two football fields wide, it is Shell's eighth and largest floating platform in the GOM (Shell 2019 Jan 25). The project began construction in 2015 in Geoje, South Korea, where Samsung Heavy Industries developed the hull, completing over 60% of the platform's fabrication (Offshore 2017 Aug 10; Freeman 2017 Oct 13). The hull was then transported to Ingleside, Texas in 2017, where the topsides of the platform, including living quarters, and subsea fabrication were added (Broadmoor, LLC c2018; Shell c2017). In 2019, *Appomattox* was completed, installed, and began production in the GOM in May of that year (Shell c2019).

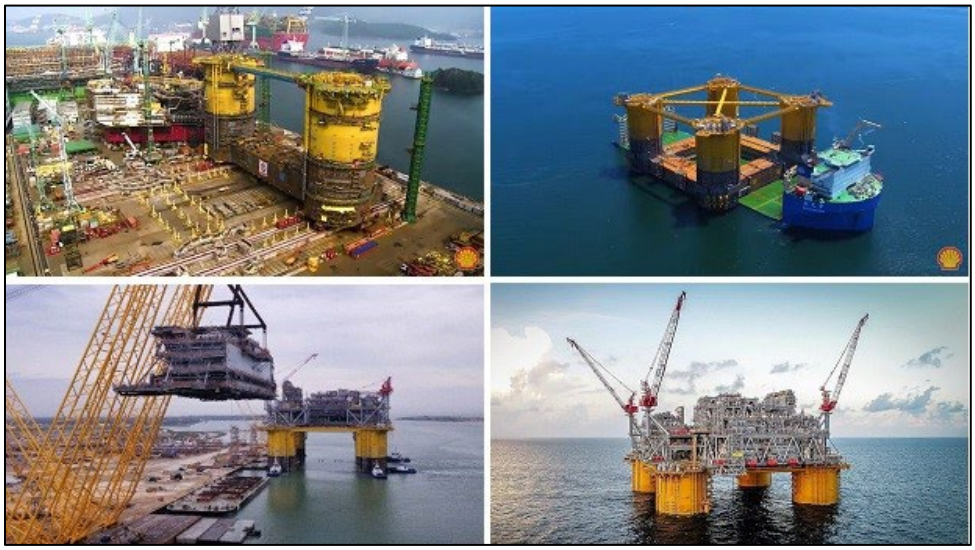

Figure 2. Royal Dutch Shell, construction of the Appomattox drilling platform.

Source: Hi-Tech Electric, Inc. and Shell Global (Hi-Tech Electric, Inc. c2020; Shell c2020).

Fabrication facilities do not work on an assembly-line approach like automotive manufacturing. Instead, these fabrication yards work on only a few projects at a time since each project is unique and can vary depending on the exact type of platform, platform characteristics, and the characteristics of the area where it will eventually be located. Often, oil and gas companies will split projects among several fabricators, contracting with different companies for different parts of the platform. For example, some yards produce jackets, and others specifically fabricate decks, living quarters, or piles (Gulf Island Fabrication 2012).

Many fabrication yards have common elements despite the often unique nature of the construction activities they conduct (Minerals Management Service 2007). Common fabrication yard characteristics include:

- steel stockyards and cutting shops to supply and shape steel for fabrication;
- shops to assemble components as they are completed: deck sections, jackets, modules, and tanks;
- paint and sandblasting shops;
- dry docks for repairs and construction, generally of small vessels;
- piers used for work on transportation equipment and platform components that are mobile; and
- shops specializing in pipe construction and welding.

Fabrication yards use a number of materials and supplies, but the most often used are steel plates, standard steel shapes, steel pipes, fuel, oil, gasoline, coatings, welding gases, and paints (Gulf Island Fabrication 2019).

Exploratory Rigs

Offshore activities require differing structures depending on a host of factors that can include location, water depth, anticipated production levels, and anticipated production characteristics. Over time, the industry has developed a variety of differing drilling craft that can be used for exploration and production activities. Five types of offshore rigs that are often used to drill wildcat or exploratory wells are summarized below.

Drilling barges are mostly used in inland, shallow waters in the GOM and are likely not candidates for offshore activities in federal waters that are three miles or more offshore. These barges or large floating platforms with drilling equipment are towed by tugboat to a drilling site often located in state waters, particularly along the GOM. A drilling barge is held in place with anchors, and are really only suitable for shallow, calm waters. The drilling barge shown in Figure 3 is used by Maersk Drilling on Lake Maracaibo in Venezuela which itself is a contained body of water. This drilling barge can operate in waters up to 120 feet (37 meters) and has a rated drilling depth of 20,000 feet (6,096 meters) (Maersk Drilling 2012).

Figure 3. Drilling barge, Maersk Drilling.

Source: (Maersk Drilling 2012).

Jack-up rigs are the most common type of drilling structure used in the GOM and in other coastal zones around the world. A jack-up rig is not self-propelled and is typically towed to a drilling location, at which point the three or four legs of the rig are lowered to the seabed. The lowering of the legs and the "jacking up" of the platform allows the working platform to stay above the surface of the water. Jack-ups are usually used in water depths of up to 400 feet (122 meters) of water, (although there are some specialized rigs that can operate in water depths of 550 to 600 feet [168 to 183 meters]) (Greenberg 2012 Jul; Diamond Offshore c2019). The jack-up rig shown in Figure 4 is the Heimdal, built by Singapore company Keppel Fels and delivered to Borr Drilling Limited in January 2020. It can operate at water depths of up to 400 feet (122 meters) and drilling depths of 30,000 feet (9,144 meters) (Borr Drilling c2020).

Figure 4. Jack-up rig, Heimdal.

Source: (Offshore Energy Today 2020 Jan 15).

Submersible rigs are one of the older forms of drilling vessels that are used for drilling activities, primarily in the GOM. Submersible rigs are the successors to the older floating structures like *Giliasso* discussed earlier. A submersible rig is not self-propelled; it is towed to a particular location and supported by large pontoon-like structures that are submerged below the water surface. Once the rig is positioned over the drill site, the air is evacuated from the pontoons, which in turn are filled with seawater, submerging (and securing) the rig to the sea floor. Because the rig must actually sit on the seafloor, submersibles only operate in shallow waters (Schlumberger 2012; and NaturalGas.org 2012a). Although no longer operational, the Noble Joe Alford submersible (Figure 5) was rated to water depths of 70 feet (21 meters) and could drill up to 25,000 feet (7,620 meters) (Noble Corp 2012).

Figure 5. Submersible rig, Noble Joe Alford.

Source: (Noble Corp 2012).

Semisubmersibles build off the structure of a submersible but do not rest on the sea floor. "Semi-subs," as they are often called, are also not self-propelled vessels and are towed to their drilling locations. The working deck of a semi-sub, like an older submersible, is mounted above its giant pontoons and hollow columns, or stilts. The pontoons are flooded with seawater and submerged but not to the full depth of the water column to the seafloor. However, a good part of the unit is underwater, leading to drilling stability (stabilized by the weight of the hull) that can be used in deep and rough waters. Semisubmersibles use an eight- or 12-point anchoring system to maintain their position. Most semi-subs today, particularly those operating in deeper waters, use dynamic positioning and GPS signals that are transmitted to computer-controlled motor-driven propellers (Diamond Offshore c2019). Semisubmersibles can operate in depths of 10,000 feet (3,050 meters) and are mainly used for drilling and production (Simpson c2018). The current world-record water depth for this type of platform is 9,472 feet (2,887 meters) set by a dynamic positions semi-sub in Brazil in 2003. In the same year, a semi-sub in the GOM set the water-depth world record for a "taut line" mooring system at 8,950 feet (2,730 meters) (Bai and Bai c2018). Another GOM semisubmersible, *Deepwater Horizon*, was the source of the world's largest accidental oil spill in 2010. *Transocean Encourage* is a newer semisubmersible drilling rig, shown in Figure 6, that was built in 2016 and contracted to Equinor until the end of 2023 (Transocean Ltd. 2019 Feb).

Figure 6. Semisubmersible rig, *Transocean Encourage*.

Source: (Transocean Ltd. 2018 Jan 30).

Drill ships are self-propelled seagoing vessels, or ships, that are outfitted with drilling equipment on the top, a derrick in the middle, and an opening called a "moon pool" through which to drill (NaturalGas.org 2013 Sep 22). Drill ships operate in water depths of up to 12,000 feet (3,658 meters) and are useful for drilling exploratory wells as they can move from location to location quickly (Diamond Offshore c2019). Like semisubmersibles, drill ships either use multiple anchors or dynamic positioning (or a combination of both) to maintain position at the drill site (Schlumberger c2020). The *Maersk Voyager* drillship, shown in Figure 7, was built in 2014, can operate in water depths up to 12,000 feet (3,657 meters), and can drill to 40,000 feet (12,000 meters) (Maersk Drilling c2020). In 2019, Maersk Drilling was awarded contracts for a three-well exploration drilling project off the coast of Angola and Namibia in Africa. As part of the project, its ship, *Maersk Voyager*, drilled at the deepest water depth recorded of 11,903 feet (3,628 meters) over a 240 day period in early 2020 (Maersk Drilling 2020 Jan 13).

Figure 7. Drill ship, *Maersk Voyager*.

Source: (Maersk Drilling 2020 Jan 13).

Production Platforms

Once oil or gas is found, an exploratory drilling rig is replaced with, or converted to, a production platform. Production platforms can vary in size and type depending on the size of the field, the water depth, and the distance offshore. The movement to deepwater has also corresponded with larger and more complex production platforms as more activity is consolidated over a larger and much more diverse deepwater area that may include differing types of production, production of differing quality and treatment needs, and the need to tie back remote fields to a single location through various production tie-backs. Within the scope of exploration and production, such subsea tiebacks are increasingly being used to link multiple wells to a single facility and/or hub. The value proposition of such subsea tiebacks is simple: they allow wells to be more efficiently spread out over larger sea floor areas (Stell 2013 April 15).

As offshore drilling became possible in deeper waters, drilling rigs increased in size and complexity. Figure 8 illustrates the various types of production platforms, both fixed and floating or subsea systems.

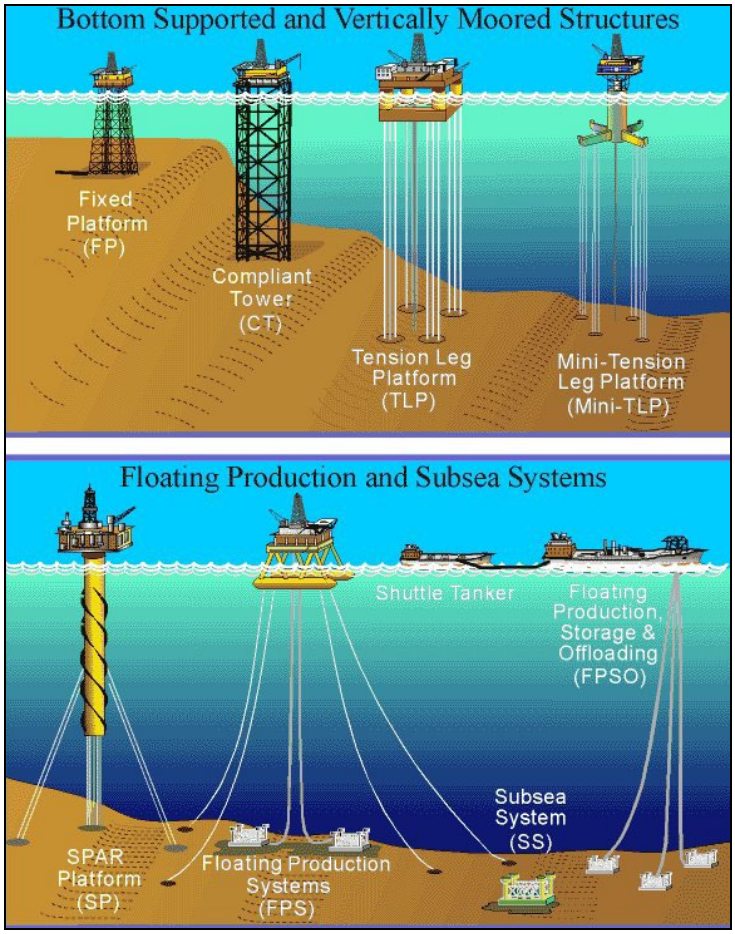

Figure 8. Fixed, floating, and subsea production systems.

Source: Bureau of Safety and Environmental Enforcement (BSEE c2020).

Fixed Platform: A fixed platform has a tubular steel jacket and deck which serves as the support for the production deck that is well above the water level. Piles are grounded in the seafloor and extend to water level, securing the jacket. The jacket supports the deck and surface facilities, including machinery for drilling, production, other equipment, and living facilities for the crew. These types of platforms are generally not used in waters deeper than 1,500 feet (457 meters) because of the expense and other engineering challenges. Fixed platforms are, however, the most commonly used platform type in shallow waters (API c2020).

Compliant Tower: A compliant tower is similar in basic structure to a fixed platform but is much more flexible, hence the name “compliant.” Instead of a jacket, a compliant tower has a narrow, more pliable tower in its horizontal position. This flexibility allows this platform structure to better withstand harsh lateral wind or water forces. These are generally used in water depths between 1,000 and 2,000 feet (305 and 610 meters) (API c2020).

Tension and Mini-tension Leg Platforms (TLP): Tension and mini-tension leg platforms use buoy systems to allow the platform to be partially submerged, similar to that used in semisubmersibles. The buoyancy of the facilities' hulls offset the weight of the platforms, requiring tight tendons, or tension legs, to secure the structure to the foundation on the seafloor. The foundation is kept sturdy and secure by driving piles into the seabed. The tension leg mooring system allows the platform to move horizontally but does not permit vertical, bobbing movement, which makes TLPs a popular choice in the hurricane prone GOM. In fact, TLPs are one of the most used types of floating production facilities in the world due to their stability in rough environments (Rigzone c2020).

Semisubmersible platform: Semisubmersible platforms have pontoons, columns, and a deck. Pontoons and columns are buoyant so that the platform is partially, or "semi" submerged during drilling. The deck, as usual, contains crew living quarters and storage space. While in transit, these platforms can float completely on top of the water, making them easier to transport. Semisubmersibles are the most stable of any floating rig, which makes them ideal in harsh conditions and in a large range of water depths (Rigzone c2020).

SPAR Platform: A SPAR is a floating platform with buoyancy chambers at the top, a flooded structure in the midsection, and a stabilizing keel at the bottom, underneath the water. There are three main variations: classic; truss; and cell. Living quarters and production equipment are fitted at the top of the structure (Rigzone c2020). SPARs are more recent developments in offshore production, conceptually designed for deepwater production in waters up to 10,000 feet (3,048 meters) deep (Maritime Connector 2020).

Floating Production Unit: A floating production unit (FPU) is a variation of a semisubmersible. It is a self-propelled unit which is kept stationary by wire ropes and chains or by dynamic positioning (API c2020). Though FPU's can be used for processing from subsea facilities, they are not used for storage. Instead, after using some gas to fuel the vessel, remaining oil and gas are transported to pipelines via export risers (Richardson et al. 2008 May). Generally, FPU's are used in water depths up to 7,500 feet (2,286 meters) (BSEE c2020).

Subsea System: Subsea production systems are wells situated on the seabed, rather than the surface. Subsea systems can be a single subsea well producing to a nearby platform, FPU, or TLP, or multiple wells that produce through a pipeline system to a production facility (API c2020). Subsea systems can be defined in terms of two categories of equipment: surface and seafloor. Surface equipment on a host platform may be very far from the wells themselves but is vital for operations as it is the control system and production machinery. The seafloor portion consists of the wells, manifolds, control umbilicals, pumping or processing equipment or both, and flowlines. Subsea systems are used in deep water, usually 7,000 feet (2,134 meters) or more. They do not have drilling capability and only extract and transport (NaturalGas.org 2013 Sep 22).

Floating Production, Storage, and Offloading (FPSO) System: FPSOs are large tanker vessels similar to FPUs, but these vessels contain equipment to collect and store oil produced from numerous sub-sea wells. A FPSO processes and stores production and periodically offloads the stored production to a smaller shuttle tanker (API c2020). FPSOs were originally developed for use in the North Sea because of their usefulness in areas with limited or no pipeline infrastructure (Rigzone c2020). Petrobras America, Inc. began production on the first FPSO production in the GOM in February 2012. *BW Pioneer* has the capacity to process 80,000 barrels of oil per day and 17.6 million cubic feet of gas per day (Petzet 2012 Mar 2).

2.2.2 Shipyards

Shipyards are often classified depending on the type of operation: shipbuilding or ship repairing; and the type of ship: commercial or military. Shipyards are also classified into four basic categories depending on capability: (1) major shipyards engaged in the construction and repair of ships; (2) major ship-repair and dry-dock facilities; (3) smaller shipyards that service inland waterways and coastal commerce; and (4) topside-repair facilities (FAS, OTA 1995 Sep).

The US major shipbuilding base (MSB) is defined as privately owned yards that have at least one shipbuilding position capable of accommodating vessels 400 feet (122 meters) or more in length (FAS, OTA 1995 Sep). These facilities also serve as major repair facilities with dry-docking capability. There are several hundred medium- and small-sized, or second-tier shipyards that primarily support the inland waterway and coastal commerce business. These shipyards build and repair tugboats, ferries, fishing vessels, barges, small government-owned vessels and oil drilling equipment. The larger second-tier shipyards can handle steel and aluminum vessels up to 183 meters in length (Brown and Garten 1994). These are the yards that also construct and service offshore service vessels, or "OSVs". This is a broad term used to describe the vessels used to support the offshore oil and gas industry. Specifically, these OSVs transport materials, equipment and personnel necessary for daily operation on the offshore drilling rig.

Shipbuilding activities in the US can vary considerably depending on the primary market a particular shipyard serves (USEPA 1997). The following subsections outline the primary markets for shipyards:

Commercial Ships

The US commercial shipbuilding industry comprises about 600 mid-tier and smaller shipyards. These yards tend to build small to medium sized ships less than 650 feet (198 meters) in length (Industrial College of Armed Forces 2009). The commercial needs for many of these types of ships can be varied and are classified into categories based on their use: dry cargo ships; bulk carriers; tankers; passenger ships; fishing vessels; industrial vessels; etc. (USEPA 1997). Dry cargo ships can be further dived into break bulk ships, container, and roll-on and roll-off types. Although most vessels built in these yards are built for specific commercial orders, some yards do serve as subcontractors to larger yards (USEPA 1997).

The commercial market is globally competitive. Commercial shipbuilders must construct cost-competitive commercial ships and repair them efficiently or else that work can move to other places around the world. This is particularly true for US commercial shipbuilders who face steep competition from shipbuilders in Asia who offer lower prices and are often considered to be more efficient (Industrial College of Armed Forces 2009).

Offshore Supply Vessels (OSVs)

OSVs are marine vessels that serve exploratory and developmental drilling rigs and production facilities through offshore and subsea construction support, installation, and decommissioning activities. OSVs are unique from other vessels in that they have great cargo-carrying flexibility and capacity for transporting deck cargo (pipe, equipment, or drummed material), liquid mud, potable and drinking water, diesel fuel, dry bulk cement, and personnel.

Seven major types of OSVs are: tugs; marine platform supply vessels (PSV); anchor handling towing and supply vessels (AHSV); fast support vessels (FSV); lift boats; mini-supply vessels (MSV); and floating, production, storage and offloading vessels (FPSO).

Every OSV type is designed and constructed specifically for its intended use and activity which means that each type has a different length, horsepower, and cargo capabilities. PSVs, for example, can range from 65 to 350 feet (20 to 107 meters) in length and are primarily used for the transportation of supplies and personnel to and from platforms. A PSV is equipped with tanks for transporting drilling mud, diesel fuel, water, and chemicals used for drilling. A PSV can also transport produced water, drilling muds, wellbore treatment chemicals, and fuels that must be returned to shore for proper disposal (Maritime Connector c2020). Anchor handling or tug supply vessels (AHTS) are ships with both anchor towing and supply carrying capabilities. These vessels are capable of towing and mooring deepwater rigs (Edison Chouest Offshore c2018). Other OSVs, meanwhile, are designed specifically for deep water use and have extra cargo capacity, larger deck space, and dynamic positioning navigational equipment (anchorless station-keeping capability) for safety (Hornbeck Offshore Services 2012).

Military and Other Federal Government Ships

Orders for military ships have been important drivers in the shipbuilding industry for a long time. This has created an economic benefit for many shipyards since the demand for military craft is less cyclical than the commercial market and more a function of longer-term government military and appropriation policies.

There are two main types of military ships: combatant and non-combatant ships. The US Navy makes most of the combatant ship orders that include submarines, aircraft carriers, and auxiliaries. The Maritime Administration's National Defense Reserve Fleet and the Navy's Military Sealift Command purchase the largest share of non-combatant ships. The US Army Corps of Engineers (ACE), National Oceanic and Atmospheric Administration (NOAA), and the National Science Foundation (NSF) are other government organizations that purchase noncombatant ships from shipyards in the US. Non-combatant ships can include cargo ships, transport ships, crane ships, patrol ships, roll on-roll off ships, tankers, ice breakers, and research ships (USEPA 1997).

Other Facility Characteristics

Major shipyards and repair facilities can usually serve as a dry dock and can repair vessels of 122 meters (about 400 feet [122 meters]). Dry-dock capable facilities must have a waterway channel that is large enough to accommodate large vessels (at least 12 feet [3.7 meters] in depth) (USDOT, MARAD 2004 Dec). Smaller shipyards construct and repair vessels under 400 feet (122 meters) that can include: patrol boats (both military and non-military); casino boats; water taxis; tugboats; towboats; fire and rescue ships; ferries; and offshore crew and supply boats. Many second-tier shipyards can make topside repairs to ships over 400 feet (122 meters) in length. Shipyards must accommodate the flow of materials and activity within its surface and marine boundaries. Like platform fabrication yards, shipyards must consider future growth and facility expansion opportunities not only for the overall shipyard itself, but for the component parts and supporting businesses that are collocated at the shipyard. Shipyard components and collocated business/activities can include:

- dry-docks;
- shipbuilding, piers, and berthing positions;
- electrical, pipe cutting and machining, assembly, painting and sanding workshops;
- areas for carpenter, sheet metal, and construction work;
- warehouses and storage (primarily for steel);
- service and fueling stations; and
- administrative and support offices.

2.3 Geographic Distribution

2.3.1 Platform Fabrication

Platform fabrication yards must have access to a navigable channel that is both wide enough and deep enough to accommodate towing bulky and long structures like offshore drilling and production platforms. Thus, platform fabrication yards are located either directly on the coast, or inland, along large channels such as the Intracoastal Waterway. Some waterway locations can limit the size and scope of projects that can be constructed at a given fabrication yard. For instance, the Houma Navigation Canal prevents the transport of most jackets designed for more than 800 feet (244 meters) of water depths (Gulf Island Fabrication 2016). However, the Gulf Intracoastal Waterway, and the 45-foot depth of the Corpus Christi Ship Channel, provide unrestricted access to the GOM and allow for any size structure that is currently in use along the GOM (Gulf Island Fabrication 2016). In May 2019, the Corpus Christi Ship Channel expanded its depth to 54 feet (16 meters) and widened it to 530 feet (162 meters) in order to accommodate the explosive growth of crude oil exports the US has produced since 2015 (The Maritime Executive 2019 May 29).

There are no oil or gas platforms located off the Atlantic coast. However, Cianbro Corporation ("Cianbro") owns several fabrication facilities in the Eastern United States that have played a role in the development and repair of various structures within the region and across the US:

1) Brewer, ME Deepwater Eastern Manufacturing Facility. This facility opened in 2008 and has since completed numerous projects for the refinery and electricity industries, the most recent of which was the construction of 60 refinery modules for Shell Pennsylvania Chemical in 2019. Around 300 to 500 Cianbro employees reportedly worked on the project (Ricker 2019 Feb 25; Ricker 2019 Mar 8). The facility includes a pier with a bulkhead capacity of 12,000 tons, around 40,000 square feet of onsite warehousing space, and an additional 200,000 square feet of offsite manufacturing space (Cianbro 2017 Jun 12).
2) Portland, ME Deepwater & Modular Manufacturing Facility. This 48,000 square foot facility was the base of operations for a 2002 project for which Cianbro constructed two oil rigs for Pride International. The two 12,000 ton semisubmersible rigs were completed in 2005 and were shipped to their destinations in the Caribbean to drill in depths of up to 20,000 feet (6,096 meters) (Offshore 2005 Jun 1; Cianbro 2017 Jun 12).
3) Baltimore, MD Deepwater & Modular Manufacturing Facility. This 80,000 square foot facility is located in Morgan's Wharf in Maryland and includes a pier with bulkhead capabilities of 400 ft x 100 ft x 14 ft depth (122 meters x 30.5 meters x 4 meters depth) (Cianbro 2017 Jun 12). This facility has been employed as a fabrication facility in the past but is currently being used for engineering design and administrative purposes.

Overall, Cianbro consists of approximately 4,000 employees across its various locations and has taken part in numerous offshore projects within the last decade. For instance, in 2010, the Stena Forth deep-sea drilling vessel underwent repairs off the coast of Maine. As part of these repairs, Cianbro installed three new propulsion units, or thrusters, at the ship's location in Rockland, Maine, nearly 60 miles south of the company's headquarters in Pittsfield, Maine (Cianbro 2010 Jun 28). In 2013, Cianbro helped construct a 65 foot (20 meters) tall floating wind turbine prototype named the VolturnUS 1:8, which became the first grid-connected offshore wind turbine to be deployed off the coast of North America and the first of its kind in the world, using advanced material to create a floating, concrete semisubmersible hull. The prototype is a one-eight-scale version of a 6 Megawatt (MW) design (Cianbro c2020).

Cianbro was also tapped to design and build a $100 million electrical service platform for the Cape Wind offshore wind farm off the coast of Massachusetts in 2013. The platform is located near the center of the wind farm and is meant to carry a substation that transforms the voltage of the electricity produced by the wind turbines before sending the power to shore (Cianbro 2013 Dec 23; Richardson 2013 Dec 24).

More recently, Cianbro has been named as a project participant for a new floating offshore wind project off Maine's coast. *New England Aqua Ventus I* is a demonstration project consisting of two 6 MW turbines that would be deployed on the VolturnUS, the floating concrete semisubmersible hull designed by the University of Maine in conjunction with Cianbro. The turbine platforms and column segments would be fabricated and assembled at Cianbro's Brewer, Maine facility. This demonstration project would likely be the first full-scale floating wind project in the Americas and is expected to produce for the duration of a 20-year power purchase agreement with Maine's Public Utilities Commission (Stromsta 2019 Jun 20; University of Maine c2019).

2.3.2 Shipyards

Six boat building shipyards were identified in the Atlantic region, as is seen below in Table 1. Most handle smaller coastal ships, boats, and barges. There are 15 repair yards, a number of which can handle large oceangoing vessels and most have dry-docking capability.

Table 1. Atlantic region shipyards and repair yards

Shipyard	City	State	Category
Bath Iron Works	Bath	ME	Shipyard
Rockland Marine Corp.	Rockland	ME	Repair yard
Washburn & Doughty	East Boothbay	ME	Shipyard
Gladding-Hearn Shipbuilding	Somerset	MA	Shipyard
Derecktor New York Shipyard	Mamaroneck	NY	Repair yard
Yank Marine	Tuckahoe	NJ	Repair yard
Yank Marine Services	Dorchester	NJ	Repair yard
J. Goodison Company, Inc.	North Kingstown	RI	Repair yard
Philly Shipyard, Inc.	Philadelphia	PA	Shipyard
Chesapeake Shipbuilding	Salisbury	MD	Shipyard
Newport News Shipbuilding	Newport News	VA	Shipyard
Colonna's Shipyard, Inc.	Norfolk	VA	Repair yard
Lyon Shipyard	Norfolk	VA	Repair yard
MHI Ship Repair & Services	Norfolk	VA	Repair yard
East Coast Repair and Fabrication	Portsmouth	VA	Repair yard
Detyens Shipyards, Inc.	North Charleston	SC	Repair yard
BAE Systems - Jacksonville Ship Repair	Jacksonville	FL	Repair yard
North Florida Shipyards, Inc.	Jacksonville	FL	Repair yard
Bradford Marine	Fort Lauderdale	FL	Repair yard
Rolly Marine Service, Inc.	Fort Lauderdale	FL	Repair yard
RMK Merrill-Stevens	Miami	FL	Repair yard

Figure 9. Location of Atlantic region shipyards.

Source: (Shipyard websites; Google Maps 2019).

Two firms dominate the US shipbuilding industry: General Dynamics and Huntington Ingalls (a sister company to Northrop Grumman) (Colton c2019). These two firms operate five of the biggest shipyards and focus almost exclusively on military and government contracts. General Dynamics owns three of the big six, two of which are on the East Coast and one on the West Coast. General Dynamics' Electric Boat facility is in Connecticut, contracts with the US Navy, and has been the world's leading submarine builder since 1899 (General Dynamics c2020). General Dynamics' other East Coast subsidiary, Bath Iron Works, is located in Bath, Maine and was historically a merchant shipbuilder. Since 1982, Bath Iron Works has specialized in cruiser and destroyer construction for the US Navy. The third yard, North American Steel and Shipping Industry (NASSCO), is in San Diego, California.

Huntington Ingalls operates Newport News Shipbuilding (Virginia) and Ingalls Shipbuilding (Mississippi) along the GOM (Huntington Ingalls 2020 Feb 13). Huntington Ingalls was created in 2008 as a spinoff company of Northrup Grumman. Newport News repairs merchant vessels, and the two in the GOM work exclusively for the US Navy and US Coast Guard (Colton 2019 Oct 20). Of such shipyards, only NASSCO accepts commercial contracts; the others process only military orders. The majority of commercial shipbuilding along the East and West Coasts is handled by a little over 100 active smaller shipyards (Colton c2019).

The largest facility in the Atlantic region, the Newport News facility, focuses mainly on designing, building, overhauling, and repairing ships for the US Navy and the US Coast Guard. This facility is (Newport News 2020):

- the sole supplier of US Navy aircraft carriers, the world's largest warships;
- one of two builders capable of building Virginia-class nuclear powered submarines;
- the home of the Western Hemisphere's largest dry dock and crane;
- the exclusive provider of refueling services for nuclear-powered aircraft carriers; and
- the largest non-governmental provider of fleet maintenance services to the Navy (Newport News Shipbuilding 2020 Feb 1).

The Newport News facility, seen below in Figure 10, is located on over 550 acres with two miles (three kilometers) of waterfront. There are approximately 23,000 employees, making it the largest industrial employer in Virginia (Newport News Shipbuilding c2020).

Figure 10. Newport News shipyard, Newport News, Virginia.

Source: (Huntington Ingalls 2016 Jul 21).

The Aker Philadelphia shipyard, now known as Philly Shipyard, Inc. (see Figure 11), has a workforce of approximately 250 employees that are both direct hires and subcontractors (Philly Shipyard 2020 Feb 11). This is a significant decrease from the 1,200 employees the company had at the beginning of 2018 due to the fact that all the shipyard's production facilities were idle and its graving docks were empty in the first quarter of 2019 (Philly Shipyard 2019 May 6). As of early 2020, there is still no shipbuilding activity at the shipyard. However, the shipyard did secure contracts in July and October of 2019 for maintenance and repair operations related to the drydocking of government cargo ships, the FSS *Antares* and FSS *Pollux*, which has allowed the shipyard to maintain an average employee count of over 200 (Philly Shipyard 2020 Feb 11). Since powering up in 2003, Philly Shipyard has delivered 28 ocean-going commercial vessels, making up more than 50 percent of the US oceangoing commercial fleet production (Philly Shipyard c2020).

Figure 11. Philly Shipyard, Philadelphia, Pennsylvania.

Source: (The Maritime Executive 2018 May 22).

Chesapeake Shipbuilding (Chesapeake) in Salisbury, Maryland builds commercial ships up to 450 feet in length. This yard specializes in the design and construction of passenger vessels, tugboats, and ferry boats. The Chesapeake facility is located on 13 acres on the Wicomico River and its facilities include:

- 2,000 feet (610 meters) of deepwater bulkhead;
- two construction basins;
- three level construction and side launch systems;
- a ground transfer system; and
- various hull fabrication buildings and shops (Chesapeake Shipbuilding c2020).

In late 2015, Chesapeake added its fifth hull fabrication building fitted with two overhead cranes and other state-of-the-art equipment. It allows larger hull sections and tugboats to be constructed entirely indoors (Chesapeake Shipbuilding 2015 Dec 22). See Figure 12 below for reference.

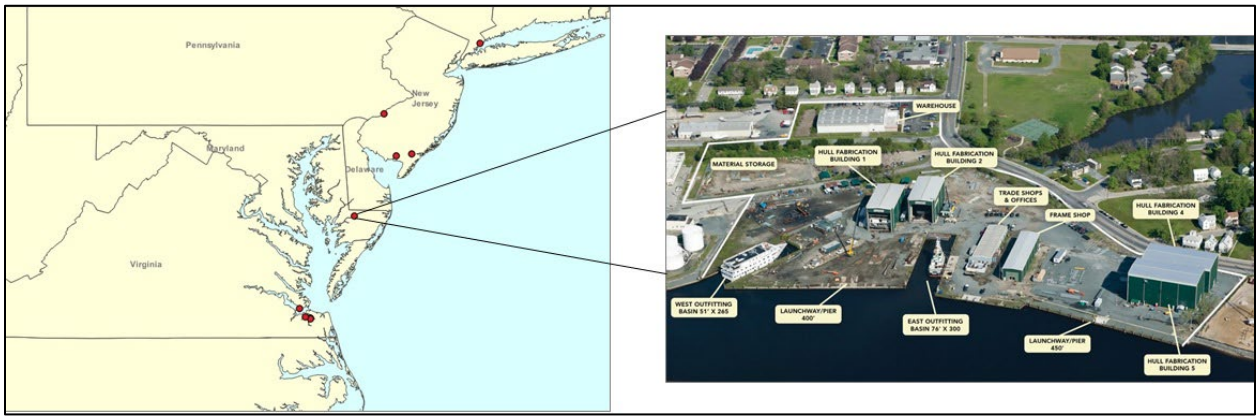

Figure 12. Chesapeake Shipbuilding, Salisbury, Maryland.

Source: (Chesapeake Shipbuilding c2020).

2.4 Scope of Economic Contribution to Regional Economy

Table 2 shows that each state's total ship and boat building employment contributions are relatively small in comparison to total statewide employment. Only Maine and Rhode Island have ship and boat building employment totals that are greater than one percent of the overall statewide employment totals. However, on a relative percentage basis, the combined shares of ship and boat building employment in Virginia is considerably larger than those in all the other Atlantic states (see Figure 13). Virginia ship and boat building jobs account for almost 20 percent of that sector's total jobs along the Atlantic seaboard which should come as no surprise, given the high level of government and military contracts that are serviced from these facilities.

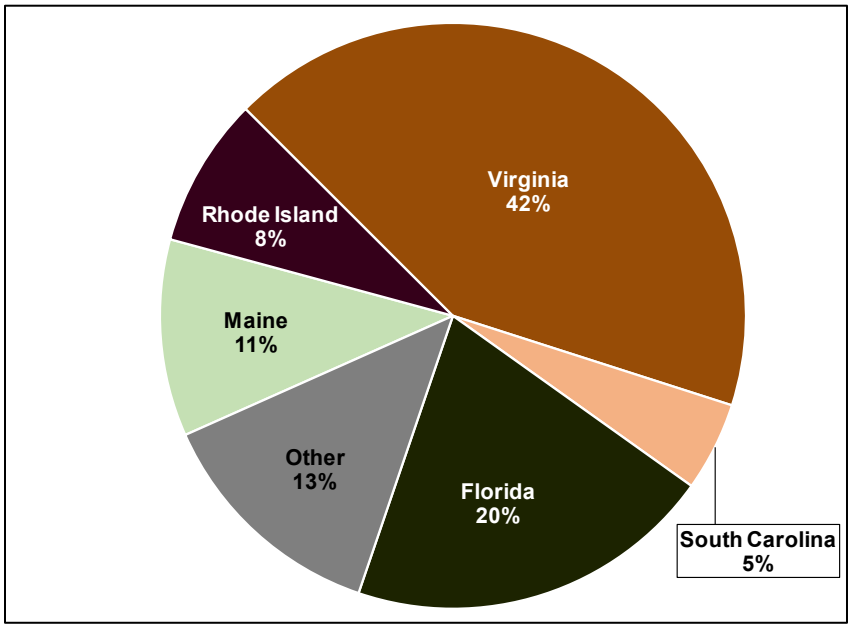

Table 2. Regional and national employment contribution, ship and boat building, 2018

	Number of Employees			
State	**Ship and boat building**	**Total state**	**Ship and boat building employment as a percent of total state employment (%)**	**Ship and boat building employment as a percent of total US Ship and boat building employment (%)**
CT	-	1,449,072	-	-
DC	-	534,661	-	-
DE	-	384,332	-	-
FL	13,103	7,635,037	0.17	9.48
GA	1,641	3,777,824	0.04	1.19
MA	649	3,156,298	0.02	0.47
MD	492	2,188,298	0.02	0.36
ME	6,999	518,990	1.35	5.06
NC	2,221	3,710,090	0.06	1.61
NH	112	574,083	0.02	0.08
NJ	1,592	3,472,611	0.05	1.15
NY	887	8,017,398	0.01	0.64
PA	846	5,193,979	0.02	0.61
RI	5,330	421,767	1.26	3.86
SC	3,167	1,743,243	0.18	2.29
VA	27,326	3,188,362	0.86	19.77
Total Region	**64,365**	**45,966,045**	**0.14**	**46.56**
Total US	**138,228**	**124,551,838**	**0.11**	**100.00**

Source: US Bureau of Labor Statistics (BLS c2020).

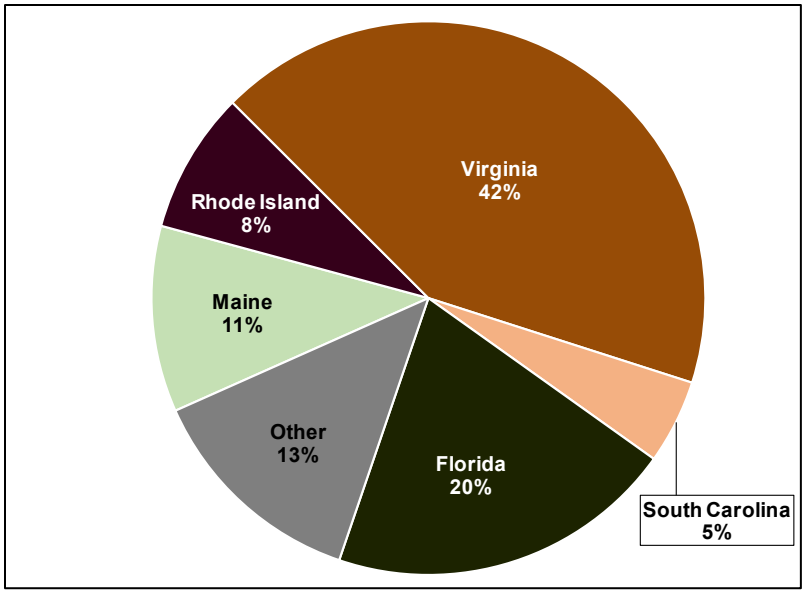

Figure 13. Atlantic region ship and boat building employment shares, 2018.

Source: US Bureau of Labor Statistics (BLS c2020).

Figure 14 shows the historic trends in regional ship and boat building employment (2009 to 2018). Total employment in this sector has continued to increase over the past decade at a reasonably solid clip of 3.8 percent on an annual average basis. While employment was up over the decade, there was a six percent dip during 2015 and 2016. This dip is mainly attributed to an 11 percent decrease in Virginia's shipbuilding workforce during that time period. In 2015, Newport News Shipbuilding laid off over 1,200 employees due to the completion of three aircraft carriers it had been repairing and maintaining with no other work queued up until 2017 (Lessig 2015 Dec 4). In 2016, BAE Systems Norfolk Ship Repair also let go about 650 employees, nearly 40 percent of its workforce, due to a drop in its work on Navy vessels (Lessig 2016 Mar 18).

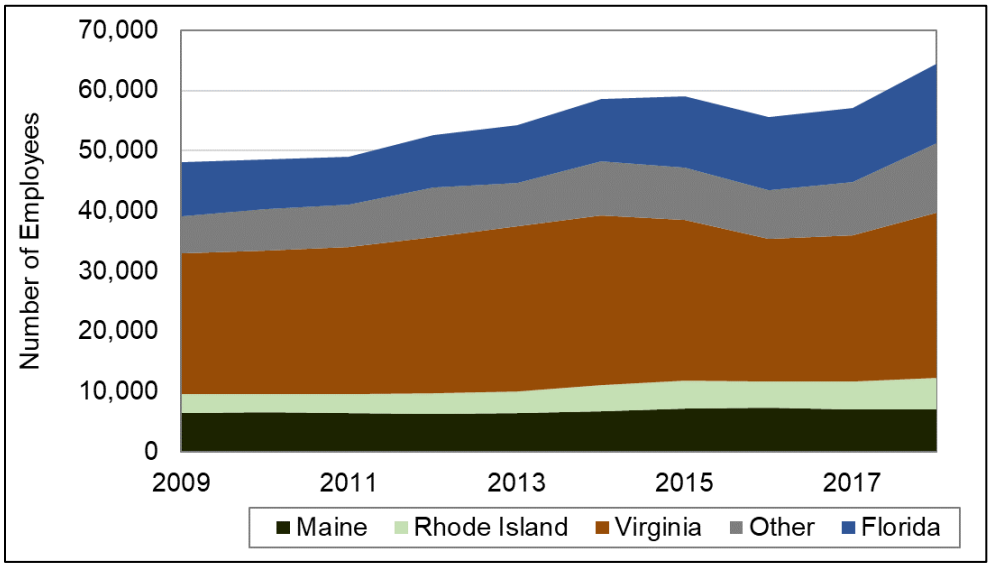

Figure 14. Trends in Atlantic region ship and boat building employment, 2009-2018.

Source: US Bureau of Labor Statistics (BLS c2020).

Regional total wage contributions, shown in Table 3, follow trends similar to employment levels discussed earlier. The regional totals are dominated by the states with the largest shares of ship and boat building employment. Regional shares of total wages paid by ship and boat building facilities are shown in Figure 15.

As of 2018, the boat and shipbuilding industry along the Atlantic seaboard paid a total of $4 billion in total wages (Figure 16).

Table 3. Regional and national wage contribution, ship and boat building, 2018

State	Ship and boat building wages (thousand $)	Total state wages (thousand $)	Ship and boat building wages as a percent of total state wages (%)	Ship and boat building wages as a percent of total US ship and boat building wages (%)
CT	-	98,976,443	-	-
DC	-	47,148,826	-	-
DE	-	21,785,214	-	-
FL	670,126	377,741,168	0.18	7.53
GA	70,209	204,738,291	0.03	0.79
MA	35,245	231,687,162	0.02	0.40
MD	26,971	128,523,234	0.02	0.30
ME	437,686	23,322,212	1.88	4.92
NC	103,837	188,651,372	0.06	1.17
NH	5,948	33,028,901	0.02	0.07
NJ	80,761	226,946,160	0.04	0.91
NY	74,345	589,087,033	0.01	0.84
PA	62,323	287,198,234	0.02	0.70
RI	318,156	21,809,170	1.46	3.57
SC	152,250	76,779,000	0.20	1.71
VA	1,977,867	184,434,708	1.07	22.22
Total Region	**4,015,724**	**2,741,857,128**	**0.15**	**45.11**
Total US	**8,902,076**	**7,124,159,437**	**0.12**	**100.00**

Source: US Bureau of Labor Statistics (BLS c2020).

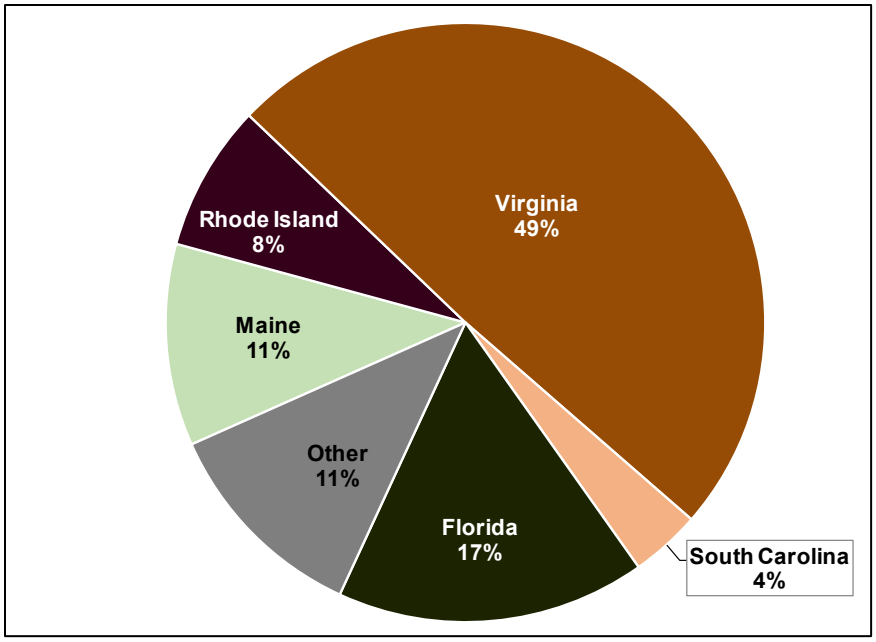

Figure 15. Atlantic region ship and boat building wage shares, 2018.

Source: US Bureau of Labor Statistics (BLS c2020).

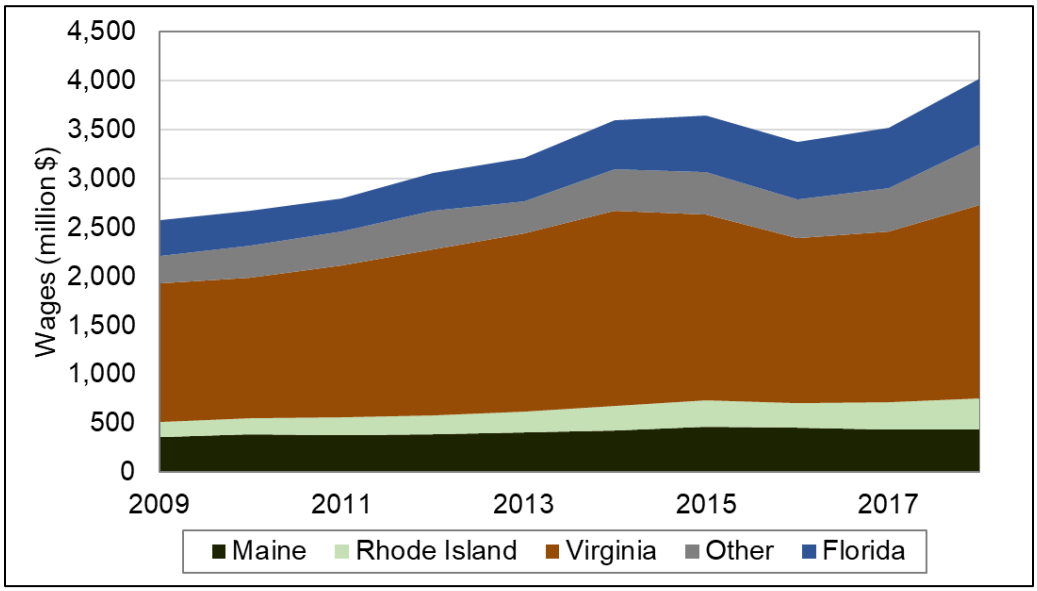

Figure 16. Trends in Atlantic region ship and boat building wages, 2009–2018.

Source: US Bureau of Labor Statistics (BLS c2020).

Table 4 provides a comparison of the average annual wages paid to employees in the ship and boat building sectors of the Atlantic region. The three highest paying states, on an annual average wage basis, are New York, Pennsylvania, and Virginia. Two of these states (Pennsylvania and Virginia) pay average wages that are considerably in excess of their respective statewide averages. New York, Pennsylvania, and Virginia also pay ship and boat building wages that are higher than the average for that sector, particularly New York which pays an average annual wage that is 130 percent of the regional sector average.

Table 4. Regional and national average annual wage contribution, ship and boat building, 2018

State	Ship and boat building average annual wage	Total state average annual wage	Ship and boat building avg. annual wage as a percent of total state avg. annual wage (%)	Ship and boat building avg. annual wage as a percent of total US Ship and boat building avg. annual wage (%)
CT	-	68,303	-	-
DC	-	88,184	-	-
DE	-	56,683	-	-
FL	51,144	49,475	103.37	79.41
GA	42,793	54,195	78.96	66.45
MA	54,327	73,405	74.01	84.36
MD	54,791	58,732	93.29	85.08
ME	62,533	44,938	139.15	97.10
NC	46,754	50,848	91.95	72.60
NH	53,305	57,533	92.65	82.77
NJ	50,724	65,353	77.62	78.76
NY	83,840	73,476	114.11	130.18
PA	73,711	55,294	133.31	114.45
RI	59,691	51,709	115.44	92.69
SC	48,073	44,044	109.15	74.65
VA	72,382	57,846	125.13	112.39
Total Region	**47,129**	**59,376**	**79.37**	**73.18**
Total US	**64,402**	**57,198**	**112.59**	**100.00**

Source: US Bureau of Labor Statistics (BLS c2020).

Trends in average annual wages for regional ship and boat building employees are shown in Figure 17. The trends show that average annual wage has been increasing at a rate of 2.2 percent, with the greatest increases in 2011 (3.7 percent) and 2018 (3.6 percent). In 2014 and 2018, New York showed the largest increases in average annual ship and boat building wages, with increases of 9.3 percent and 10.0 percent, respectively. As of 2018, New York paid the highest wages at $83,840, considerably higher than those in 2012, which had fallen to around $60,000 per year.

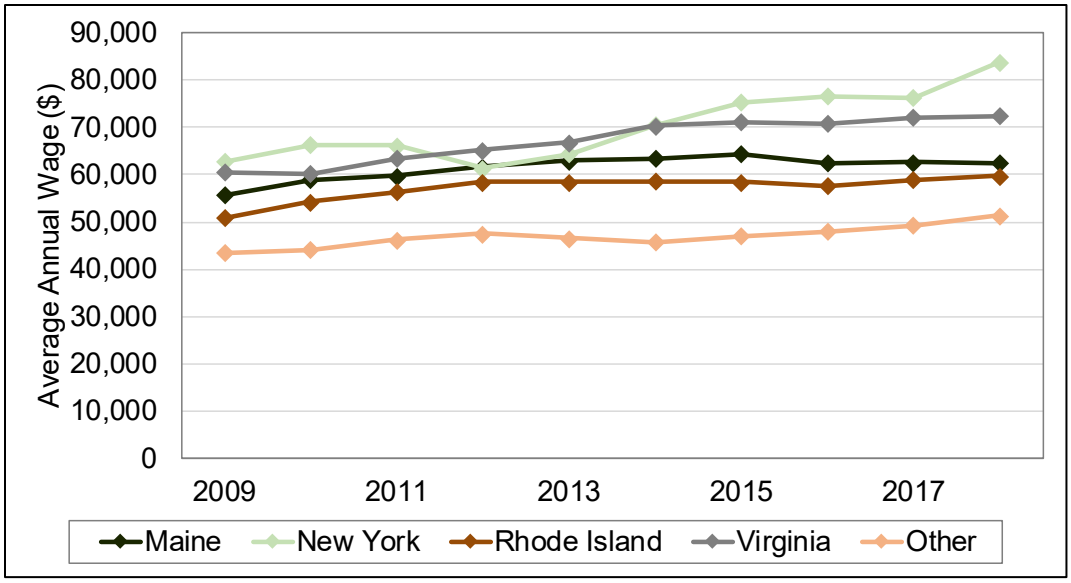

Figure 17. Trends in Atlantic region ship and boat building average annual wage, 2009–2018.

Note: Connecticut, Washington, DC, Delaware, Georgia, and Pennsylvania were excluded for lack of consistent data.

Source: US Bureau of Labor Statistics (BLS c2020).

2.5 Current Trends

2.5.1 Regulatory Changes

The regulations that govern platform fabrication and shipbuilding industries are provided in MARAD's Compilation of Maritime Laws. Relevant environmental regulations include the Oil Pollution Act of 1990, the Resource Conservation and Recovery Act (Subtitle C regarding dumping waste), the Comprehensive Environmental Response, Compensation, and Liability Act, and the Clean Water Act. There are also a number of non-environmental regulations. The Jones Act and the Byrnes-Tollefson Amendment, in particular, have had significant impacts on the US shipbuilding industry.

Merchant Marine Act of 1920 (The Jones Act): Requires that any vessel sailing between US ports must be owned and operated by US citizens and sail under the US flag. The Jones Act was designed to protect the US shipbuilding industry (Goure 2011). Vessels must fit into one of three categories: be US built and flagged; be reconstructed in the US and US flagged; or be foreign-built but forfeited under violation of US law and now US flagged (USDOT, MARAD 2019 Nov 6). Although this Act was originally intended to protect US shipyards, vessels, and sailors, there have been recent debates on whether the Jones Act serves the intended purpose or has instead stifled the competitiveness of US shipbuilding due to high domestic shipping costs and the limited capacity of the US fleet (Frittelli 2019 Nov 21).

Byrnes-Tollefson Amendment: This law requires that vessels and major components of the hull or superstructure for the US armed forces be built in US shipyards. There are two exceptions to this amendment: 1) presidential waiver for national security interests and 2) exception for inflatable boats or rigid inflatable boats, or both (10 USC. §8679) (US OLRC 2018).

Other, more recent regulatory changes include the following.

National Defense Authorization Act (NDAA) of 2006: This granted MARAD the authority to make grants, under the Small Business Act, to shipyards that were classified as a "small business concern" and had fewer than 1,200 employees. The funds are intended to be used for capital improvement projects, and were originally appropriated to MARAD in the amount of $25 million for each of the fiscal years 2006 to 2010 (Public Law 109-163 Sec. 3506) (109th Congress 2006 Jan 6; USDOT, MARAD 2019 Mar 29). Yearly updates of this Act have continued the program, which is referred to as the Assistance to Small Shipyard Grant Program.

Consolidated Appropriations Act of 2020: This Act provided additional grant money ($20 million in total) to small shipyards (those covered in NDAA), which improved infrastructure development and thereby impacted the quality of domestic ship production (116th Congress 2019 Dec 20).

2.5.2 Trends

Platform Fabrication

Over the past decade, advances in technology and labor-market forces have affected all industries. For the platform fabrication industry, there have been opportunities, as well as challenges and obstacles related to these trends. The major factors that have shaped the platform fabrication industry over the past include the following:

- The ability to build platforms at greater ocean depths
- Automation
- Emerging technologies
- Employment trends

The cyclical nature of the oil and gas industry strongly influences how the platform fabrication industry operates. The sector benefits, and typically sees considerable economic activity, when oil prices are high and contracts when oil prices and other upstream activities are down. Fabrication yards attempt to avoid these swings by diversifying into other activities in order to keep existing yard equipment used and, equally important, retain their skilled workforce. Fabrication yards may engage in drilling rig maintenance or renovations, fabrication of barges and other marine vessels, dry-docking, or equipment surveying to diversify away from core platform development work. These other diversifications are significantly smaller in scale than these yards' core activities, but they do allow the platform fabrication firms to survive the cyclical nature of their business and maintain functionality until the "good times" return.

Most of the construction trends for the platform fabrication industry are driven by GOM-related activities since this is the only place in the US that is seeing considerable offshore oil and gas activity and since US platform fabrication companies do not perform significant work for international clients (Cianbro c2020). Even in the GOM, most of the construction activity is focused on supporting deepwater (not shelf) activities. For instance, the Independence Hub,[2] which was developed over a four-year period and came on-line in 2007, is a semisubmersible production facility responsible for setting several installation and operation records (Figure 18). At the time, it was the world's deepest platform, located in 8,000 feet (2,438 meters) of water, and set the record for deepest subsea completion, steel catenary riser (SCR) installation, and export pipeline. The Independence Hub, which is shown below via Figure 18, spans one of the largest geographic areas in the GOM, covering 142 blocks or 1,800 square miles (4,662 square kilometers) in Mississippi Canyon block 921. A 12-line mooring system is connected to twelve suction piles and holds the platform in place (Paganie 2007 Dec 1). The Independence Hub taps 16 wells in 10 discovery fields using 10 to 45 mile-long (16 to 72 kilometers) umbilical lines (Murdock 2009 Apr 17). Touch screens located on the deck and control room of the central processing platform control the valves of the subsea infrastructure (Paganie 2007 Dec 1). For over eight years, the Independence Hub produced a gross 1.3 Tcf of natural gas, exceeding estimates by 30% when it was first constructed. However, in 2015, the last natural gas well still producing at the hub was shut down, and the site was abandoned with the possibility of repurposing or decommissioning it in the future (Davis 2016 Feb 6).

The hub's hull was fabricated in Singapore, and the hull and mooring systems were designed, constructed, and transported to the staging site from Ingleside, Texas (by Atlantia Offshore of Houston (Paganie 2007 Sep). Heerema Marine Contractors transported the hull and mooring systems from Singapore, Alliance Engineering of Houston designed the topsides, and Kiewit Offshore Services of Ingleside, Texas fabricated and installed those topsides (Tubb 2005; Kammerzell 2005 Mar). Allseas USA was awarded the contract to install the flowlines and gas export pipeline (Tubb 2005). FMC Technologies supplied subsea trees, manifolds, valves, and connector hubs (Paganie 2007 Sep).

[2]The Independence Hub is the result of a combined effort. Six companies worked together to facilitate the development of a number of ultra-deepwater natural gas and condensate discoveries in the Eastern GOM. The hub is an affiliate of Enterprise and the Atwater Valley Producers Group, which includes Anadarko, Dominion, Kerr-McGee, Spinnaker, and Devon Energy (Offshore Technology c2020).

Figure 18. Independence Hub.

Source: (Murdock 2009 Apr 17).

In 2010, Shell broke the water depth record for subsea production with its Perdido Development in the Tobago Field, 200 miles (322 kilometers) southwest of Houston in the GOM (Shell Oil Company 2011 Nov 17). The well is at a water depth of 9,627 feet (2,934 meters). The platform is moored in 8,000 feet (2,438 meters) of water and is jointly owned by Shell (33.34 percent), BP (33.33 percent) and Chevron (33.33 percent) (Shell Oil Company 2011 Nov 17). From this platform, the Great White, Tobago, and Silvertip oil and gas fields are accessed through subsea wells up to seven miles (11 kilometers) away. This project recorded a number of firsts including (Shell Oil Company 2011 Nov 17):

1) Deepest water depth record for an offshore oil drilling and production platform;
2) First water injection in 8,000 feet (2,438 meters) of water in the GOM (Great White GB001), which helps push oil through the reservoir, from the injector wells to the production wells;
3) First commercial production from the Lower Tertiary geological formation, which many see as the next big opportunity in deep water;
4) Deployment of an innovative subsea separation and boosting system that compensates for the low-pressure reservoir and about 2,000 psi of backpressure from the wells. The system includes five specially designed 1,500-horsepower electric pumps embedded in the seafloor to boost production to the surface;

5) First spar with direct vertical access wells and production hardware on the seafloor at a depth of more than 8,000 feet (2,438 meters);
6) Perdido weighs 50,000 tons and sits in water six times deeper than the height of the Empire State Building; and
7) The entire Perdido project achieved 13 million man-hours without a lost-time injury.

The drilling depth record was broken in 2016 by Maersk Drilling's *Venturer* drillship. The *Venturer* drilled a well off the coast of Uruguay at a water depth of 11,155 feet (3,400 meters) (Offshore Energy Today 2016 Apr 1). In January 2020 this record was broken again. The *Venturer*'s sister ship, the *Voyager*, was hired to lead an exploration drilling project off the coast of Angola and Namibia and drilled a well at a new world record water depth of 11,903 feet (3,628 meters), almost reaching the limit of its operating maximum water depth of 12,000 feet (3,657 meters)(Maersk Drilling 2020 Jan 13). The *Voyager*'s dual pipe handling system, five knuckle boom cranes, and HP single-acting triplex mud pumps gives the ship the capacity to drill at a depth of up to 40,000 feet (12,000 meters) (Maersk Drilling c2020).

The development of platform technology and efficient design has been critical in the move to deep water. Besides the typical civil and marine architecture developments, these advancements also include improved systems and software innovations. One major development was the movement to unoccupied platforms by using remote power systems. For example, the MT-Power ™ supplied by Northern Power Systems Inc. and used a fully integrated fossil-fuel based micro turbine in a continuous run mode as its primary source of power generation (PR Newswire 2005a). Other remote technologies exist as well. For example, T.D. Williamson's "Subsea 1200 RC Tapping Machine" is a remotely operated machine used for installing hot taps in water depths of up to 9,842 feet (3,000 meters) (T.D. Williamson c2020). Another innovative software is called Online Monitoring (OLM) and is a cost-effective way to monitor the safety of jacket structures. Not only can OLM detect member severance, but it is accurate and can provide guidance on the specific location of the problem (Hydro International 2007 Nov 20). This is being used in the North Sea, West Africa, Malaysia, and the GOM. Additionally, artificial intelligence (AI) and automation have become more common in order to increase efficiency and productivity of exploration operations as well as enhance physical infrastructures. Aker BP recently partnered with a tech company to enhance the presence of AI in its operations. The AI system will monitor topside and subsea installations of more than thirty offshore structures using machine learning algorithms to analyze sensor data. This will allow Aker BP to identify impending failures before they occur (Ali 2019 Apr 2).

Technologies continue to emerge in the industry that make physical human presence offshore unneeded. For instance, the first fully automated offshore platform in the world just recently began production in 2019. The Oseberg H is a fully automatic, unmanned, remote-operated wellhead platform with a predicted volume capacity of 110 million barrels of oil equivalent expected to be produced through eleven wells located 360 feet (110 meters) below sea level. Because many features found on a normal production platform, such as living quarters, were not needed for the Oseberg H, the time and cost of the platform's construction were both greatly reduced. As such, it is seen as a pilot project that will help form the future of the industry (Offshore Technology 2019 Feb 11). Already, the United Kingdom is planning an unoccupied production facility on a floating structure in an effort to bring automation through the entire oil supply chain (Ocean News 2019 Jun 7).

As efficiency and productivity improves with the emergence of new technology, the number of people needed to operate a rig is expected to reduce. It is estimated that, with increased technology and automation, an offshore rig with 100 employees at present would need only ten to fifteen full-time employees and onshore rigs currently employing ten to fifteen full-time workers would require five to ten full-time workers (Grijpink et al. 2020 Nov 6). Changes in the corporate and organizational structure of many service companies have also impacted the way deepwater properties are explored and developed. Two recent changes include industry consolidation and closer sector integration.

From a corporate organizational perspective, many fabricators and shipyards are finding it profitable to purchase other, smaller companies and form larger corporations. For example, Gulf Island Fabrication purchased LEEVAC Shipyards in 2016, along with their facilities in Jennings and St. Charles, Louisiana, their machinery, equipment, and their contract backlog. Gulf Island explained that the acquisition would allow the company to expand its presence in the Gulf South market and further diversify its fabrication capabilities. Through the acquisition, Gulf Island obtained a new plasma cutter, eight crawler cranes, eight track cranes, ten overhead cranes, and six dry docks ranging from 1,500 to 3,500 tons. Additionally, Gulf Island acquired approximately $112 million of construction backlog, which included four new build construction projects to be delivered in 2016 and 2017 (Gulf Island Fabrication 2016). Similar examples can be seen in nearly all the larger platform fabrication companies.

The second impact of enhanced deepwater development is closer integration of the industry. This results from alliances, relationships stemming from special projects, and joint ventures. In 2014, Gulf Island signed a cooperative agreement with Bechtel Oil, Gas, and Chemicals, Inc. in a combined effort to "pursue opportunities for offshore projects for the GOM and abroad" (Gulf Island Fabrication 2014 Jul 24). With Gulf Island's fabrication experience and infrastructure, along with Bechtel's engineering, project management, and construction hiring capabilities, the companies hoped to use this joint agreement to deliver fixed, floating, and subsea facilities to the offshore market (Gulf Island Fabrication 2014 Jul 24).

The number of employees at a platform fabrication yard varies from fewer than one hundred up to several thousand, depending upon the size of the fabrication yard. Also, because the work is project-oriented and seasonal, companies often use temporary, contract workers during busy times. Employment trends are cyclical and seasonal, as is the case with most oil and gas related industries. Similarly, employment relies heavily upon large orders and fluctuations of client needs (Gulf Island Fabrication 2019). A typical workforce of a platform fabrication company can vary throughout the year with increases and decreases in contract labor dependent upon backlog and the specific orders underway.

Skilled personnel are necessary for a fabrication yard to remain productive and profitable, though during periods of high activity, the supply of these workers can be quite limited. Specifically, yards must be able to attract and retain talented construction workers, welders, fitters, and equipment operators (Gulf Island Fabrication 2019). Because the majority of construction occurs outdoors, there are significantly fewer labor hours during the winter months. Note, however, that some work does continue year-round in covered areas of yards (Gulf Island Fabrication 2019). To deal with this seasonality, some firms in other industries may choose to lay off workers; however, because skilled personnel are so vital in the fabrication industry, firms use other tactics. For example, Gulf Island Fabrication chooses to reduce the number of hours worked per day, based on the hours of sunlight, by all employees instead of letting employees go. Interestingly, in recent years, the impact of seasonality has been decreasing due to increased investment in machinery and covered areas for fabrication use (Gulf Island Fabrication 2012). These same labor-related issues also apply to shipyards, which, in some instances, compete for the same workers as platform fabricators.

Shipyards

The US shipbuilding industry reached its peak in the mid-1970s at a time when the industry supplied all military orders and controlled a significant portion of the international commercial market. Government financial support for the industry, however, started to wane after the early 1970s. By the 1980s, the number of shipbuilding and repair yards in the US, and the actual work done at each yard, had decreased dramatically. Commercial construction activities at first tier shipyards fell from an average of 1,000 gross tons (approximately 77 ships) per year in the mid-1970s to just eight ships through the late 1980s and early 1990s. The military build-up of the 1980s was soon offset by the end of the Cold War. By the 1990s, the US shipbuilding industry saw a much smaller military market share with a very limited commercial market share. Even second-tier ship repairing companies suffered during this time period, albeit not as drastically. The large decrease in oil and gas prices experienced in 1986 and afterwards further depressed the shipbuilding industry along with all other even remotely related sectors (all supporting industries such as repair yards, local crafts, and trades professionals who worked on a contract basis were also impacted) (USEPA 1997).

Several factors have contributed to the US shipbuilding and repair industry's decline in the commercial shipbuilding market. First, a worldwide shipbuilding boom in the 1970s created a capacity bubble of surplus tonnage generated in large part by significant subsidization from many countries attempting to provide financial support for their own domestic shipbuilding and repair industries. This high level of subsidization made it difficult for US companies to compete on a global basis. This shifted market share away from US firms and towards those operating abroad. Congress did respond to this challenge by offering some temporary support through attempts to reduce "Construction Differential Subsidies" (CDS) in 1980 by providing allowances to reduce the difference between foreign and domestic shipbuilding costs in competitive bidding. More than 40 percent of the US shipbuilding industry was eligible for these monetary allowances; however, the program was cancelled in 1981 (USEPA 1997).

Today, the outlook for the domestic shipbuilding industry looks grim; the current US commercial shipbuilding market share is less than 0.5 percent globally (Paris 2018 May 31). Philly Shipyard, one of the country's last remaining commercial shipbuilding powerhouses, has required financial support on two different occasions over the last twenty years. The Jones Act of 1920 is arguably the last remaining effort by the US government to keep domestic shipyards competitive in the world market, although many critics have argued that it is actually stifling the competitiveness of US shipyards due to the higher costs it takes to build commercial vessels compared to those built in foreign countries. To avoid paying the high prices, shipping companies have delayed replacing their vessels, which has reduced the amount of work shipyards receive (Paris 2018 May 31; Grabow 2019 Apr 25). A bill entitled the Energizing American Shipbuilding Act was introduced in May of 2018 that would promote the construction of about 50 new Jones Act vessels to handle the fast-growing US LNG export industry (Paris 2018 May 31). This bill quickly died in Congress but was reintroduced in July 2019, where it is currently awaiting consideration by committee (116th Congress 2019 Jul 18).

Figure 19 depicts historical trends in new ship orders from the 1970s to the mid-2000s for ships of 1,000 gross tons and over. The rapid deterioration in domestic shipbuilding activity is readily recognizable on this chart. Though activity increased somewhat in 2000 to 2002, new shipbuilding activity is still a fraction of the level of effort observed in the late 1970s. One major stimulus for the increase in shipbuilding activity has been the increase in deepwater oil and gas activity (USDOT 1999 Sep). The graph shows an increase in shipbuilding orders that corresponds with the passage of the Deepwater Royalty Relief Act of 1995.

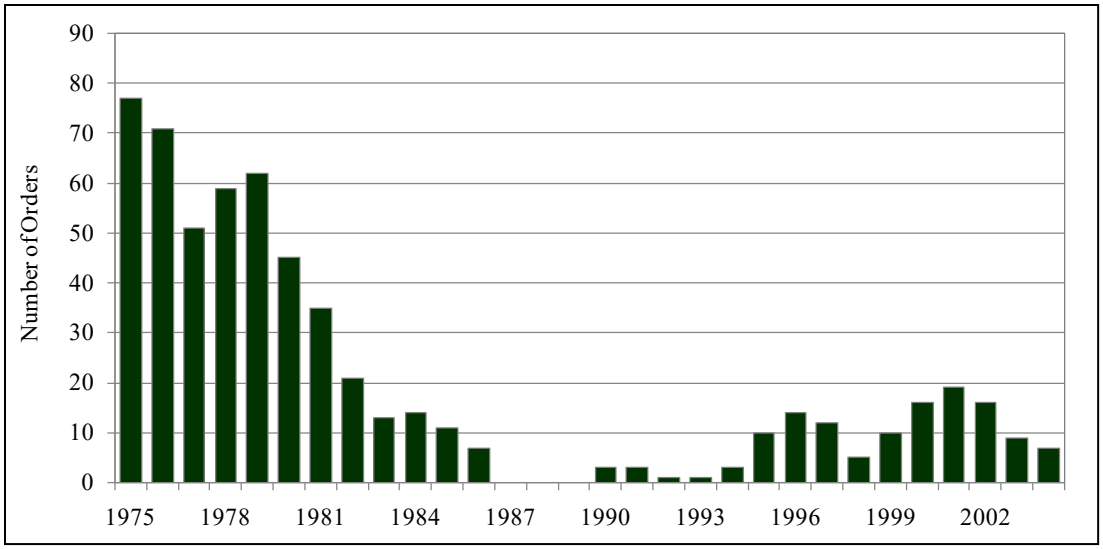

Figure 19. Commercial shipbuilding order history (through 2004).

(1,000 gross tons and over). Source: US Department of Transportation, Maritime Administration (USDOT, MARAD 2004 Dec).

Despite a spike in domestic oil and gas production, the number of commercial ships constructed per year since 2004 has not grown. As shown in Table 5, the number of large vessels delivered by US shipyards has actually decreased in recent years. Philly Shipyard has delivered more than half of all the Jones Act ocean-going merchant ships since the shipyard's inception in 2003. In total, Philly Shipyard has constructed and delivered 30 ships since that time, averaging less than two ships per year (Philly Shipyard c2020; Philly Shipyard c2020).

Table 5. Deliveries by US shipyards, by type of vessel, 2010–2014.

Type of Vessel	2010	2011	2012	2013	2014
Large deep-draft vessels	16	11	11	8	12
Offshore service vessels and crew boats	38	21	28	44	52
Tugs and towboats	81	110	119	105	114
Passenger vessels (>50 feet)	23	30	33	23	21
Commercial fishing vessels (>50)	8	20	15	27	18
Other self-propelled vessels (>50)	19	23	25	14	10
Large oceangoing barges	14	6	2	6	2
Inland tank barges	141	185	279	327	311
Inland freight and deck barges	861	1,053	749	593	527
Total Delivered	**1,201**	**1,459**	**1,261**	**1,147**	**1,067**
New constructed contracts*	75	89	84	114	77

Note: The delivery date for a vessel was determined by the date on which its Certificate of Documentation was issued, which should be, but may not be, the date on which the shipyard made the delivery.

*Announced new construction contracts with US shipyards for self-propelled vessels and oceangoing barges. Excludes inland barges, tugs, and towboats. Note, each contract may cover the construction of one or more vessel.

Source: US Department of Transportation, Maritime Administration (USDOT, MARAD 2015 Nov).

The decline of commercial shipbuilding demand in the 1980s negatively impacted the industry's ability to attract and retain skilled labor. A survey conducted by the US Department of Commerce's Bureau of Industry and Security (2001) considered the operating and labor conditions in US shipyards and found that the lack of skilled labor has reduced shipyard profits, negatively altered construction costs, and resulted in significant schedule delays for projects at a majority of shipyards. The number of private shipyard workers decreased by 5.5 percent from 2001 through 2018, illustrating that there may be a lack of skilled labor in the industry attributable to the cyclical nature of the industry and the younger generation's shift away from an education in trade and toward college and more white-collar professions (Industrial College of Armed Forces 2017; BLS 2020).

Turnover rates at shipyards are high relative to other manufacturing industries. The work can be strenuous and is almost entirely outdoors where workers are exposed to uncomfortable environmental conditions, especially during the summers of coastal high heat and humidity. This exacerbates the problem of finding skilled labor in today's market and has compelled many shipyards to contract out work they historically did in their own yard (USDOC, BIS 2001 May). Additionally, the push for just-in-time and other efficiencies has encouraged shipyards to switch to contract labor which, in turn, has reduced the number of consistently available jobs, thus driving workers away from the industry.

In an attempt to diversify and endure downturns in the industry, shipbuilders and platform fabricators have expanded into supply and support activities for the oil and gas industries and other related industries. Some general attributes related to successful diversification are general large geographic areas for work and storage; various unskilled and skilled labor (i.e., electricians, pipefitters, welders); and access to supportive infrastructure (i.e., roads, waterways, ports, communications). Now shipbuilders and fabricators can engage in dry-docking, inspections, maintenance, and surveys of stacked rigs and equipment. Employees can also work on production systems, and, despite its low dollar per task, it is a more stable employment option than traditional fabrication work and helps keep important yards economically viable during downturns.

The OSV market has become much more global in recent years, and its stability is reliant upon the number of rigs (especially in deepwater areas, which is where the bulk of new developments are). As of February 2019, 32 floating rigs and 75 high-spec jack-up rigs were under construction or on order. However, most of these rigs were ordered prior to the drop in oil prices that have continued since late 2014. Therefore, the market for deepwater drilling rigs is expected to be over-supplied for the foreseeable future (Hornbeck Offshore Services 2019).

2.6 Outlook

Platform fabrication and shipyards supporting the oil and gas industry face very similar challenges, as do other sectors that support offshore activities. These challenges include cost pressures, labor shortages, and the engineering and economic challenges created as new technologies are developed and exploration extends to deeper waters.

2.6.1 Platform Fabrication

Much has changed in the offshore drilling industry since the first subsea wellhead was installed in 1961. The total number of oil and gas rotary rigs in operation in the US dropped from 1,546 rigs in 2010 to 944 rigs in 2019 and is expected to continue decreasing through 2020, although production is expected to slowly increase through 2021 (EIA 2020 Jan 1; EIA 2020 Jan 27).

Additionally, while exploration in deeper water, particularly in the GOM, is a strong motivator for the platform fabrication industry's decisions to develop and expand their operations, low oil prices have reduced incentive to explore and drill. As such, exploration and production companies have halted operations at many of their rigs and plan to cut spending on new drilling for the second year in a row in 2020 (Reuters 2020 Jan 10).

Currently, there is no drilling off the US Atlantic Coast; therefore, platform fabrication facilities on the Atlantic Coast are essentially nonexistent. Cianbro is the only fabrication company in this region that has helped construct offshore platforms, though this is not the focus of their work. If and when fabrication facilities are developed in the Atlantic region depends strongly on the degree of progression in the production process in this area. Under a limited or moderate development scenario, most likely GOM or international sources would be the main producer of these materials and equipment, rather than the development of production facilities in the Atlantic states. Development of production facilities in the Atlantic OCS is increasingly less likely as the production technologies become more complex and require a greater and greater upfront capital investment (particularly the investment of space).

The capital costs of a platform fabrication facility are considerable and likely to be too large to support only limited offshore activities in the Atlantic OCS. For instance, Cianbro's two main fabrication yards in Georgetown, Massachusetts and Pittsfield, Maine are situated on a 13-acre and 15-acre parcel, respectively. The Georgetown site includes 43,550 square feet of manufacturing floor space in its fabrication facility, while the Pittsfield site contains only 21,000 square feet of floor space for fabrication. However, neither location is situated near a body of water that would be able to provide easy access or transportation for offshore projects (Cianbro c2020). This is a hefty commitment to surface development and is only the initial necessary commitment. There also must be other supporting equipment and site investments for a platform fabrication yard to function effectively and efficiently. Developments of this kind would require a significant offshore drilling market in the Atlantic OCS. A more reasonable expectation would be a more limited offshore development scenario. Under such an expectation, it is most likely that 1) the GOM region would continue to fabricate platforms and other structures and export them to necessary locations (or even international construction); 2) the Atlantic OCS would be supported by a system of FPSOs; or 3) a combination of 1) and 2).

With a long-term commitment to offshore oil and gas exploration in the Atlantic OCS, as well as ports potentially servicing offshore windfarms via the construction of different types of WTG foundations, new platform fabrication facilities may begin to operate in this region. It would likely take at least moderate offshore development to support such a facility in the area. As we increase the scale and scope of the development scenarios, the potential profit for project investors increases. This is vital for development, because investors will undertake the large upfront costs only if they believe there will be a long period of use and potential earnings.

2.6.2 Shipyards

Today, the US shipbuilding sector is almost entirely dependent on military contracts and is not adequately competitive on the international stage. Philly Shipyard completed construction on a container ship in March 2019 but has had no new prospects for shipbuilding since then. This lack of shipbuilding work has forced Philly Shipyard to shift its focus on maintenance and repair jobs as well as transitioning into a shipyard that can provide a mix of commercial and government work. As a testament to this possible shift, the shipyard was hired to provide maintenance and repairs to two government cargo ships owned by MARAD that will keep the shipyard busy through 2020 (Philly Shipyard 2020 Feb 11). Even with these efforts to stay afloat, the US industry needs to continue to invest in worker training and retention, efficiency, research and development, and efficiency improvements if it hopes to improve its global competitiveness.

Like other offshore support industries and other heavy construction and manufacturing sectors, workforce development is a major concern. A lack of skilled labor can hamper efficiency and profits. Companies in this situation may face financial pressures of lower profits, impacted construction costs, and delayed or untimely completion of projects. In an attempt to compensate for such shortages, yards may employ contract workers, especially during busy times. This problem is expected to compound with the retirement of the existing workforce, especially for shipyards, because workers require many years of experience and take ample time to replace adequately (Industrial College of Armed Forces 2017). In the US, over one third of shipyard workers are over the age of 50 and the average age of a worker is 45 (Industrial College of Armed Forces 2008).

In the early 20th century, the US shipbuilding industry suffered from a lack of necessary capital; however, Title XI of the Merchant Marine Act of 1936 began a program to provide financial capital support and debt-underwriting to assist US ship operators. The program was entitled the “Federal Financing Guarantee Program” (FFGP) and provided an assurance of payment by the federal government. Specifically, the FFGP guarantees full payment to the lender of the unpaid principal and interest in the event of default by the vessel owners or general shipyard facility (Transportation Institute 2019 Oct 11).

In December 2016, a $374 million loan guarantee was approved to construct two LNG powered ConRo vessels – a hybrid of a roll-on/roll-off vessel and a container ship (USDOT, MARAD 2018a Oct 30). Philly Shipyard’s two most recently built containerships were also approved under Title XI for a loan amounting to $413 million (USDOT, MARAD 2019 Feb 7). The current portfolio of Title XI contains 39 individual loan guarantee contracts, covering nearly 250 vessels including drill rigs, tankers, barges, containerships, passenger vessels, supply vessels, and tugboats (Transportation Institute 2019 Oct 11). Since its inception, Title XI has funded over 121 projects, including passenger vessels, supply vessels, tugs, and shipyard modernization projects (USDOT, MARAD 2018b Oct 30). In 2007 the American Shipbuilding Association’s president boasted that Title XI helps American shipyards to retain their skilled employees, expand the fleet of US-built commercial ships available to the Department of Defense in time of war, and provide the highest construction standards in the world (2007 Mar 15).

There are 22 shipyards identified in the Atlantic region. These facilities range in size from those that construct or repair small vessels for coastal or inland use to those that focus on large oceangoing naval and commercial ships. A limited number of the facilities are used for new construction; the majority are for repairing existing vessels. Repair facilities, like the yards themselves, vary in size and capabilities: some have only topside capabilities, others have dry-docking options for smaller ships, boats, and barges, and then some facilities have dry-docking capability for large ocean vessels. There are medium-sized shipyards in several states along the Atlantic Coast that would be the most likely to offer support for expansion of the oil and gas industry to the Atlantic OCS.

If drilling were to begin in the Atlantic OCS region, it is most likely that medium-sized vessel construction and repair shipyards would best serve the industry. The majority of medium-sized shipyards in this area are in Virginia and Florida. Massachusetts and Maine also have a good number of yards (USDOT, MARAD 2004 Dec). Because these yards already exist, it is unlikely that any new facilities would be constructed to support oil and gas activity, but existing yards may expand to meet demand.

New shipyards in the Atlantic area would still compete with other shipyards in all coastal regions of the US, especially in the GOM. The three most likely scenarios for supplying the Atlantic OCS with OSVs, tugs, barges, and other support craft are summarized in the following sections.

Scenario 1: Greenfield Development

One or several shipyard facilities could be developed along the Atlantic coast, which will be dedicated to the construction of various offshore vessels to support oil and gas activities. This scenario could only occur with the development of a several hundred-acre tract of land along navigable water. There is a large upfront capital requirement for this scenario, which includes new construction pads, electricity, lighting, roads, terminals, slips, bulkheads, construction shelters, maintenance buildings, storage buildings, transportation and construction equipment, and much more. Because this would be a significant capital investment, this scenario is unlikely unless there is a well-defined and expansive Atlantic oil and gas industry development plan. An extensive development would be necessary for shipyard developers to gain an adequate assurance of profitability upon their investment.

Scenario 2: Expansion within the Atlantic OCS Study Area

Existing shipyards along the Atlantic coast may expand to take on the additional demand resulting from drilling and other oil and gas activities in the area. Most facilities in the area specialize in construction or repair of craft similar to what is used for oil and gas activities. This scenario requires incremental investments, rather than the large upfront investment required with the construction of a new yard. Therefore, this scenario would require less strong assurance of the future drilling activity in the area for yards to act. The actual unfolding of this scenario is uncertain; it depends on the existing configurations of shipyards in the area and their financial and business interests regarding expansion. For many of these facilities, a moderate oil and gas development scenario would likely be enough motivation to take on the new business prospects and investments to expand onsite facilities. Many existing facilities are already equipped to repair oil and gas industry support vessels, even in a limited oil and gas development scenario.

Scenario 3: GOM Construction

No new shipyard development will take place; instead, the new demand in the Atlantic region will be met by existing producing areas along the GOM. It is also possible that during early phases of Atlantic OCS development, craft from the GOM are diverted for use in the Atlantic and no new craft are built at all. Depending on the state of the industry when Atlantic OCS development occurs, if industry conditions are tight with high use of existing vessels and high commodity prices, diversion of existing craft will be much less likely.

This scenario is likely to occur because existing facilities in the GOM will have cost-effective opportunities for expansion and to create geographic diversity to their vessel construction operations and businesses. The shipbuilding industry is extremely competitive. The GOM firms may want to expand to increase their competitive edge and would have advantages, such as already possessing yards with adequate capacity, a skilled workforce, experience in engineering and design, and relationships with input vendors and with service and production companies.

This is even more likely given the recent history of mergers and consolidations of firms along the GOM. Firms are trying to take advantage of the scale efficiencies and larger, more strategic locations. The development of new firms in the Atlantic OCS may be challenging in the absence of expansive regulation with tight oil and gas market conditions for an extended period of time.

2.6.3 Factors Impacting East Coast Development

Both shipbuilding and platform fabrication for the oil and gas industry depend on the industry itself, which is impacted by the following (among others) (Gulf Island Fabrication 2019):

a. Local and international political and economic conditions and policies;
b. Customer capital spending budget changes;
c. Unavailability of exploratory or drilling rigs, or both;
d. Oil and natural gas prices and expectations about future prices and volatility;
e. Worldwide demand for oil and gas;
f. Availability and rate of discovery of new oil and natural gas reserves in offshore areas;
g. Cost of offshore exploration for, production of, and transportation of oil and natural gas; and
h. Environmental and other regulations concerning oil and gas producers and their service providers.

Both the shipbuilding and platform fabrication industries must be resilient to the inevitable downturns in demand as demand in the oil and gas industry decreases. Also, firms are extremely competitive, which increases the difficulty of new firms entering the market or creating a new supporting structure in the Atlantic region.

The oil and gas industry supports offshore development in the Atlantic OCS, but as of yet there are no major platform fabrication companies suggesting any future investments in the region. This is a result of governmental policies regarding drilling, but for a company to undertake such an investment there must also be:

a. The availability of a suitable location with water access and (preferably) multi-modal transportation;
b. A skilled workforce with trade experience;
c. Favorable local siting conditions; and
d. Favorable local business conditions.

The extent of offshore renewable energy development may influence the siting of a new platform fabrication yard. Offshore wind (OSW) energy is going to have a particularly strong role. There are currently at least eight states across the eastern seaboard with leases currently in place with BOEM for OSW development, and it is uncertain exactly what influence this will have on development of the oil and gas industry in the area (BOEM 2018). The two technologies can be complimentary; one company, Keppel Offshore and Marine, engages in support activities for oil and gas, from platform fabrication to shipbuilding and repair, but in recent years is also investing in research and development of OSW technologies. In fact, in 2018, Keppel secured contracts worth $720 million related to the design, construction, and installation of two converter stations that will serve offshore wind farms in the North Sea as well as two offshore wind stations in Taiwan (Keppel Offshore & Marine 2019 Mar). There is the potential for OSW activity, coupled with policy support, to increase business support for a platform fabrication facility; however, this is speculative and depends on a number of factors.

There are currently only two operational offshore wind farms in the US—a 30 MW site off the coast of Rhode Island and a 12 MW project off the coast of Virginia–but many Atlantic states are eager to construct larger projects. As of February 2018, thirteen ocean area leases were awarded offshore in Maryland, Massachusetts/Rhode Island, New Jersey, New York, North Carolina, and Virginia (Figure 20) (Weissman et al. 2018; Hand 2018 Mar 23).

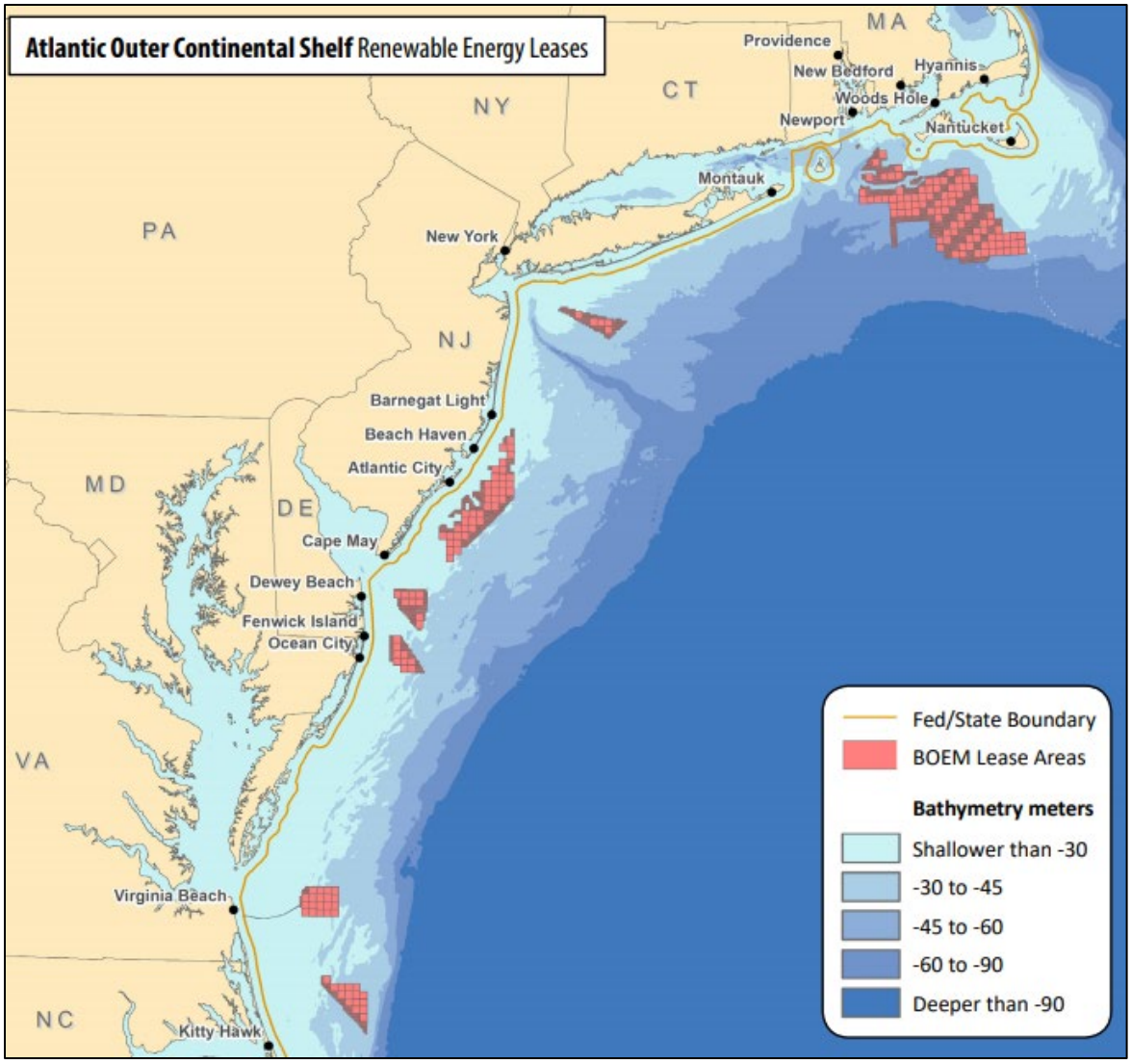

Figure 20. Atlantic OCS offshore wind leases.

Source: Bureau of Ocean Energy Management (BOEM 2019 Mar).

Maine's 12 MW Aqua Ventus is expected to be installed in 2023 (New England Aqua Ventus 2020 Aug 5) . The project will act as a test for advanced technology that was developed by University of Maine researchers. It will include floating turbines that are meant to help provide access to deepwater areas where fixed-base offshore foundations cannot be installed. The project has received $40 million in funding from the USDOE and will be partially constructed by Cianbro's fabrication facility in Brewer, ME (Weissman et al. 2018; Broehl 2019 Oct 10).

Maryland currently has two major OSW project proposals in the works. The first, the Skipjack Wind farm, is one of the large-scale projects likely to be commissioned soon around 2022 or 2023. It is being developed by Denmark company Ørsted and announced a multi-million dollar staging area in the Port of Baltimore in July of 2019 (Broehl 2019 Oct 10). The second project, the 268 MW *US Wind Maryland*, was developed by Italian-based Renexia S.p.A. and will contain 32 wind turbines. The two projects have a combined capacity of 870 MW and already have subsidies in place that will pay each wind plant $132/MWh (Weissman et al. 2018; Broehl 2019 Oct 10).

Massachusetts reportedly has more offshore wind technical potential than any other state in the US To capitalize on this, two OSW projects are currently being planned and may receive approval in the next few years (Weissman et al. 2018). The 800 MW Vineyard Wind farm already has a power purchase agreement in place with several electric utilities and won a competitive power contract auction that will provide it with an offtake payment of $65/MWh and is expected to be commissioned in 2023 (Thomas et al. 2019a Aug 22; Broehl 2019 Oct 10). In October 2019, Mayflower Wind was selected to begin contract negotiations to provide 804 MW of offshore wind power to the state. The energy output from these two projects would be enough to cover 12 percent of Massachusetts' total annual energy demand (CBS Boston 2019 Oct 20).

New Jersey recently increased its target for offshore wind-generated electricity from 3.5 GW to 7.5 GW by the year 2035 (Frangoul 2019 Nov 21). Ørsted won the state's first offshore wind solicitation with a 1,100 MW project named Ocean Wind. The wind farm would be built 15 miles (24 kilometers) off the coast of Atlantic City and is expected to be commissioned in 2024 (Stromsta 2019 Jun 21). Likewise, New York has the US's leading offshore wind target of 9 GW by 2035 and recently confirmed its plan to issue its second 2020 solicitation for offshore wind farms that would add at least 1 GW to the state's pipeline on top of the 816 MW Empire Wind project that is already planned for an area 20 miles (32 kilometers) south of Long Island (Equinor 2019 Jul 18; Stromsta 2020 Jan 9).

Rhode Island, Connecticut, North Carolina, and Virginia also have OSW projects in the works, the first of which is a 12 MW pilot project off the coast of Virginia Beach that could be online as soon as 2021 (Weissman et al. 2018; IER 2019 Jul 12).

In total, states along the East Coast have set targets to procure more than 19.3 GW of offshore wind capacity through 2035 (Thomas et al. 2019a Aug 22). A study prepared by the Special Initiative on Offshore Wind (SIOW) and Renewables Consulting Group projected that offshore renewable energy will generate nearly 20 GW of power in seven East Coast states as soon as 2030, resulting in a nearly $70 billion capital expenditure (CAPEX) revenue opportunity for US businesses in the offshore wind supply chain, as shown in Figure 21 (McClellan 2019 Mar).

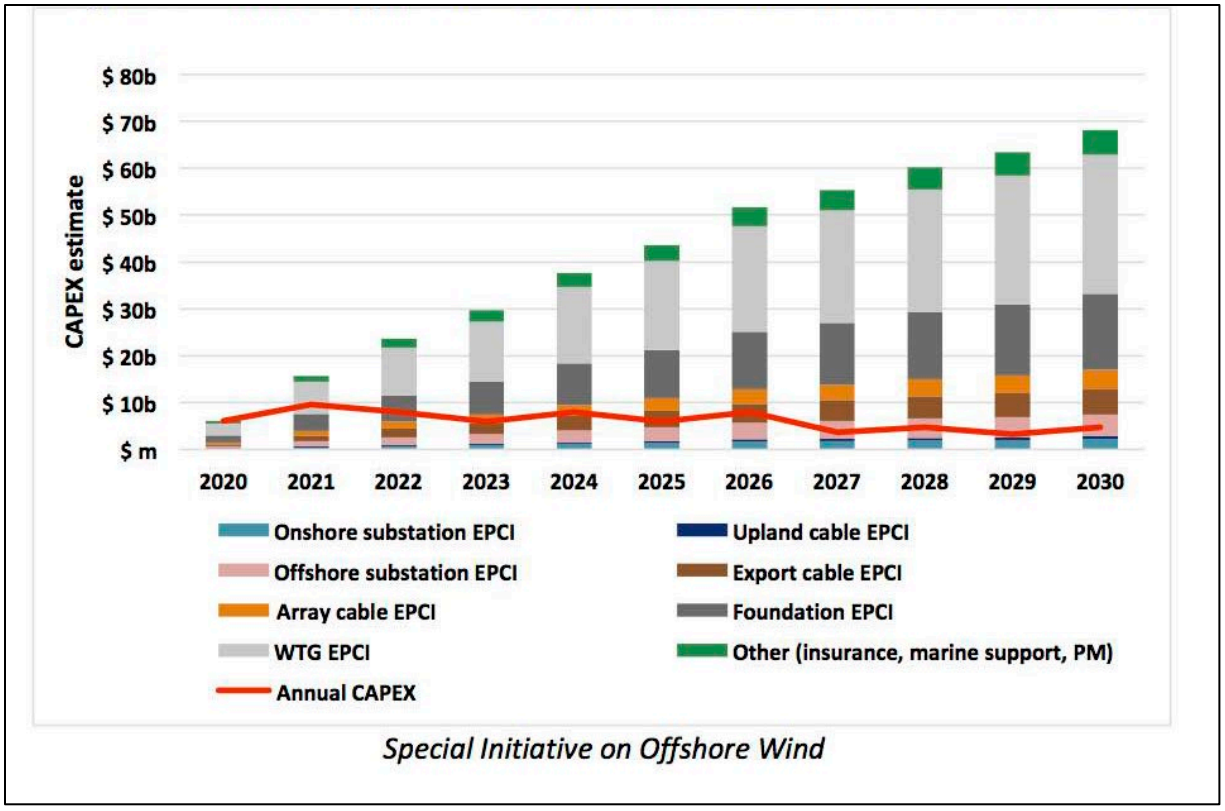

Figure 21. Offshore wind supply chain contracts cumulative CAPEX Forecast.

Source: Special Initiative on Offshore Wind (McClellan 2019 Mar).

SIOW estimated the CAPEX associated with engineering, procurement, construction, and installation (EPCI) contracts of several offshore components signed between 2018 and 2030. The EPCI contracts include costs for manufacturing, installation, and vessels. Assuming for costs associated with technological advances and economies of scale, SIOW determined that the primary drivers of offshore wind CAPEX would be (McClellan 2019 Mar):

- Turbine supply and installation;
- Foundation supply and installation;
- Offshore substation supply and installation; and
- Export cable supply and installation.

Despite this positive outlook regarding the OSW industry, the Atlantic region is currently ill-equipped to support state OSW targets driving offshore wind development, which are outlined at length in Chapter 2, Section 6. If state targets are to come close to being met, major investments will need to be made to accommodate for this surge of new power, including port staging and foundation fabrication.

Many of the OSW project developers currently seeking government approval to construct offshore wind farms in the Atlantic OCS are foreign-based companies. As a result, many of the components and services needed for these projects may be procured overseas, since there is already an established offshore wind industry overseas, especially in Europe. For example, Massachusetts' Vineyard Wind farm is being developed by Avangrid Renewables and Copenhagen Infrastructure Partners, who selected manufacturer, GE, to supply wind turbines for the project (Broehl 2019 Oct 10; Offshore Engineer Staff 2020 Dec 2). Another feasible option would possibly be to have the various onshore wind-manufacturing facilities in the US produce the components needed for the new OSW market. However, as more OSW projects receive approval, and construction on a large-scale basis begins on the Atlantic Coast, these methods could prove to be costly in the long run.

The turbines used in OSW projects are much larger than those made for inland generation, and the wind facilities already established in the US have historically not been large enough to efficiently produce the necessary components. Gulf Island Fabrication, for instance, played a role in the US's first OSW project by producing turbine foundations, jackets, and piles for Rhode Island's Block Island wind farm in 2015 (Barnes 2017 May 15). However, some of these facilities are in the process of being altered and remodeled to accommodate the larger parts.

However, the transportation costs to move vast quantities of large equipment would likely increase and may prove to be too great in the long run as more projects are green lit for construction. Thus, the need for localized manufacturing facilities capable of supplying large OSW components to the Atlantic OCS is imperative to reach the capacity targets set by the East Coast. This will require a large capital investment, as the estimated cost to establish manufacturing facilities for turbines alone is around $200 million to $300 million based on recent projects in Europe (Lefevre-Marton et al. 2019 Apr). This up-front expense could make it hard for new companies to form and take advantage of this open market. Instead, fabrication yards in the GOM region may see this as a chance to expand their operations to the Atlantic and use their assets to acquire spots for themselves in this new industry.

For example, in 2018, Gulf Island Fabrication announced a collaboration with international steel pipe manufacturer, EEW Group, to open and staff a Massachusetts facility that would manufacture offshore wind components for the state's Bay State Wind project, located 25 miles off the coast. The new facility is expected to generate approximately 500 annual construction jobs and nearly 1,200 additional indirect jobs in the local community. The facility would produce monopile foundations and transition pieces, including secondary steel components, painting, and prefabricated components for the OSW turbine foundations. Gulf Island's work, specifically, would focus on outfitting the secondary materials and painting (Gulf Island Fabrication 2018 Apr 3).

There could also be a spike of investment by foreign companies to open their own manufacturing facilities in the Atlantic region. In 2019, Ørsted announced plans to help German company EEW Group find a location to produce steel foundations for offshore wind platforms in Paulsboro, New Jersey (Stromsta 2019 Jul 3). As of July 2019, more than $200 million had reportedly already been spent to upgrade the port of Paulsboro in an effort to make it the most appealing choice to host offshore wind production (Johnson 2019 Jul 2).

If OSW platform fabrication yards are established in the US, the shipbuilding industry could also benefit from a new source of work. The size of OSW turbine components, the physical limits of bridges and harbors, and the challenges of assembling and installing these components at sea reveal the need of construction and maintenance vessels (Lefevre-Marton et al. 2019 Apr). Wind turbine installation vessels (WTIVs), specifically, are needed to install large turbines in deep water. However, under the US Jones Act, vessels that are used to transport OSW components from U.S ports to offshore sites must be manufactured and registered in the US Therefore, shipyards along the East Coast would likely see an increase in contracts for shipbuilding, but only if the OSW industry became large enough. WTIVs can cost between $100 million and $200 million and take at least two years to build by experienced workers. With such a high construction cost, it would only be worth investing in WTIVs if OSW project installations increased exponentially to the point that it would be costlier, riskier, and more time-consuming to use smaller transport vessels, such as barges, that are not compliant with the Jones Act (Lefevre-Marton et al. 2019 Apr). As of December 2020, only one company, Dominion Energy, has announced the development of the first Jones Act compliant WTIV (Dominion Energy 2020 Dec 16).

Pacific Orca, shown in Figure 22, finished construction in Korea in 2012 and is the world's largest WTIV capable of carrying and installing up to 12 wind turbine generators rated at 3.6 MW each. *Pacific Orca* is a specialized heavy-lift jack-up vessel, measuring 528 feet (170 meters) in length, that can install wind turbine generators in water depths of 197 feet (60 meters). If offshore wind becomes a new main source of energy, it's possible that shipyards will be contracted to build ships of this size so that wind power can be accessed further offshore in deeper waters (Ship Technology c2020).

Figure 22. *Pacific Orca* wind turbine installation vessel.

Source: (Ship Technology c2020).

Even if shipbuilding does not become a large part of the US industry, shipyards in the region are likely to see an increase in work related to maintenance and repairs of OSW segments and the vessels that maintain them due to the yards' proximity and experienced workforce.

3. Ports

3.1 Description of the Industry and Services Provided

Ports have a vital role in supporting offshore oil and gas exploration and production. Ports are the delivery, transfer, and launching points for the necessary structures, equipment, supplies, crew, and other elements important to offshore installations. In addition, the marine vessels and aircraft that support offshore platforms are based, kept, and maintained at ports. Offshore E&P operations depend heavily on goods, equipment, and support services arriving from onshore areas, and ports are critical link between onshore and offshore activities.

However, ports are diversified in both their setup and the types of commerce they facilitate. While ports are important for offshore oil and gas activities, that is not the only, nor is it usually the primary activity that they conduct. Ports primarily serve as locations through which produced goods, commodities, equipment, and other materials move. Some of the leading commodities that are shipped for domestic and foreign trade through US ports include (USACE 2018 Oct 1):

- •Coal
- •Coal coke
- •Crude petroleum
- •Petroleum products
- •Chemical and related products
- •Forest products, wood and chips
- •Pulp and waste paper
- •Sand, gravel, and stone
- •Iron ore and scrap
- •Non-ferrous ores and scrap
- •Sulfur, clay and salt
- •Primary manufactured goods
- •Food and farm products
- •All manufactured equipment
- •Waste and scrap, NEC

Figure 23, presented below, illustrates the principal commodity groups that were carried by water in the US from 2007 through 2016, the most recent year in which data is available. During this time, waterborne commerce for many commodities remained steady, with the notable exception of coal, which declined by approximately 39 percent. Waterborne commerce for petroleum and petroleum products has also remained, generally, consistent over time and comprised 42 percent of all US waterborne commerce in 2016 (USACE 2017 Nov 15). Chemical commodity exports, which rely heavily on hydrocarbons as their feedstock, have slightly increased over the past several years.

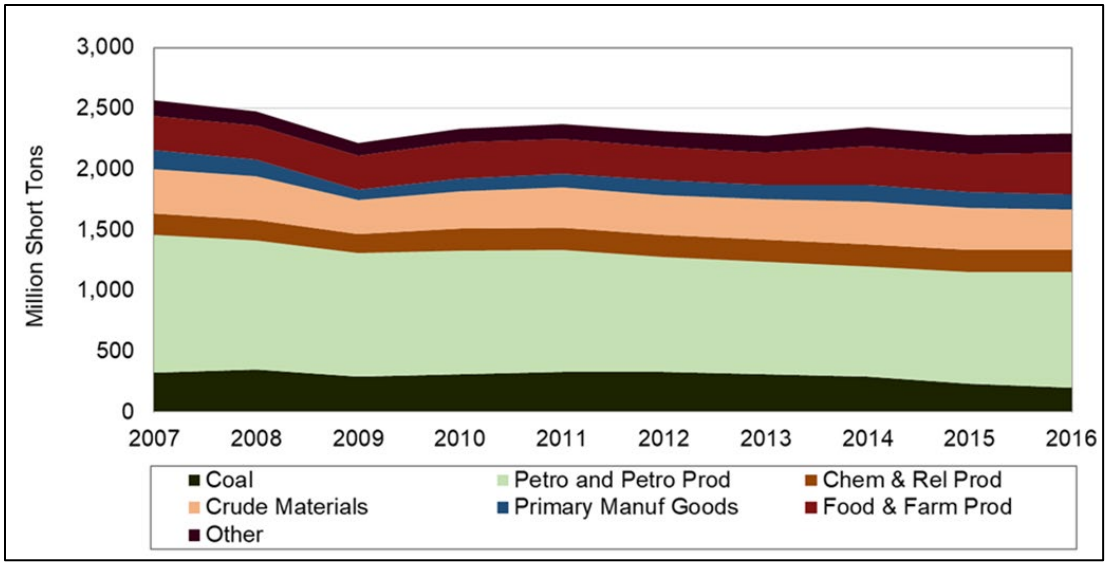

Figure 23. Principle commodity groups carried by water, 2007–2016.

Source: US Army Corps of Engineers (USACE 2018 Oct 29).

3.2 Typical Facility Characteristics

In general, there are two major types of port facilities: 1) deep-draft seaports; and 2) inland river and intra-coastal waterways port facilities.

Deep-draft seaports accommodate ocean going vessels whereas inland ports are usually located on rivers or intra-coastal waterways (USACE 2018 Oct 1). Inland ports are also less concentrated geographically than deepwater facilities and provide almost limitless access points to the waterways (Marine Transportation System 1999).

Ports also vary considerably by size, specialty, and other defining characteristics that include:

Channel depth: Ocean going shipping vessels require port depths of up to 50 feet (15 meters) deep, and a coastal port's capacity to serve vessels is affected by its ability to intake large vessels with significant channel depth requirements (USDOT 2020 Jan 15).

Berth length for container ships: A berth refers to the physical location in which shipping vessels stop at the port. The number of berths and their total length affects a port's ability to provide adequate services (USDOT 2020 Jan 15).

Container terminal size: Ports need physical space to store storage containers (both loaded and empty), and they use container terminals to do so (USDOT 2020 Jan 15).

Presence of rail transfer facilities: A port's capacity is affected by its ability to intake and deliver cargo from inland areas, and rail is the primary medium with which cargo containers are shipped inland at distances of greater than 500 miles (805 kilometers (Ashar and Swigart 2017).

Number and type of container cranes: Container cranes serve as the link between the water-side and the land-side of a port, and they are used to load and unload container vessels. A port's capacity to provide reliable service to shipping vessels is affected by the number and size of container cranes at the port (USDOT 2020 Jan 15).

Air draft restrictions (vertical clearance in feet): Bridges cross many navigation channels, and a port's capacity for vessel intake may be limited by the height of such bridges (USDOT 2020 Jan 15).

Some of the aforementioned characteristics are illustrated below in Table 6, Figure 24, and Table 7, which present comparisons of the number of container terminals with rail access, the number of container cranes, and the air draft restrictions at select ports in the Atlantic.

Table 6. Number of container terminals at select Atlantic ports

Port	Container terminals	On-dock rail access
Jacksonville, FL	3	1
Miami, FL	3	3
New York, NY, and NJ	6	6
Palm Beach, FL	1	1
Savannah, GA	1	1
Port of Virginia, VA	3	2
Wilmington, NC	1	1

Note: This is a small sample of ports in the Atlantic area. The sample was constrained due to data unavailability.

Source: US Department of Transportation (USDOT 2020 Jan 15).

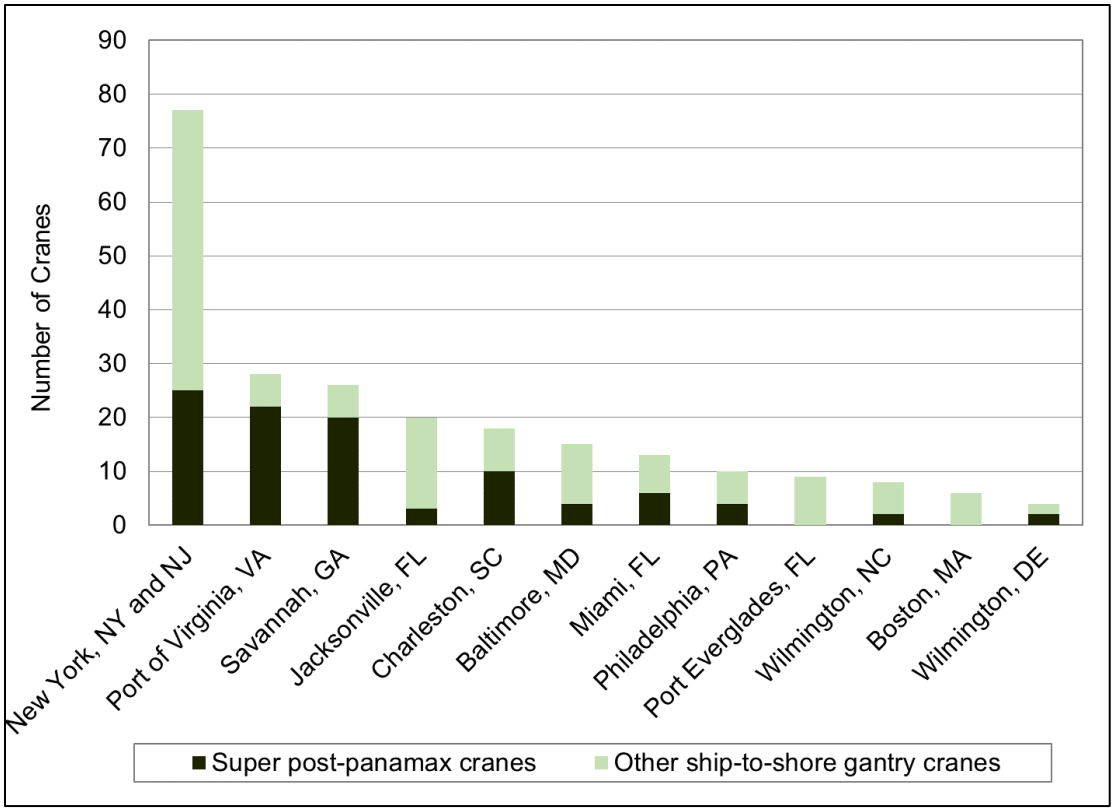

Figure 24. Number of cranes at Atlantic ports.

Source: US Department of Transportation (BTS 2017 May 20).

Table 7. Air draft restrictions of Atlantic ports

Port	Bridge	Air draft in feet
Baltimore, MD	Chesapeake Bay	182
Charleston. SC	Ravenel	185
Jacksonville, FL	Napoleon B. Broward	169
New York, NY, and NJ	Bayonne	215
New York, NY, and NJ	Verrazano-Narrows	215
Philadelphia, PA	Benjamin Franklin	135
Savannah, GA	Talmadge Memorial	185
Tampa. FL	Sunshine Skyway	180
Wilmington, DE	Delaware Memorial	188

Source: US Department of Transportation (USDOT 2020 Jan 15).

The aforementioned infrastructure components are integral to a port's operations, which are illustrated in Figure 25 and Figure 26 below. Figure 25 presents the process by which ports service shipments of dry bulk, while Figure 26 illustrates the process by which ports service shipments of containers. Figure 27, meanwhile, illustrates the manner with which ports handle shipments of liquids.[3]

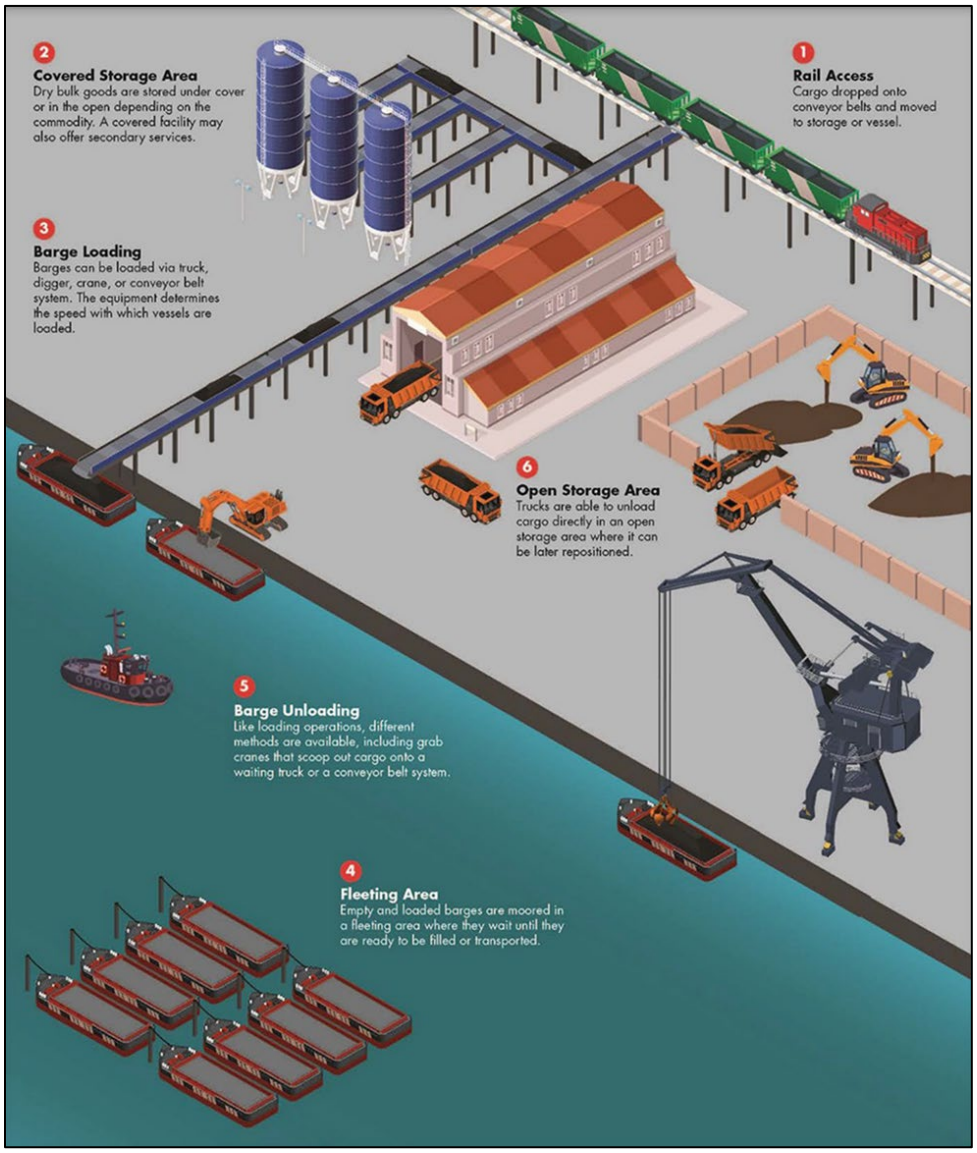

Figure 25. Dry bulk terminal flow.

Source: US Department of Transportation (BTS 2017 May 20).

[3] The relationship between LNG and Ports is further discussed in Chapter 9.

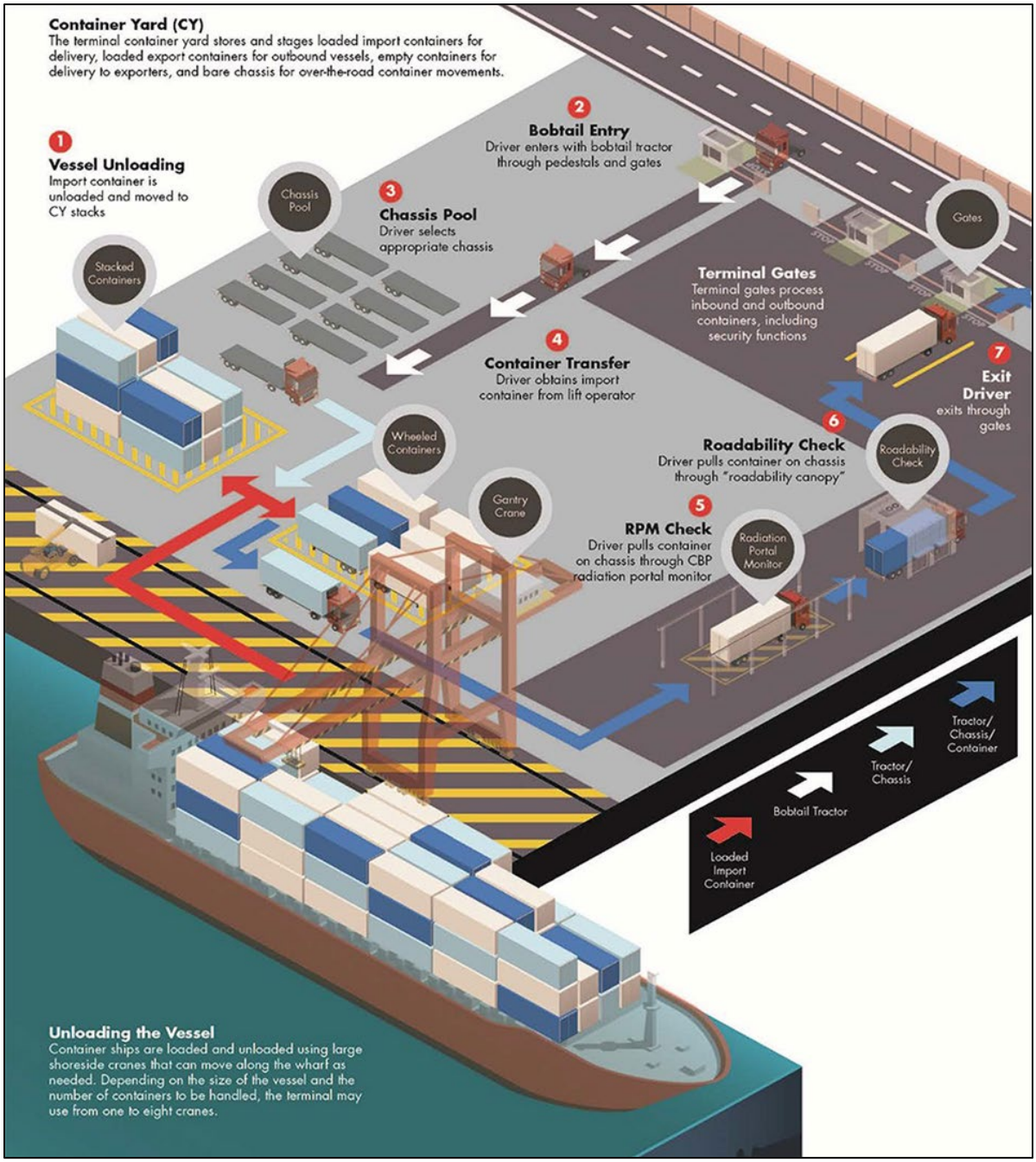

Figure 26. Container terminal flow.

Source: US Department of Transportation (BTS 2017 May 20).

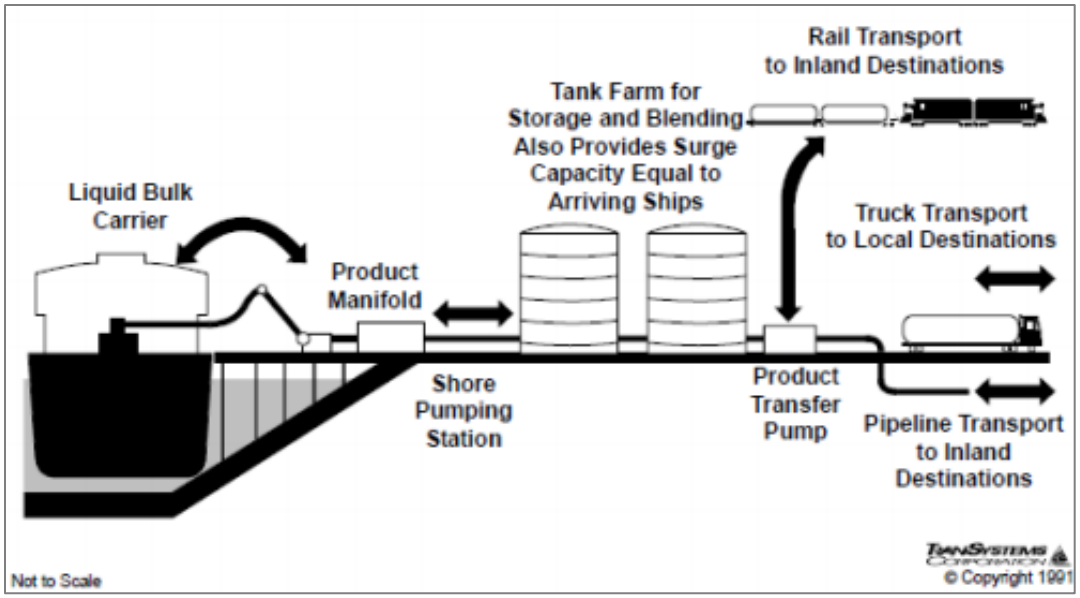

Figure 27. Liquid bulk terminals.

Source: (Madueke c2013).

3.3 Geographic Distribution

Table 8 presents a list of the principle Atlantic ports that handle greater than 5 million tons of shipments per year. Principle ports in the Atlantic region that handle less than 5 million tons of shipments per year, meanwhile, are detailed in Table 9.

Table 8. Principle Ports in the Atlantic region (Tonnage > 5 million tons)

Port	Total Tonnage (2017)
New York, NY, and NJ	135,874,693
Port of Virginia, VA	67,251,530
Baltimore, MD	45,474,946
Savannah, GA	39,865,610
Philadelphia, PA	28,523,744
Charleston, SC	26,980,805
Pittsburgh, PA	26,022,535
Port Everglades, FL	24,901,038
Jacksonville, FL	18,526,032
Paulsboro, NJ	18,362,258
Boston, MA	16,618,977
Marcus Hook, PA	14,132,355
New Haven, CT	8,868,274
Providence, RI	8,489,693
Miami, FL	7,824,022
New Castle, DE	7,139,208
Wilmington, DE	6,864,705
Camden-Gloucester, NJ	6,734,653
Albany, NY	6,009,212
Wilmington, NC	5,518,252
Port Canaveral, FL	5,086,577

Source: US Army Corps of Engineers (USACE 2018 Oct 29).

Table 9. Principle Ports in the Atlantic region (Tonnage < 5 million tons)

Port	Total Tonnage (2017)
Portland, ME	4,898,165
Port Manatee, FL	3,791,805
Morehead City, NC	2,517,846
Brunswick, GA	2,487,757
Palm Beach, FL	2,470,562
Penn Manor, PA	2,258,031
Chester, PA	2,187,677
Bridgeport, CT	2,031,424
Port Jefferson, NY	1,969,927
Searsport, ME	1,442,361
Hopewell, VA	804,584
Hempstead, NY	762,218

Source: US Army Corps of Engineers (USACE 2018 Oct 1).

Atlantic ports are highly industrious relative to other US coastal regions. Of the top 25 ports in the United States (ranked in terms of TEU, or twenty-foot equivalent units), 13 are located along the Atlantic. The largest port in the Atlantic region is the Port of New York and New Jersey. This port ranks first among all ports in the Atlantic in terms of tonnage and container TEUs. It also receives the most first port-of-calls in the Atlantic region (72%), and has the most container terminals with on-dock rail access (6) and the most cranes (77) (USDOT 2020 Jan 15; PANYNJ c2020).

3.4 Scope of Economic Contribution to Regional Economy

The BLS utilizes the North American Industry Classification System ("NAICS") for collecting and publicizing statistical data related to the US economy. NAICS class 483, for instance, encompasses all water transportation, including both deepwater transportation and inland water transportation. Additionally, it includes all shipping and port activities. NAICS 488310, meanwhile, includes all "port and harbor operations," such as port facility operations, harbor operations, and terminal maintenance activities. Thus, at the aggregate three-digit level, NAICS 483 encompasses all port related activity ranging from the port itself to the water transportation moving into and out of the port. While the Bureau of Economic Analysis (BEA) collects state GDP information at the higher three-digit level (NAICS 483), it does not provide information at the sub-level like that provided on labor data by the Bureau of Labor Statistics (BLS).

Table 10 compares each Atlantic state's water transportation (NAICS 483) to its own state-level gross domestic product (or "GDP") to ascertain the importance of port and transportation activities to each Atlantic state's economy and the region as a whole. From a regional perspective, the Atlantic region accounts for roughly 42 percent of all water transportation economic activity, as represented by GDP.

Within the Atlantic region, Florida's water transportation activities are the largest, accounting for over half (54 percent) of total regional economic activity (GDP). There are two primary reasons why Florida stands out as an outlier in the below tables and charts. First, there is a large volume of international trade within certain key ports in Florida. In 2018, the state of Florida ranked 6th in terms of the total annual tons of cargo imported and exported (USACE 2019 Dec 12). Second, the data from the BEA and BLS is unable to distinguish across specific counties in Florida, which means that economic data is presented across the entire state, including the panhandle.

Other large water transportation-related states, as measured by NAICS 483 GDP, include New York and New Jersey, which comprise 13 percent and 10 percent of the regional water transportation GDP, respectively.

Table 10. Regional and national GDP contributions, water transportation sector, 2017

State	Water Transportation GDP (Millions in current $)	Total GDP (Millions in current $)	Water Transportation GDP as a Percent of Total State GDP (%)	Water Transportation GDP as a Percent of Total US Water Transportation GDP (%)
CT	259	268,311	0.10	1.85
DC	3	134,043	0.00	0.02
DE	2	70,775	0.00	0.01
FL	3,235	985,665	0.33	23.07
GA	43	566,474	0.01	0.31
MA	228	540,786	0.04	1.63
MD	194	394,259	0.05	1.39
ME	9	62,040	0.01	0.07
NC	17	538,402	0.00	0.12
NH	8	80,900	0.01	0.05
NJ	616	595,325	0.10	4.39
NY	777	1,604,134	0.05	5.54
PA	103	744,290	0.01	0.73
RI	39	58,506	0.07	0.28
SC	69	223,111	0.03	0.49
VA	339	509,373	0.07	2.42
Total Region:	**5,941**	**7,376,392**	**0.08**	**42.37**
Total US	**14,020**	**19,519,424**	**0.07**	**100.00**

Source: US Bureau of Economic Analysis (BEA c2020).

Figure 28 compares the water transportation GDP across the individual Atlantic region states, for 2017. Florida reports the highest 2017 water transportation-related GDP relative to any other state in the region at $3.2 billion per year. Meanwhile, New York and New Jersey respectively report $777 million and $616 million in water transportation-related GDP.

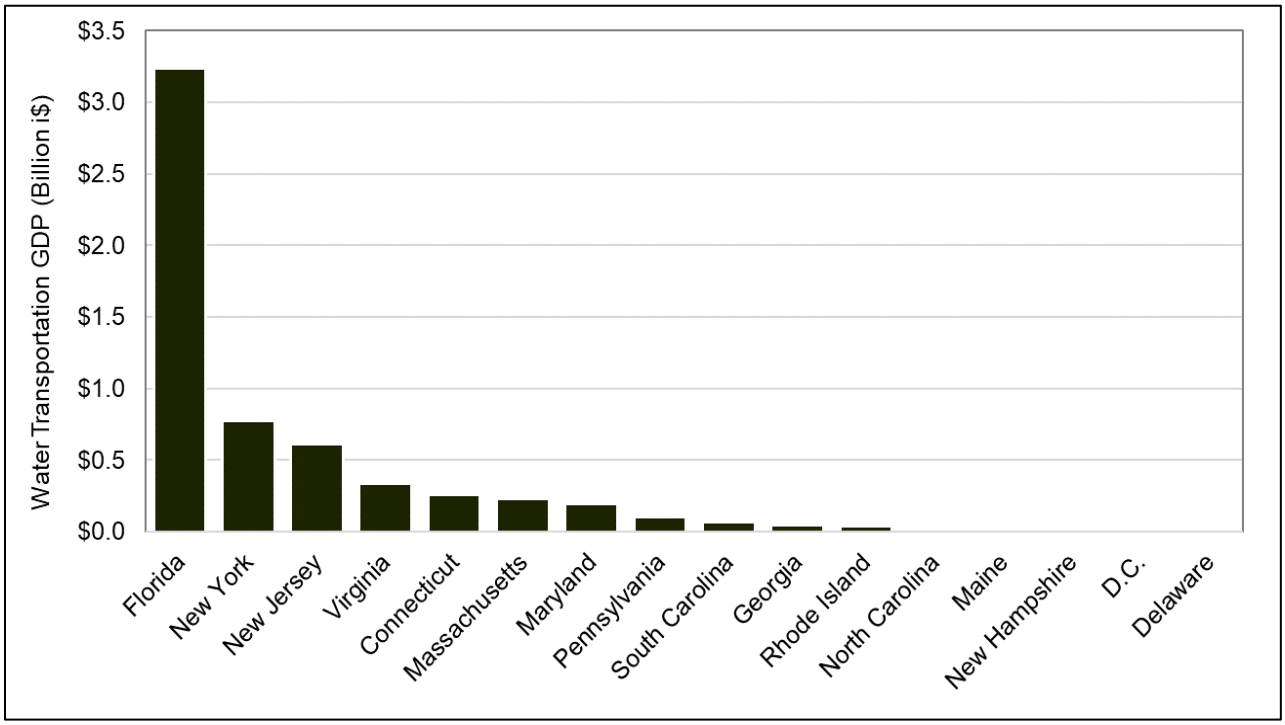

Figure 28. Atlantic region water transportation GDP shares, 2017.

Source: US Bureau of Economic Analysis (BEA c2020).

Figure 29 compares the trends in water transportation GDP since 1997. The chart shows rapid water transportation-related economic activity, particularly after 2005 when economic activity surged in the Atlantic region. Most of this rapid increase in economic activity appears to be driven by the influx of international trade activities in Florida, as explained earlier.

The chart also shows a clear realignment of water transportation economic activity, particularly in the aftermath of the 2008 to 2009 economic recession. For instance, New York, New Jersey, and all other Atlantic states (on a collective basis) have seen the relative shares of regional water transportation economic activity fall as Florida grows, particularly in 2012 after the sharp drop following the BP oil spill in 2010 (Allen, 2011). As mentioned above, BEA and BLS are unable to distinguish GDP data across specific counties in Florida, which means that economic data is presented across the entire state, including the panhandle. Water transportation GDP was relatively constant until 2004, when an increasing trend commenced. Since 2008, however, overall water transportation sector GDP is down across both the region (by 20 percent) and the nation (by 15 percent).

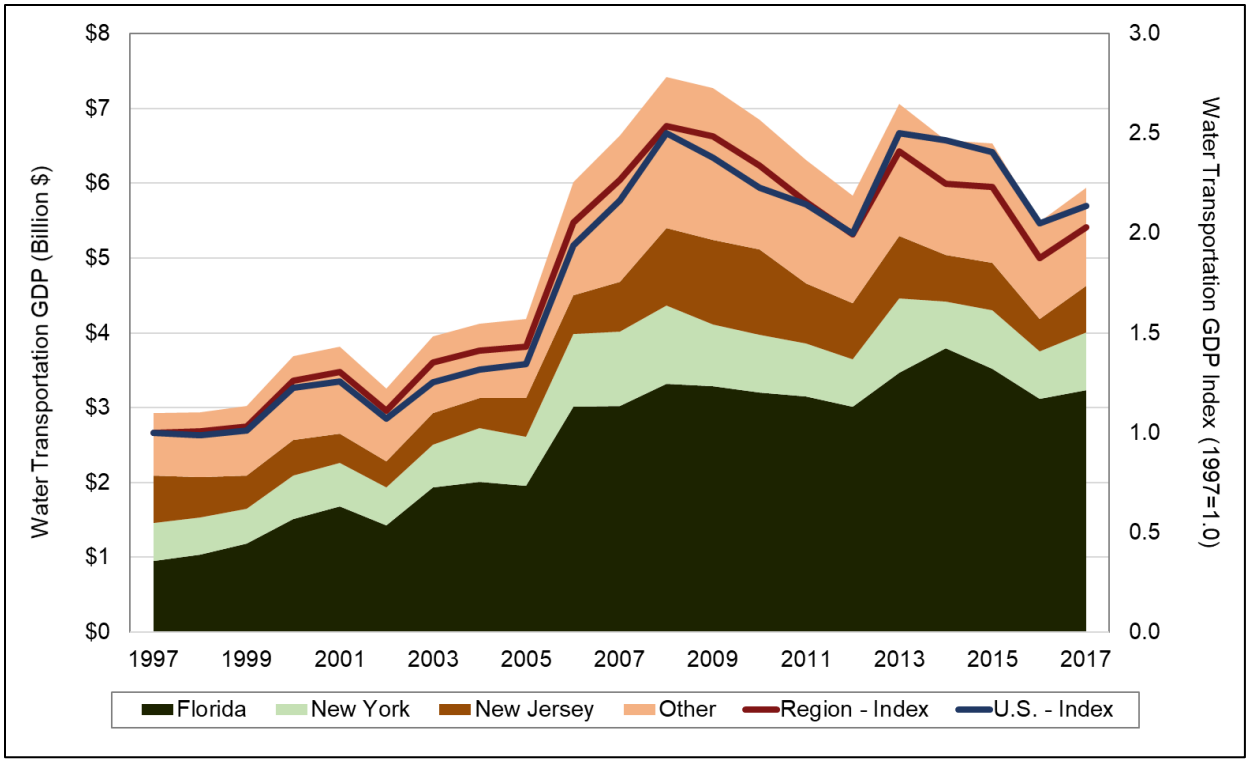

Figure 29. Trends in Atlantic region water transportation GDP, 1997–2017.

Source: US Bureau of Economic Analysis (BEA c2020).

Regional water transportation (or "ports-related") employment trends follow those comparable to the GDP trends discussed earlier. At the aggregate level (all water transportation), water transportation sector employment has remained stagnant since 2010. The falling waterborne commerce levels in the Atlantic region since 2008, as discussed later in the trends section, are contributing to this trend. Table 11 and Figure 30 demonstrate the regional water transportation sector employment levels. On a regional basis, Florida has the highest share of water transportation employment. Moreover, it accounts for roughly 21.8 percent of all water transportation in the United States. Water transportation across the Atlantic region, meanwhile, accounts for approximately 37.9 percent of all water transportation sector employment in the United States.

Table 11. Regional and national employment contribution, water transportation sector, 2018

State	Number of Water Transportation Jobs (2018)	Total State Jobs (2018)	Water Transportation Employment as a Percent of Total State Employment (%)	Water Transportation Employment as a Percent of Total US Ports Employment (%)
CT	925	1,449,072	0.06	1.43
DC	0	534,661	0.00	0.00
DE	43	384,332	0.01	0.07
FL	14,031	7,635,037	0.18	21.77
GA	296	3,777,824	0.01	0.46
MA	697	3,156,298	0.02	1.08
MD	973	2,188,298	0.04	1.51
ME	109	518,990	0.02	0.17
NC	238	3,710,090	0.01	0.37
NH	0	574,083	0.00	0.00
NJ	1,222	3,472,611	0.04	1.90
NY	3,621	8,017,398	0.05	5.62
PA	723	5,193,979	0.01	1.12
RI	187	421,767	0.04	0.29
SC	349	1,743,243	0.02	0.54
VA	1,032	3,188,362	0.03	1.60
Total Region:	**24,446**	**45,966,045**	**0.05**	**37.92**
Total US	**64,463**	**124,551,838**	**0.05**	**100.00**

Source: US Bureau of Labor Statistics (BLS c2020).

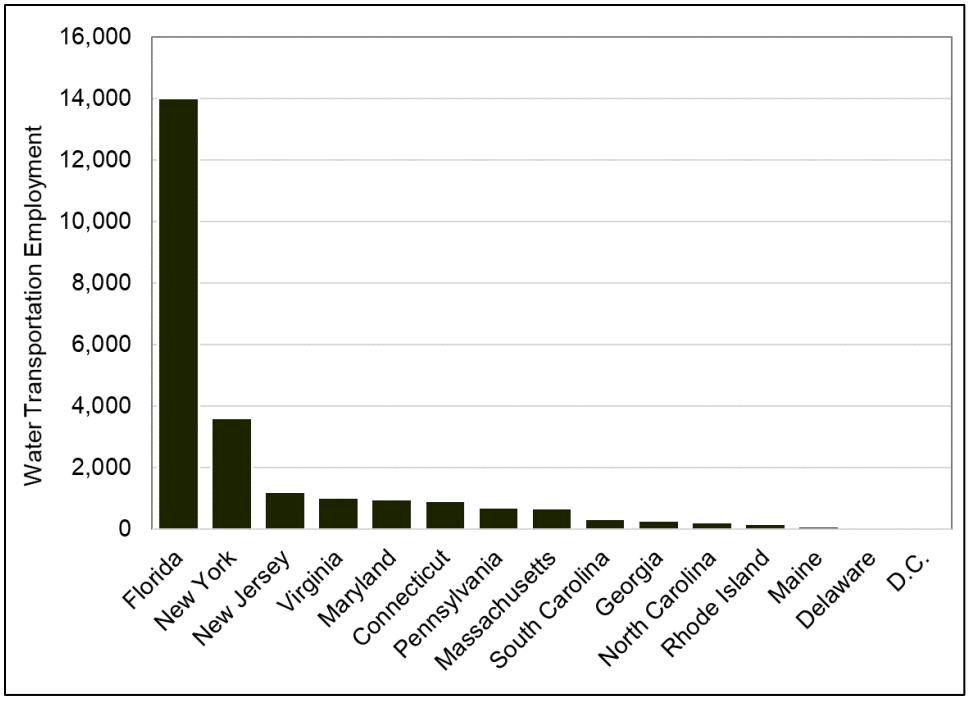

Figure 30. Atlantic region water transportation employment, 2018.

Source: US Bureau of Labor Statistics (BLS c2020).

Figure 31 illustrates the trends in regional and national water transportation sector employment over the past decade. Since 2009, regional water transportation sector employment has increased by only two percent, while national water transportation sector employment has increased by only three percent. Over this same period, Florida experienced water transportation sector employment gains of 16 percent.

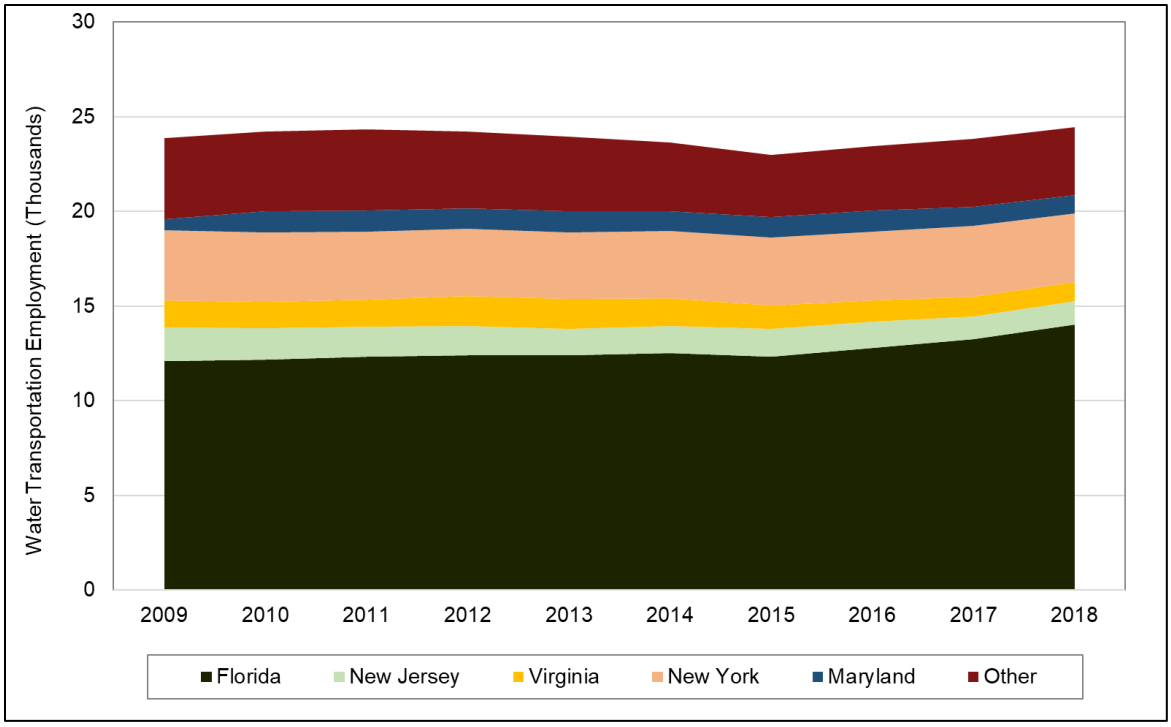

Figure 31. Trends in Atlantic region water transportation employment, 2009–2018.

Source: US Bureau of Labor Statistics (BLS c2020).

Despite minimal water transportation sector employment growth, there has been strong growth in port wages, which are presented in Table 12, Figure 32, and Figure 33. The Atlantic region accounts for 41 percent of ports industry wages in the United States. Within the region, Florida, New York, and Virginia account for the three highest shares of total wages.

Table 12. Regional and national wage contribution, water transportation sector, 2018

State	Water Transportation Wages (Millions $ in 2018)	Total State Wages (Millions $ in 2018)	Water Transportation Wages as a Percent of Total State Wages (%)	Water Transportation Wages as a Percent of Total US Ports Wages (%)
CT	71	98,976	0.07	1.24
DC	0	47,149	0.00	0.00
DE	2	21,785	0.01	0.04
FL	1,372	377,741	0.36	23.95
GA	19	204,738	0.01	0.33
MA	49	231,687	0.02	0.85
MD	88	128,523	0.07	1.54
ME	3	23,322	0.01	0.06
NC	10	188,651	0.01	0.17
NH	0	33,029	0.00	0.00
NJ	112	226,946	0.05	1.95
NY	370	589,087	0.06	6.46
PA	53	287,198	0.02	0.92
RI	13	21,809	0.06	0.22
SC	28	76,779	0.04	0.49
VA	157	184,435	0.09	2.74
Total Region:	**2,347**	**2,741,857**	**0.09**	**40.96**
Total US	**5,731**	**7,124,159**	**0.08**	**100.00**

Source: US Bureau of Labor Statistics (BLS c2020).

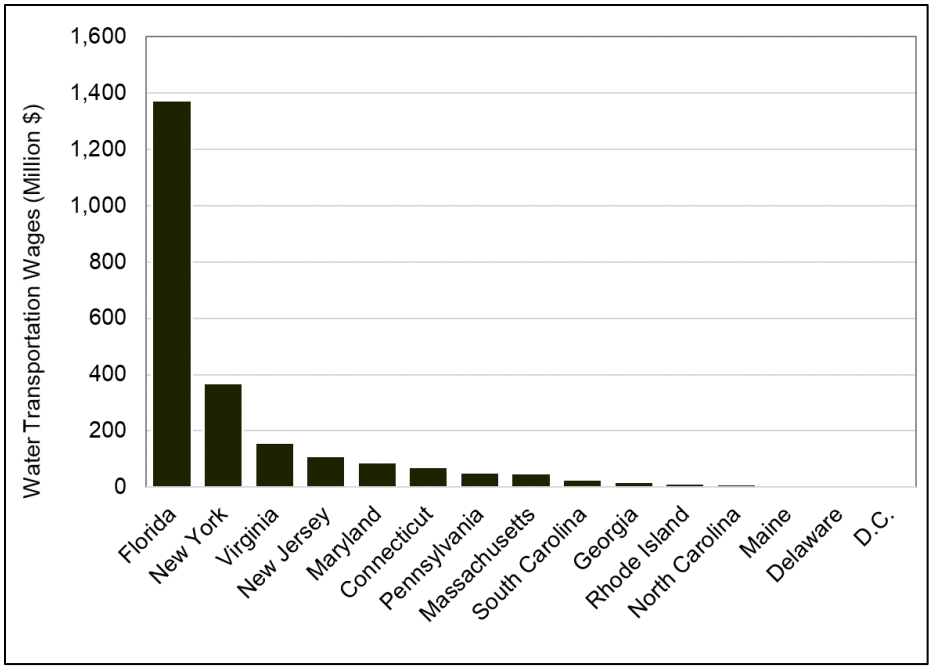

Figure 32. Atlantic region water transportation wage shares, 2018.

Source: US Bureau of Labor Statistics (BLS c2020).

Over the past decade, water transportation wages increased by 30 percent across the Atlantic region and 28 percent across the United States. These regional water transportation sector wage gains parallel the overall US economy, which has seen total wages rise by 48 percent over the past decade. Such water transportation sector wage gains are largely driven by Florida, which has experienced the highest levels of port wages within the region, and an increase in water transportation wages of 76 percent since 2009.

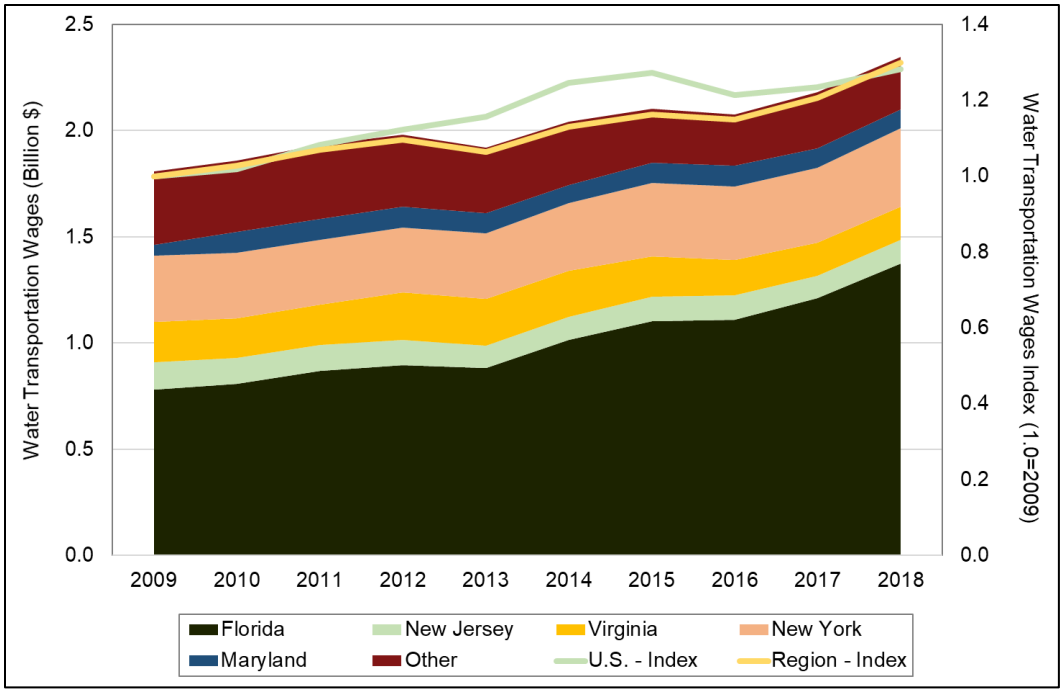

Figure 33. Trends in Atlantic region water transportation wages, 2009–2018.

Source: US Bureau of Labor Statistics (BLS c2020).

Average annual pay within the regional water transportation sector is below that of the US water transportation industry. However, it is above the US economy as a whole. Several states, including Virginia, New York, and Florida report average wages in excess of the US industry baseline. Table 13 and Figure 34 present the trends of average water transportation wages by state.

Table 13. Regional and national average annual wage contribution, water transportation, 2018

State	Average Annual Pay (Water Transportation) ($)	Average Annual Pay (All) ($)	Water Transportation Avg. Annual Pay as a Percent of Total State Avg. Annual Pay (%)	Water Transportation Avg. Annual Pay as a Percent of Total US Ports Avg. Annual Pay (%)
CT	76,743	68,303	112.36	86.31
DC	NA	88,184	NA	NA
DE	53,048	56,683	93.59	59.66
FL	97,822	49,475	197.72	110.02
GA	62,945	54,195	116.15	70.80
MA	70,023	73,405	95.39	78.76
MD	90,466	58,732	154.0	101.75
ME	30,579	44,938	68.05	34.39
NC	41,596	50,848	81.80	46.78
NH	NA	57,533	NA	NA
NJ	91,600	65,353	140.16	103.02
NY	102,198	73,476	139.09	114.94
PA	73,204	55,294	132.39	82.33
RI	68,413	51,709	132.30	76.95
SC	80,989	44,044	183.88	91.09
VA	152,028	57,846	262.82	170.99
Total Region:	**77,975**	**59,376**	**114.9**	**76.7**
Total US	**88,911**	**57,198**	**155.4**	**100.0**

Source: US Bureau of Labor Statistics (BLS c2020).

Over the past decade, the water transportation sector has experienced moderate wage gains across both the region and nation. Since 2009, average annual wages in the water transportation sector increased by 25 percent in the US During this time, some Atlantic states, such as New Jersey, have experienced average wage growth in excess of this baseline (51.7 percent), while other states, such as Maryland, have experienced the opposite (0.6 percent).

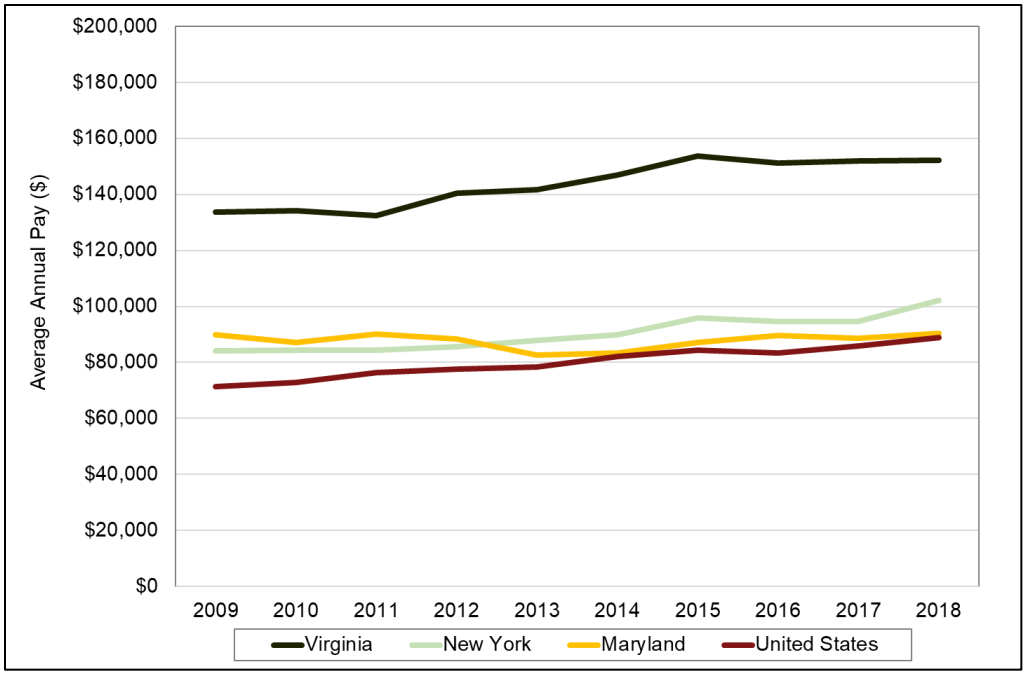

Figure 34. Trends in Atlantic region water transportation average annual wages, 2009–2018.

Source: US Bureau of Labor Statistics (BLS c2020).

BLS also provides labor statistics at the five- and six-digit NAICS level that focus exclusively on port activities and not on the broader set of activities associated with all deepwater and inland water transportation. An examination of these smaller NAICS categories provides some insight into the physical, and likely more specific port-related activities than those reported at the higher three digit "water transportation" level (i.e., at the NAICS 483 level). These five- and six-digit categories include:

- 488310: Port and Harbor Operations: Canal maintenance services (except dredging); Canal operations; Docking facility operations; Harbor maintenance services (except dredging); Harbor operations; Lighthouse operations; Maintenance services, waterfront terminal (except dredging); Port facility operations; Seaway operations; Waterfront terminal operation (e.g., docks, piers, wharves); Wharf operations.
- 488320: Marine Cargo Handling: Loading and unloading services at ports and harbors; Longshoremen services; Marine cargo handling services; Ship hold cleaning services; Stevedoring services.
- 488330: Navigational Services to Shipping: Cargo checkers, marine; Cargo surveyors, marine; Drydocks, floating (i.e., routine repair and maintenance of ships); Marine cargo checkers and surveyors; Ship dismantling at floating drydock; Ship scaling services not done at a shipyard.
- 713930: Marinas: Boating clubs with marinas; Marinas; Marine basins, operation of; Sailing clubs with marinas; Yacht basins; Yacht clubs with marinas.

Hereafter, these NAICS sectors, collectively, will be referred to as the region's "port sector." Table 14 and Figure 35 present several relative employment statistics for the Atlantic and US ports sector. Overall, Atlantic ports employment contributions are relatively small in comparison to the total employment in each of the region's states. No Atlantic state, for instance, has ports employment totals that comprise over 0.25 percent of the overall statewide employment totals. On a regional basis, Florida and Maine have the highest share of total ports employment, at 0.21 percent. Port employment along the Atlantic coast, however, accounts for a little less than half (40 percent) of total US port employment. The region is important relative to overall US port employment and activity, and this is consistent with the results discussed earlier for water transportation GDP.

Table 14. Regional and national employment contribution, ports sector, 2018

State	Number of Ports Jobs (2018)	Total State Jobs (2018)	Ports Employment as a Percent of Total State Employment (%)	Ports Employment as a Percent of Total US Ports Employment (%)
CT	1,269	1,449,072	0.09	1.05
DC	0	534,661	0.00	0.00
DE	600	384,332	0.16	0.49
FL	15,872	7,635,037	0.21	13.09
GA	5,428	3,777,824	0.14	4.48
MA	2,287	3,156,298	0.07	1.89
MD	4,472	2,188,298	0.20	3.69
ME	1,085	518,990	0.21	0.89
NC	1,266	3,710,090	0.03	1.04
NH	244	574,083	0.04	0.20
NJ	4,688	3,472,611	0.13	3.87
NY	4,367	8,017,398	0.05	3.60
PA	2,039	5,193,979	0.04	1.68
RI	780	421,767	0.18	0.64
SC	2,795	1,743,243	0.16	2.30
VA	1,578	3,188,362	0.05	1.30
Total Region:	**48,770**	**45,966,045**	**0.11**	**40.22**
Total US	**121,260**	**124,551,838**	**0.10**	**100.00**

Source: US Bureau of Labor Statistics (BLS c2020).

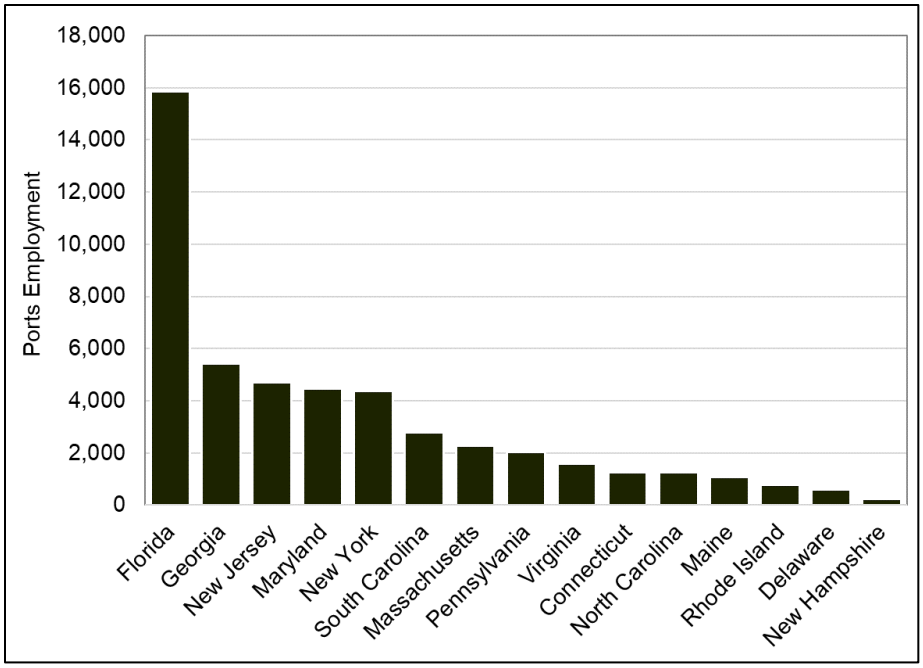

Figure 35. Atlantic region ports employment, 2018.

Source: US Bureau of Labor Statistics (BLS c2020).

Figure 36 illustrates the trends in regional and national ports sector employment over the past decade. Since 2009, regional ports sector employment has increased by 26 percent, and national ports sector employment has increased by 10 percent. Over this same period, Florida experienced ports sector employment gains of 41 percent.

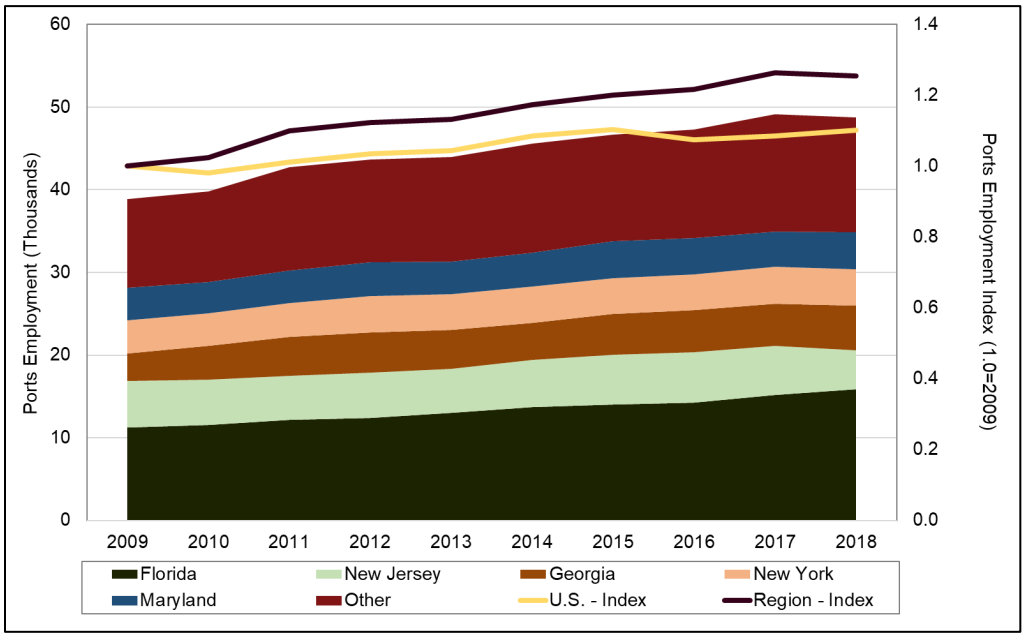

Figure 36. Trends in Atlantic region ports employment, 2009–2018.

Source: US Bureau of Labor Statistics (BLS c2020).

The growth in ports sector employment levels are corroborated by similar levels of growth in port wages, which are presented in Table 15, Figure 37, and Figure 38 below. The Atlantic region accounts for 34 percent of ports industry wages in the United States. Within the region, New Jersey, Florida, and New York account for the three highest shares of total wages.

Table 15. Regional and national wage contribution, ports sector, 2018

State	Ports Wages (Millions in 2018)	Total State Wages (Millions in 2018)	Ports Wages as a Percent of Total State Wages	Ports Wages as a Percent of Total US Ports Wages
CT	62	98,976	0.06	0.77
DC	0	47,149	0.00	0.00
DE	34	21,785	0.16	0.42
FL	663	377,741	0.18	8.21
GA	216	204,738	0.11	2.68
MA	108	231,687	0.05	1.34
MD	229	128,523	0.18	2.84
ME	47	23,322	0.20	0.58
NC	44	188,651	0.02	0.54
NH	10	33,029	0.03	0.13
NJ	730	226,946	0.32	9.04
NY	231	589,087	0.04	2.86
PA	123	287,198	0.04	1.53
RI	34	21,809	0.15	0.42
SC	106	76,779	0.14	1.32
VA	138	184,435	0.08	1.71
Total Region:	**$2,779**	**$2,741,857**	**0.10**	**34.39**
Total US	**$8,078**	**$7,124,159**	**0.11**	**100.00**

Source: US Bureau of Labor Statistics (BLS c2020).

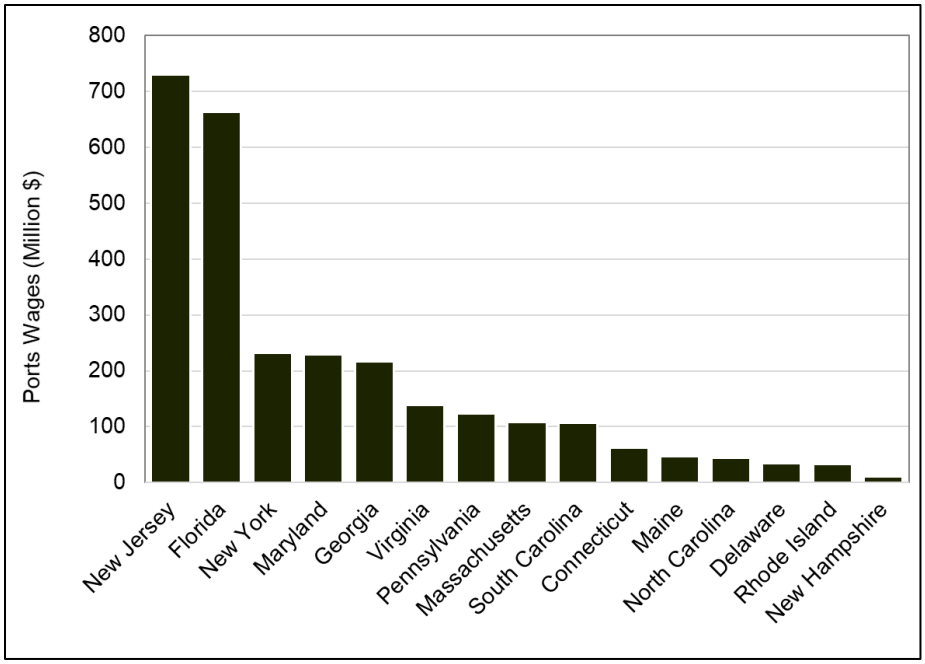

Figure 37. Atlantic region ports wage shares, 2018.

Source: US Bureau of Labor Statistics (BLS c2020).

Over the past decade, ports wages increased by 57 percent across the Atlantic region and by 42 percent across the United States. These ports sector gains are in line with the overall US economy, which has seen total wages rise by 48 percent over the past decade. New Jersey, which has the highest levels of port wages within the region, has experienced growth in ports wages of 61 percent since 2009.

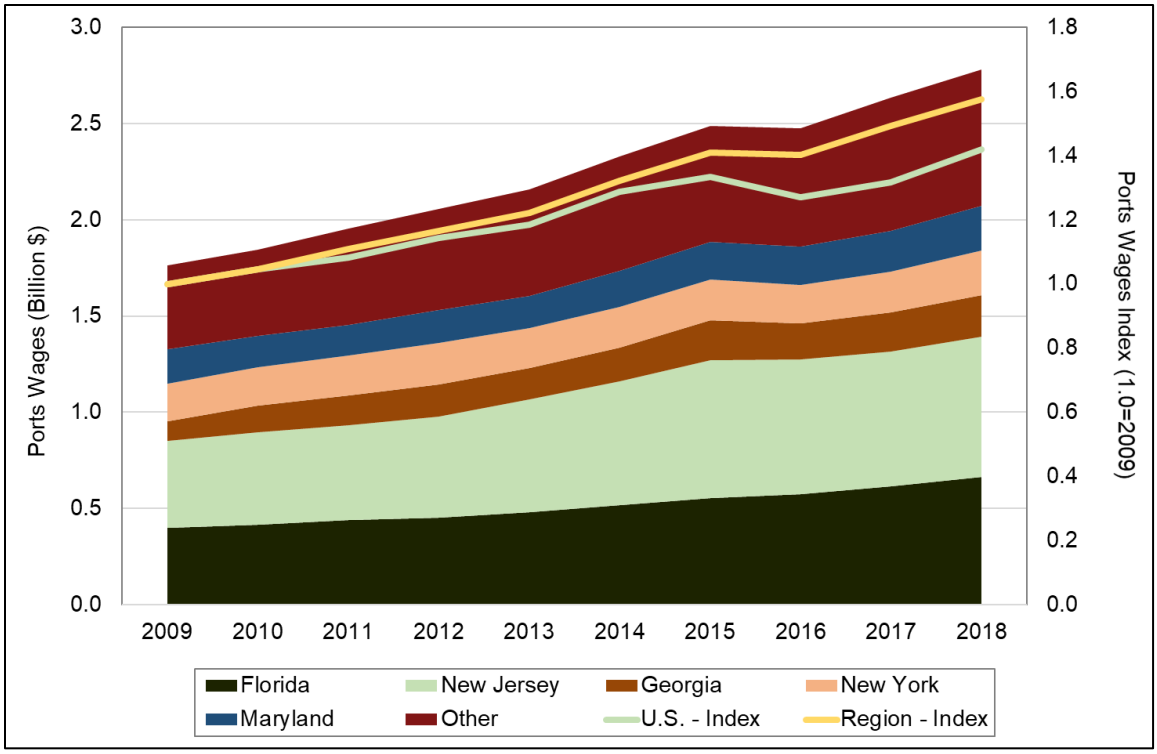

Figure 38. Trends in Atlantic region ports wages, 2009–2018.

Source: US Bureau of Labor Statistics (BLS c2020).

Average annual pay within the regional ports sector is below that of the US ports industry, as well as the US economy as a whole. However, several states, including New Jersey and Virginia, report average wages in excess of the US industry baseline. Table 16 and Figure 39 present the trends of average port wages by state.

Table 16. Regional and national average annual wage contribution, ports, 2018

State	Average Annual Pay (Ports) ($)	Average Annual Pay (All) ($)	Ports Avg. Annual Pay as a Percent of Total State Avg. Annual Pay (%)	Ports Avg. Annual Pay as a Percent of Total US Ports Avg. Annual Pay (%)
CT	46,183	68,303	67.61	68.69
DC	NA	88,184	0.00	0.00
DE	42,215	56,683	74.48	62.79
FL	54,855	49,475	110.87	81.59
GA	45,872	54,195	84.64	68.23
MA	60,587	73,405	82.54	90.12
MD	58,145	58,732	99.00	86.48
ME	52,026	44,938	115.77	77.38
NC	41,812	50,848	82.23	62.19
NH	43,082	57,533	74.88	64.08
NJ	121,902	65,353	186.53	181.31
NY	57,963	73,476	78.89	86.21
PA	58,319	55,294	105.47	86.74
RI	49,573	51,709	95.87	73.73
SC	42,736	44,044	97.03	63.56
VA	87,720	57,846	151.64	130.47
Total Region:	57,533	**59,376**	**90.8**	**80.2**
Total US	**67,233**	**57,198**	**117.5**	**100.0**

Source: US Bureau of Labor Statistics (BLS c2020).

Over the past 10 years, the ports sector has reported steady wage gains across both the region and nation. Since 2009, average annual wages in the ports sector increased by 22 percent in the US During this time, some Atlantic states, such as New Jersey, have experienced average wage growth in excess of this baseline (52.1 percent), while other states, such as New York, have experienced the opposite (-4.2 percent).

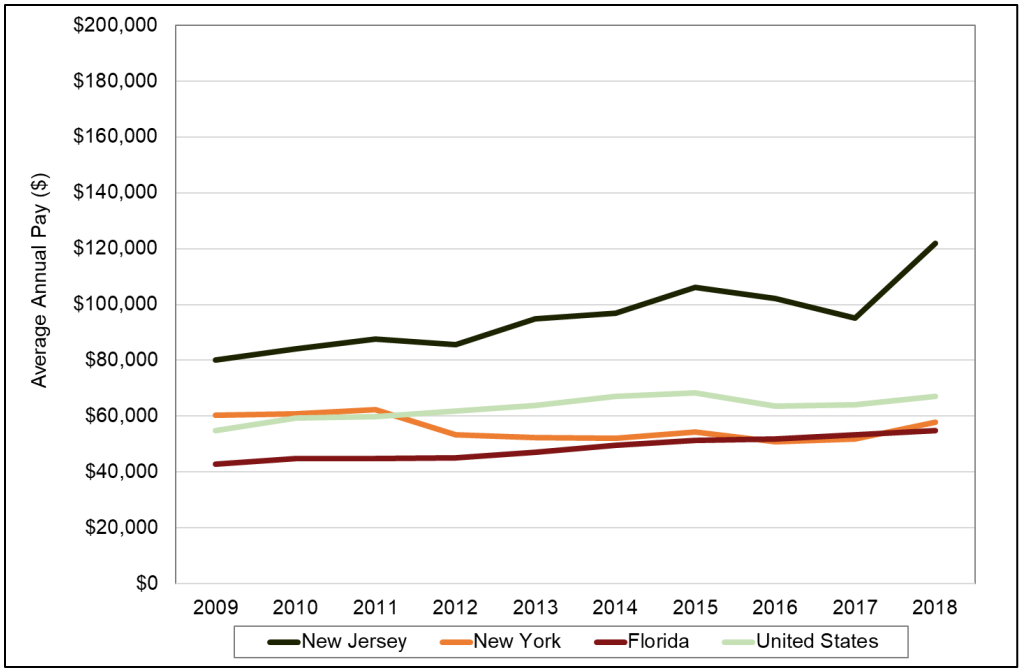

Figure 39. Trends in Atlantic region ports average annual wages, 2009–2018.

Source: US Bureau of Labor Statistics (BLS c2020).

3.5 Current Trends

In recent years, ports along the Atlantic have been impacted by a variety of factors. Most notably, the emergence of larger container ships has altered the depth requirements of shipping channels and forced ports along the East Coast to adapt. Additionally, there has been a decline in waterborne commerce, both across the country and in the Atlantic region.

3.5.1 Dredging of Shipping Channels

Over the past several decades, there has been an upward shift in the size of waterborne container vessels, and as a result, ports, including those on the East Coast, have been required to dredge their shipping channels in order to accommodate such vessels. Figure 40 illustrates the growth in container ship sizes over the past few decades.

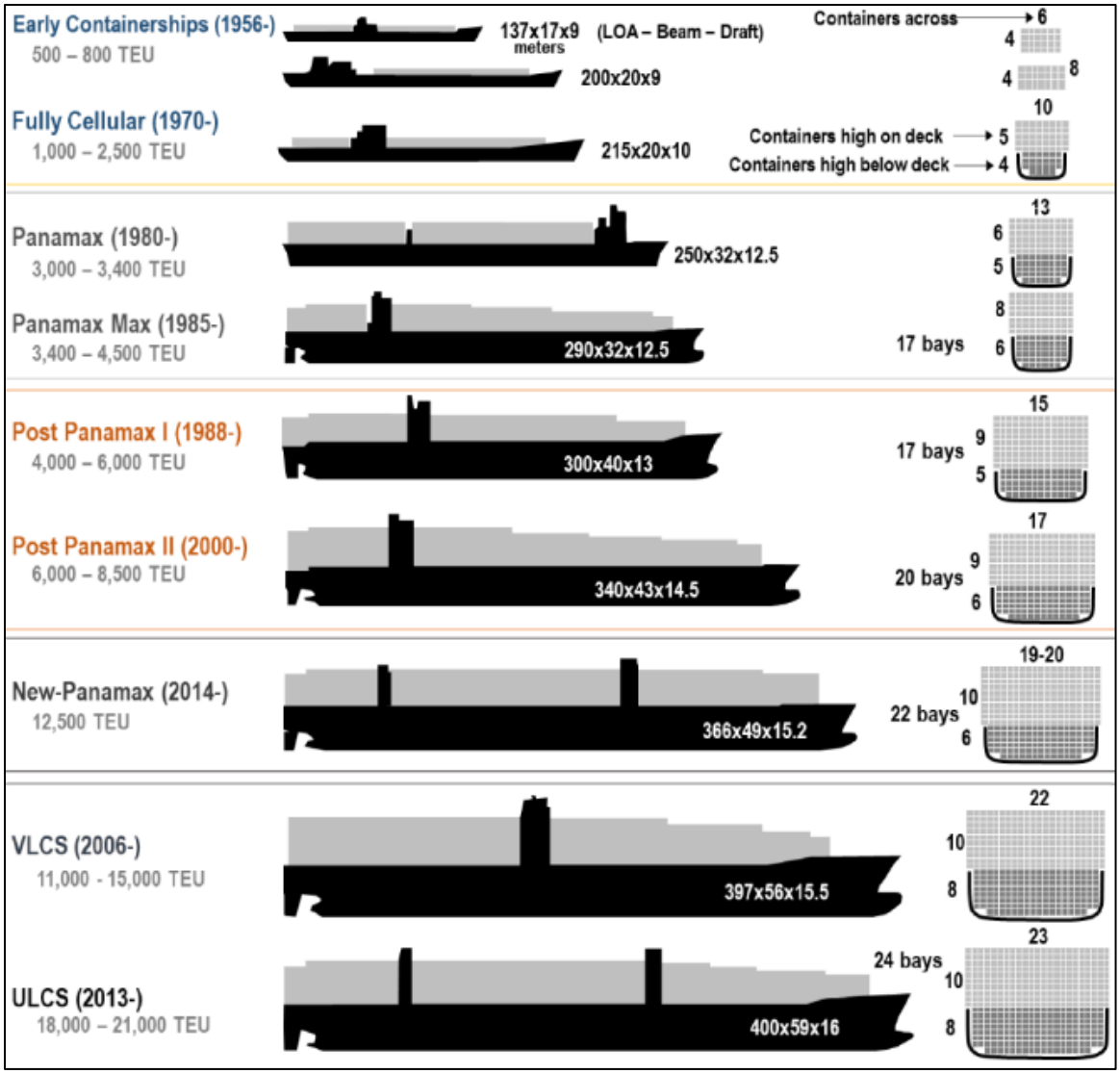

Figure 40. Historical growth of container vessels.

Source: (Rodrigue c2020).

VLCS, or very large container ships, have capacities of 11,000 to 15,000 TEUs (twenty-foot container equivalent). There are approximately 340 container ships with the designation of VLCS in existence. ULCS (ultra large container ships) have capacities of 18,000 to 21,000 TEUs with 47 ships in the global fleet (Statista, 2021).

Most recently, around 2014, larger container vessels, referred to as New-Panamax ships, began being manufactured. This shift prompted a significant expansion of the Panama Canal in 2016; its locks were widened from 110 feet to 180 feet (34 meters to 55 meters) and deepened from 42 feet to 60 feet (13 meters to 18 meters) in order to accommodate such ships (Mufson 2016 Jun 26). Likewise, ports along the Atlantic coast also began expanding their channels in preparation for receiving larger ships. Over recent years, state governments and their port authorities have spent billions to build larger ports and expand existing ports in the quickest manner.

3.5.2 Declining Domestic Waterborne Commerce

Domestic waterborne commerce has been declining, both across the United States and the East Coast. The below figures (Figure 41, Figure 42, and Figure 43) illustrate this trend since 2008. From 2008 to 2016 (the most recent year in which data is available), waterborne commerce, as measured in short tons, fell by 19 percent amongst states in the Atlantic region and by seven percent across the nation. Likewise, over the same period, ports in the Atlantic region received 21 percent less cargo, while ports across the nation received 20 percent less cargo.

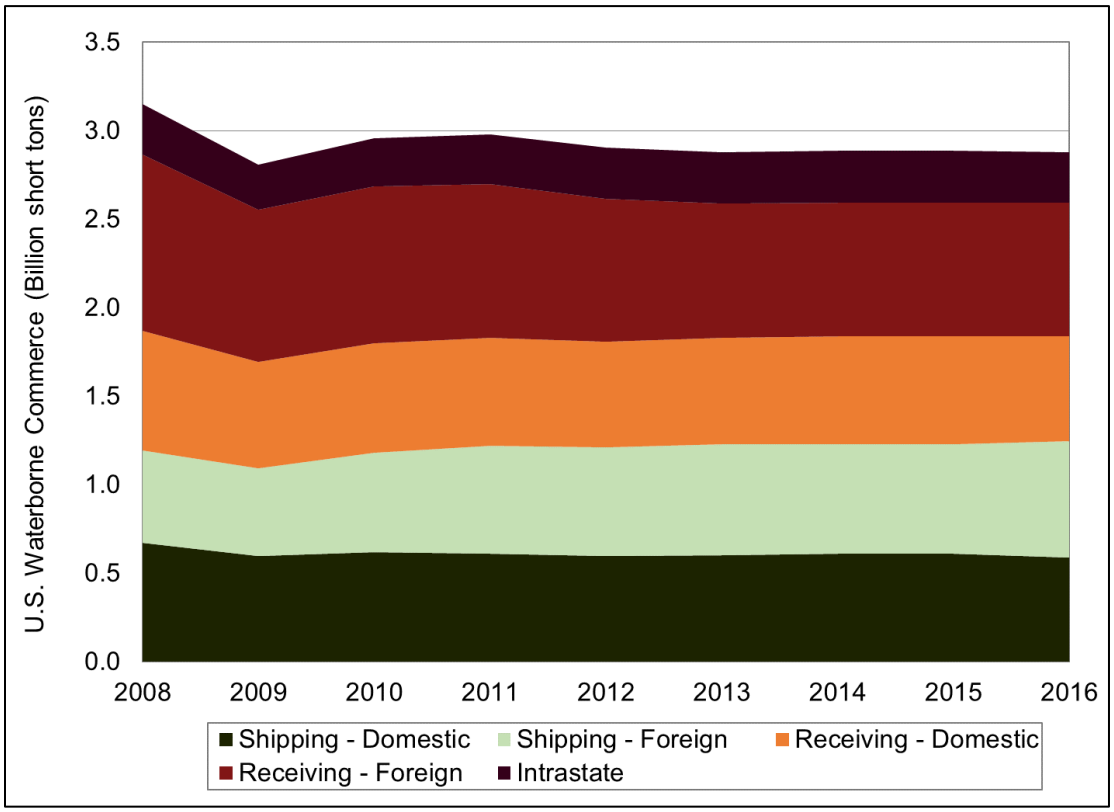

Figure 41. US waterborne commerce, 2008–2016.

Source: US Army Corps of Engineers (USACE 2017 Nov 15).

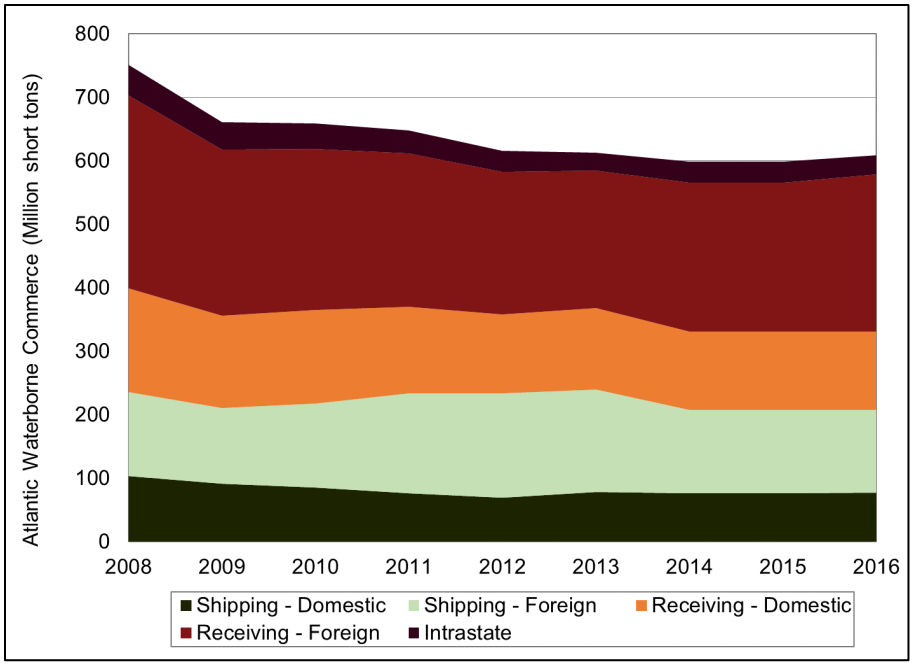

Figure 42. Atlantic waterborne commerce, 2008–2016.

Source: US Army Corps of Engineers (USACE 2017 Nov 15).

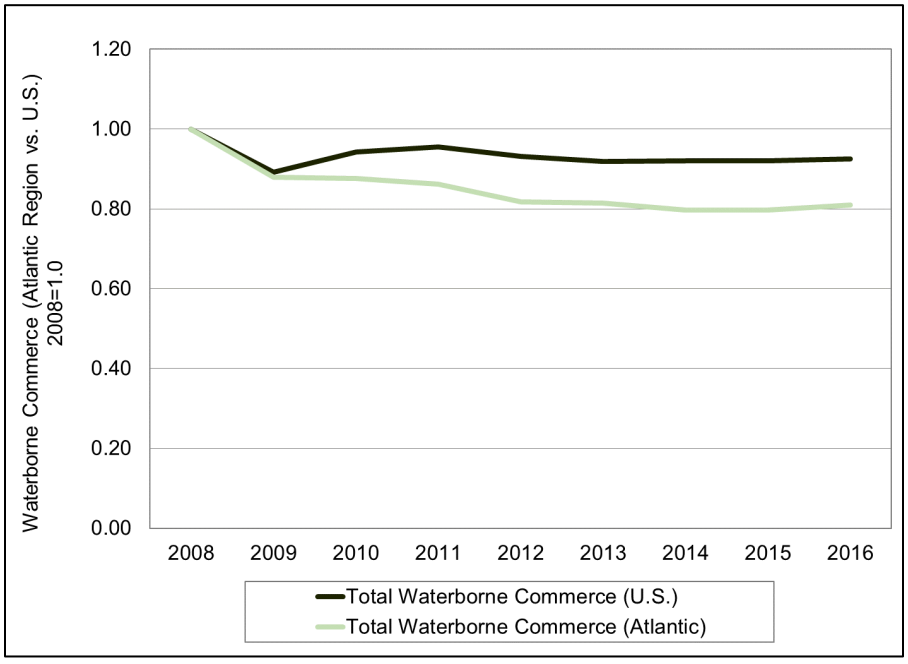

Figure 43. Atlantic waterborne commerce vs. US waterborne commerce (2008–2016).

Source: US Army Corps of Engineers (USACE 2017 Nov 15).

The declines in domestic waterborne commerce are largely attributable to increases in waterborne commerce with Canada and Mexico, as well as transportation of goods via intercity trucks, oil pipelines, and railroads. See Figure 44 for reference.

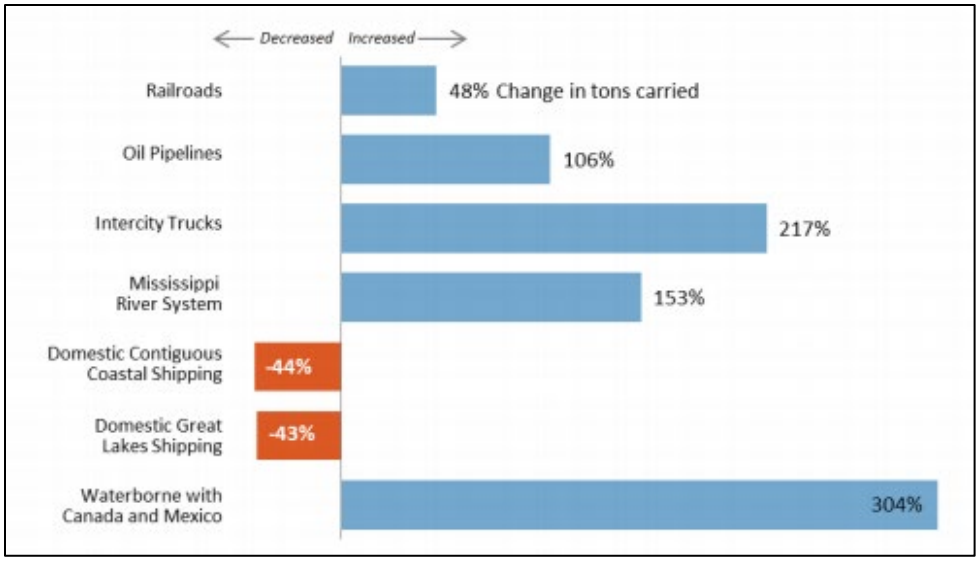

Figure 44. Percentage Change in Tons Carried, (1960–2014).

Source: Congressional Research Service (Frittelli 2017 May 2).

3.6 Current Outlook

The factors that that have impacted US ports over the past decade will continue to shape the ports sector in the years ahead. Additionally, there will be an emerging set of issues that will affect the industry that include:

- Offshore wind (OSW) development and production;
- Automation; and
- Continued dredging of shipping channels.

3.6.1 Offshore wind Development and Production

In the years ahead, the OSW industry is anticipated to expand significantly, particularly along the East Coast as states implement their clean energy goals over the next decade. Ports will be the critical place where these economic development opportunities arise.

Ports are vital to the construction and staging of OSW projects, and states, aiming to grow their offshore wind capacity, have begun to upgrade their ports in order to ensure that such ports are capable of sufficiently supporting offshore wind projects. Figure 45. State offshore wind targets (as of 2019). presents the offshore wind targets of states along the Atlantic, and Figure 46 presents an outline of the projects that are currently in operation and development.

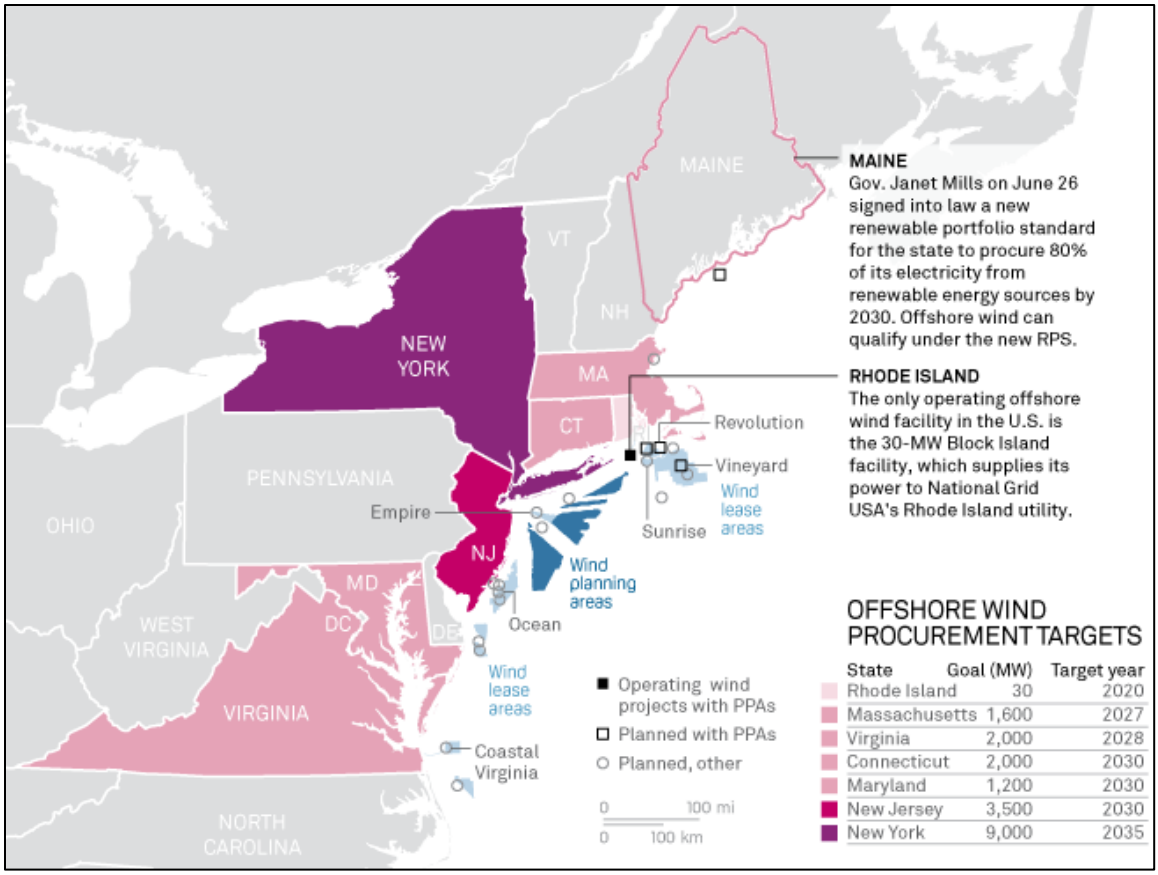

Figure 45. State offshore wind targets (as of 2019).

Source: S&P Global (Thomas et al. 2019b Aug 22).

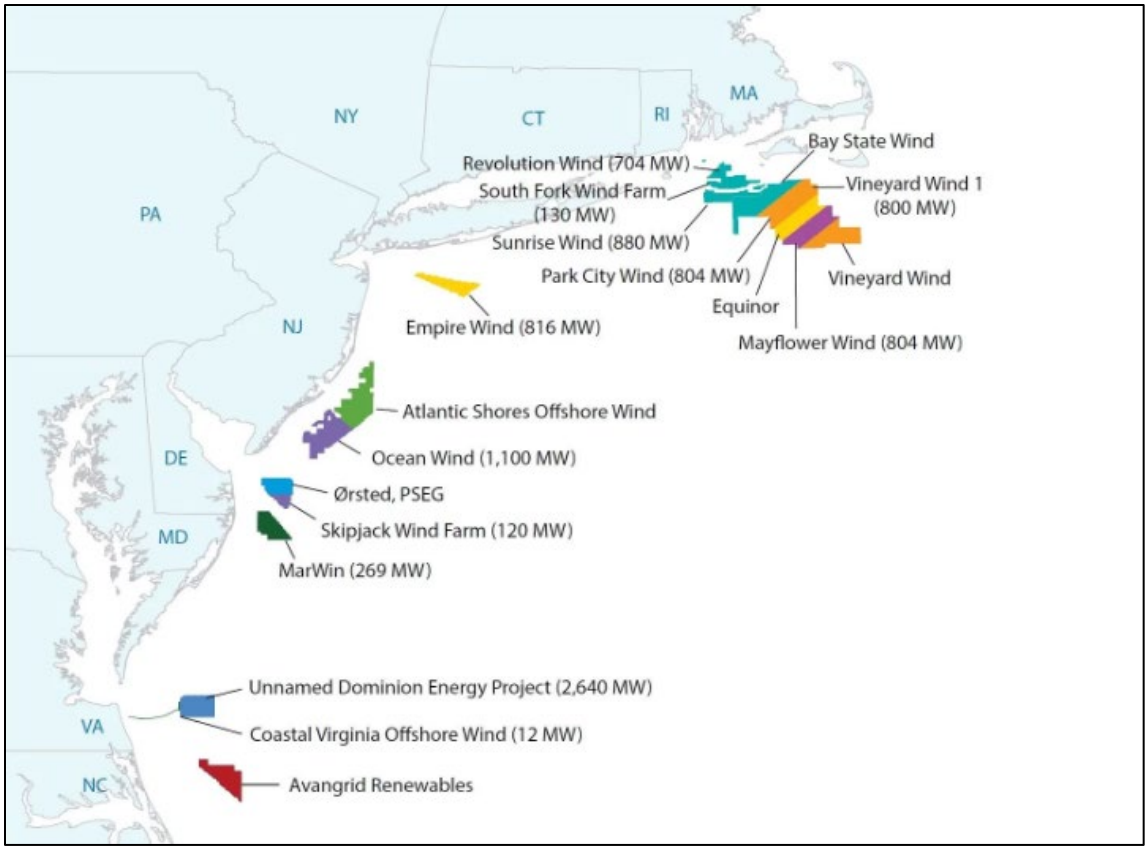

Figure 46. Atlantic offshore wind projects and lease areas (as of 2020).

Source: (Stromsta 2020 Mar 12).

Along the East Coast, the targeted growth of the OSW industry is quite significant. Currently, only 42 MW of operational offshore wind capacity exists in the United States (a 30 MW project off the coast of Rhode Island and a 12 MW project off the cost of Virginia). However, by 2025, states along the Atlantic aim to have more than 2,000 MW of installed capacity. The targeted capacity for 2030, meanwhile, is more than 8,000 MW, and the targeted capacity for 2035 is more than 19,000 MW. See Figure 47 below.

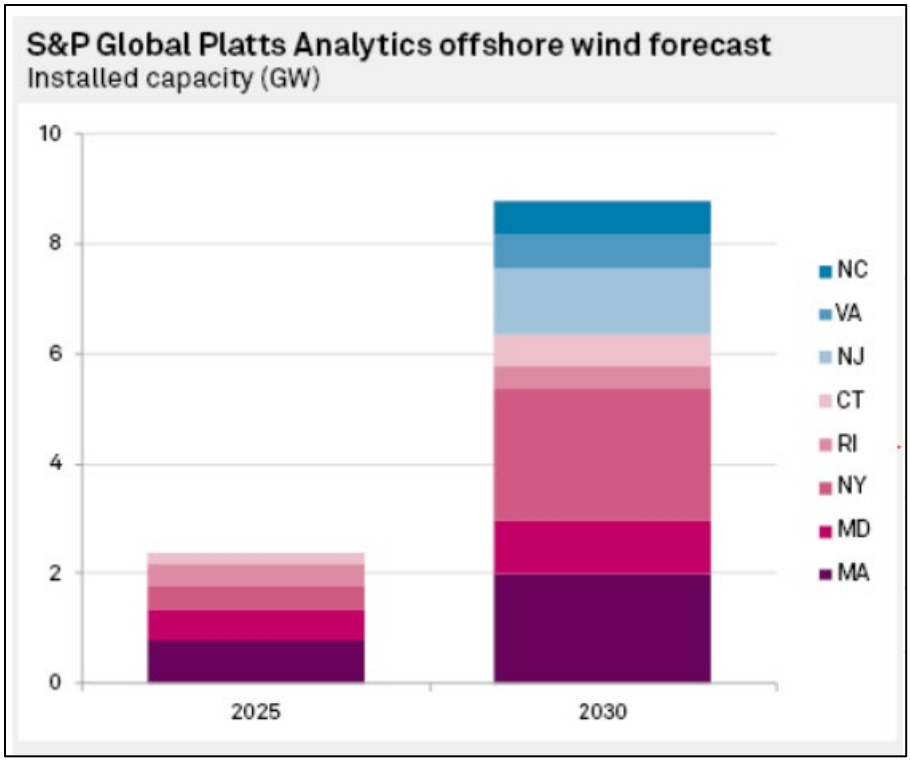

Figure 47. Atlantic OSW wind targets.

Source: S&P Global (Thomas et al. 2019b Aug 22).

The nation's first operational wind farm was the 30 MW, five-turbine Block Island project off the coast of Rhode Island. The construction of the project was successfully completed in 2016 across four different ports in Rhode Island. However, over the next five years, as Atlantic states look to augment offshore wind capacity by more than 6,000 percent, it is forecasted that there may be challenges meeting the sector's needs at East Coast ports. That is, some industry experts argue that Atlantic ports are not equipped to fulfill the technical demands of OSW industry. The Ørsted North America President, in 2019, stated that "It's no secret that we don't have all the ports that we need to support a build-out of this size. You would need to see quite significant investment into ports up and down the coast" (Muoio 2019 Mar 19).

The coming arrival of the OSW industry in the Atlantic has required regional ports to make numerous considerations with regard to how their facilities may need to be retrofitted. A few of the notable considerations at hand are presented below (Guillen et al. 2011):

- Inbound logistics: OSW developers will likely be sourcing turbines and other large components from Europe; ports must have shipping berths that can accommodate large shipping vessels used for such transport. Additionally, ports must have the capacity to receive components trucked via major highways and shipped via rail.
- Crane lifting: Components used in OSW development can weigh several hundred tons, and it is vital that ports possess cranes that can handle such loads.
- Outbound logistics: Components of OSW turbines are exceptionally large; accordingly, horizontal and vertical clearances are important considerations for ports.
- Area Considerations: OSW projects require at least 50 acres of space for assembly, storage, and inventory.
- Other operations onsite: Ports must have capacity for offshore wind operators to conduct logistics, warehouse supplies, and fabricate materials.

The prospect of furthering offshore wind capacity has led several Atlantic states to fund the capital improvements and facility upgrades that are required for offshore wind projects. An overview of the recent (2020) happenings at some Atlantic ports is presented below:

- Connecticut: In February 2021, the city of New London, Connecticut signed a Host Community Agreement (HCA) with Ørsted and Eversource Joint Venture. The purpose of this agreement is to redevelop the city's State Pier into a modern OSW facility. With this agreement, the city is expected to generate an annual base revenue of $750,000 (State of Connecticut 2021 Feb 26). Also, in October 2019, OSW developers, Vineyard Wind, were selected to revitalize Bridgeport into an emerging US OSW industry (Vineyard Wind 2019 Oct 11).
- Maryland: In 2019, Tradepoint Atlantic in partnership with Ørsted begun a new development at the Sparrows Point site for a 50- acre offshore wind staging center. As at March 2021, Ørsted announced the completion of the initial phase of the project and is preparing to commence the second phase (CBS Baltimore 2021).
- Massachusetts: Massachusetts is targeting 3,200 MW of OSW capacity by 2035, and it is focused on ensuring that its ports are capable of supporting such development. The developers of Vineyard Wind, a $2.8 billion, 800 MW offshore wind project planned outside of Martha's Vineyard, recently signed a $6 million annual lease for terminal space at the Port of New Bedford, where the state has directly invested $113 million in capital improvements to support offshore wind projects (Muoio 2019 Mar 19). There is also the Brayton Point Commerce Center which is being transformed from what once served as a coal-fired power plant to a world-class logistical port and support center for offshore wind activities (Brayton Point Commerce Center 2020).
- New Jersey: In 2010, then-Governor Chris Christie signed the state's Offshore Wind Economic Development Act (OWEDA), which created subsidies for 1,100 megawatts of offshore wind and a tax credit program for offshore wind facilities. The signing of the bill took place at the then-vacant Port of Paulsboro, and after $200 million in improvements, the Port of Paulsboro opened in 2017. Many anticipate that New Jersey will rely upon the Port of Paulsboro for future OSW projects; however, there are air draft issues at the port that may prove challenging. According to Brian Sabina, senior vice president of economic transformation at the New Jersey Economic Development Authority, "[T]he Delaware Memorial Bridge and some power lines downriver…kind of takes away Paulsboro as a marshalling port, but certainly Paulsboro could continue to be really important for a manufacturing port…for other components if the industry moves in that direction." (Muoio 2019 Mar 19; Johnson 2019 Apr 24).
- New York: New York is targeting 2,400 MW of wind capacity by 2030 and 9,000 MW of offshore wind capacity by 2035 (COWI North America 2019). To meet this objective, New York has committed $200 million towards capital improvements at its ports (NYSERDA 2020 Apr 1). In January 2021, Governor Andrew Cuomo announced a $400 million funding, both state and private, for the renovation the South Brooklyn Marine Terminal (SBMT), which will serve as a staging facility and operations and maintenance hub for offshore wind components. The assembly plant is expected to begin operations in 2025 (Adams 2021 Jan 13). Governor Cuomo also announced that the Port of Albany has been selected as a wind tower manufacturing site, with construction expected to commence in 2021 (Mercure 2021 Jan 14).
- Rhode Island: To date, the nation's only operational OSW farm exists in Rhode Island, and the state is committed to ensuring that its ports support further OSW projects. Quonset Point at Narragansett Bay was the hub of the Block Island project, and there is currently an active proposal for $90 million in further capital improvements to support OSW at this port (PortStrategy 2020 Feb 18).

- Virginia: In January 2020, the Port of Virginia agreed to lease part of its Portsmouth Marine Terminal to Danish OSW developer, Ørsted. If all options of the lease are completed, the agreement could grow to be worth nearly $13 million and result in $20 million in facility upgrades (Commonwealth of Virginia 2020 Jan 28). With the upgrades, Virginia Port Authority CEO, John F. Reinhart, believes the Port of Virginia is capable of being a strong base of offshore wind operations in the region, saying, "We're a deepwater port, we have no airdraft restrictions to get out to the open water – and these turbines are pretty big platforms – so we can be a really unique staging base… Now, we're looking at the other supplying subcontractors to see if there are other opportunities to grow the supply chain for offshore wind here in Virginia" (Abbott 2020 Mar 9).

3.6.2 Automation

Advancements in software and machine learning will undoubtedly spur automation across numerous industries, and the ports industry is no exception. In the coming years, as ports look to increase efficiency, improve profitability, and reduce emissions, they will increasingly rely upon advancements in automation to do so. Some of the possible ways in which automation may impact ports are presented in Figure 48.

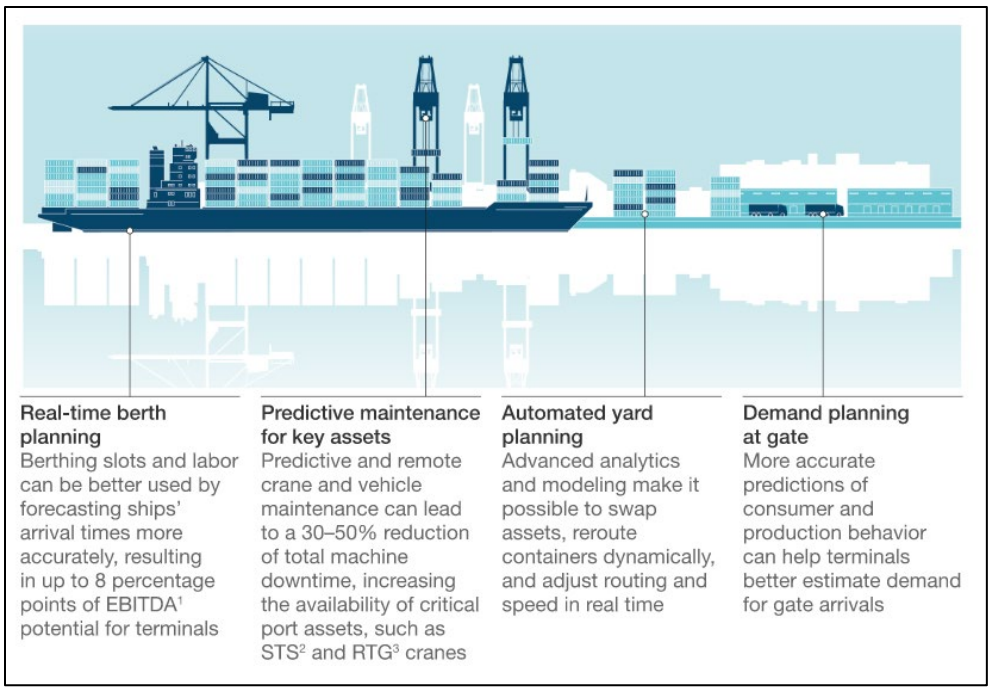

Figure 48. Automated port facilities.

Source: McKinsey (Chu et al. 2018 Dec 1).

There are a variety of technologies that have the potential to aid in the operational efficiency, profitability, and emissions of ports in the coming years; a few additional technologies that will be used heavily in the coming years are:

- Automated stacking cranes;
- Automated berths;
- Automated container carriers;
- Blockchain; and
- Remote control stations;

Automation development is considerable at the Port of Virginia where, in 2016, it completed the largest order of automated stacking cranes (ACSs) in industry history, ordering 86 cranes for $217 million (The Port of Virginia 2016 Nov 21). Then, in 2019, the Port of Virginia installed five remote control stations for their container cranes; it was the first instance in which the technology had been deployed in the United States (AJOT 2019 May 1).

Automation at ports in the Atlantic region will likely impact employment in some capacity as well. It is reasonable to expect that automation may have a negative impact upon the quantity of individuals employed at ports, but a positive impact upon the earnings of highly technical employees.

3.6.3 Continued Dredging of Shipping Channels

The previous section of this chapter detailed the growth in size of container ships and the efforts to expand shipping channels along the East Coast in order to accommodate such ships. Over the next decade, channel depth will continue to be a critical issue for all ports, especially those along the East Coast. Regional ports will continue their dredging efforts in order to accommodate New-Panamax ships. Table 17 details the upcoming channel dredging projects that are set to take place along the East Coast in the coming years.

Table 17. Channel dredging along the Atlantic Coast

State	Port	Channel	Target Channel Depth (ft)	Targeted Completion Date
FL	Port Everglades	Inner Entrance	48	2022–2025
FL	Port Everglades	Outer Entrance	55	2022–2025
FL	Jacksonville Port Authority (FL)	Blount Island Terminal	47	2023
GA	Georgia Port Authority	Savannah Harbor	47	2022
MA	Port of Boston	Entrance Channel	51	2021
MA	Port of Boston	Main Channel	47	2021
MD	Port of Baltimore	Brewerton Angle	51	2020
MD	Port of Baltimore	Brewerton Channel	51	2020
MD	Port of Baltimore	Brewerton Channel Eastern Extension	36	2020
MD	Port of Baltimore	Tolchester Channel	36	2020
MD	Port of Baltimore	Northwest Branch East Channel	50	2020
MD	Port of Baltimore	York Spit Channel	51	2020
NC	Port of Wilmington	Wilmington Harbor	47	NA
SC	Port of Charleston	Harbor Entrance Channel	52	2022
VA	Port of Virginia	Atlantic Channel	59	NA
VA	Port of Virginia	Thimble Shoals	56	NA
VA	Port of Virginia	Norfolk Harbor	55	NA
VA	Port of Virginia	Newport News	55	NA

Sources: (Port of Everglades 2018 Jun 19; McLeod 2018 Oct 25; Ogg 2019 Sep 6; O'Neal 2019 Sep 26; Morley 2019 Nov 12; Ashe 2019 Dec 23; DredgingToday 2020 Feb 25).

3.6.4 Factors Impacting Atlantic Coast Development

All areas of the Atlantic region have good port coverage, and it is highly unlikely that any new ports would be constructed to support offshore energy production activities under any development scenario. There are two primary factors that may influence port development in response to offshore activity: (1) the specific offshore location where development is expected to occur; and (2) the degree to which offshore support activities compete, or are in conflict with, bulk container and cargo trade that is currently the focus of larger regional ports.

Smaller and medium-sized ports in the central portion of the Atlantic region may be more suitable for offshore support activities since they are: (a) more likely to offer affordable and flexible leasing arrangements; (b) less likely to have significant competing bulk cargo activities; (c) likely to have access to marine craft that operate in activities comparable to oil and gas supply and support; and (d) proximate to potential lease areas under consideration.

Consider that along the GOM, small, specialized ports like Port Fourchon (Louisiana), Venice (Louisiana), Freeport (Texas), and Port Arthur (Texas) serve as primary support facilities for offshore oil and gas activities. Larger facilities, such as the Port of Houston, the Port of South Louisiana, and the Port of Mobile, tend to focus on major international trade opportunities and not smaller niche markets like offshore oil and gas development. This is not to suggest that major ports are not interested in potentially serving offshore activities, but simply to recognize that major ports (unlike their smaller counterparts) have certain opportunity costs in pursuing support activities for offshore activities.

For instance, many major ports along the eastern seaboard, particularly in the upper areas of the Atlantic region, are in highly developed locations that have relatively expensive or limited expansion possibilities. Offshore oil and gas support development at these ports will need to be evaluated against the alternative uses for waterfront and port surface space. These returns, particularly for cargo-oriented activities, will be heavily influenced by the economies of scale associated with bulk operations that are entirely different than the smaller sized specialized activities associated with offshore oil and gas service activities. In other words, focusing on bulk cargo is likely to yield a higher return for limited port capacity than specialized oil and gas activities.

Smaller and medium-sized ports may also have more incentives and greater interest in pursuing oil and gas support activities. Smaller facilities, being located in relatively less congested areas, are more likely to have available surface and marine terminal expansion opportunities. These ports are also less likely to see a trade-off, or competition, between offshore oil and gas activities and cargo traffic since few of these facilities currently handle large-scale bulk cargo operations. In addition, state and federal funding mechanisms for infrastructure development can be defined by cargo tonnage, often creating a circular challenge for smaller ports. These ports do not qualify for additional funds given their low cargo tonnages but cannot reach these critical tonnage levels without further investment.

In fact, it could be the case that oil and gas support activities will create additional sources of business that would be credited to these ports' annual tonnage amounts. Increased tonnage, in turn, could help facilitate additional on-site infrastructure development (through tonnage-based state and federal public investment or appropriation formulae), which, in turn, could assist these facilities in securing bulk cargo business. Thus, rather than competing, oil and gas activities could be complementary to current cargo activities at smaller-sized ports.

Last, there are a number of moderately-sized ports located in the Chesapeake Bay region that could serve as likely support bases for offshore oil and gas activities. These central Atlantic region ports are the closest to possible offshore development.

4. Support and Heliport Facilities

4.1 Description of the Industry and Services Provided

The offshore oil and gas industry relies on an extensive onshore support system to provide its supplies and transportation. These support activities range from the supply products and services like electric generators, chains, gears, tools, pumps, compressors, to engine and turbine repair and construction. Additionally, there are inputs required for daily operation which must be transported from onshore support facilities to offshore structures: drilling muds, chemicals, lubricants, and other fluids. Many types of transportation vessels and helicopters are also used to transport workers, equipment, and materials to and from offshore platforms. Typical facilities for this sector include general support facilities, repair and maintenance yards, supply bases, heliports, and offshore service vessels.

Historically, these support activities were "internal" to offshore oil and gas companies, but over time third party companies have developed. This third-party influx was a result of downsizing and specialization, and they now provide a large amount of the onshore support and transportation services on a contract basis. Industry downsizing specifically has reduced the numerous layers and complicated nature of oil and gas operations by many offshore producers. In using contract services, producers are able to utilize supply, transport, and logistics resources on an as-needed basis as opposed to providing the services permanently. One additional benefit of outsourcing is the degree of flexibility for offshore operators, allowing them to keep costs down during periods of oil and gas commodity price downturns (Dismukes 2010; Oceanwide).

Because offshore support and transportation facilities are highly dependent upon the drilling and production markets, they are also strongly impacted by the cyclical nature of oil and gas commodity prices. Specifically, the supply and transport side of the offshore industry are likely to be the first to be impacted by oil and gas industry downturns. During an economic contraction, the first things to be cut to reduce exploration and production company costs are discretionary supply, repair, storage, and maintenance activities. Support and transportation facilities are thus under pressure to perform efficiently, and to be able to diversify when possible, be cost effective, and adequately respond to tenant needs.

Both major corporations and independent producers provide onshore support and transportation services. Firms involved in the support sector of this industry are heterogeneous; however, all firms have one major source of volatility in common: a large proportion, or perhaps even the entirety, of support firms' business activity, profits, and earnings are greatly impacted by the cyclical nature of the oil and gas industry. This relationship has led to two different survival tactics employed specifically by these firms: concentration and diversification. Concentration has occurred as a result of general merger and acquisition activity. Alternatively, diversification stems from taking on a broader number of support and service activities from other maritime-based industries so that falling oil and gas prices have a reduced impact on earnings.

The support and transport sector is crucial to the oil and gas industry. It consists of a variety of components to function efficiently including management, personnel, construction, and design innovations. As energy prices increase, offshore oil and gas activity increases, and in turn generates a greater level of demand for offshore logistical support.

4.2 Typical Facility Characteristics

Due to the number of different and specialized products and services that are contained within the title of "support industry" it is not easy to define any aspect as "typical." Firms can be very large corporations or private businesses with few employees. For example, land-based supply and fabrication centers are generally very large as they provide the equipment, personnel and supplies necessary for the industry to function through intermodal connections. Other onshore support services include inland transportation to supply bases, equipment manufacturing, and fabrication. Also, offshore support includes waterborne and airborne transportation.

Ports, as discussed in the previous chapter, determine the number and type of tenants and port users for support services as well. For example, the Port of Iberia is the Gulf Coast's largest shallow water draft port at over 2,000 acres. It houses over 100 companies and employs more than 5,000 workers (including welders, pipefitters, mechanics, managers, secretaries, accountants and other occupations) (Port of Iberia c2018).

4.2.1 General Support Facilities

Support facilities can also take many forms; however, one common feature is close proximity to a port. The port is a centralized location for crews to disembark, storage and loading facilities for materials, and generally also has physical attributes that complement support activities. In fact, this has become an explicit business practice at ports: developing and providing the necessary infrastructure to support offshore drilling and production activities. Most support or service companies have one or more of the following characteristics:

- Access to intermodal transportation such as roads, inter-coastal waterways, railways, etc.;
- Protected wharfs, docks, and dry-docks to load materials destined for offshore locations (also can be used for short-term storage);
- Storage and demurrage facilities for longer term equipment and material storage;
- Crew housing;
- Communication facilities and equipment; and
- Workshops and machine and tooling shops.

4.2.2 Repair and Maintenance Yards

Much of the repair and maintenance support work done at platform fabrication facilities and shipyards, which are discussed in Chapter 1, is associated with maintaining equipment and vessels for drilling and production activities. However, the specific method of repair varies from job to job in both time and scope. Depending upon the requirements of the repair or maintenance task, it can take anywhere from one day to over a year. As with other aspects of the oil and gas industry, repair jobs are sensitive to oil and gas prices. When prices are high work needs to be completed as quickly as possible so that the equipment can be put back into service. Similarly, there are strong time constraints during hurricane restoration and recovery because of the limited amount of working equipment and personnel. In many cases, a number of repair-oriented tasks are pre-fabricated and then taken offshore for final assembly and repair. This is often the case with such activities as piping, ventilation, electrical and other machinery. Some of the more typical maintenance and repair operations consist of the following (EPA 1997):

- Blasting and repainting the ship hulls, freeboard, superstructure, and interior tanks and work areas;
- Major rebuilding and installation of machinery such as diesel engines, turbines, generators, pump stations, etc.;
- Systems overhauls, maintenance and installation (e.g., piping system flushing, testing and installation);

- System replacement and new installation of systems such as navigational systems, combat systems, communication systems, updated piping systems, etc.;
- Propeller and rudder repairs, modification, and alignment;
- Creation of new machinery spaces through cut outs of the existing steel structure and the addition of new walls, stiffeners, vertical, webbing, decking, etc.; and
- Creation of raw materials (pipes, sheet metal, machinery, etc.) or provision of specialty services (carpentry, maintenance, warehousing, etc.) by support shops working for the yard.

4.2.3 Supply Bases

Supply bases are a vital part of the logistics chain and can consist of large yards with a range of services and logistics management to smaller shops that supply one or a few of the supplies needed on an offshore platform or vessel. Some of the larger companies offering supply chain management services operate from various locations and move equipment and supplies from land-based supply houses to offshore drilling platforms. Many of the smaller suppliers can be thought of more as combined retail and equipment rental stores which supply anything from crane rentals, warehouse space, trailer rentals, and dispatch services, to engine parts, fuel, navigation tools, potable water, and lubricants (motor oil, hydraulic oil, natural gas, compressor oils, grease, gear oil, and synthetics).

4.2.4 Heliports

A heliport is a central location where helicopters land and take off for offshore service. Helicopters are used to move crew and equipment to areas as far as 250 miles offshore (PHI c2019). A trip of this distance takes about one and a half hours and can reach the majority of deepwater platforms and facilities. Supply boats, discussed below, are used for shorter distances and are able to carry heavier loads. One other important distinction is that helicopters are used in instances where speed of delivery (equipment, personnel) may be pressing. For example, the Sikorsky S-92 can travel up to 547 nautical miles (101.3 kilometers), and has a cruising speed of about 151 knots (Sikorsky c2018). A supply boat (specifically a crew boat for transporting personnel), on the other hand, has a cruising speed of up to 40 knots (Ship Technology c2020).

Figure 49. Sikorsky S-92 Helicopter.

Source: (PHI c2019).

Heliport service providers usually retain a mix of size and quantity of aircraft, consisting of small, medium, and heavy helicopters. The light helicopters are better suited for support of production management activities, daytime flights and shorter routes (SEC 2019a). Medium and large helicopters are most often used for crew changes on offshore production facilities and drilling rigs. For example, Bristow classifies its light helicopters as those carrying four to eight passengers, its medium helicopters as those carrying 12 to 16 passengers, and its large helicopters as those carrying 16 to 25 passengers (SEC 2019a).

Helicopters are an important means of transportation, and there are many companies that currently support the offshore industry with this endeavor. Three major providers to the existing offshore oil and gas industry in the US include: Bristow Group, Petroleum Helicopters Inc. (PHI), and Era, Inc. The Bristow Group is the largest provider of helicopter transportation services globally, with a fleet of 272 aircraft (Bristow Group c2020). In the US, the company operates from three locations in the Gulf of Mexico in addition to search-and-rescue operations at South Lafourche Airport in Galliano, Louisiana (SEC 2019b). Services pertaining to the offshore industry specifically include offshore and onshore transportation, and transportation for company officials or key personnel including special security precautions (Bristow Group c2020). PHI is primarily used for service related to the offshore oil and gas industry, but a secondary focus is emergency healthcare transportation. This company also specializes in deepwater support for rigs more than 200 miles (322 kilometers) offshore (PHI c2019). They have provided some service internationally, but mainly support the Gulf region with locations spanning the Gulf Coast and headquarters in Lafayette, Louisiana (SEC 2019a). Era Helicopters operates from ten bases in the Gulf of Mexico (SEC 2019c). As of December 31, 2018, Era's total fleet comprised 108 helicopters, 82 of which were located in the US (SEC 2019c).

4.2.5 Crew Services

Many companies exist solely to support the crew and staff required for successful offshore drilling. For example, crew members who live on the offshore rigs need catering (hot meal delivery and service), laundry, and cleaning and maintenance services for crew barracks. A number of companies provide temporary personnel to operate offshore rigs, act in human resource positions, and provide on-site services like paramedics and food service (Oceanwide). Additionally, though drilling companies sometimes hire medics directly, it is particularly common to hire a third-party medic as part of the crew to ensure safe and efficient operations (Safety Management Systems c2020).

Platforms used for accommodations provide housekeeping services including laundry and maintenance of living quarters. Offshore accommodations are a large contributor to operating costs. Also, there is a strong need for skilled labor, and in order to attract these workers it is necessary to have comfortable accommodations and other non-salary work environment benefits. Many companies now are even building accommodation barges, such as the one in Figure 50. This barge is the Offshore Olympia and is one of many variations of crew vessels. It has capacity for up to 836 people in 298 cabins (Intership c2020). There is also an onsite hospital facility and numerous recreational options for the crew: sauna, gym, television, and game rooms.

Figure 50. Accommodation barge with helipad.
Source: (Intership c2019).

Crew services companies also provide medical, entertainment, security, and waste management services. A critical service is potable water transportation and waste management. There are numerous federal and state laws which require the safe disposal of offshore drilling wastes, some of which necessitate being returned to shore. Many offshore supply companies use special tanks on OSVs to transport waste to specialized onshore transfer facilities which will later send the waste to their final disposition point. The specific details of this process will be discussed in Chapter 5.

4.2.6 Offshore Support Vessels

Regular transportation of supplies, materials, and personnel is necessary for any functioning offshore oil and gas production operation. Offshore support vessels (OSVs) performing these operations are required at practically every stage of the offshore drilling and production process. Drilling companies may even solicit and bid for specific support vessels for a particular activity or project.

OSVs can take many forms: Platform Supply Vessels (PSV), Anchor Handling Towing Supply (AHTS) vessels, crew boats, and Seismic Survey Vessels. All of these support vessels perform a range of services like drilling, production, exploration, pipe and cable laying, subsea construction, towing and salvage, heavy lift, and related operations (International Marine Contractors Association; Swire Pacific Offshore c2020). For example, the PSV shown in Figure 51 can carry up to 1,600 tons of deck cargo, 300 cubic meters of bulk cargo capacity, and additional tanks for fuel, water, brine, and liquid mud (Swire Pacific Offshore 2020). Though these OSV's are discussed as distinguishable types, often many boats are built with functionality that crosses over into another type class (Barrett 2008 Feb).

Figure 51. *Pacific Harrier*: a Swire Pacific offshore platform supply vessel.

Source: (Swire Pacific Offshore 2020).

The main purpose of PSVs is to deliver supplies needed for drilling and production: fuel, water, drilling fluids, dry bulk cement, drill pipe, casing, etc. These boats are fundamental in the support of offshore drilling and production and are easily adaptable to serve more specialized needs (Tidewater). PSVs can often provide assistance with construction tasks, along with vessels specifically designed as construction support vessels. These boats are generally pipe-laying barges, diving support vessels, pipe carriers used to aid in building offshore platforms and pipelines to shore-based storage facilities and the installation of associated offshore loading facilities (Tidewater).

AHTS vessels are used primarily in the towing, positioning, and mooring of drilling rigs and other equipment. These vessels are also used to transport supplies and equipment to offshore drilling rigs, platforms and other installations (MI News Network 2019).

Crewboats (fast supply vessels) are much smaller than their OSV counterparts, likely due to the fact they are used to transport crew members to, from, and between rigs offshore. Therefore, their cargo is significantly smaller than other OSVs. New generation crew boats have been built with the capability to carry some supplies, although those amounts are very small and meant to be used in emergencies or time-sensitive situations (Barrett 2008 Feb). There are still other types of vessels, with more specific functions that include collection of geophysical data by survey vessels, fracturing and acidizing of producing wells (well stimulation), maintenance work, and multi-purpose supply vessels which can service most deepwater operations (Barrett 2008 Feb). OSVs can also be also equipped for firefighting and oil recovery operations in the event of an oil spill at an offshore platform. Once the necessary infrastructure of the offshore site and support is in place, there is a continuing requirement for the transportation of food, supplies, personnel, and equipment to the platforms.

The services companies operating in the GOM can be used to illustrate the diversity between companies and services provided. For instance, the Atlantic Communications 2011 Gulf Coast Oil Directory lists 30 companies in the "Marine Supply Bases- Expediters" section. While the majority of companies employ between 1 and 25 people, some have between 100 and 250 or even over 1,000 employees and up to seven locations in multiple states (Atlantic Communications 2011). Supply bases provided by these companies are equally diverse from large yards with many services to smaller shops specializing in one or a few items needed by an offshore platform or marine vessel. The following is a simplified list including some products and services provided by these bases:

- Dock(s) for loading and offloading, crane services, and pipe storage.
- Personnel: dispatchers, material expediters, and rig clerks.
- Office space, computer sales and rentals.
- Brokering tug, offshore, and crew boats and barges.
- Fueling for rigs and other vessels.
- Ability to purchase, sell, store, and deliver marine diesel fuel and lubricants.
- Complete galley, deck, and engine supplier.
- Electrical cables for offshore marine applications.
- Wire rope, marine and lifting equipment.
- Navigational supplies and weather instruments.
- Marine supplies, dock, harbor, and vessel mooring, hardware.
- Living quarters and temporary accommodation cabins, galleys, diners, utility buildings.

The directory also has a section for catering services. Some of the 26 companies listed provide chef and catering services, while others delivery groceries. For example, Affiliated Marine of Houma, Louisiana delivers all groceries from meat to fresh produce, and even has butchers on staff (Affiliated Marine c2009). Taylors International Services, Inc. is a large company operating in the GOM and internationally, and employs 500 to 1,000 personnel (Atlantic Communications 2011). Taylors catering services provide a range of cuisines and fresh produce (and claim to do so under any weather conditions), but also other support services such as management services, accommodations, and personnel like cooks, stewards, bakers, utility hands, etc.(Taylor's International Services c2020).

4.2.7 Existing Infrastructure in the Atlantic Region

Dedicated support facilities for offshore oil and gas exploration and production do not exist in the Atlantic region, as it currently has no offshore oil or gas production. However, the Atlantic region boasts an extensive maritime industry, aspects of which may still provide certain support to offshore oil and gas production, either directly or indirectly, through the development of the necessary support infrastructure.

Barge construction and charter services

Barges and the tugboats that drive them play multiple important roles in the oil and gas industry. Barges can be outfitted to serve roles in offshore construction, storage, and transport, both on the open ocean and along inland waterways. Barges can serve as floating storage units for LNG transfer, or they can be outfitted with bunkers for bulk oil transport (Damen c2020). There exist charter services in the Atlantic region which offer barges as large as 260 feet by 72 feet (Mobro Marine c2020). In addition, the Atlantic region also contains barge construction facilities.

Marine construction and related industries

As stated earlier, the facilities needed to support offshore oil and gas production do not currently exist in the Atlantic region. However, the infrastructure network necessary to build these facilities currently does exist. Marine construction, engineering, architecture, and welding services are located across the Atlantic region, and discussion of these infrastructure networks can be found in Chapter 1, which discusses platform fabrication and shipyards.

Commercial diving

Offshore oil and gas production requires an extensive network of underwater infrastructure, both for the transport of products and on the rigs themselves. The dangerous tasks involved in creating and maintaining this infrastructure falls to commercial divers, who perform a wide variety of tasks, from the construction of underwater pipelines to inspecting the underwater portions of the rig (Divers Institute of Technology c2020). Though the Atlantic region does currently offer some commercial diving services, the sector as a whole would need to expand in order to accommodate offshore oil and gas production.

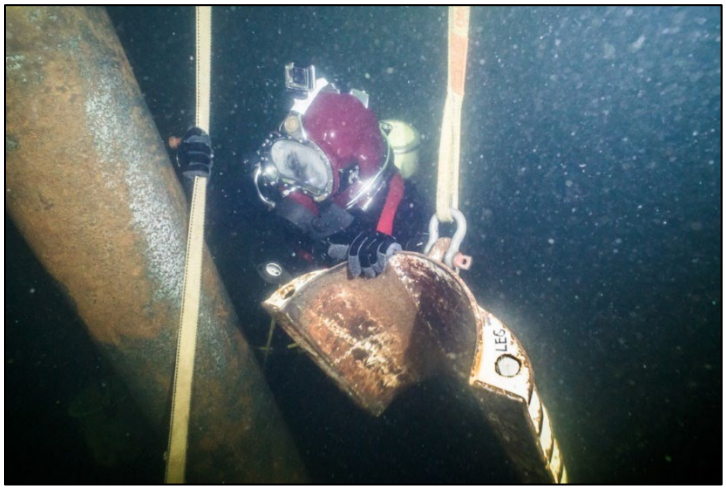

Figure 52. A diver secures a pipeline with a riser clamp.

Source: (Divers Institute of Technology c2020).

Corrosion control, coating, and inspection

Pipelines are not the only element of the oil and gas industry subject to corrosion damage. Seawater can corrode the steel supports of oil platforms, causing pitting that can lead to structural breaks and equipment failure (Christopher 2015 Oct 7). The risk of corrosion-related failure could be further exacerbated by the low water temperatures of the northern Atlantic (Necci et al. 2019: 23). Corrosion can be controlled through the use of protective coating and cathodic protection, including sacrificial anodes, which are active metals that are used to prevent corrosion.

Figure 53. Sacrificial anodes mounted on a metal jacket structure.

Source: (Chetan 2005).

In addition, proper painting and coating practices are crucial to preventing corrosion and extending the life of the oil and gas assets. This process does not end with the installation of the rig: Oil and gas assets should be inspected for coating and painting needs by a professional contractor on a regular basis, and these services are available in the Atlantic region (Dromgool 2015 Jul 8).

Marine demolition and salvage

The exploitation of the Atlantic region's oil and gas resources will, at some point, necessitate the decommissioning and removal of the rigs that are used to do so. The complexity of decommissioning, demolishing, and salvaging an offshore platform can rival that of the platform's construction. All topside facilities are first removed, and then any structural supports are generally severed 15 feet below the mudline (BSEE). This is done via either mechanical severance, in which the supporting structure is methodically severed using mechanical cutting equipment, or explosive severance, which cuts pipe through the use of an explosive charge (Bull and Love 2019).

Although such services are not readily available in the Atlantic region, an excellent example of the complexity of oil rig removal is the North West Hutton platform, located northeast of the Shetland Islands in the North Sea. The rig was decommissioned in two phases, with the topside and support frame removed in 2008, and the jacket removed in 2009. The topside and support frame required 22 individual lifts to remove all of the modules, while the jacket was removed in 58 individual sections, requiring 224 underwater cuts (Nixon 2013 Dec). Steel jackets on rigs can be exceedingly thick and thus difficult to cut. Canadian Natural Resources' Murchison rig, for instance, had a jacket of steel that reached 80 millimeters in thickness in some areas (Neilson 2016 Mar 3).

Maritime supply and crew services

Much like the offshore oil and gas industry, the maritime industry also relies on dedicated companies for provisioning and crew services. These companies that undertake this task are called ship chandlers (Chopra 2019 Sep 18). The Atlantic region is home to many such ship chandlers, who provide food, toiletries, and other sundries to ship crews. Beyond the capacity to supply support vessels and bulk carriers, some ship chandlers in regions near offshore oil fields (i.e. the GOM) explicitly offer supply services to oil rigs (Daron; Salvo Grima c2019). It is worth noting that such ship chandlers generally do not provide services to international companies. That is, Canadian ship chandlers support Canadian offshore oil and gas operations, while American ship chandlers support American oil and gas operations. A review of the 144 support facilities located within the Atlantic region revealed that none service any offshore Canadian oil and gas operations.

Marine emergency response

Oil spills are far from the only emergency that can strike in the offshore oil industry. Accidents on both rigs and support vessels can necessitate services including search-and-recovery, ship salvage and towing, and lightering. Lightering barges may be needed to remove cargo to prevent hazardous material discharge or to help ballast a ship as shown in Figure 54 depicting the lightering of grounded coal carrier M/V Montrose.

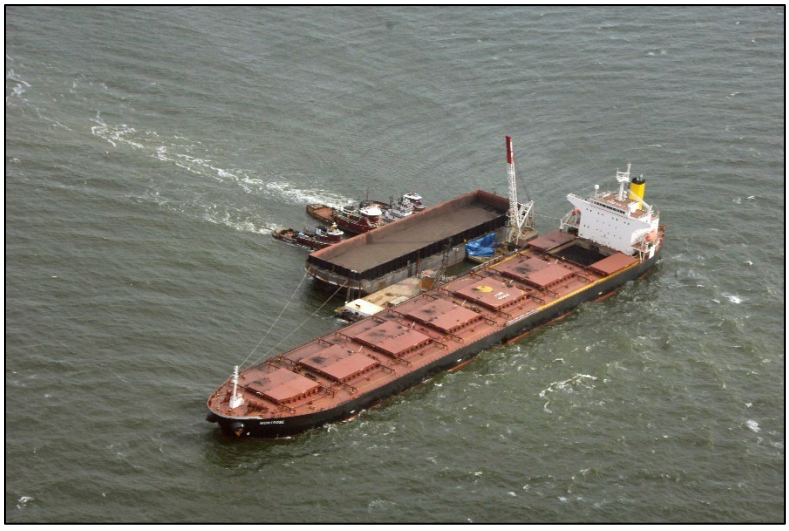

Figure 54. Lightering of the M/V *Montrose*.

Source: United States Coast Guard (USCG 2007).

Stranded and sunken ships across the Atlantic can necessitate the usage of crane barges to recover them and tugboats to tow them home. Figure 55 depicts one such rescue by Resolve Marine Group, which maintains a fleet of tugs and barges, as well as a 24-hour hotline.

Figure 55. *Delta Amber* after its recovery by RESOLVE Marine Group.

Source: (Resolve Marine Group 2017 Jan).

Logistical support and integrated solutions

Beyond providing a place to unload cargo, marine terminals offer services to firms relying on intermodal transportation and vessel operations. This can include supply chain management and stevedoring of equipment and supplies for platform supply vessels, along with other vessel support services. Davis Ship Service in Baltimore, for instance, specializes in the receipt and shipping of spare ship parts (Davis Ship Service c2010).

Integrated solutions firms offer services that support and integrate multiple aspects of the oil and gas industry, including engineering, construction, safety, and crew accommodation (Oceaneering c2020; Stallion Oilfield Services c2020). One such company is Stallion, which already maintains locations in Pennsylvania to support exploitation of the Marcellus Shale resources (Stallion Oilfield Services c2020).

Metocean consulting

Metocean, or meteorological and oceanographic, data is crucial for the safe design and operation of offshore oil and gas installations, so much so that the International Association of Oil and Gas Producers (IOGP) maintains a committee specifically dedicated to development and application of this data (International Association of Oil & Gas Producers c2020). For decades, the IOGP has sponsored joint industry projects that aimed to share costs and risks amongst producers in the gathering and application of metocean data (Shaw 1999; International Association of Oil & Gas Producers c2020). In addition to standard engineering and operation considerations, metocean analysis is used to determine when a tropical cyclone necessitates the shutdown and evacuation of rig operations. One example of this application of metocean data is Oceanweather's Topical Cyclone Operational Prediction System, which uses national warning center data to drive its own model and produces probabilistic storm tracks and wind/wave forecasts (Oceanweather, Inc. c2019).

Waste remediation

The oilfield itself is not the only source of petroleum waste that must be processed and disposed of. Refineries, petrochemical plants, and tankers also produce waste which must be remediated, such as that of petroleum contact water from storage tank condensate. Waste remediation and environmental consultancies exist in the Atlantic region to fill that role.

4.3 Geographic Distribution

4.3.1 Heliports

Heliports are located throughout the United States, but those that service the offshore oil and gas industry are obviously more prevalent in the GOM region. The heliports identified in the Atlantic region are likely not being used for oil and gas operations. In the short term, then, the oil and gas industry will need to make use of existing facilities as appropriate.

The FAA maintains a database of airports and heliports as reported by operators through the FAA 5010 Airport Master Record forms (Alexander 2016 Jun). However, the FAA's data on existing heliports is both unreliable and of limited use. In 2015, an initial examination of heliport records in two states found that only 55% to 60% of reported heliports even existed (Alexander 2016 Jun). The reason for this inaccuracy is that the FAA does not audit or inspect private facilities after they have been established (Alexander 2016 Jun).

This report's survey of heliports within 20 miles of the Atlantic coast corroborates that research. Satellite image searches of the reported locations of heliports instead frequently led to empty fields, baseball diamonds, residential neighborhoods, and open water.

In addition to its lack of reliability, the existing FAA heliport data is a poor tool for determining the usefulness of a heliport in oil and gas operations. The data does not specify whether a heliport is ground- or rooftop-based, for instance (Cowan 2019). Even properly documented heliports, such as the DelDOT Helistop shown in Figure 56, are not necessarily suitable for oil and gas operations.

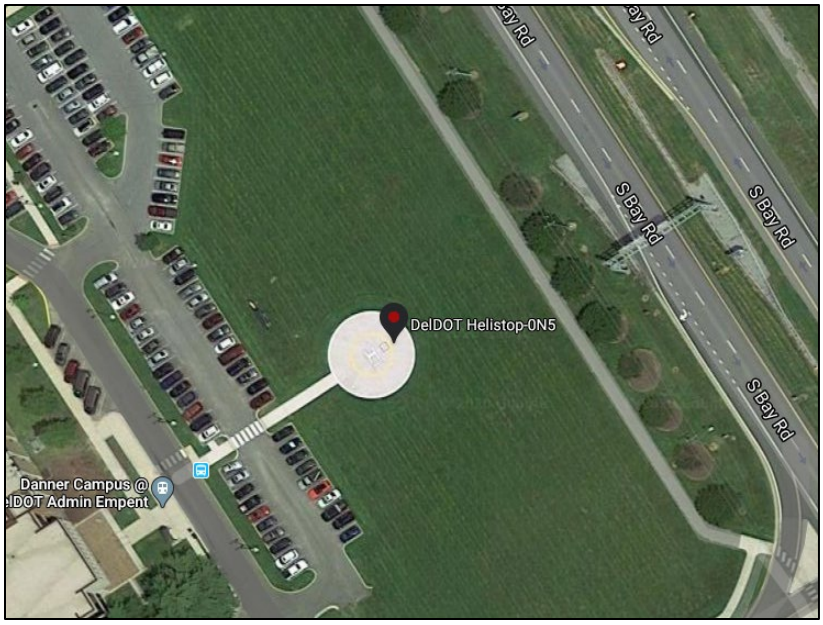

Figure 56. DelDOT Helistop.

Source: (Google Maps c2020).

However, helicopter operations are not limited to dedicated heliports. Oil and gas helicopter operations also take place at airports. Era Helicopters, for instance, operates out of several airport in the GOM region (Era Helicopters c2020). Airports offer existing infrastructure that preclude the need for building dedicated oil and gas heliports in the short term, such as office space, fuel access, and crew and passenger services. Thus, airports within 20 miles of the Atlantic coast with access to turbine fuel (Jet-A) and which already field helicopter operations were included in this survey. Their inclusion increased the number of potential facilities for oil and gas helicopter operations from three to 113. Figure 57, Figure 58, and Figure 59 below show the locations of these facilities, in addition to their potential helicopter range using range specifications for an AW139, the most common helicopter in Era's fleet (SEC 2020), layered over the BOEM Atlantic OCS planning regions. The inner radius, marked by a striped pattern, is approximately 449 nautical miles, which Era describes as the "average range" of an AW139 (Era Helicopters 2020). The outer radius is approximately 573 nautical miles, which is the maximum range according to manufacturer Leonardo (Leonardo 2020).

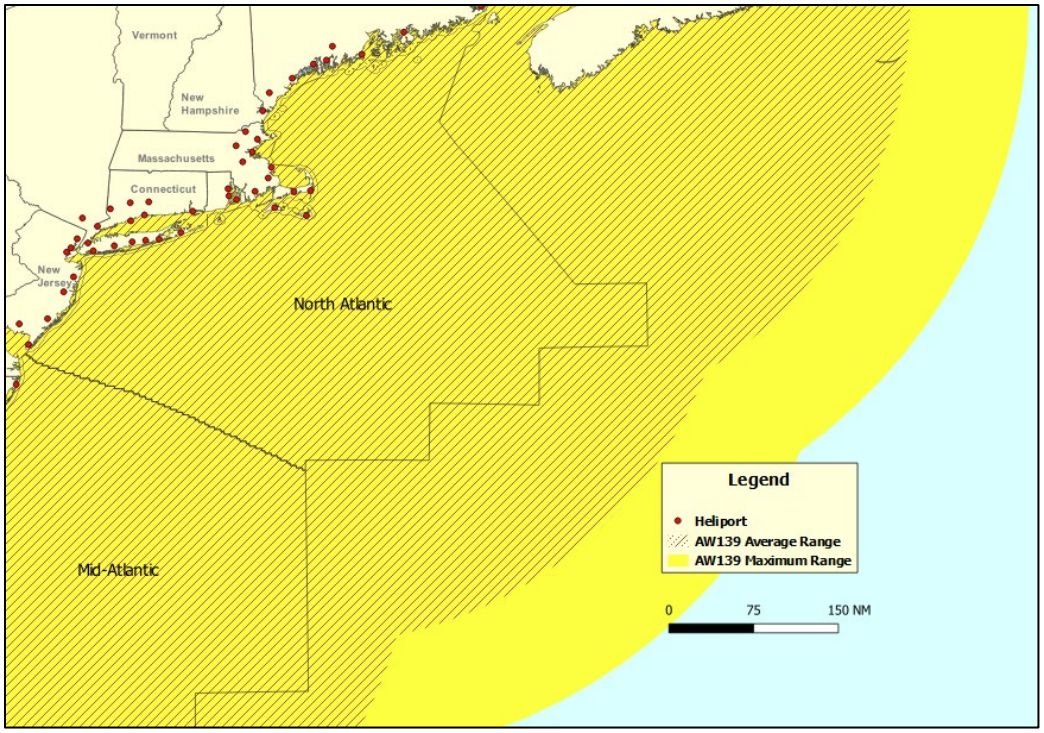

Figure 57. Heliports and estimated range, North Atlantic Region.

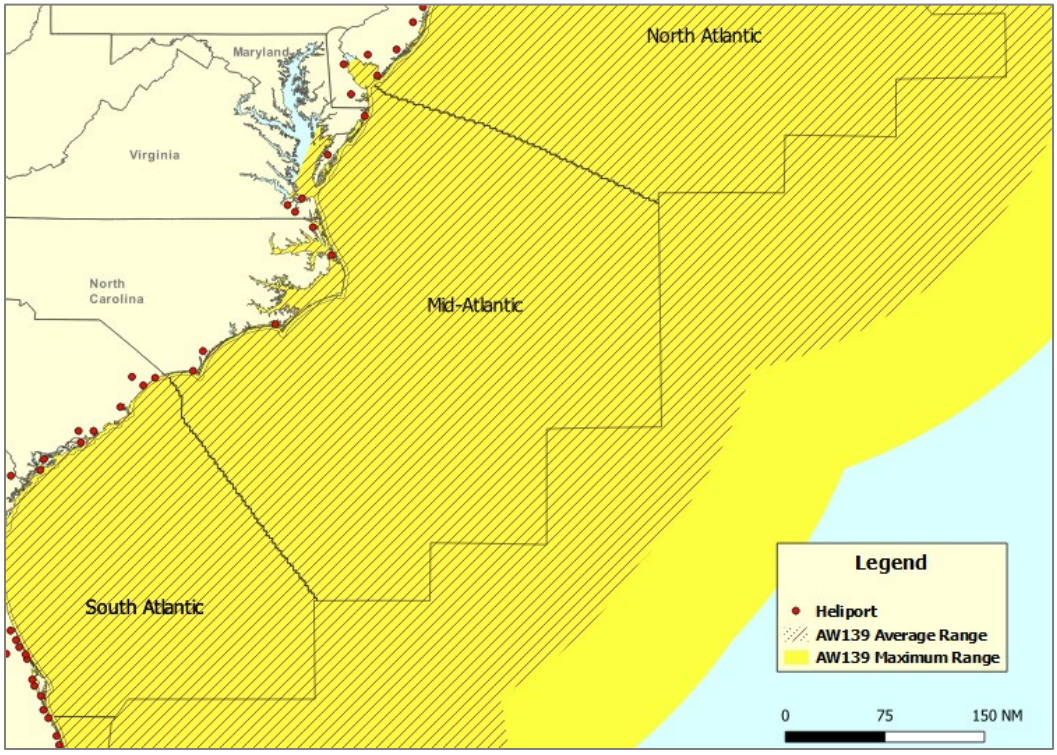

Figure 58. Heliports and estimated range, Mid-Atlantic Region.

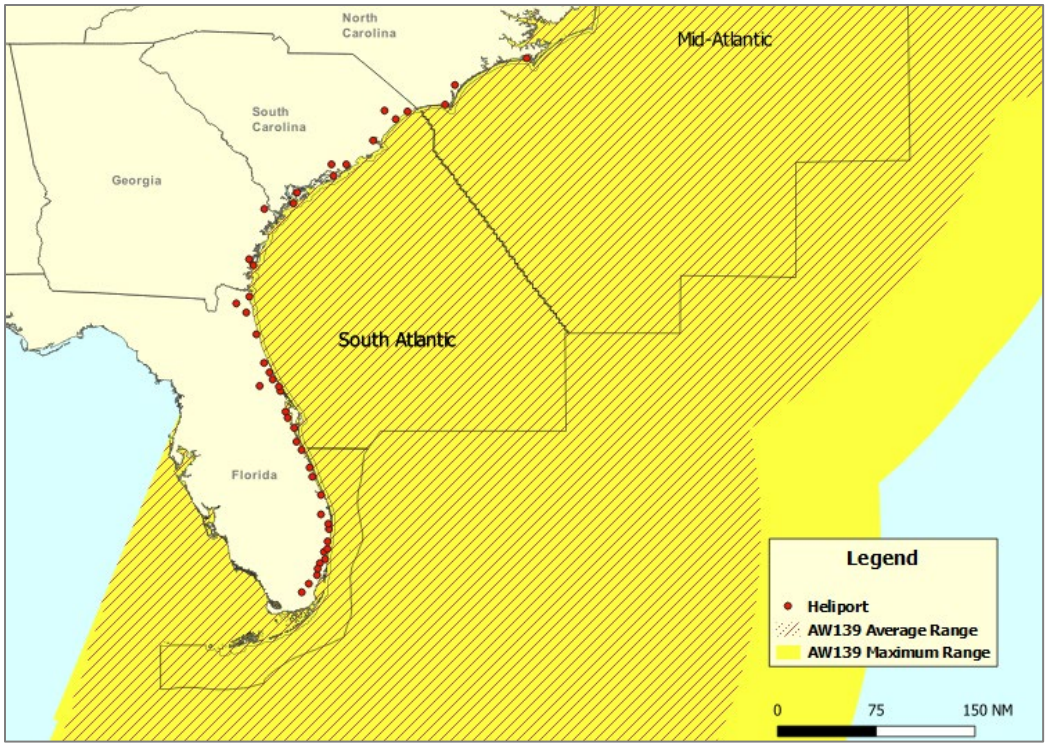

Figure 59. Heliports and estimated range, South Atlantic region.

4.3.2 Other Support Facilities

As stated earlier, dedicated offshore oil and gas operations support facilities do not currently exist in the Atlantic region. However, a limited survey of certain facilities serving functions described in section 0 was undertaken and are mapped in Figure 60 and Figure 61.

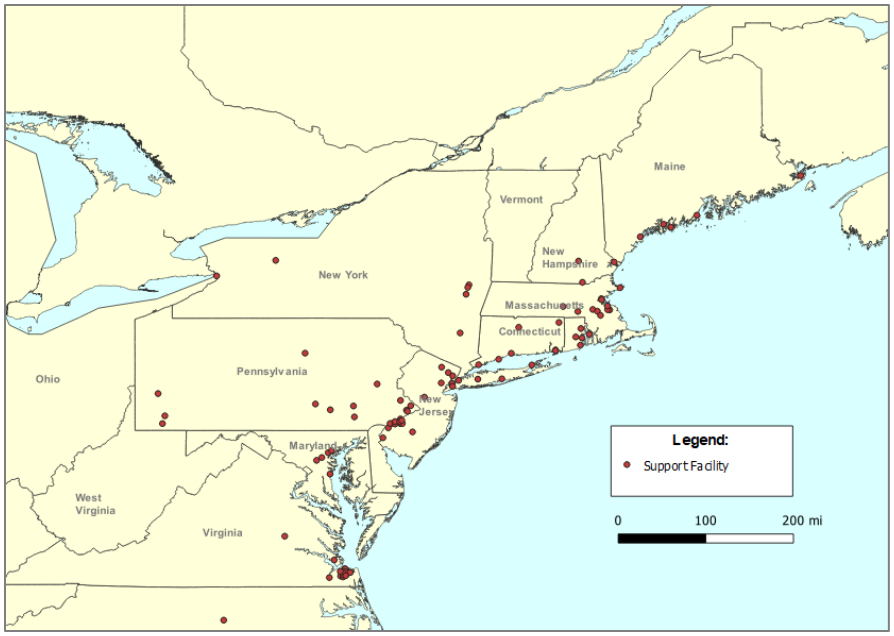

Figure 60. Other support facilities, North and Mid-Atlantic regions.

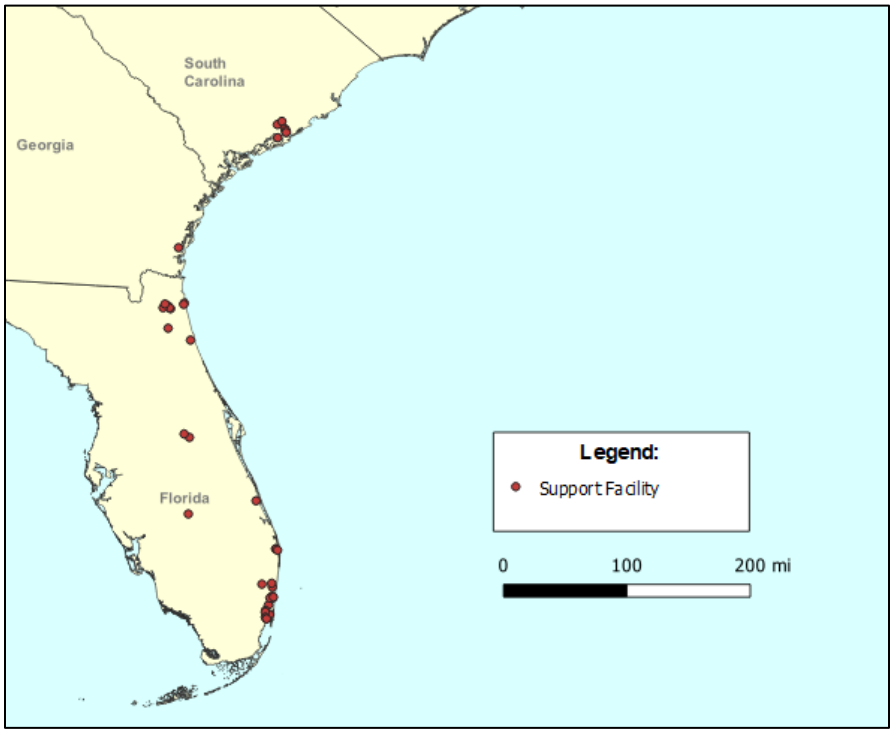

Figure 61. Other support facilities, Southeast Atlantic region

4.4 Scope of Economic Contribution to Regional Economy

The economic contribution of this sector cannot yet be estimated. Although many potential support facilities in the Atlantic region have been identified, these facilities are currently not focused on offshore oil and gas operations, and are only a very small part of their respective industries at a regional and particularly national basis. For example, ship chandlery as a service is provided by businesses spanning three NAICS industries within the subject area 4883: Support Activities for Water Transportation (United States Census Bureau), and even in the presence of Atlantic region drilling activity, the utilization of ship chandlers would be very small. In the absence of drilling activities and resulting economic data in the Atlantic region, the effect these support operations will have on the regional economy is impossible to quantify.

4.5 Current Trends

4.5.1 Trends

Support and transportation facilities serving the offshore oil and gas industry are dependent upon drilling and production activities and the price of oil and gas. This dependence requires support companies to diversify so that they can accommodate changes in the industry such as exploration in deeper waters. Further, as Era states in its 2018 10-K filing's statement of risk factors, "The offshore helicopter services industry is cyclical (SEC 2019c)." These companies face risk not only from commodity price fluctuations, but also from budget cuts to any government agencies they do business with. Bristow Group's largest client by revenue in the fiscal year ended March 31, 2019, for example, was the United Kingdom Department for Transport (SEC 2019b).

This volatility has led to significant negative developments in the offshore helicopter industry. On March 19, 2019, PHI filed for bankruptcy relief, with Bristow Group following shortly thereafter on May 11 (SEC 2019a; SEC 2019b). These bankruptcy proceedings loomed large in the risk factors sections of the companies' respective 10-K filings. In January 2020, Bristow Group and Era announced an agreement to merge, with the final company bearing Bristow's name but keeping Era's NYSE stock listing (Perry 2020 Jan 24). Combined, they will field a fleet of over 300 helicopters (Perry 2020 Jan 24).

The support and transport sectors are generally very competitive. For instance, oil and gas companies usually select one helicopter provider for all services within a region by competitive bidding (if not throughout all service regions). In Bristow Group's 2019 10-K filing, they present a break-down of their clients' contributions to gross revenue. The top ten clients comprise more than 57 percent of their total revenue and their top client, the United Kingdom Department for Transport, accounts for 16.5 percent of their revenues (SEC 2019b). Additionally, these companies face the threat of vertical integration: Their customers could implement their own helicopter transportation operations (SEC 2019b).

Domestic and international competition also forces companies to be efficient and to use more advanced technologies. Autonomous vehicles like Alseamar's SeaExplorer glider, shown in Figure 62, can gather metocean data and search for resource reserves thousands of feet below sea level (de Fommervault et al. 2020 Mar 1)

Figure 62. The Alseamar SeaExplorer glider.

Source: (Rosenfield).

The transportation sector of the support industry also utilizes technological developments to improve safety of boat and flight performance. In 2007 Appareo Systems, on behalf of Bristow's Air Logistics unit, developed a flight monitoring tool called Aircraft Logging and Event Recording for Training and Safety ("ALERTS") to store flight data and allow the information to be downloaded and analyzed using company software (Twombly 2007 Mar 12). In addition, Bristow began installing a more advanced version of traffic alert and collision avoidance avionics, TCAS-II, on its helicopters in 2008 (Kaminski-Morrow 2008 Apr 11).

4.5.2 Outlook

Like most sectors that support the offshore oil and gas industry, if activity in oil and gas exploration, development, or production in any region declines drastically, the need for support services would also decline. This is difficult to predict.

If drilling were to begin off the Atlantic coast, support and transport services would be needed by the oil and gas industry, which would create a boom (and a beginning) for the support and transport sector in this region. However, even if drilling were to begin off the Atlantic coast, the uncertainty in the future of a leasing program could serve to dampen enthusiasm for investment in the support sector. Also, as is true with most offshore drilling-related industries, the service industry is cyclical and dependent upon oil and gas prices. Higher prices stimulate exploration efforts and the extent of economic growth, which drive the construction market.

4.5.3 Regulatory Changes

There are a number of regulations which apply to the oil and gas industry, particularly concerning potential spills in water and other types of air and water pollution. These regulations therefore impact the support and transport sector as well. These regulations encompass international, federal, state, and local levels. Similarly, a range of US governmental agencies have jurisdiction over these support and transport operations: the US Department of Transportation, National Transportation Safety Board, the Department of Homeland Security and its related agencies (US Customs and Border Protection, US Coast Guard), and the Environmental Protection Agency (EPA), as well as these agencies' foreign equivalents, and industry organizations such as the American Shipping Bureau (SEC 2019d)

Onshore support services are not explicitly regulated; however, they do have to follow environmental statutes because they coincide with other regulated industries. For example, repair and maintenance often falls under regulations applied to the shipbuilding industry and its regulations as discussed in Chapter 1 of this fact book. Some regulations applicable here are: the Resource Conservation and Recovery Act; United States Code, Title 10, Section 7311; the Clean Air Act; the Clean Water Act; and the Comprehensive Environmental Response, Compensation, and Liability Act.

Specific regulations for the design and construction of offshore supply vessels were adopted by resolution by the International Maritime Organization (IMO). *The Guidelines for the Design and Construction of Offshore Supply Vessels 2006* are actually an amended and revised version of regulations originally adopted in 1981 (International Maritime Organization 2006). Following, in May 2012, the US Coast Guard issued a policy letter implementing the IMO's resolution and providing the United States' interpretations for the design, construction and operation of new and existing US flagged OSVs (USCG 2012). The provisions of both the IMO guidelines and the USCG interpretations "have been developed so that limited quantities of cargoes regulated under these Guidelines may be carried in bulk with minimum risk to the offshore support vessel, its crew, and to the environment" (USCG 2012). The guidelines address stability, machinery and electrical installations, fire protection, lifesaving appliances, radio communications and the transport of hazardous and liquid noxious substances in bulk.

FAA Regulations

There are specific state and federal regulations for heliports, in part due to the Federal Aviation Administration (FAA), which oversees all flight operations. The National Transportation Safety Board is responsible for reducing the number of accidents in all transportation media. They are an independent government entity which investigates past accidents and creates recommendations as needed prevent future accidents (NTSB 2020). However, note that the NTSB has no true authority to regulate the transportation industry. The Communications Act of 1934 also has a minor role in regulatory concerns for heliport owners and operators. As with all other workspaces that have been discussed hereto, workplace health and safety standards are defined by the federal Occupational Safety Act (OSHA).

The FAA's jurisdiction is widespread and includes oversight of flight operations in general, to personnel, aircraft, and ground facilities. In order to transport personnel and equipment to offshore regions air transportation providers must have an Air Taxi Certification from the FAA. Similarly, air transportation companies are required to file flight operation reports periodically. Under the Federal Aviation Act, aircraft for hire must be registered with the FAA and the operator must receive an operating certificate (SEC 2019b). These operating certificates are only issued to US citizens, and a company may be considered a US citizen as long as: at least 75 percent of its voting interest is held by a citizen of the US, the president of the company and at least two thirds of the directors are a US citizens (SEC 2019b).

Because heliports own and operate radio and communications equipment used in flight coordination, the air transportation companies are subject to certain regulations associated with the Communications Act of 1934.

4.6 Current Outlook

From 1976 to 1983 there were 433 lease sales and 51 wells were drilled in the US Atlantic region. This was an exploration phase and only one "discovery" of gas shows was made. No production resulted from this exploratory event (BOEM 2020a). This is the extent of activity in the oil and gas offshore industry in the US Atlantic region to date.

As discussed earlier in this chapter, helicopter operations supporting offshore oil and gas exploration and production would primarily need to be based at existing airports in the region. Since heliports and support facilities are required in areas to enhance offshore production, this industry will only grow in the Atlantic region if drilling begins offshore.

It is unclear whether the Atlantic region will begin producing offshore, and until that time there is no reason that a support structure will develop for drilling. Land-based supply and fabrication centers provide equipment, personnel, and supplies necessary for the industry to function through intermodal connections with ports. Other necessary onshore counterparts to offshore drilling are inland transportation to supply bases, equipment manufacturing, fabrication, and crew services. The offshore support includes a variety of waterborne and airborne transportation.

BOEM released a study in 2016 using data and information available as of January 1, 2014 to assess the undiscovered oil and gas resources for the Atlantic region. Ten assessment units were included in the analysis. Since drillships are now able to drill in 12,000 feet (3,658 meters) of water to depths of 40,000 feet (12,192 meters) there are no longer engineering or technology issues to limit exploration in the Atlantic OCS, though there is little supporting pipeline infrastructure to the coastal regions into the OCS (BOEM et al. 2016). The assessment estimates the undiscovered technically recoverable oil and gas are between 1.15 and 9.185 Bbls of oil and 12.799 and 68.709 Tcf of natural gas in the Atlantic region (95 percent and 5 percent confidence intervals, respectively) (BOEM et al. 2016).

4.6.1 Factors Impacting East Coast Development

No dedicated support and transport facilities have been identified in the Atlantic region. However, heliports/airports and some potential support facilities have been identified. General offshore support and transportation is tied directly to ports. Our research does not suggest the development of private (company-owned) service facilities arising until offshore activity moves to the Atlantic OCS. Like ports, development in response to offshore activity will be influenced by the specific location of offshore activity.

The capital cost of developing such types of facilities by an individual offshore operator may be too expensive for one company alone. Support facility development is likely to track port development. Factors weighing against private support base facilities include:

- Potential conflicts with recreation and residential development.
- Permitting challenges.
- Facility development costs.
- Offshore development scenario uncertainties.
- Lower cost commercial port opportunities.

We have identified 101 heliports and airports with potential to support offshore oil and gas operations. These facilities do not provide service to offshore oil and gas development since there is no development of the Atlantic OCS at this time. With support from the government for drilling in this region there is a chance that this support infrastructure will develop. Some influential factors for the expansion of the existing heliport system in the region to oil and gas support are below:

- renewable energy infrastructure utilization;
- current heliport services;
- regulatory issues;
- public funding and development incentives;
- general business conditions; and
- proximity to OCS development.

5. Oil Spill Response

5.1 Description of the Industry and Services Provided

Oil spills can have profound impacts on human health, regional ecologies, and regional economic activity. The BP oil spill in 2010, for instance, underscores how a considerable geographic area can be impacted by a major spill. Not all spills, however, originate from the same source, nor do they have the same impacts. Thus, responses and the resources needed to adequately respond to these spills can differ. Further, while many spills can remain offshore and not reach land, other types of spills can impact coastal areas. This will require coordination between both state and federal stakeholders. This chapter provides details regarding the nature and methodologies concerning oil spill responses, and also, it provides a brief overview of the oil spill response organizations in the Atlantic region.

5.1.1 Federal Oversight

The US federal government coordinates oil spill responses through the National Oil and Hazardous Substances Pollution Contingency Plan (NCP). The NCP was established in 1968, and defines the institutions, regulations, and processes for an oil spill response such as (Bearden and Ramseur 2017 Aug 29):

- National Response Center (NRC): When an oil spill occurs, the NRC is responsible for collecting data on reported oil spills and notifying the proper federal authorities (i.e. the National Response Team).
- National Response Team (NRT): The NRT is the federal government's oil spill response task force. It comprises a collection of 15 federal departments and agencies, each of which has a specific role in remediating oil spills.
- Regional Response Teams (RRT): There are 13 RRTs in the United States. These response teams primarily consist of officials from state and local governments, which are tasked with carrying out the immediate safety measures following an oil spill.
- Area Committees: Qualified personnel from federal, state, and local agencies are invited to join Area Committees, which are designed to support the RRTs.
- Area Contingency Plans (ACP): An ACP comprises the specific contingency plan for each designated geographic area.
- State Emergency Response Commission (SERC) and Local Emergency Planning Committee (LEPC): Each state is required by the Emergency Planning and Community Right-to-Know Act (EPCRA) to create a SERC, as well as a LEPC.

Figure 63 illustrates the relationship between the different oil spill remediation agencies and committees, and shows that federal oil spill responses in coastal areas are managed differently than inland spills. For instance, responses to inland spills are primarily led by the EPA, and coastal and offshore spill responses are managed, in very large part, by the US Coast Guard (USEPA 2020 Apr 1).

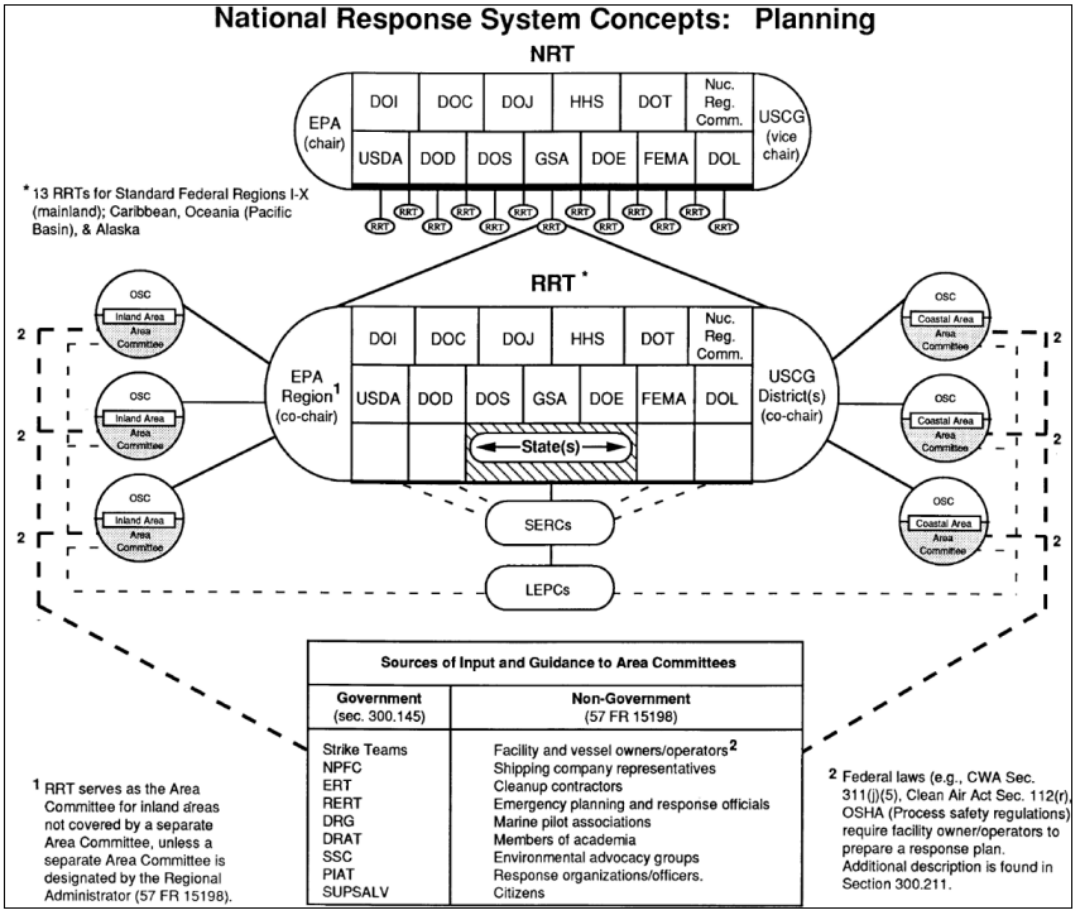

Figure 63. National response system concepts.

Source: US Congressional Research Service (Bearden and Ramseur 2017 Aug 29).

Figure 64, meanwhile, provides a breakdown of the 13 different geographic regions from which RRTs are assigned. These response teams consist of government officials from state and local agencies, which are tasked with carrying out the immediate safety measures following an oil spill.

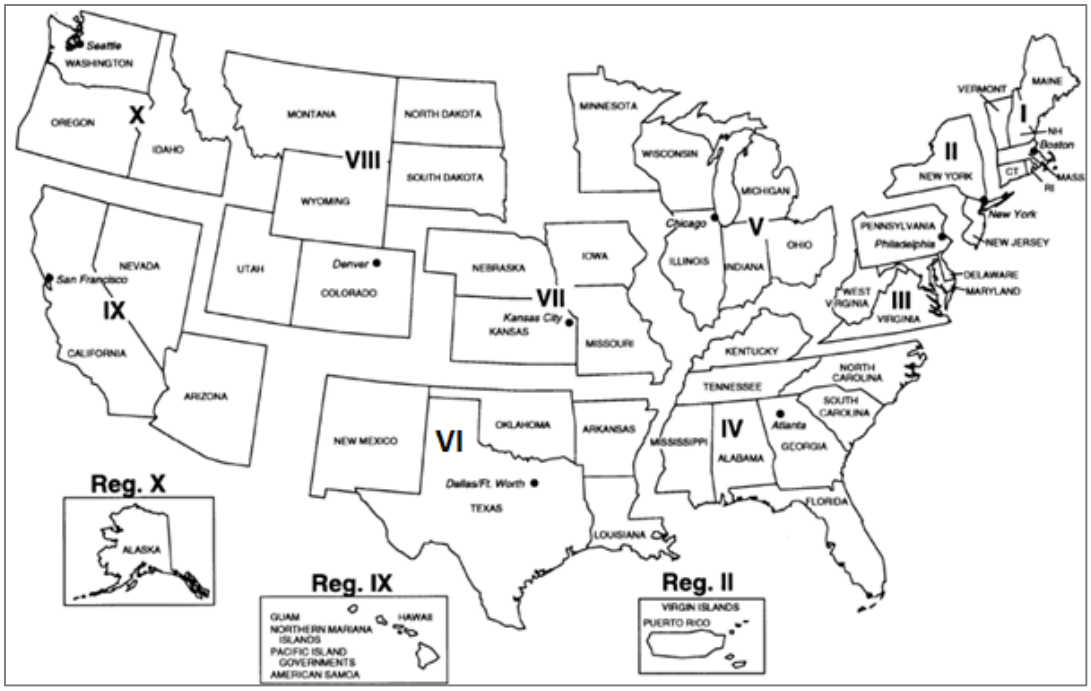

Figure 64. Regional response teams.

Source: US Congressional Research Service (Bearden and Ramseur 2017 Aug 29).

All oil spill response, regardless of location, follow a set of federal guidelines that establish a spill's potential impact to the environment and public health and include examining whether an oil spill: (USEPA c2020):

- Violates applicable water quality standards;
- Will lead to a film or results in a discoloring of the surface water adjoining shorelines; and
- Leads to a sludge or emulsion that could be deposited beneath the surface of the water or upon adjoining shorelines.

5.1.2 Historical Oil Spills

Historically, three of the most well know offshore oil spills are the 1969 Santa Barbara oil spill, the 1989 *Exxon Valdez* spill, and the 2010 *Deepwater Horizon* Spill.

The Santa Barbara oil spill began January 28, 1969 about five miles (eight kilometers) off the coast on a shallow drilling rig platform called the "Alpha." The spill lasted for eleven days before it was capped, leading to an 800 square mile (2,072 square kilometers) oil slick and directly impacting 35 miles (56 kilometers) of coastline. Later studies of the spill suggest that a major cause of the incident was a regulatory waiver that allowed the drilling company to use lower quality casing materials (Clarke and Hemphill 2002).

A second major oil spill occurred on March 23, 1989 when the *Exxon Valdez* tanker struck Bligh Reef in Prince William Sound, Alaska. *Exxon Valdez* discharged 10.8 million gallons of crude oil into the surrounding ecosystem (Alaska Oil Spill Commission 1990 Feb 1) before the leak was under control.

Lastly, the April 2010 *Deepwater Horizon* incident, which occurred 50 miles (80 kilometers) off Louisiana's coast, resulted in the largest oil spill in US history and received considerable international attention. The spill arose from a platform explosion that occurred during drilling operations which killed 11 individuals and resulted in an 87-day leak of crude oil. In total, more than three million barrels of oil leaked into the GOM, a large part of which made it to the coastal areas of five different coastal states. This was the largest marine oil spill in US history (Gulf Spill Restoration c2020).

Figure 65 details the largest oil spills that have ever impacted US waters.

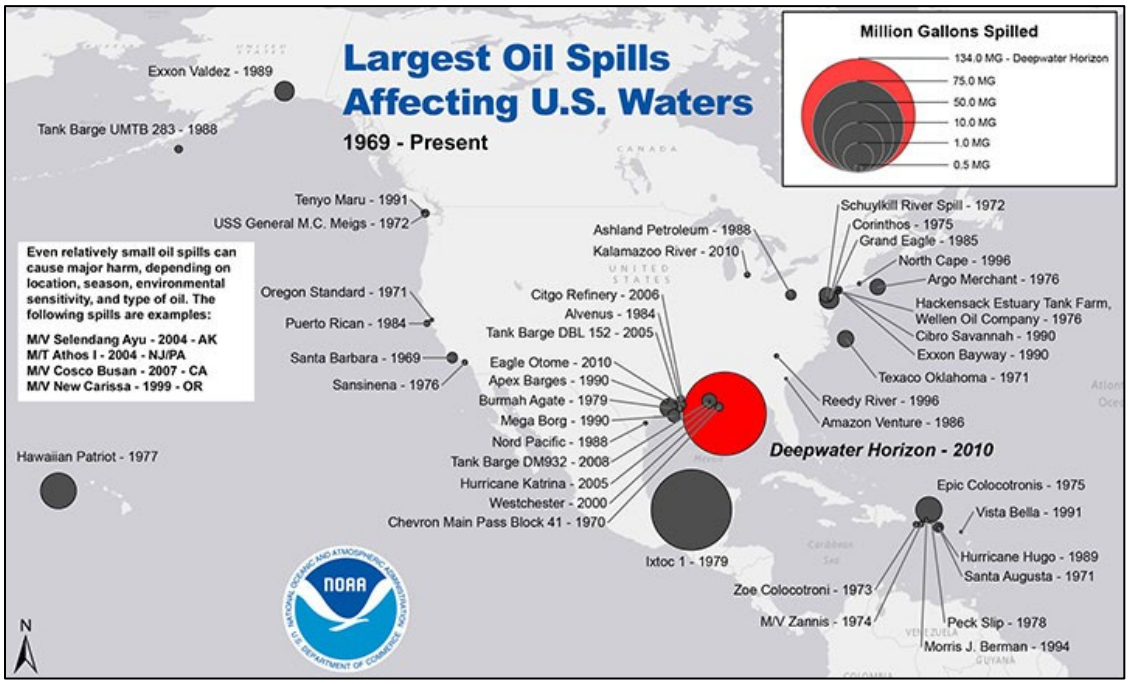

Figure 65. Largest oil spills affecting US waters (1969–2017).

Source: National Oceanic and Atmospheric Administration (NOAA 2017 Apr 5).

5.2 Typical Facility Characteristics

In general, the oil spill response industry is knowledge-based and highly mobile, as many varying factors of an oil spill play a major role in the type of response effort employed. Some of the most influential factors include geographic isolation, weather, the type of water, and shoreline impacted. For deepwater spills, there are additional concerns including accommodations, access, and communication for volunteers on the site. Similarly, small communities may not be able to support a full-fledged emergency response effort with sufficient facilities, phone, or radio equipment. Warm water environments are most conducive to biodegradation and dispersing agents, while moderate wave activity renders gelling agents more effective. Moving water also acts as a natural cleaning agent, while spills in stationary water are more severe, since oil has a tendency to pool and stay in the same area for an extended period of time. The ecological environment of the spill site should also be considered when developing a response plan, so that the scheduled oil and cleanup operations do not threaten marine habitats. Depending upon the exact type of biological community, some are more sensitive to the physical intrusion that goes along with some commonly used methods of cleanup (USEPA 2012a).

Other factors also play a large role in oil spill response efforts, in particular the specific OSV category and the speed at which the OSROs can reach the site of an oil spill. Specific OSV categories, discussed in an earlier chapter of this fact book, typically play a strong role in oil spill response as well. OSVs can be differentiated by design, length, horsepower and cargo capabilities. For example, PSVs are involved in providing offshore drilling and production facilities with various supplies including equipment, pipes, lubricants, chemicals and drilling mud. However, these vessels can also perform firefighting and oil recovery operations in case of an oil spill at an offshore platform. In some cases, companies may redesign vessels to be more specifically suited for oil spill response (MSRC 2012).

The speed at which the OSROs can reach the site of an oil spill additionally determines the response efforts employed. Usually, if the OSRO are able to reach the site of a spill within the first few hours, the initial employed response is targeted towards containment, wherein special plastic booms are deployed to prevent the oil slick from dispersing further. Once contained, the OSROs can employ skimmers to pull oil from the surface of the water while leaving the water behind. This oil is collected in tanks or vacuum trucks to be disposed of or recycled. Additionally, OSROs can employ biological sorbents to safely break down oil compounds. The use of biological sorbents has the added benefits of being able to be used along shorelines if shorelines are contaminated (Triumvirate Environmental 2012).

There are a variety of factors that influence the scope of an oil spill that can include geographic location, weather, oil viscosity, and water type, among others. Pre-staged/approved contingency plans are important for responding personnel to prepare for such a wide variety of factors and apply the most appropriate remediation techniques.

5.2.1 Contingency Planning

Effective oil spill responses usually are the result of good contingency planning, which defines the remediation and other administrative steps that are necessary before, during, and after an oil spill incident. Optimal oil spill contingency plans attempt to explicitly define steps and responses that will be taken under differing spill scenarios. The EPA identifies four major common elements of an oil spill contingency plan: (1) hazard identification; (2) vulnerability analysis; (3) risk assessment; and (4) response actions (USEPA 1999 Dec 1).

Hazard Identification

Oil spill plans identify and analyze the factors that can lead to a potential incident by identifying key hazards within a particular environment. This process is known as “hazard identification” and can include the collection of the following information (USEPA 1999 Dec 1):

- Common crude oil and other hydrocarbon types that are within the area (both underground, and transported within);
- Identifying large crude oil storage locations;
- Assessing local/regional crude oil transportation methods (i.e. pipelines, railroads, trucks or tankers);
- Typical and extreme weather conditions that can impact crude oil movements and storage; and
- Response equipment and personnel locations.

Vulnerability Analysis

Vulnerability analyses identify and examine regional/local vulnerabilities to an oil spill. These analyses include identifying (USEPA 1999 Dec 1):

- All community public safety officials;
- Special attention facilities (i.e. schools, nursing homes, hospitals, and prisons);

- Recreational areas, such as campgrounds or beaches;
- Special events (i.e. their dates, times, and location); and
- Sensitive environmental areas that can be particularly impacted by crude oil or other form of pollution.

Risk Assessment

The risk assessment phase builds upon the findings included in the hazard identification and vulnerability analysis. This stage of the planning process examines and prioritizes potential outcome probabilities, typically examining, and often raking potential spill outcomes based upon their likelihood and environmental consequence. For instance, some incidents can have relatively high probabilities from an oil spill perspective, but relatively low consequences (such as minor spills associated with materials handling). Other spills can have very low probabilities, but exceptionally high consequences (like the BP *Deepwater Horizon* incident) (USEPA 1999 Dec 1).

Response Actions

Response actions are developed to guide remediation efforts in the event of an incident. These actions can range from the very routine, to the extreme. The EPA identifies the following important response actions (USEPA 1999 Dec 1):

- Notifying all relevant and oil spill responsible entities (including private companies and government agencies);
- Ensuring timely remediation response of trained personnel and equipment;
- Determining spill magnitude, content, and location;
- Assessing spill direction and speed;
- Ensuring public and response personnel safety;
- Stopping oil spill flow and preventing ignition;
- Oil spill containment;
- Crude oil removal; and
- Crude oil disposal.

Final Steps

Trial exercises are often used to test the effectiveness and efficiency of contingency plans. These trial exercises are often held on a periodic basis and can include a range of practices from a simple responder meeting and discussion to a full-scale oil spill simulation (USEPA 1999 Dec 1).

Further, most state and federal oil spill response agencies conduct post-spill analysis of the contingency plan in order to determine the aspects of the response that can be improved. Contingency plans must evolve and improve as the approaches and methods to responding to spills are not constant (USEPA 1999 Dec 1).

5.2.2 Common Remediation Methods

There are a variety of ways in which oil spills can be contained and ultimately remediated.

In Situ Burning

In situ burning (or onsite burning) is the oldest oil spill remediation method. During an offshore spill, boats are used to pull fire-resistant containment booms across the spilled oil in order to create a contained and controllable burn environment. Figure 66 provides a photograph of the in situ burning that was carried out during the 2010 *Deepwater Horizon* oil spill (Federici and Mintz 2014 May 1).

Figure 66. In situ burning at the 2010 *Deepwater Horizon* spill.

Source: Bureau of Safety and Environmental Enforcement (Federici and Mintz 2014 May 1).

There are many advantages of in situ burning (Federici and Mintz 2014 May 1) such as:

- Minimizing oil slick spread;
- Permanently removing crude oil from the site (which eliminates waste disposal concerns);
- Being cost-effective; and
- Needing fewer remediation and clean up personnel.

While in situ burning does have several advantages, there are both concerns and limitations on the process. Factors that can limit in situ burning opportunities include:

- Oil slick thickness: The sustained burning of oil can only occur on oil slick with thickness of at least 1.0 mm. Oil slick that is thinner than 1.0 mm will not support this remediation technique (Federici and Mintz 2014 May 1).
- Density of oil: The in situ burning of dense oils requires thicker slicks (3 mm–10 mm) in order to initiate burning (Federici and Mintz 2014 May 1).
- Wind speed: In situ burning should not be employed if wind speeds are above 20 knots (Barnea c2020).
- Wave height: Wave height should be below three feet (Barnea c2020).

- Timing: The effectiveness of in situ burning decreases with time and oil weathering. After more than 72 hours, oil that has spilled may not be able to be remediated via in situ burning (Federici and Mintz 2014 May 1).

There are additional considerations as well, namely the human health issues, the worker safety hazards, and the environmental consequences that may result from in situ burns (Barnea c2020):

- In situ burning emits smoke that contains toxic gases and particulates. Such particles can cause severe health problems if inhaled in high concentration.
- The flames that emit from in situ burning present numerous safety hazards for response personnel, particularly during the ignition process.
- Considerations regarding marine life and environmental resources should be made. There are some situations in which in situ burning may significantly threaten environmental resources.

Dispersants

Dispersants are chemical molecules that are used to biodegrade oil and are designed to minimize discharged oil from reaching the shoreline. They are most effective at removing oils with low viscosity (Federici and Mintz 2014 May 1). Figure 67 provides a diagram of how dispersants work including their application to an oil slick, how those dispersants attach to the oil and are broken into smaller oil droplets. The resulting droplets mix into the water column and are degraded by microbes and other organisms.

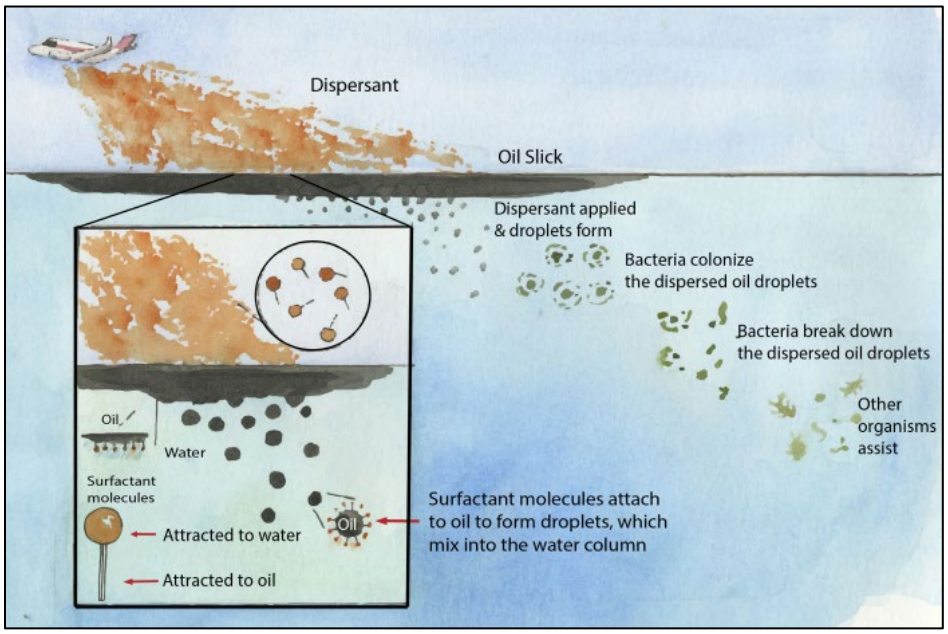

Figure 67. In situ burning at a crude oil spill.

Source: Mississippi-Alabama Sea Grant Consortium (Graham et al. c2020).

Figure 68 shows that dispersants contain solvents and surfactants. The solvents enable the chemical molecules to remain mixed together and dissolve into the water, while the surfactants aid the mixture between the chemical molecules and water.

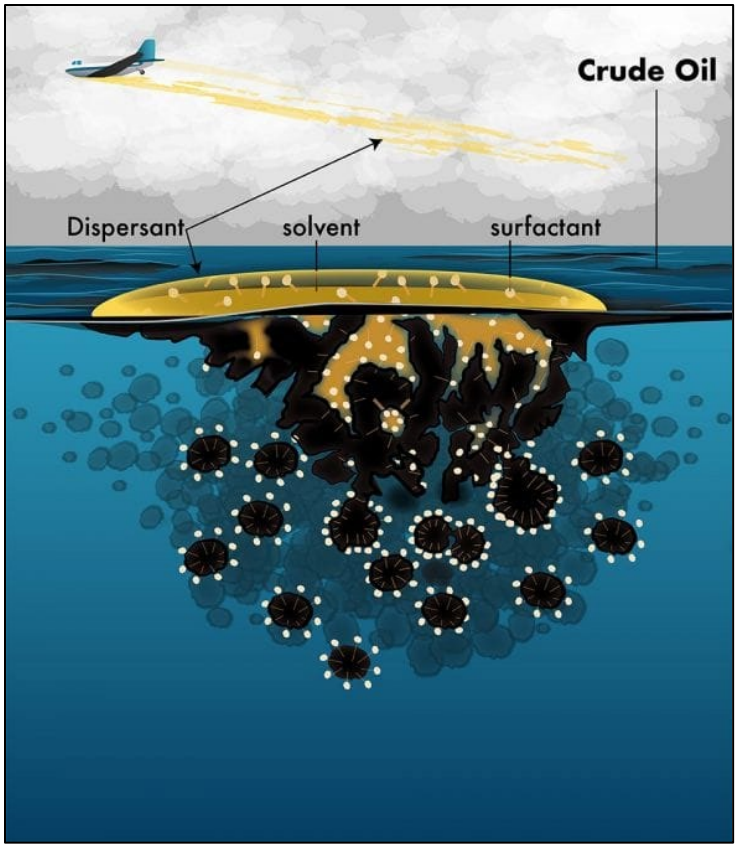

Figure 68. In situ burning at a crude oil spill.

Source: Woods Hole Oceanographic Institution (Reddy and Ward 2018 Apr 25).

Dispersants may be applied to an oil spill in conjunction with other remediation methods, such as in situ burning. For instance, during the 2010 *Deepwater Horizon* spill (diagram and dispersant locations provided in Figure 69), responding personnel applied nearly one million gallons of surface dispersants over close to 300 square miles of oiled surface waters. In addition, as much as 771,000 gallons of dispersants were injected at the surface location of the leak one mile beneath the water surface (Graham et al. c2020).

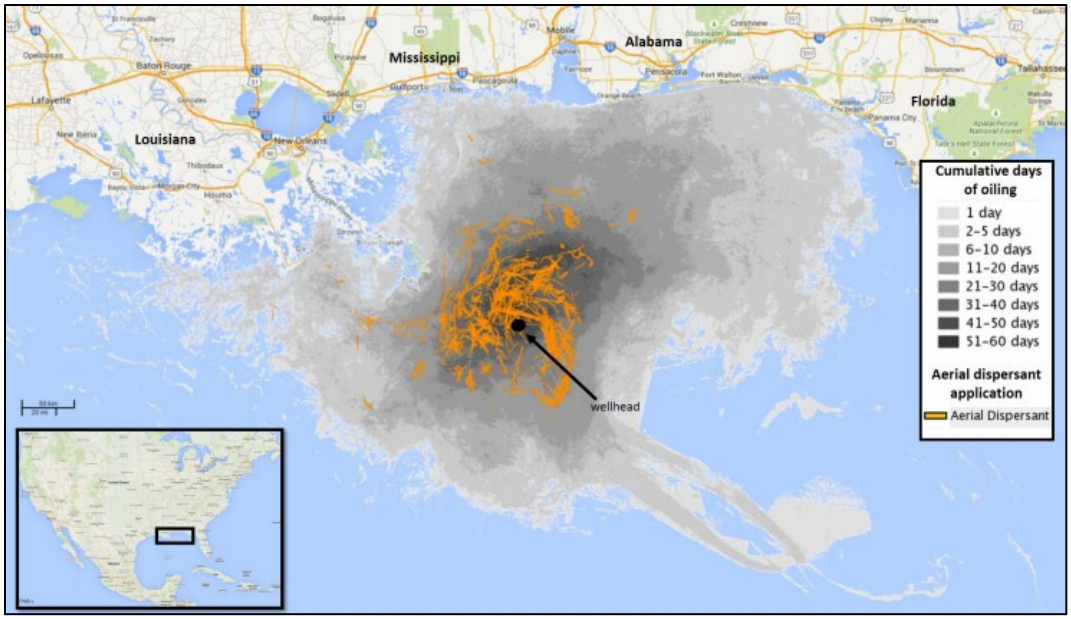

Figure 69. Aerial application of dispersants, 2010 *Deepwater Horizon* spill.

Source: Mississippi-Alabama Sea Grant Consortium (Graham et al. c2020).

Skimmers

Skimmers are mechanical devices that separate oil from water, and they are an attractive remediation application for two primary reasons:

1) Unlike other remediation methods, such as dispersants, skimmers effectively recover oil across a wide range of viscosity; and
2) There are minimal environmental consequences of applying skimmers to an oil slick.

Generally, there are two types of skimmers. Oleophilic skimmers, which are illustrated below by Figure 70, use oil-attracting coatings on the surface of a drum, brush, or other shape to attract and separate oil from the underlying water. Weir skimmers, meanwhile, use gravity to separate oil from water; these are illustrated below in Figure 71 (Federici and Mintz 2014 May 1).

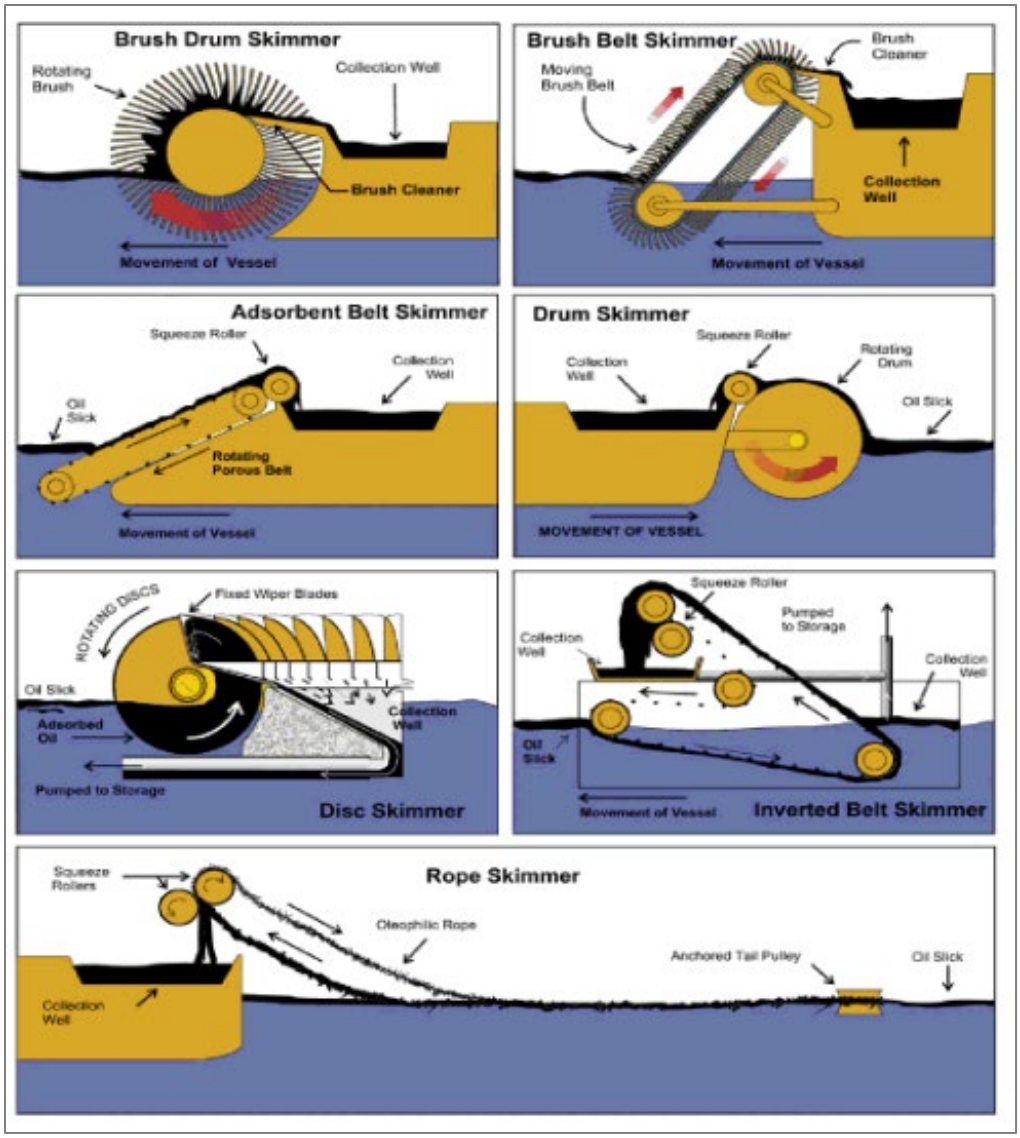

Figure 70. Oleophilic skimmers.

Source: Bureau of Safety and Environmental Enforcement (Federici and Mintz 2014 May 1).

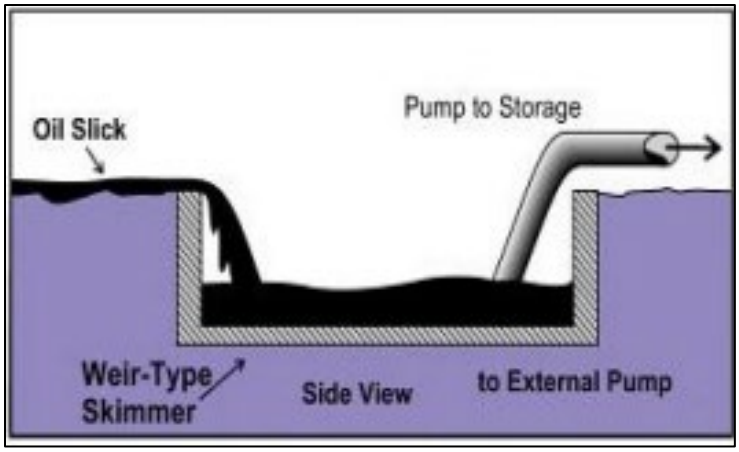

Figure 71. Weir skimmers.

Source: Bureau of Safety and Environmental Enforcement (Federici and Mintz 2014 May 1).

During the 2010 *Deepwater Horizon* spill, responders used between 6080 skimmers on a daily basis, which effectively recovered three percent of all spilled oil (147,000 barrels) (Federici and Mintz 2014 May 1). Figure 72, below, illustrates skimmers being used during the *Deepwater Horizon* spill.

Figure 72. Skimmers used during the 2010 *Deepwater Horizon* spill.

Source: Office of Response & Restoration (OR&R 2019 Apr 24).

Sorbents

Sorbents are oil-absorbing materials that are commonly used to clean up the final traces of oil on water and shorelines. They may consist of organic materials (carbon-containing materials, moss, wood products, clay, cotton, etc.) or synthetic materials (polyester or polypropylene). Furthermore, sorbents vary by form and function. The four basic types of sorbents (illustrated in Figure 11) include:

- Type 1: Roll, film, sheet, blanket, or pad;
- Type 2: Loose adsorbent (powder form);
- Type 3: Enclosed sorbent (pillows, adsorbent booms); and
- Type 4: Agglomeration unit ("pompoms"—for highly viscous oils).

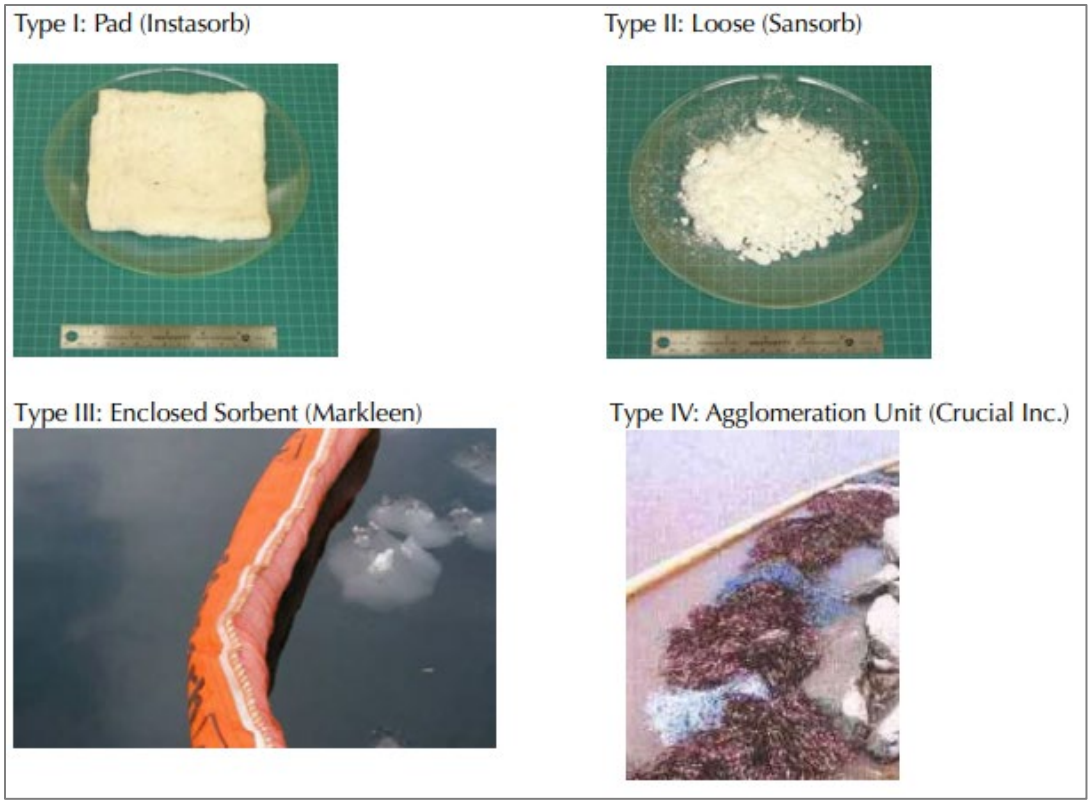

Figure 73. Types of sorbents.

Source: Bureau of Safety and Environmental Enforcement (Federici and Mintz 2014 May 1).

5.3 Geographic Distribution

Historically, oil spills in the Atlantic region have been refinery-oriented and arise during water-borne transfer activities and other materials handling and on-site activities. Because of this, there are numerous companies that provide oil spill response services across the Atlantic region. The private companies involved in the oil spill response industry are extremely mobile; they may be stationed in one location but offer their services across the entire US or even internationally.

Table 18, for instance, lists the capabilities of one oil spill response organization, Marine Spill Response Corporation (MRSC). It operates across the Atlantic, from New York to Florida, and provides remediation services across all types of offshore and inland areas.

Table 18. Marine Spill Response Corporation: Atlantic region operating capabilities

Marine Spill Response Corporation: East Coast Geographic Zones	Ocean	Offshore	Near Shore	Inland	River or Canal	Great Lakes
Baltimore	✓	✓	✓	✓	✓	
Boston	✓	✓	✓	✓	✓	
Buffalo	✓	✓	✓	✓	✓	✓
Buffalo (Oswego, NY)	✓	✓	✓	✓	✓	✓
Charleston	✓	✓	✓	✓	✓	
Delaware Bay	✓	✓	✓	✓	✓	
Delaware Bay (Lewes, Lower Del. Bay)	✓	✓	✓	✓	✓	
Hampton Roads	✓	✓	✓	✓	✓	
Jacksonville	✓	✓	✓	✓	✓	
Jacksonville (Port Canaveral, FL)	✓	✓	✓	✓	✓	
Key West	✓	✓	✓	✓	✓	
Long Island Sound	✓	✓	✓	✓	✓	
Miami	✓	✓	✓	✓	✓	
New York	✓	✓	✓	✓	✓	
New York (Albany)	✓	✓	✓	✓	✓	
Northern New England	✓	✓	✓	✓	✓	
Pittsburg	✓	✓	✓	✓	✓	
Savannah	✓	✓	✓	✓	✓	
Southern New England	✓	✓	✓	✓	✓	
St. Petersburg	✓	✓	✓	✓	✓	
Wilmington (Fort Macon)	✓	✓	✓	✓	✓	
Wilmington	✓	✓	✓	✓	✓	

Source: US Coast Guard (USCG).

5.4 Scope of Economic Contribution to Regional Economy

Oil spill response services are included in NAICS code 562910, Remediation Services, which itself includes a broad range of other clean up activities that go beyond those associated with oil spills such as remediation and cleanup of contaminated buildings, mine sites, soil, and ground water; wastewater treatment; and the removal of hazardous material, such as asbestos, lead paint, and other toxic materials.

Table 14 presents regional employment data across the entire remediation sector (NAICS 562910, which includes more than just oil spill remediation alone). The regional sector comprises 37 percent of total US remediation employment. New York, Florida, and Pennsylvania employ the greatest number of response workers in the Atlantic region, as can be seen in Figure 35.

Table 19. Regional and national employment contribution, remediation sector, 2018

State	Number of Remediation Jobs (2018)	Total State Jobs (2018)	Remediation Employment as a Percent of Total State Employment	Remediation Employment as a Percent of Total US Remediation Employment
CT	1,697	1,449,072	0.12	1.94
DC	0	534,661	0.00	0.00
DE	394	384,332	0.10	0.45
FL	3,487	7,635,037	0.05	3.99
GA	1,556	3,777,824	0.04	1.78
MA	2,830	3,156,298	0.09	3.24
MD	2,362	2,188,298	0.11	2.70
ME	352	518,990	0.07	0.40
NC	1,795	3,710,090	0.05	2.05
NH	390	574,083	0.07	0.45
NJ	3,295	3,472,611	0.09	3.77
NY	8,038	8,017,398	0.10	9.19
PA	3,327	5,193,979	0.06	3.81
RI	205	421,767	0.05	0.23
SC	819	1,743,243	0.05	0.94
VA	1,878	3,188,362	0.06	2.15
Total Region:	**32,425**	**45,966,045**	**0.07**	**37.09**
Total US	**87,426**	**124,551,838**	**0.07**	**100.00**

Source: US Bureau of Labor Statistics (BLS c2020).

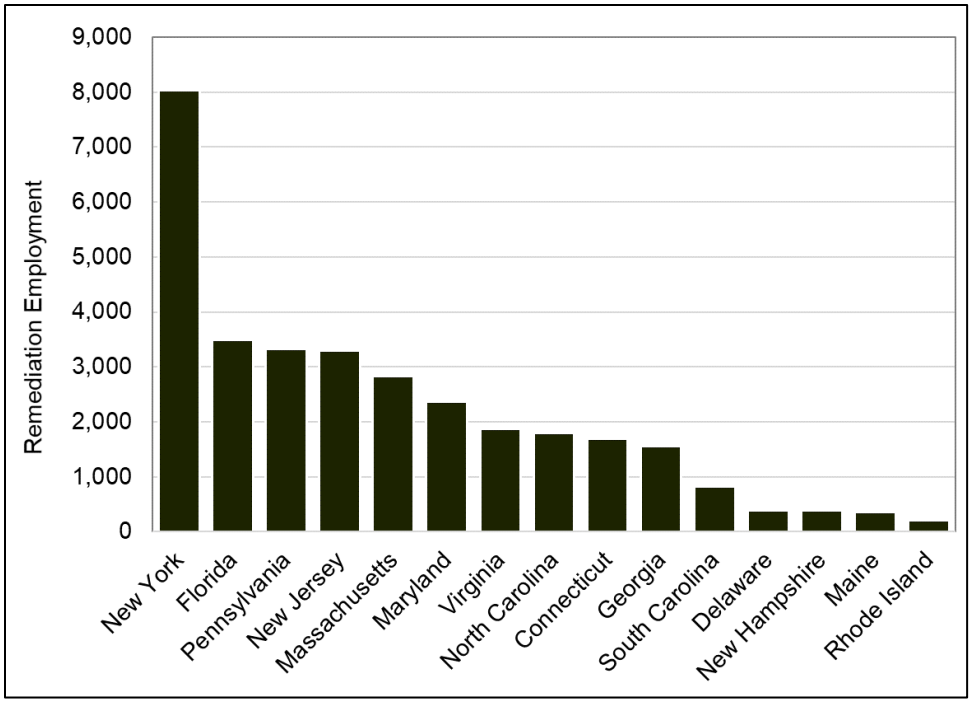

Figure 74. Atlantic region remediation employment shares, 2018.

Source: US Bureau of Labor Statistics (BLS c2020).

Figure 36 illustrates the trends in regional and national sector employment over the past decade. Since 2009, regional sector employment has increased by 28 percent, and national sector employment has increased by 27 percent. Over this same period, New York experienced sector employment gains of 18 percent.

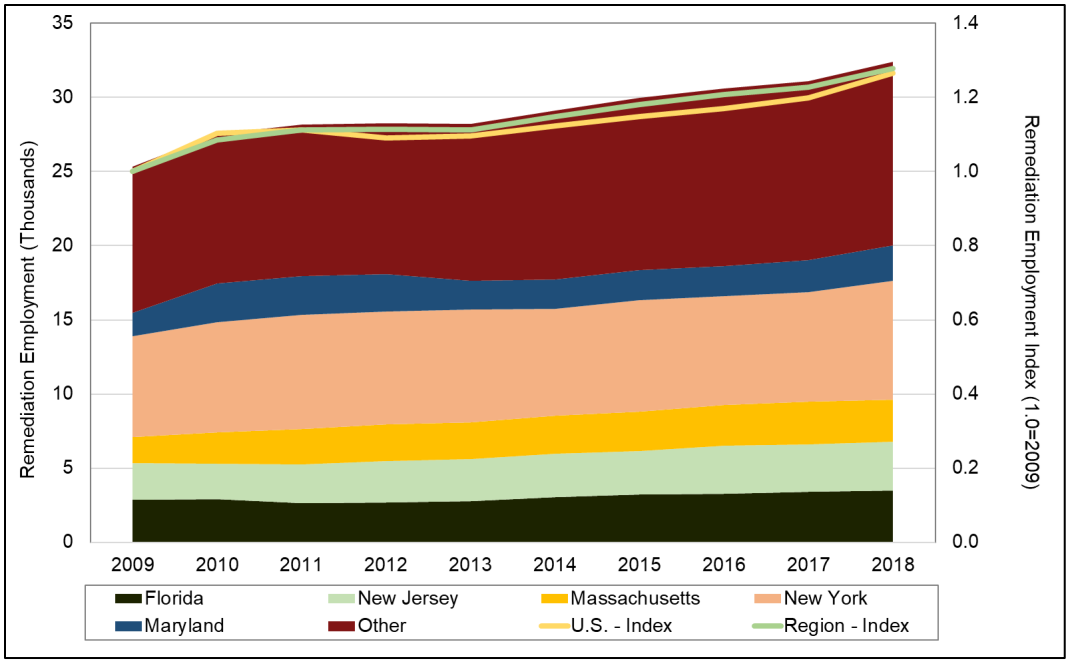

Figure 75. Trends in Atlantic region remediation employment, 2009–2018.

Source: US Bureau of Labor Statistics (BLS c2020).

The growth in sector employment levels are corroborated by similar levels of growth in remediation wages, which are presented in Table 15, Figure 37, and Figure 38 below. The Atlantic region accounts for 36 percent of remediation industry wages in the United States. Within the region, New York, Florida, and Pennsylvania account for the three highest shares of total wages.

Table 20. Regional and national wage contribution, remediation sector, 2018

State	Remediation Wages (Millions in 2018) ($)	Total State Wages (Millions in 2018) ($)	Remediation Wages as a Percent of Total State Wages (%)	Remediation Wages as a Percent of Total US Remediation Wages (%)
CT	128	98,976	0.13	2.26
DC	NA	47,149	0.00	0.00
DE	22	21,785	0.10	0.39
FL	234	377,741	0.06	4.13
GA	80	204,738	0.04	1.40
MA	185	231,687	0.08	3.27
MD	134	128,523	0.10	2.37
ME	17	23,322	0.07	0.31
NC	99	188,651	0.05	1.74
NH	26	33,029	0.08	0.46
NJ	227	226,946	0.10	4.00
NY	505	589,087	0.09	8.91

State	Remediation Wages (Millions in 2018) ($)	Total State Wages (Millions in 2018) ($)	Remediation Wages as a Percent of Total State Wages (%)	Remediation Wages as a Percent of Total US Remediation Wages (%)
PA	229	287,198	0.08	4.03
RI	13	21,809	0.06	0.23
SC	40	76,779	0.05	0.71
VA	99	184,435	0.05	1.75
Total Region:	**2,039**	**2,741,857**	**0.07**	**35.94**
Total US	**5,674**	**7,124,159**	**0.08**	**100.00**

Source: US Bureau of Labor Statistics (BLS c2020).

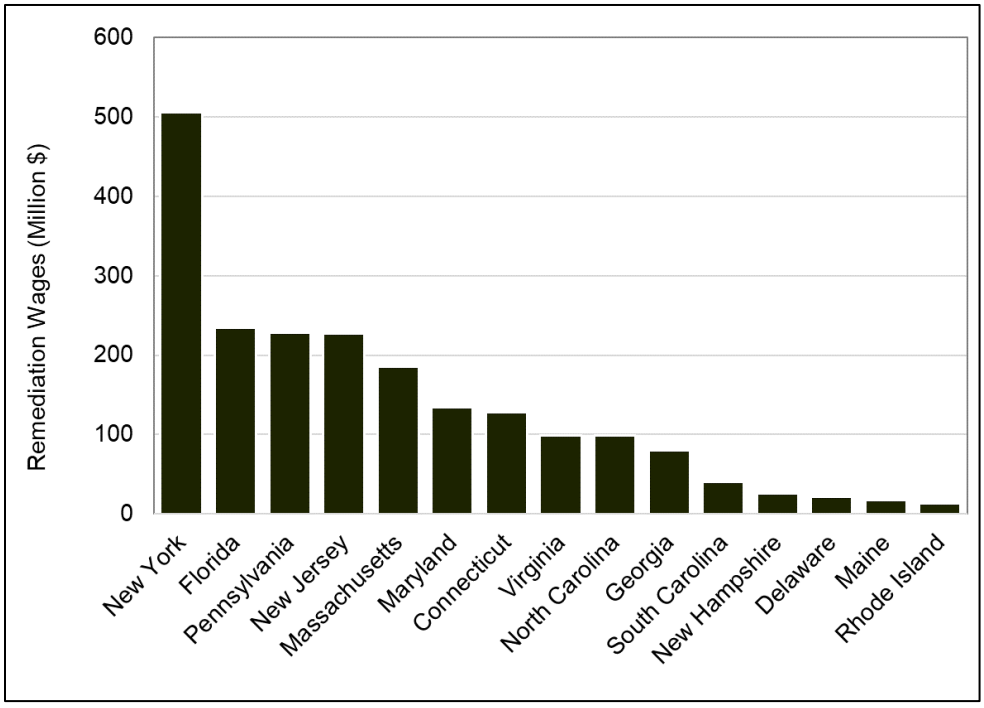

Figure 76. Atlantic region remediation wage shares, 2018.

Source: US Bureau of Labor Statistics (BLS c2020).

Over the past decade, remediation wages increased by 58 percent across the Atlantic region and by 52 percent across the United States. These sector gains are in line with the overall US economy, which has seen total wages rise by 48 percent over the past decade. New York, which has the highest levels of remediation wages within the region, has experienced growth in remediation wages of 40 percent since 2009.

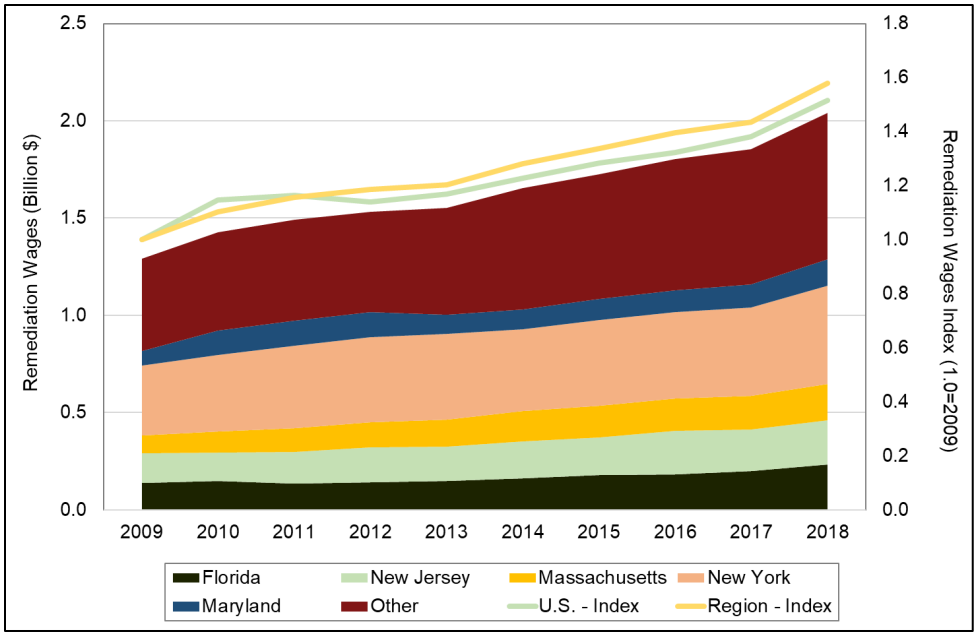

Figure 77. Trends in Atlantic region remediation wages, 2009–2018.

Source: US Bureau of Labor Statistics (BLS c2020).

Average annual pay within the regional sector is below that of the US remediation industry, as well as the overall US economy. However, several states, including New Jersey and Pennsylvania, report average wages above the US industry baseline. Table 16 and Figure 39 present the trends of average remediation wages by state.

Table 21. Regional and national average annual wage contribution, remediation, 2018

State	Average Annual Pay (Remediation) ($)	Average Annual Pay (All) ($)	Remediation Avg. Annual Pay as a Percent of Total State Avg. Annual Pay (%)	Remediation Avg. Annual Pay as a Percent of Total US Remediation Avg. Annual Pay (%)
CT	75,738	68,303	110.9	116.7
DC	NA	88,184	0.0	0.0
DE	55,799	56,683	98.4	86.0
FL	67,170	49,475	135.8	103.5
GA	51,177	54,195	94.4	78.9
MA	65,533	73,405	89.3	101.0
MD	56,882	58,732	96.9	87.6
ME	49,260	44,938	109.6	75.9
NC	54,920	50,848	108.0	84.6
NH	66,657	57,533	115.9	102.7
NJ	68,934	65,353	105.5	106.2
NY	62,873	73,476	85.6	96.9
PA	68,714	55,294	124.3	105.9
RI	63,551	51,709	122.9	97.9
SC	48,951	44,044	111.1	75.4
VA	52,751	57,846	91.2	81.3
Total Region:	**56,807**	**59,376**	**95.7**	**87.5**
Total US	**64,903**	**57,198**	**113.5**	**100.0**

Source: US Bureau of Labor Statistics (BLS c2020).

Over the past 10 years, the remediation sector has reported steady wage gains across both the region and nation. Since 2009, average annual wages in the remediation sector increased by 20 percent in the US During this time, some Atlantic states, such as Florida, have experienced average wage growth above this baseline (38 percent), while other states, such as New Jersey, have experienced the opposite (13 percent).

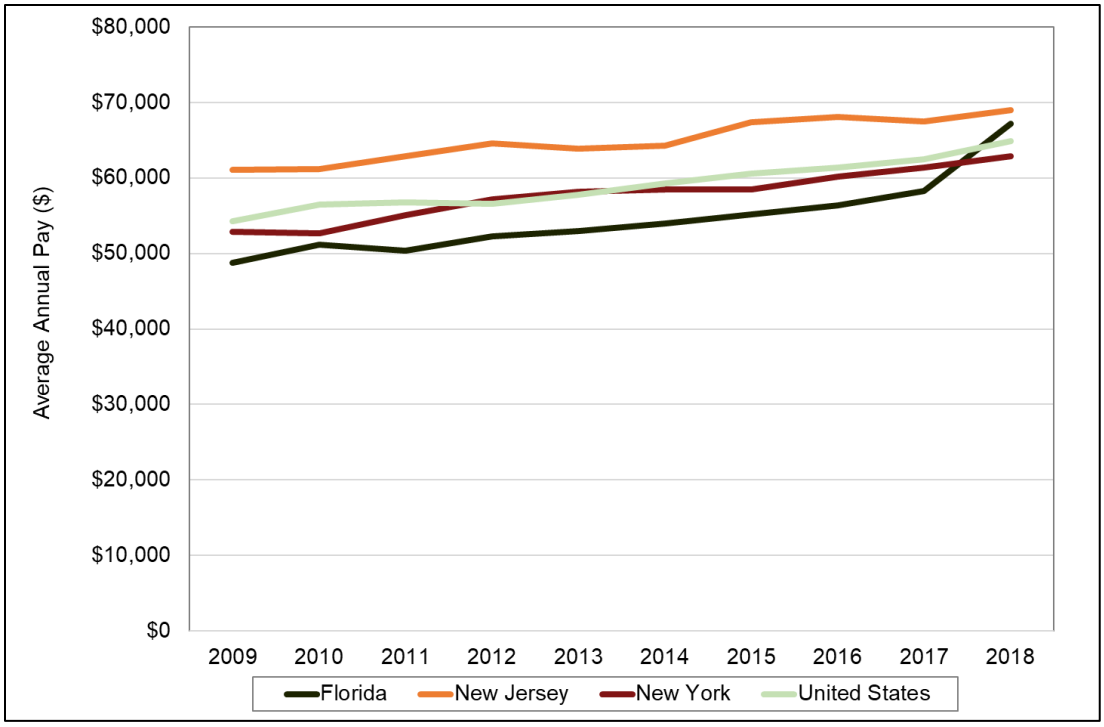

Figure 78. Trends in Atlantic region remediation average annual wages, 2009–2018.

Source: US Bureau of Labor Statistics (BLS c2020).

5.5 Current Trends

5.5.1 Decline in Frequency and Magnitude of Oil Spills

Since 2001, there has been a significant decline in the frequency and magnitude of oil spills in the United States. From 1995 to 1999, the United States averaged 8,770 oil spills per year, 5,453 of which were attributable to petroleum discharges from vessels. Meanwhile, over the most recent five-year period in which data is available (2014–2018), the United States experienced only 2,784 oil spills per year, 1,626 of which were derived from vessels. This marks a reduction in oil spill incidents of more than 68 percent, which is highlighted below in Figure 79.

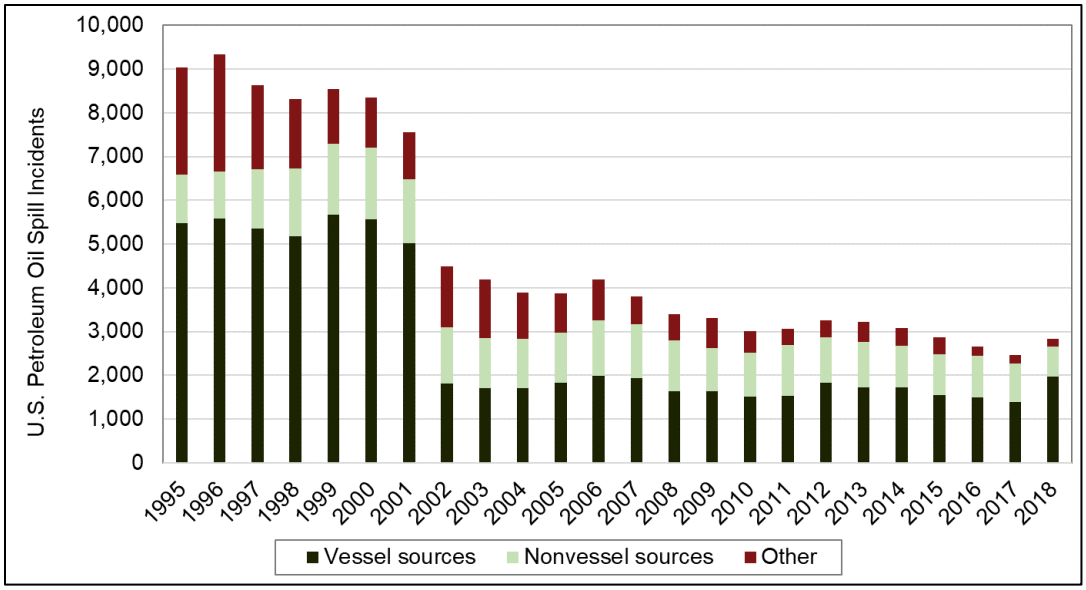

Figure 79. US petroleum oil spill incidents (1995–2018).

Source: Bureau of Transportation Statistics (BTS 2017 May 21).

There have been similar levels of improvement in the magnitude of oil spills. From 1995-1999, 8.8 million gallons of petroleum oil were spilled in the US. Meanwhile, during the most recent five-year period in which data is available (2014–2018), only 2.1 million gallons of petroleum were spilled in the United States. Figure 80 and Figure 81 illustrate this improvement.[4]

[4] The 2010 *Deepwater Horizon* spill is an exception to this decline, as is evident via Figure 80.

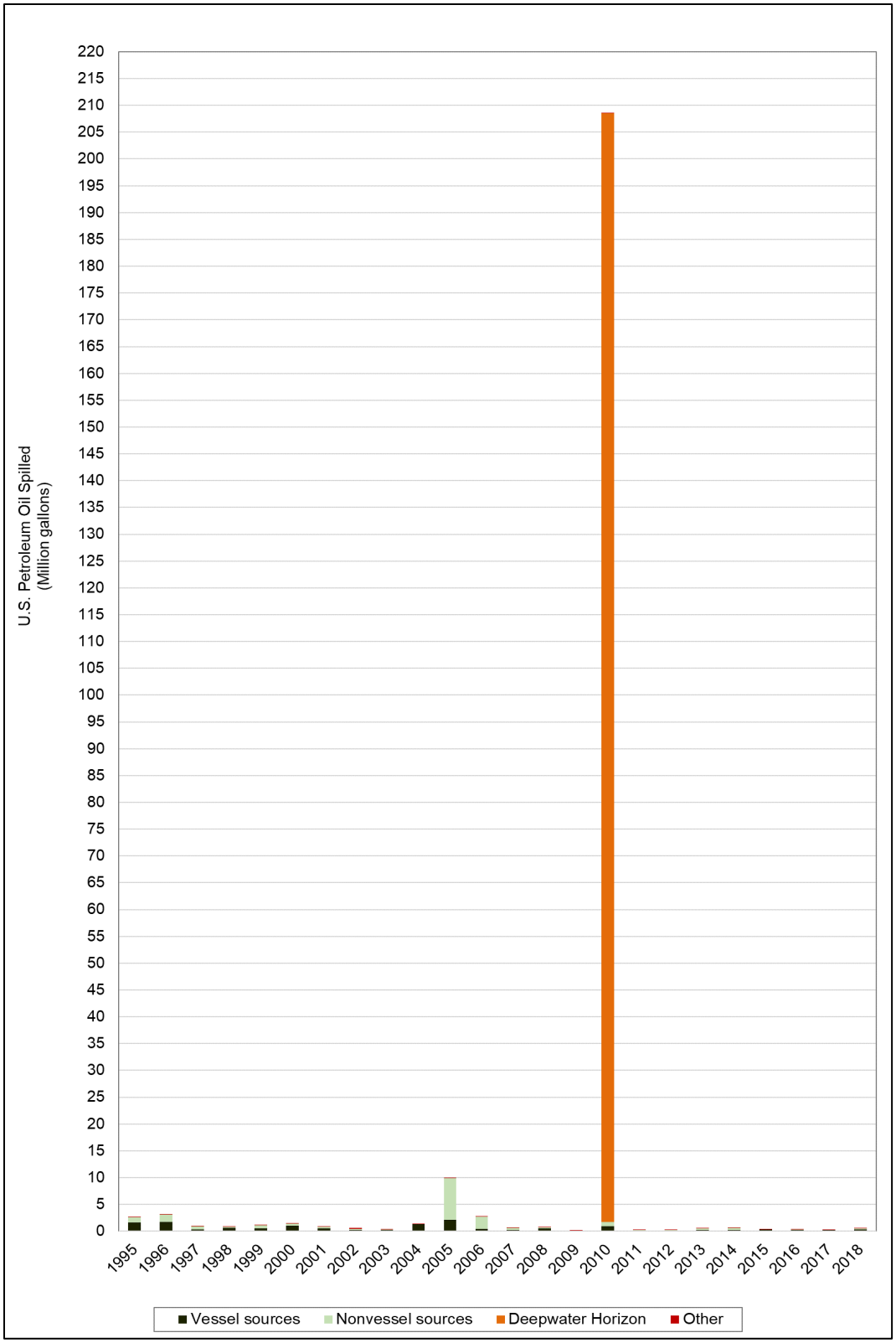

Figure 80. US petroleum oil spill spilled (1995–2018).

Source: Bureau of Transportation Statistics (BTS 2017 May 21).

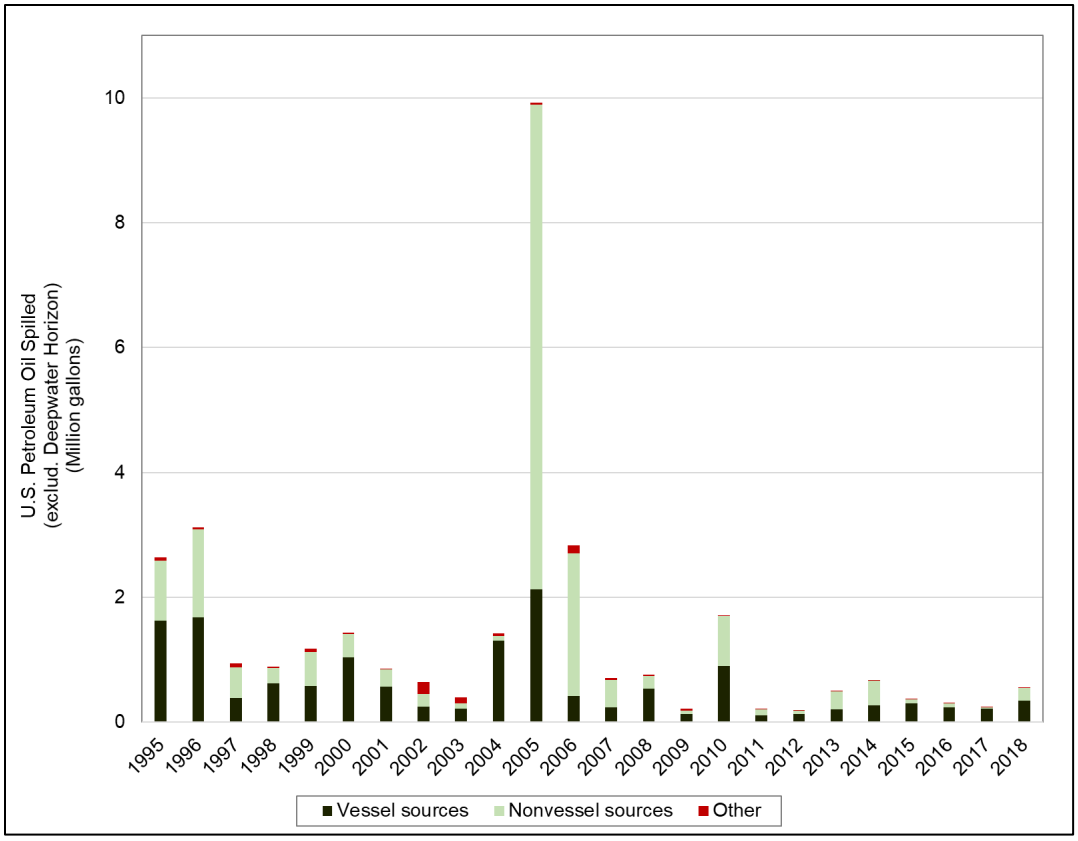

Figure 81. US petroleum oil spill spilled (1995–2018).

Source: Bureau of Transportation Statistics (BTS 2017 May 21).

The transformative reductions in the frequency and magnitude of oil spills are not limited to the United States. Around the world, there has been a decline in oil spills, particularly those which are attributable to oil tankers. Figure 82, below, demonstrates the sharp decline in international oil tanker spills from 1970 to 2019 (ITOPF 2020 Jan 1).

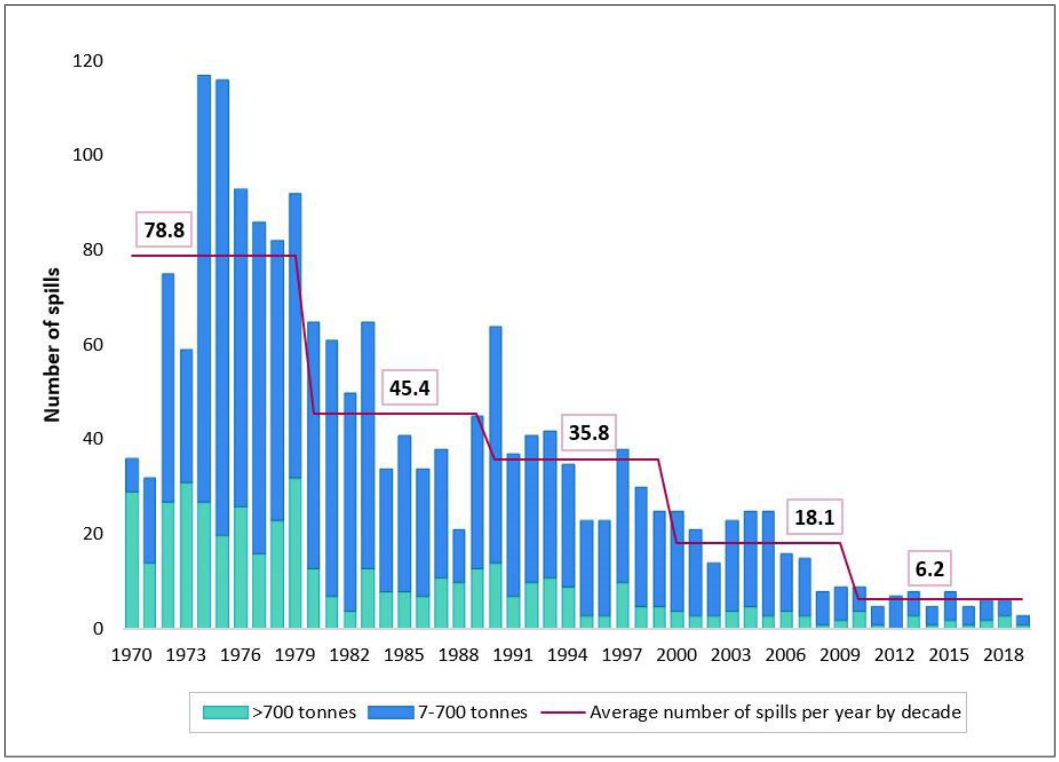

Figure 82. Oil tanker spills (1970–2019).

Source: International Tanker Owners Pollution Federation (ITOPF 2020 Jan 1).

5.6 Current Outlook

5.6.1 Factors impacting East Coast Development

Oil spills have occurred on the Atlantic OCS, and these have often been attributable to deliveries to refineries or other industrial activities that receive water-borne shipments. Fortunately, there are numerous companies in the Atlantic region that provide oil spill response capabilities. Also, the oil spill response industry is highly mobile. Therefore, assets from other producing areas, particularly the GOM region, can likely be used in the event of a catastrophic accident where more regional activities need to be supplemented with additional remediation personnel and equipment. If the oil and gas industry were to expand to the Atlantic OCS, it is unlikely that new oil spill response investments would be undertaken or even necessary in the area given (a) the already significant penetration of firms in the region; (b) the generally improving environment for oil spills; and (c) the infrequency of major oil spill events.

6. Oil Field Waste Disposal

6.1 Description of the Industry and Services Provided

Waste management is an important support activity for both onshore and offshore crude oil and natural gas drilling and production. There are many different types of waste generated at drilling sites and production locations including offshore platforms. Some wastes that arise in oil and gas activities are common to many other manufacturing or industrial operations, while others are unique to the oil and gas industry. The different types of waste generated from offshore exploration and production activity include:

- Solids, such as drill cuttings, pipe scale, produced sand, and other solid sediments encountered during drilling, completion, and production phases.
- Drilling muds--oil-based, synthetic, or water-based.
- Aqueous fluids having relatively little solids content, such as produced waters, waters separated from a drilling mud system, clear brine completion fluids, acids used in stimulation activities, and wash waters from drilling and production operations.
- Naturally Occurring Radioactive Materials (NORM), such as tank bottoms, pipe scale, and other sediments that contain naturally high levels of radioactive materials.
- Industrial hazardous wastes, such as solvents and certain compounds with chemical characteristics that render them hazardous under Subtitle C of the Resource Conservation and Recovery Act and thus not subject to the exemption applicable to wastes generated in the drilling, production, and exploration phases of oil and gas activities.
- Non-hazardous industrial oily waste streams generated by machinery operations and maintenance, such as used compressor oils, diesel fuel, lubricating oils, pipeline testing, and pigging fluids.
- Municipal solid waste generated by the industry's personnel on offshore rigs, platforms, tankers, and workboats.

During the drilling process, the largest amounts of waste include drilling fluids, drill cuttings, and waste water (API 2001). Drilling fluids or "drilling muds" are a special mixture of clay, water, and chemical additives that are pumped down-hole through the drill pipe to facilitate the drilling process. Drilling fluids help reduce friction and lubricate and cool the drill bit. During the drilling process, cuttings are created in the well (ground rock and earth), so drilling fluids act as a carrier, keeping the cuttings suspended in the mud until they are carried up the well to the surface. These drilling fluids also help control pressure and aid in stabilization. Weighting agents are added to drilling fluids to keep pressure on the walls of a well, and additives are also used to ensure that the drilling fluids are not absorbed by the rock formation and that the pores of the rock formation do not become clogged (Rigzone 2020c).

There are three main categories of drilling fluids: water-based mud (WBM); oil-based mud (OBM); and synthetic-based mud (SBM). WBMs are water-based and can be easier to process and dispose than other more common drilling fluids that have other bases. OBMs use petroleum products as the base fluid, such as diesel fuel. OBMs are used when there is a need for higher levels of lubrication and viscosity. OBMs can also withstand higher levels of heat before breaking down. SBMs have synthetic oils as the base fluid. These are often used offshore where there is a need for increased viscosity, but less toxicity. The waste disposal infrastructure needed to manage the variety of waste generated by offshore exploration and production activities can be categorized as:

- Transfer facilities at ports, where the waste is taken from supply boats and moved to another transportation mode, either barge or truck, toward a final disposition point.
- Special-purpose waste management facilities that are dedicated to handling specific waste types.
- Generic waste management facilities that receive waste from a broad spectrum of US industry, of which waste generated in the oilfield is only a small part.

6.2 Typical Facility Characteristics

The characteristics of drilling waste vary by location as different waste disposal facilities have varying conditions, environments, infrastructure, and regulatory requirements. Therefore, no single waste management technique is used at all locations (NPC 2011a). The Argonne National Laboratory identifies three major categories of management technologies and practices for the management of drilling wastes: (1) waste minimization; (2) recycle/reuse; and (3) disposal (DWMIS 2012).

Waste minimization activities take place in the field during drilling and completion. For offshore oil and gas production waste minimization activities take place on offshore oil platforms and drilling rigs, as does the separation of cuttings from drilling fluids so that the drilling fluids can be reused. The location of cuttings treatment facilities depends on the disposal method. Cuttings released at sea are treated on the platform or rig, while cuttings that will be recycled into fill or aggregate or disposed of in landfills are treated after being brought to shore. Drilling fluid recycling and other liquid waste treatment facilities supporting offshore oil and gas exploration and production are often located in or near marine terminals.

6.2.1 Waste Minimization

Efforts are made during waste minimization to reduce produced waste volumes. Waste minimization practices take place in the field and include directional drilling, drilling smaller diameter wells, and the use of drilling techniques that use less drilling fluid.

a) Directional drilling is the process of drilling at angles that are not vertical, enabling producers to reach reservoirs that are not located directly beneath the drilling rig. Directional drilling has been around since the 1920's but has gained popularity in recent years because of advancements in technology that has made this process more efficient and profitable (Rigzone 2020c). This technique is particularly useful in avoiding sensitive environmental habitats and other sensitive areas both above and below the surface. Environmental benefits to directional drilling include, but are not limited to, fewer production wells, less waste, and a lesser impact on sensitive environments (USDOE 1999).

- There are three major types of directional drilling: horizontal, extended-reach and multi-lateral. (USDOE 1999) Horizontal drilling allows producers to access hydrocarbon formations that extend over a large area. This enables producers to reach more of the reservoir, so that more resources can be pulled from a single well. In Mississippi's Black Warrior Basin, horizontal wells provide six times as much natural gas deliverability as some conventional vertical wells (USDOE 1999). Extended reach drilling (ERD) is the directional drilling of long horizontal wells. With ERD technology a wellbore can be drilled several miles away to reach deposits that may lie under sensitive areas (Offshore Magazine 2014 Sep 17). This is particularly useful when it is impractical or too costly to drill from directly above the target formation (DWMIS 2012). And, multilateral drilling employs multiple offshoots from a single wellbore that extend in different directions, reaching deposits at various depths (USDOE 1999).

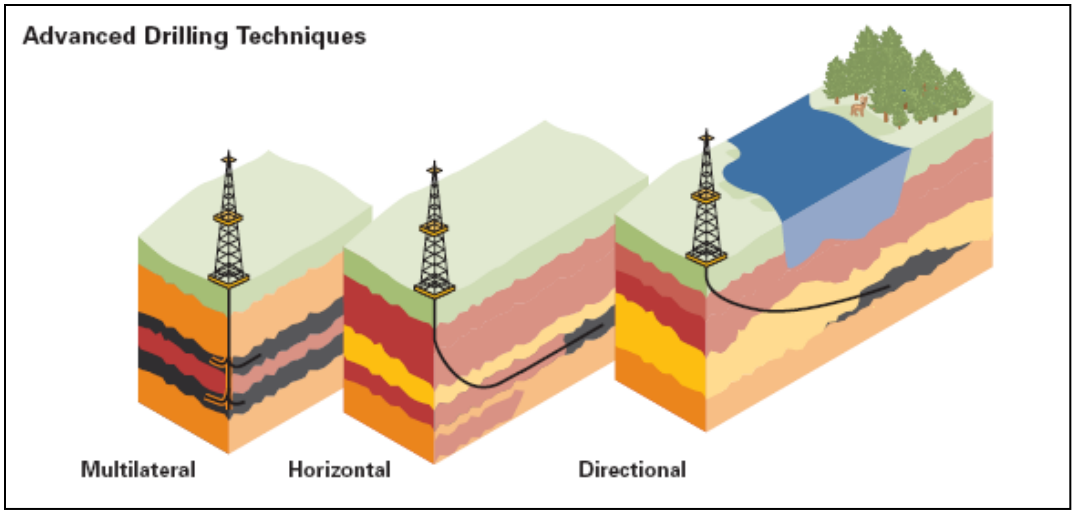

Figure 83. Advanced drilling techniques.

Source: (USDOE 1999).

b) The volume of drill cuttings from a well is directly related to the diameter of the hole being drilled. There are many ways in which smaller diameter wells can be developed and used. One example is through casing string spacing. With technological advancements in case milling, there is a larger variation in casing available for use, allowing for closer spacing of successive casing strings, and subsequently a lower volume of drill cuttings. Also, slimhole drilling, defined as a wellbore six inches (15 cm) or less in diameter, will reduce the volume of mud, casing, cement, water, and fuel used, and will produce smaller volumes of cuttings (Schlumberger). Slimhole drilling also reduces the operational footprint and area cleared for the drilling location (since equipment is smaller) (USDOE 1999). Coiled tubing drilling is a type of drilling that uses a continuous length of tubing rather than individual sections of drill pipe (DWMIS 2012). These mobile trucks allow for cheaper and more efficient ways of drilling than the traditional workover well heads (Schlumberger 2014). The tubing is smaller in diameter than drill pipe, so like the slimhole drilling, the volume of waste is reduced as shown in Figure 84.

Figure 84. Schlumberger coil tubing

Source: (Schlumberger 2014).

c) In some locations, wells can be drilled using pneumatic drilling, either reducing or eliminating the need for drilling fluids. Pneumatic drilling uses air, natural gas, mist or foam (Wilson 1981). With pneumatic drilling, only drill cuttings are generated which significantly reduces the waste management and disposal requirement (USDOE 1999). This technology has limited applications but can be used in fluid sensitive formations or formations with low pressures.

Drilling waste may also be minimized by using drilling muds and additives that have lower environmental impacts. As noted earlier, SBMs combine the higher performance of OBMs and the environmentally friendly qualities of WBMs, making them ideal for complex and remote offshore drilling environments. SBMs are recycled while WBMs can generally be discharged on-site (DWMIS 2012).

6.2.2 Reuse and/or Recycle

While most WBMs are disposed of once drilling is completed, many OBMs and SBMs are recycled. There are several steps in the drilling fluid reuse and recycling process. As drilling fluid comes back up the borehole it goes through a series of mixing and cleaning processes. Large drill cuttings are sifted through a "scalping shaker.". The fluid is then spun into a centrifugal mixing pump which cleans filters smaller and smaller pieces until all solids are removed and the remaining "clean" drilling fluid and is pumped back down to the drill to be used (Trenchless Technology 2016).

Most drill cuttings are disposed of but some are ground down into smaller and smaller parts and ultra-fine particles will accumulate in the drilling mud and eventually the drilling fluid will have to be further cleaned or completely disposed of (Trenchless Technology 2016).

There are numerous options for drilling fluids and cuttings disposal at offshore drilling and production locations. While each option has various environmental advantages and disadvantages, the primary consideration in utilizing a particular method include the operational circumstances of the drilling or production location and costs (NPC 2011b) The three main options for waste produced offshore are offshore discharge, re-injection and onshore discharge.

Offshore Discharge

Offshore discharge is the most operationally effective disposal method for an offshore producer. It is also, the least expensive since the cost of transporting waste is essentially eliminated. WBMs consist primarily of water and have been demonstrated to have a limited effect on the environment (NPC 2011b). The EPA has evaluated the environmental impacts from WBMs and established guidelines for the discharge of WBMs and associated cuttings (40CFR 435).

SBMs, however, cannot be discharged in offshore areas. However, cuttings coated with SBMs may be discharged once the cuttings have been separated from the mud (BOEM 2020b). This allowance is important from an economical perspective since it facilities more cost-effective deep water exploratory drilling and production activities given the long distances to shore as well as the limitations on other disposal options (NPC 2011b). Extended guidelines have been formed in relation to SBMs Lastly, OBMs may not be discharged offshore. A summary of all offshore waste disposal allowances and requirements are provided in Table 22.

The Clean Water Act allows for the discharge of materials that are considered toxic such as metals or organic chemicals, but limits the amount of these toxins are released (Argonne National Laboratory 2001). Release levels are set by water tests that determines the toxicity relative to location to assure a low concentration that will not negatively impact water quality for activities such as fishing.

Table 22. Summary of US offshore requirements for drilling wastes

Baseline Requirements

- No discharge of free oil (using a static sheen test) or diesel oil
- Acute toxicity must have a 96-hour LC50 > 30,000 ppm (using EPA's mysid shrimp toxicity text)
- Metals concentrations in the barite added to mud must not exceed 1 mg/kg for mercury; or 3 mg/kg for cadmium
- No discharge of drilling wastes allowed within 3 miles (5 kilometers) of shore*

Additional Requirements for Synthetic-Based Muds (SBMs)

- SBMs themselves may not be discharged
- Cuttings coated with up to 6.9 percent SBMs may be discharged
    - Ester SBMs can have up to 9.4 percent SBM on cuttings
- Ratio of Polynuclear aromatic hydrocarbon mass to mass of base fluid may not exceed 1 x 10-5
- Biodegradation rate of chosen fluid shall be no slower than that for internal olefin
    - Base fluids are tested using the marine anaerobic closed bottle test
- Base fluid sediment toxicity shall be no more toxic than that for internal olefin base fluid
    - Base fluid stocks are tested by a 10-day acute solid-phase test using amphipods (*Leptocheirus plumulosus*)
    - Discharged cuttings are tested by a 4-day acute solid-phase test using amphipods (*Leptocheirus plumulosus*)
- No discharge of formation oil
    - Whole muds are tested onshore by GC/MS analysis
    - Discharged cuttings are tested for crude oil contamination by fluorescence method
- Conduct seabed survey or participate in industry-wide seabed survey

Source: (DWMIS 2012)

Re-injection

Offshore E&P activities can also dispose various wastes through various types of injection or encapsulation methods. The injection process, for instance, allows waste to be injected into disposal wells or wells that are about to be abandoned. The EPA regulates and approves these on a case-by-case basis given certain guidelines (US EPA 2015a). Injection wells must be located below the "deepest drinking water aquifer, must be isolated above and below by any shale layers, and not contain any producing wells" (NPC 2011b).

There are two main types of encapsulation, the first allows for waste to be placed directly into the well while the second involves placing waste in a pipe and then into the well that is then capped by cement (NPC 2011b). This usually depends on the type of waste being re-injected, water or brine water can usually be injected without a cement casing given its lower risk to surrounding area. If injecting carbon dioxide or other hazardous waste, the re-injection well requires many layers of casing cement in order to prevent this waste from leaking and causing harm (US EPA 2015a). The EPA designates six different types of underground injection wells. Each one may have different regulations that apply given the content of what is put into the well as the following list shows (US EPA 2015 Jun 11):

- Class I wells are used for hazardous and non-hazardous waste into deep isolated rock formations.
- Class II wells are strictly for fluids used with oil and natural gas production.
- Class III are used to inject fluids to dissolve and extract minerals.
- Class IV shallow wells used to inject hazardous or radioactive waste.
- Class V wells used to inject non-hazardous fluids underground, most are used to dispose of waste into or above underground drinking water sources.
- Class VI wells used to inject CO_2 in subsurface rock formation for long term storage.

Sub-surface injection is complicated and impacted by geologic considerations. For instance, any injected slurry must not be able to migrate into other formations, or back to the surface. Further, the types and volume of waste, surface equipment and well design must be considered before injection is performed (NPC 2011b). If re-injection can be used, it can have a number of advantages (Guo and Geehan 2004):

- It can achieve zero discharge as no waste is left on the surface.
- It eliminates transportation risks, as there is not transportation to another facility or temporary storage.
- It eliminates future clean-up liabilities once the disposal well is plugged.
- It ensures the operator total control over the waste management process.
- It is not limited by location, and it has been operated from the GOM to Alaska, from the North Sea to the Sakhalin Islands.
- It often has favorable economics.

During the production process, produced water creates the largest volume of waste and re-injection is the primary method for produced water disposal (GPRID 2012).

Onshore Disposal

Waste materials can also be transported back to shore for further treatment and disposal, This option, however, requires extensive use of support vessels, and it increases environmental and safety risks and costs. (Argonne National Laboratory 2001) Some onshore transportation is often required in offshore operations given material types as well as waste volumes. Once onshore however, there are numerous options for disposing of drilling waste. These options are listed below in the following subsections. The practicality of each of these options depends on environmental conditions, components of the drilling waste, regulations, operational limitations and economic factors (NPC 2011b).

Pits and Landfills: Pits and landfills are used for the disposal of cuttings at many onshore drilling sites. The pit is lined with local soil or some other material to prevent chemicals from leaking into ground water. Pits can be temporary or permanent depending upon the waste(s) in question. There are certain restrictions on permanent pits such as fencing or netting to prevent humans or animals from interacting with possible harmful contaminants. There are roughly 20 different types of pit classifications that are defined by various state regulations (EPA 2019b). These state-specific regulations can vary from establishing pit sizes to defining allowable waste types. Reserve pits are used as temporary pits that can store drilling fluid, drill cuttings, and spent fluid. These reserve pits are only used during drilling; once the drilling process is complete, wastes are transferred to a permanent location (EPA 2019b). A relatively-recent survey of 21 states found that 11 allowed encapsulated of drill cuttings at the well site, while 13 allowed for disposal in municipal solid waste landfills and 9 allowed for disposal in non-municipal landfills, with States reporting multiple disposal options in many instances (BUTF 2015).

Non-hazardous solid wastes generated by oil and gas activities (both onshore and offshore) includes general trash and garbage, which, for offshore activities, is transported to shore for disposal in landfills. Many offshore producers separate some solid wastes for recycling (NPC 2011b). Hazardous and combustible wastes such as oil, oily rags, spent solvents, paint cans and used oil filters are placed in approved hazardous material containers, sealed, labeled and brought onshore for disposal in an approved hazardous waste handling facility (NPC 2011b).

Land Application: Drilling muds, produced sand, and other fine solids are candidates for land application, also called "land farming". Land farming can be a low-cost method for managing oily waste. With this method, the waste is spread over pasture or farmland, allowing the waste to be diluted or break down naturally (Cooper 2013). One of the primary benefits of land application is the ability for the decomposition of organic compounds (EPA 2019b). However, it may also add salts or heavy metals to the soil and water run-off from the property may create environmental concerns (Cooper 2013).

Bioremediation: Bioremediation uses microorganisms to biologically decompose hydrocarbon-contaminated waste (Puder and Veil 2006). The goal is to accelerate the natural decomposition process by controlling oxygen, temperature, moisture, and nutrients.

Thermal treatment: Thermal technologies use high temperatures to destroy or remove hydrocarbons from waste materials. Incineration is a technology that heats hydrocarbons to very high temperatures, thereby destroying them. The other technology, thermal desorption, applies heat to the waste, vaporizing volatile and semi-volatile hydrocarbons. In both cases, additional treatment may be needed for metals and salts. Waste streams high in hydrocarbons, like OBMs are treated with thermal technologies (Puder and Veil 2006). This can be a fairly efficient method for onshore and offshore waste by removing 99% of base oil waste (Halliburton 2020c).

Salt Cavern Disposal: Salt caverns are used for a variety of underground storage purposes and can be used for the disposal of drilling wastes. Salt cavern disposal may be used for drilling muds, cuttings, produced sands, tank bottoms, contaminated soil and completion and simulation wastes. Wastes are transported to the cavern site and are combined with water or brine to make slurry. When the waste slurry is pumped into the cavern it displaces the brine used to create the cavern. The brine is either sold or injected into another disposal well. One benefit of salt cavern disposal is that it protects water supplies and water tables from being contaminated. Another benefit is the that it eliminates the risk of air pollution by being buried in salt caverns rather than using other methods such as thermal treatment (NPC 2011b). However, salt caverns can be used for other high-value storage applications including natural gas, crude oil and other liquid hydrocarbons (i.e., LPGs and NGLs). Thus, salt caverns are not typically used along the GOM for waste storage purposes given their higher valued alternatives.

6.3 Geographic Distribution

The Argonne National Laboratory collected information on commercial exploration and production waste disposal companies in different states in 1997. In 2005 and 2006 this information was updated with a focus on the availability of offsite commercial disposal companies and prevailing disposal methods (Puder and Veil 2006). The researchers found that the availability of offsite commercial disposal companies and facilities falls into three categories:

1. States with high oil and gas production typically have a dedicated network of offsite commercial disposal companies and facilities in place.
2. In other states, such infrastructure does not exist and often, commercial disposal companies only focus on produced water services.
3. About half of the states do not have any industry-specific offsite commercial disposal infrastructure. If there is any oil and gas produced waste in these states, operators transport that waste to local municipal landfills (if permitted) or haul the waste to other states (Puder and Veil 2006).

Considering that there is little exploration and production activity in the impact region states (with the exception of Pennsylvania), there is likely a minimal number (or zero) offshore commercial disposal companies. Pennsylvania is the most prominent state that has commercial waste disposal companies, however states such as Maryland, North Carolina, and New York have a few but not enough to handle offshore waste disposal at the present time. Figure 85 shows a map of these facilities.

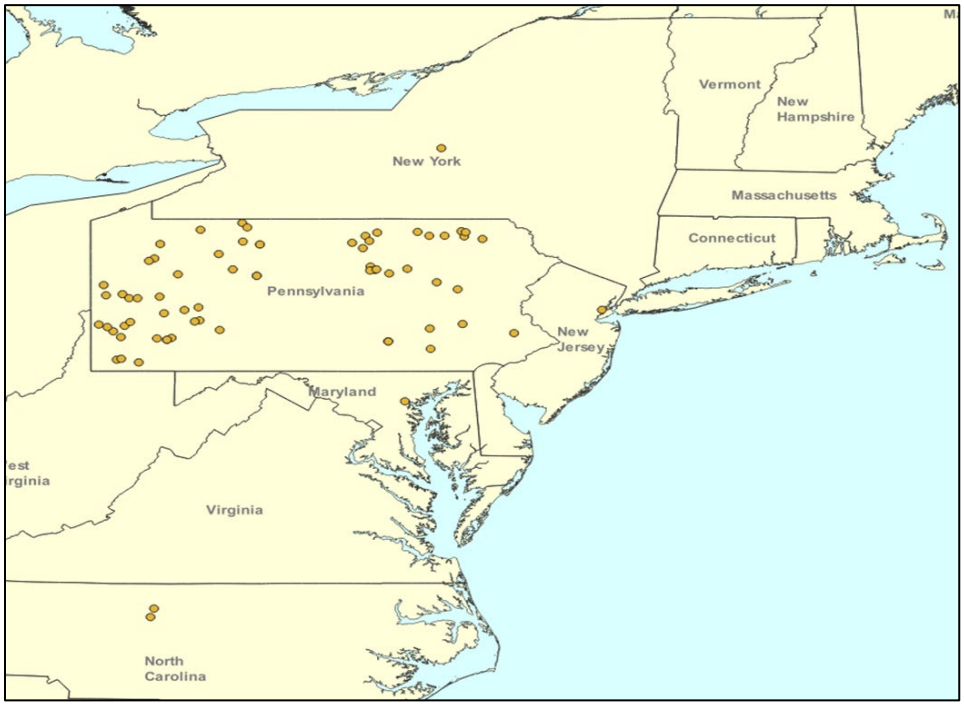

Figure 85. Oil Field Waste Disposal Facilities

Source: (EPA 2019a)

There are many companies located in Pennsylvania that can dispose produced water through a "National Pollutant Discharge Elimination System" (NPDES) permit or "Publicly Owned Treatment Works" (POTW). The NPDES is a permit program authorized by the Clean Water Act and controls water pollution by regulating point sources that discharge pollutants into US waters. In general, authorized states administer the NPDES permit program and industrial facilities must be permitted to discharge directly to surface waters.

POTWs are municipal wastewater treatment plants and are generally designed to take domestic sewage (residential, commercial) only. However, POTWs can also receive wastewater from industrial users. The General Pretreatment Regulations under the Clean Water Act establish the responsibilities of federal, state, and local governments; industry; and the public to implement pretreatment standards to control pollutants from industrial users (US EPA 2015b).

6.4 Current Trends

Several factors influence the need for commercial disposal companies, including the supply, demand, and pricing of oil and gas commodities. Without drilling activity there is no need for oil field waste disposal. Over the last 10 years the oil and gas industry has been through many ups and downs. New technology, oversupply, and changing landscape of energy laws have all contributed to the boom and bust cycles of this industry. One of the primary industry changes in the Atlantic region, relative to oil and natural gas, has been the considerable development of unconventional shale resources in the mid-Atlantic-Appalachian region. This development has resulted in the supporting development of a number of different industries backing up the drilling and production supply chain in the region. This recent experience provides some insights into how new support industries, such as oil field waste services, may arise in the Mid-Atlantic if offshore oil and gas development were authorized.

For instance, states such as Pennsylvania, Texas, and North Dakota have seen a recent increase in commercial waste disposal companies in very large part due to the unconventional shale gas plays in these states (Times-Picayune 2013). Each well can use millions of gallons of water throughout the life of the well. This makes water treatment plants and services necessary to reuse water from wells or return back to the natural water table. States such as Texas have large numbers of commercial waste companies because of the historic reliance on oil and gas. Others such as Pennsylvania have seen a rise in commercial waste disposal companies over the last few years due to unconventional development.

More unconventional development around the US has, and will continue to have, the need for waste disposal services and facilities.

However, currently, the bulk of US offshore oil and gas drilling and production takes place off the coast of Texas and Louisiana. Both states have large onshore and offshore infrastructure including commercial waste disposal companies. There is currently no current offshore drilling on the Atlantic or Pacific coast. Most waste disposal companies in those places are not equipped to handle oil field waste, even though they may be qualified to handle other industrial hazardous waste.

The following subsections discuss two main industry trends that have affected commercial waste disposal companies: environmental impact concerns and environmental regulations. Environmental impacts play a large role in waste disposal activities of all types, including those associated with the oil and gas industry. The second important trend impacting oil and gas waste disposal activities is federal, state, and local government regulations. Regulation highly influences these activities due to tighter or more defined cleaning and disposal requirements which can increase the cost and/or complexity of oil and gas waste disposal activities.

6.4.1 Environmental Impacts

Offshore drilling off the Atlantic coast has been non-existent over the last 40 years. During the 1970-1980s there were 51 exploratory wells drilled in parts of the Atlantic ocean (BOEM 2020c). In the 1980s there was a moratorium placed on offshore wells off the Pacific and Atlantic that was expanded in the first Bush administration in 1990 and the Clinton administration: these orders expired in 2012 (Ayala 2009 Sep 27).

An important issue for offshore oil and gas activities is the allowance for waste and water discharges during their operations. Many environmental groups and other non-governmental organizations have raised concerns about these allowances. Collateral issues such as water use and air emissions will also continue to be a concern. How drilling and production wastes are handled, and the possibilities of mishandling, leakages and spills arising will be big issues for those opposed to offshore oil and gas development. Offshore drilling on the Atlantic coast will raise some of the same issues as unconventional oil and gas production as both involve the development of oil and gas resources in areas where such activities were rare or entirely absent.

Environmental and climate change considerations have weighed heavily on the oil and gas sector over the last 20 years. These considerations and concerns have only grown with the industry's increased focus on unconventional oil and gas activities exploration and production activities in states that previously seen only very limited activity. As an example, consider the recent state regulatory changes arising in Pennsylvania due to unconventional activity.

In early 2000, Pennsylvania had very few active and producing natural gas wells. By 2019 Pennsylvania produced over 20 percent of all domestic natural gas supply (Clemente 2009 Mar 21). An important environmental issue arising in unconventional development has been its impact on ground water supplies and the potential for toxic materials to leach into these supplies.

Dose and concentration are two main measurements to determine environmental impact across industrial and commercial wastes (Sharif MD et al. 2017). One way to measure environmental impact is to track different animal species around drill sites. If lethal chemicals trickle into the environment, they can harm or kill wild populations. A lethal dose that can be deadly for 50 percent of animals is called LD50 (Sharif MD et al. 2017). A lethal dose depends on the concentration of chemicals as well which is tracked separately to determine the probability of harmful environmental impacts.

One of the main environmental impacts from fracking is the use of water. Water is one of the main resources needed for fracking as it is used in drilling muds or straight water pumped down wells. Today more companies are looking into water purification plants that can take wastewater and clean it enough to have it returned to water tables, lakes, and rivers. According to an article in the Science Journals, from 2011 to 2016 the Marcellus region increased their water use by 20% (Kondash et al. 2018). According to one map which shows shale plays laid over baseline water stress, the Marcellus shale is in a better place than the Bakken, Niobrara, and Permian shale plays since those are all in drier climates that have less water available. Still a severe drought can put strains on water supplies that would threaten the amount of fracking operations in each area.

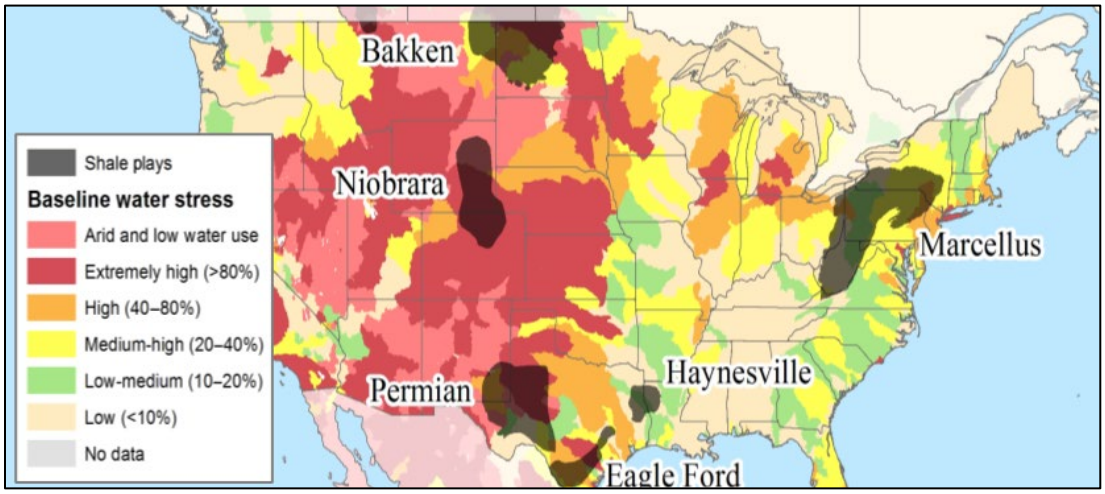

Figure 86. Water Stress Map

Source: (Kondash et al. 2018)

The culmination of all these factors has led to an increase in waste disposal companies. Because of regulations there are strict guidelines for how waste should be properly handled on a drill site. Many companies that operate the drill site choose to use third party companies who specialize in waste management. Below are a few companies that operate mainly in the northeast and Marcellus shale regions:

Lorco- Founded in 1957 Lorco one of the leading companies for petroleum recycling in the northeast. They operate in New York, New Jersey, Pennsylvania, Delaware, Maryland and Virginia. They provide many services including wastewater treatment, oil recycling, oil/water separators, parts washer services, and others (Lorco 2016).

Clean Harbors- This large national company provides many environmental, energy, and industrial cleaning services across the US. They offer a wide range of on-site and off-site equipment and services (Clean Harbors 2020).

McCutcheon Enterprises Inc. – Founded in 1947 this company carries many services from industrial to energy industry clean up. They rent equipment needed for cleanup of ponds as well as treatment facilities. They also provide emergency services, health and safety training, and environmental services (chadmc 2017).

Eureka Resources- Founded in 2008 this is one of the leading providers of wastewater treatment in the Marcellus Shale. Their goal is to return water that was once deemed unusable, back into the natural environment. A combination of initial treatment, water distillation, and mineral crystallization allows them to return clean water as defined by the EPA (Eureka 2020).

6.4.2 Regulatory Changes

Waste disposal and management are regulated by federal, state, and local laws. Major federal legislation impacting this sector includes the Clean Water Act, Safe Drinking Water Act, and Resource Conservation and Recovery Act, to name a few. Agencies such as the EPA and DOE help set standards and guidelines for how waste should be handled across all energy sectors. State and local level regulations vary and tend to be more specific, particularly in defining the locations where disposal activities may occur. Further, most state level regulations, and some local regulations, define the licensing, inspection and leasing (if any) processes for in-state disposal, Further, state laws define any special fees or taxes that may be assessed on disposal and landfill facilities.

At the federal level, the EPA oversees major federal laws governing waste materials and management activities which include the Resource Conservation and Recovery Act (RCRA), the Clean Water Act (CWA), and the Safe Drinking Water Act (SDWA). Table 23 provides a summary of the major federal laws governing waste materials and management activities. Within the Outer Continental Shelf, BOEM regulates waste disposal, injection criteria, and encapsulation criteria. These regulations are detailed in 30 CFR Part 250 (Oil and Gas and Sulphur Operations in the Outer Continental Shelf), at §250.300 (Pollution Prevention) and § 250.874 (Subsea Water Injection Systems).

Table 23. Federal laws governing waste materials and management activities

Law	Material Subject of Regulation	Activity Subject to Regulation
Clean Water Act	Aqueous waste streams	Surface discharge
Resource Conservation and Recovery Act	Solid and hazardous wastes (unless excluded or exempted)	Generation, transportation and treatment, storage and disposal
Safe Drinking Water Act	Waste fluids or slurries	Underground injection

Source: (Puder and Veil 2006).

The Safe Drinking Water Act helps regulate and ensure that water resources are protected for public usage. The Energy Policy Act of 2005 exempted hydraulic fracking from being regulated by the SDWA. However, in recent years there has been a new classification of injection wells that specifically address oil and gas activities. The EPA defines three well types; disposal wells, enhanced recovery wells, and hydrocarbon storage wells. Offshore underground injection wells are not regulated under the SDWA since there are no offshore water tables used for human consumption.

In 2002, EPA issued a publication entitled *Exemption of Oil and Gas Exploration and Production Wastes*. The document explains the exemption of certain oilfield wastes from regulation as hazardous wastes under RCRA Subtitle C. The report includes background on the exploration and production exemption, basic rules for determining the exempt or non-exempt status of wastes, examples of exempt and non-exempt wastes, the status of waste mixtures, and clarifications of several misunderstandings about the exemption. A subsequent analysis summarizing the findings of the Report noted:

> With respect to petroleum production, primary field operations include activities occurring at or near the wellhead or production facility, but before the point where the custody of the

> petroleum is transferred from an individual field activity or centrally located facility to a carrier for transport to a refinery. Without a transfer of custody, the primary field operation ends at the last point of separation. Crude oil stock tanks are considered separation devices (Puder and Veil 2006).

In addition to specific oilfield waste regulations, the report noted that wastes that are a product of treatment of an exempted waste usually remain exempt, and the exemption is not negated by offsite transportation. However, wastes that are not specifically associated with primary field operations are not exempted. Any waste that is not associated with primary field operations is subject to further inspection for purposes of classification (EPA 2002). The EPA also noted in the report:

> In general, the exempt status of an E&P waste depends on how the material was used or generated as waste, not necessarily whether the material is hazardous or toxic. For example, some exempt E&P wastes might be harmful to human health and the environment, and many non-exempt wastes might not be as harmful (EPA 2002). Table 24 presents examples of exempt and non-exempt E&P wastes.

Table 24. Examples of exempt and nonexempt exploration and production waste streams

Exempt E&P Waste Streams	Nonexempt E&P Waste Streams
- Caustics if used as drilling fluid additives	- Batteries (lead-acid and nickel cadmium)
- Cement slurry returns and cement cuttings	- Caustic or acid cleaners
- Debris, crude-oil soaked, crude-oil stained	- Cement slurries, unused
- Drill cuttings and solids	- Chemicals, surplus/unusable
- Drilling fluids and muds	- Compressor oil, filters, and blowdown waste
- Drilling fluids and cuttings from offshore operations disposed of onshore	- Debris, lube oil (contaminated)
- Liquid hydrocarbons removed from the production stream	- Drilling fluids (unused)
- Liquid and solid wastes generated by crude oil and tank bottom reclaimers	- Drums or containers, containing chemicals or lubricating oil
- Pit sludges and contaminated bottoms from storage or disposal of exempt wastes	- Drums, empty and rinsate
- Produced sand	- Hydraulic fluids (used)
- Produced water	- Sandblast media
- Produced water constituents removed before disposal	- Scrap metal
- Soils, crude-oil contaminated	- Soil, chemical-contaminated, lube oil-contaminated and mercury contaminated
- Tank bottoms and basic sediment from storage facilities that hold product and exempt waste (including accumulated materials such as hydrocarbons, solids, sand, and emulsion from production separators, fluid treating vessels, and production impoundments)	- Solvents, spent (including waste solvents)
- Volatile organic compounds from exempt wastes in reserve pits or impoundments or production equipment	- Thread protectors, pipe dope-contaminated
- Well completion, treatment, and stimulations, and packaging fluids	- Vacuum truck rinsate (from tanks containing nonexempt waste)
- Workover wastes (blowdown, swabbing and bailing wastes)	- Well completion, treatment and stimulation fluids (unused)

Source: (Puder and Veil 2006).

In May of 2016 a federal lawsuit was filed by the Environmental Integrity Project alleging that the EPA had failed to perform its duty under Section 2002(b) to evaluate Subtitle D solid waste regulatory requirements (EPA 2019b). The EPA conducted a study to determine if these steps were necessary, and concluded that any revisions to the federal regulations of waste for crude oil and natural gas was not necessary at this time (EPA 2019b). Along with federal regulations there are state regulations regarding drill sites and how waste is disposed of. The state in the impact region with the most oil field waste disposal is Pennsylvania. The bulk of state regulations for sites falls under the Pennsylvania code title 25 which discusses environmental protections (EPA 2014 Apr 1).

The Marcellus shale is the largest shale play on the east coast and encompasses some of the Atlantic impact states such as Pennsylvania and New York. Both states have taken different approaches when it comes to the regulation of oil and gas exploration, specifically hydraulic fracking. Although allowed in Pennsylvania, hydraulic fracking has been banned in the State of New York with a permeant ban aimed for FY2021. Fracking in New York state has been banned since 2015 (Kaplan 2014 Dec 17).

Maryland is also along the Marcellus shale play. In 2017 Governor Larry Hogan signed a bill banning fracking in Maryland despite approving an LNG export facility that will likely export considerable natural gas produced in the Marcellus play (McKinney 2019 Jun 19).

Virginia is another state that sits on part of the Marcellus shale. Most of the oil and gas exploration in the state of Virginia are in the western portion of the state. Laws, regulations, and permits are handled by the Virginia Department of Mines, Minerals, and Energy. There has been much debate in Virginia as to the environmental impact of oil and gas exploration. There are certain areas such as the Chesapeake Bay where oil and gas drilling is prohibited (Code of Virginia Title 62.1).

6.5 Current Outlook

The outlook for oil field waste disposal depends heavily on the continued growth of natural gas production in the Atlantic region. The only offshore energy production that could influence the waste disposal industry short of oil and natural gas is offshore wind (OSW) since facilities development and ongoing production activities will generate some degree of waste, admittedly types that are likely concentrated with typical solid wastes.

The bulk of waste materials produced by offshore oil and gas activities are formation water (produced water) and drilling muds and cuttings. These waste streams are regulated by the EPA through discharge permits and are either released after treatment or returned to shore for disposal. The EPA requires that certain waste streams be returned to shore for disposal, including oil-based drilling muds and cuttings, produced sands, synthetic-based muds, waste oil, chemical products, and trash and debris. Solid waste from offshore energy production is hauled to landfills, while liquids are sent to a treatment plant, which may be located at a marine terminal or inland (USBOEM 2021).

Accurate Marine Environmental has a wastewater and oil treatment plant at their Portsmouth, Virginia terminal that can treat 144,000 gallons of wastewater per day. However, existing treatment capacity is limited. Offshore oil and gas producers would need contract with companies like Accurate Marine Environmental so that they could invest in additional wastewater treatment capacity to accept offshore drilling waste (FURGO Consultants 2015 Mar 26).

6.5.1 Environmental Outlook

One of the largest factors impacting the future of waste disposal companies is the environmental pressure put on energy extraction. In one sense, stricter laws would increase the need for specialized cleaning and disposal, which could help increase the amount of third party cleaning companies. However, when there are more barriers to extract resources, such as natural gas and oil, producer companies, may decide to not extract these resources at all, leading to less of a need for waste disposal companies.

Atlantic Coast States have passed laws increasing environmental pressure on offshore oil and gas production. States such as Virginia and New Jersey recently passed laws banning both oil and gas development and the development of pipelines and other infrastructure supporting oil and gas production from State waters. These State environmental regulations will substantially increase the cost of oil and gas production in federal offshore waters (Virginia General Assembly 2020 Mar 25).

In recent years, investor environmental activism, and climate change activism in particular has had an increasing impact on the private sector. In 2019 and 2020 Goldman Sachs, JPMorgan, Wells Fargo, Citi and Morgan Stanley, six of the largest banks in the US, announced that they would not provide funding for oil and gas projects in the Artic (Ellfeldt 2021 Mar 9). BLM's subsequent January 2021 Alaska oil and gas lease sale received only thirteen bids, with eleven bids coming from an agency of the State of Alaska (USBLM 2021 Jan 6). Environmental activism could also limit private sector interest in offshore oil and gas development and production on the Atlantic Coast.

6.5.2 Offshore Wind

OSW has become more relevant as states look to diversify their energy portfolio. The Block Island wind farm was the first offshore wind farm set up in the United States. This 30 MW wind farm which powers Block Island off the coast of Rhode Island has been operational since December 2016 (Power Technology 2020c). More states such as New Jersey are looking at establishing larger windfarms in order to combat climate change(Murphy 2019).

If offshore wind becomes a more prominent source of energy for the Atlantic Coast, this could facilitate the expanded financial support for offshore-specific waste disposal companies. In theory, these facilities could be operated in a fashion that takes wastes from either type of offshore activity, particularly non-hazardous solid wastes.

Many states are proposing more offshore wind initiatives, including New York, New Jersey, Connecticut, Virginia, and Rhode Island, to name a few. Many project this industry to continue to grow over the next 5 to 10 years. Below is a list of impact states that have taken initiative to establish offshore wind into their energy portfolio.

Connecticut- In 2018 the Connecticut Department of Energy and Environmental Protection selected a 200 MW as its first approved wind farm. Governor Malloy also issued a statement in which he stated Connecticut would invest $15 million in a shipping pier in order to help attract future investors (AWEA). Vineyard Wind was recently awarded to construct a 800 MW offshore wind farm off the coast of Bridgeport (Stromsta 2019 Dec 5).

Maryland- In 2017 Maryland approved two projects totally 368 MW which are planned to come online between 2020-2022 (AWEA).

New York- Governor Cuomo announced in that New York was committed to developing 2.4 GW by 2030. New York also added $15 million investment for upgrading port infrastructure.

New Jersey- Governor Murphy signed an executive order to develop 3,500 MW of offshore wind by 2030 (AWEA).

Virginia- In 2018 Dominion Energy filed for a 12 MW offshore wind project (AWEA), and in 2020, the project became operational.

One important solid waste issue for OSW that is growing concerns the disposal of used turbine blades, particularly for locations that upgrade turbines before the end of their useful lives, in order to achieve higher capacities and more efficient operations. Typical OSW facilities, and their individual components such as the blades, have a 20-year life.

7 Pipe Coating

7.1 Description of the Industry and Services Provided

Pipelines used to transport oil and natural gas are coated to protect against corrosion and other damage. Pipes transporting hydrocarbons can be coated internally and externally to both protect against corrosion and to improve flow. In addition to corrosion protection, offshore-based pipes may be concrete-coated in order to decrease pipe buoyancy to ensure that the pipe remains on the seabed.

Pipeline integrity may be compromised by corrosion, natural forces (earthquakes, landslides, lightning, heavy rain, floods, mudslides, frost heave, frozen components), excavation, material defects, or equipment malfunctions (PHMSA 2019a). The most common pipeline integrity threat outside excavation is corrosion. Corrosion occurs when an electrical current flows from a pipe into the surrounding soil, causing metal loss, or a breakdown in material composition. Pipe coating is one way to assist in preventing corrosion (Folga 2007). Because coatings are the first line of defense in protecting pipes from corrosion, they must be well bonded, continuous, and able to resist the effects of their environment (Löffler, Thomas 2018).

Effective pipe coating practices and properties include (Kennedy 1993):

- application ease;
- application adherence;
- impact resistance;
- flexibility;
- soil stress resistance;
- water resistance;
- electricity resistant;
- chemical and structural stability; and
- bacteria, marine organisms, and cathodic disbondment resistance.

7.2 Typical Facility Characteristics

Pipe coatings are usually applied before the pipe is delivered to the installation site. Coating mills apply pipe coatings to protect the line pipe from corrosion. Coating mills are often located adjacent to the pipe mill, so line pipe moves straight from the manufacturing line to the coating facility (INGAA 2019). At the construction site, the coating is rechecked for imperfections or damage that could occur during transportation. When pipe lengths are coated and wrapped at a coating yard, a short length at each end of the pipe is left bare so the joints can be welded together. A new coating is then applied at the welded joints by sandblasting the weld and applying a new layer of coating (Folga 2007).

Pipe coating can also be done at the job site. Individual lengths of pipe are first welded together, and the pipeline is suspended over a trench. Special machines then move along the pipe to extrude coating onto the pipe and welds. Tape is wrapped over the coating by a tape machine in a spiral. The wrapping machine maintains tension on the tape so that it fits tightly over the coating (Kennedy 1993).

Figure 87. Pipeline coating applied at installation site.

Source: North American Oil & Gas Pipelines 2019.

7.2.1 Coatings

Pipes can be coated with several different coatings. Historically, pipes have been coated with such materials as coal tar enamels, asphalt enamels, wax, or an enamel tape wrap (Larsen 2017 Mar 1). Today, fusion bond epoxy (FBE) coating or an extruded polyethylene (Guan et al. 2005; Folga 2007) are the most common materials. FBE coating is light blue in color and can often be seen on pipe being transported by rail or truck.

Fusion bonded epoxy

Fusion bonded epoxy (FBE) coating, or "powder coating," has been a primary pipe coating method because of its durability, corrosion protection properties, and low cost (Ijaz 2018 Mar 1).

The preparation work for an FBE coating includes a cleaning process that heats the external pipe surface by what is known as a shot-blast process. The pipe is then heated to a set temperature (450°F-500°F). Three heating methods can be used: (1) electrical induction; (2) gas fired forced air; or (3) a combination of high velocity direct flame impingement and infrared. After the pipe is heated, it passes through a powder coating machine where the epoxy powder is electrostatically applied (Khanna 2008).The powder melts onto the heated pipe, forming a water-tight barrier. Before the pipe is transported to the job site, it is both visually inspected and tested with high voltage electricity to evaluate the coating's insulating effectiveness (Folga 2007).

Three-layer polyolefin (3LP)

The second most common application is what is known as a three-layer polyolefin (3LP) coating that consists of (1) an FBE primer, (2) a polyethylene (PE) or polypropylene (PP) adhesive layer, and (3) a top-coat of PE or PP. The first task of the 3LP process is to apply an FBE primer to maintain steel integrity. An adhesive is then applied using either PE or PP, to the FBE (Bayou Companies 2019a).

Disbondment, the deterioration of adhesion due to cathodic reaction, is one potential 3LP disadvantage which can hinder the cathodic protection current and expose the pipeline to environmentally-induced cracking (Guan 2010).

Internal diameter coatings

Internal diameter (ID) coatings create a smooth, defect-free surface on the inside of a pipe and are used to improve the flow of gas and other materials through a pipeline. ID coatings also: (1) help to reduce wax and hydrate formation; (2) act as an insulator on electrically heated pipe-in-pipe to reduce pipe maintenance and make pipeline inspection easier; (3) are used in potable water applications (Bayou Companies 2019b).

Concrete weight coating

Concrete weight coating (CWC) is used to provide negative buoyancy (a weight greater than the buoyant force of the water) for offshore pipelines or for river or road crossing applications (Bayou Companies 2019c). A mix of cement, iron ore, and wire wrap is used in combination with other coating systems, such as FBE.

There are three major requirements of concrete coating in maintaining the stability of pipelines on the seabed (Kiernan 1982):

1. Negative buoyancy: Originally, the chief function of negative buoyancy was to add sufficient weight to the pipeline to achieve the required negative buoyancy, hence the term "weight coating." This primary function has not changed over the years since the first offshore lines were laid in the GOM in the late 1940s.
2. Resistance to damage: from natural environmental hazards while operating on sea-beds, from the effects of human hazards, such as fishing trawls and trailing cables from floating vessels and coatings must be able to withstand the physical installation challenges arising during laying and trenching operations.
3. Protection of anticorrosion coating: All presently used techniques of anticorrosion coating are subjected to damage when exposed to trawl gear or trailing cables.

7.2.2 Cathodic Protection

Cathodic protection is a method for preventing corrosion in metal by using electric voltage to prevent or slow the corrosion process. It is used along pipelines, underground storage tanks, ship hulls, water treatment facilities, bridges, and steel pilings. In a cathodic protection system, anodes are installed, and an electric current flows through the soil between the pipe and the anodes. The pipeline becomes the cathode of the system, and corrosion is decreased. The anodes are the part of the system that is corroded or sacrificed.

Current magnitudes in a cathodic protection system depends on several factors including: the temperature; moisture content and concentration of salts in the soil; the chemical constituents of the soil; distance between anode and cathode; and surface areas of the anode and cathode (Kennedy 1993).

In 1971, the Department of Transportation passed federal legislation requiring that all oil, gas, and gas products pipelines be cathodically protected. The Code of Federal Regulations, Section 192.455 (CFR 2019 Nov 18) requires all buried metallic pipe installed after July 31, 1971 be coated and have a cathodic protection system designed to protect the pipe in its entirety. A system with cathodic protection must also be monitored and tested annually for effectiveness.

7.3 Geographic Distribution

Eight facilities have been identified in the Atlantic impact region, and these facilities are illustrated in Figure 88. Five of these facilities are located inland in the Appalachian region within the states of Pennsylvania and New York. One is located on the coast of Massachusetts, and the remaining two facilities are in Florida– one along the northern Gulf coast and the other along the southern Atlantic coast. These companies are listed in and depicted below in Figure 88. Liberty Coating Company, Dura-Bond Coating, and Berg Pipe all specialize in pipeline coating applications and are described below. The remaining companies provide general industrial coating services but have been confirmed to provide pipe coating application.

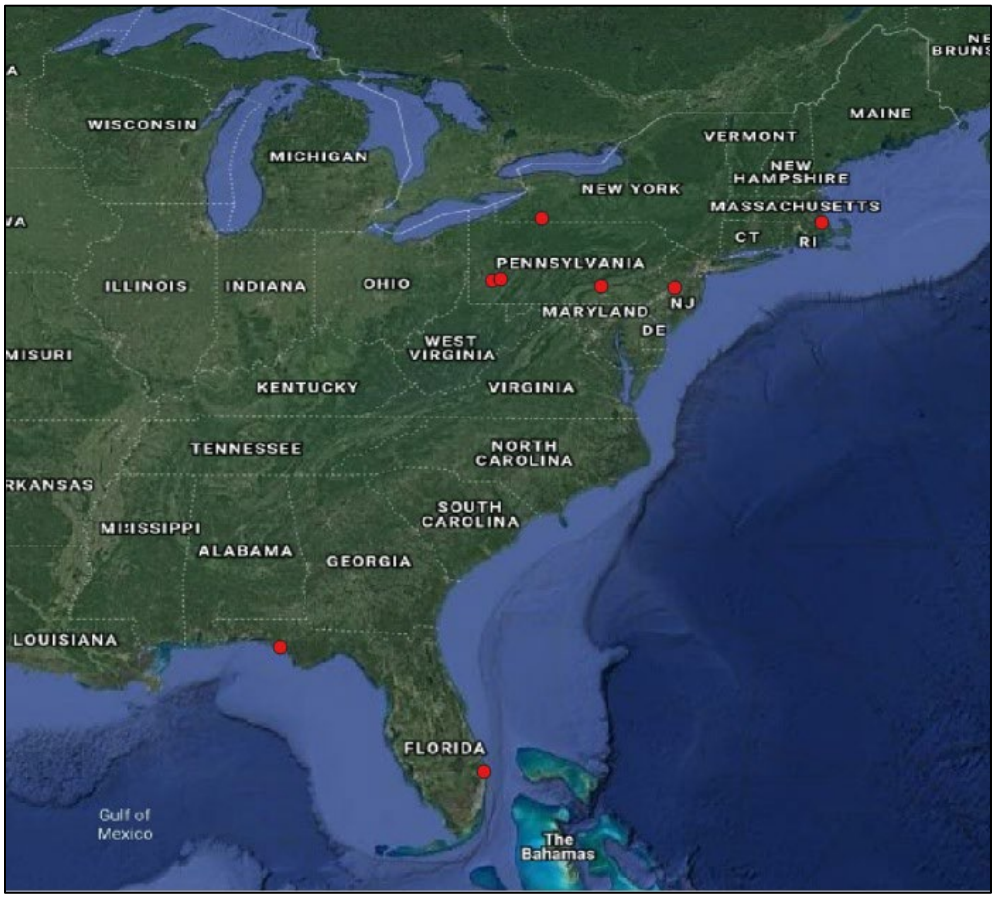

Figure 88. Atlantic impact region pipe coating facilities.

Table 25. Atlantic impact region pipe coating facilities

	Company	City	State
1	Dura-Bond Coating, Inc.	Steelton	PA
2	Dura-Bond Coating, Inc.	Duquesne	PA
3	Dura-Bond Coating, Inc.	Export	PA
4	Liberty Coating Company	Morrisville	PA
5	MJ Painting Contractor Corp.	Olean	NY
6	A&G Industrial Services, Inc.	Plymouth	MA
7	Berg Pipe	Panama City	FL
8	Prime Technical Coatings	West Palm Beach	FL

Liberty Coating Company, LLC (Liberty) provides industrial coatings for the oil, gas, and water industries in Morrisville, PA. It is located on 35 acres with six coating buildings that cover over 110,000 square feet (10,219 square meters). Liberty boasts over 100 employees (Liberty Coating) and offers a number of coating options, including a proprietary coating system called Pritec®. This is a dual layer coating system that uses butyl rubber adhesive and polyethylene. The two materials are heated and applied through a dual-extrusion process. Pritec® protects pipe with a firmly bonded, damage resistant coating and can be applied to pipe ranging in diameter from ¾" to 48" (Liberty Coating 2019).

Figure 89. Liberty coating storage yard.

Source: Liberty Coating 2019.

Dura-Bond Coating has three locations in Pennsylvania. Dura-Bond's focus is on the Marcellus Shale region as well as gas transmission and distribution. For example, in 2015, the company signed agreements to provide pipe for the Atlantic Coast Pipeline, as well as to provide pipe to Dominion for 39 miles of steel pipe for a supply header project in West Virginia and Pennsylvania.(Ritenbaugh 2015 Feb 4) In addition, the company provides pipe for the Trans Canada Leach X-Press and Williams Constitution pipelines (Norris 2018 Sep 24). Dura-Bond Coating also performs work for gas distribution utilities. For example, it provided pipe coating services for the New York utility St. Lawrence Gas Company in its 2012-2015 expansion project in Franklin and St. Lawrence counties (Harris Beach PLLC 2018). The company offers a number of products for corrosion protection: fusion bond epoxy; X-Tec extruded polyethylene; dual layer fusion bond; Powercrete® abrasion resistant overcoating: tape systems: and internal linings (Dura-Bond 2016). Dura-Bond also uses protective paint and coating systems to non-fabricated structural steel such as pipe piling, steel piling, and H-Beams for the construction market (Dura-Bond 2016).

MJ Painting Contractor in southwestern New York offers a number of services for natural gas pipelines including sand and water blasting, quality inspections, above ground painting, and below ground coating. The company applies epoxy pipeline coatings using its Plural Component Spray Rig, which can spray 100 percent solids pipeline coatings (MJ Painting 2019a). MJ Painting's service area ranges from the Mid-West to the Atlantic coast and has assisted multiple natural gas companies such as UGI Utilities and Tennessee Gas Pipeline with their coating needs (MJ Painting 2019b).

Figure 90. Plural component spray rig.

Source: MJ Painting Contractor Corp. 2019.

Berg Pipe has a manufacturing facility in Panama City, Florida that specializes in longitudinal seam-welded large-diameter pipes up to 60" in diameter. The company provides anti-corrosion services in the form of external and internal pipe coatings. The external coating consists of two layers: (1) a layer of FBE coating to protect the pipe against corrosion, and (2) a layer of Abrasion Resistant Overlay ("ARO"), which protects from damage to the pipeline itself. Liquid Epoxy Resin is sprayed on the inside of the pipes, creating a 3 to 4 mils layer that minimizes the frictional resistance within the pipe and improves the gas transportation capacity (Berg Pipe 2019). The Company has produced pipe for the pipelines in diverse parts of the continent, from the Gulfstream pipeline in the Gulf of Mexico, to the Tarahumara in Chihuahua, Mexico, to the Rover Pipeline in the Marcellus Shale region (Berg Pipe).

7.4 Scope of Economic Contribution to Regional Economy

Though a few companies have been identified along the Atlantic coast in Pennsylvania, New York, Massachusetts, and Florida, there is no drilling activity on the Atlantic OCS, and as described in the previous section, several of these facilities are serving oil and gas operations in the Appalachian region as well as projects in the Gulf and other regions across North America.

Similarly, there are no useful NAICS codes or industry data to use to analyze the contribution of the support economy to the area. Pipe coating services are likely included under NAICS code 332812, “Metal Coating, Engraving (except Jewelry and Silverware), and Allied Services to Manufacturers.” This sector includes establishments primarily engaged in one or more of the following: (1) enameling, lacquering, and varnishing metals and metal products; (2) hot dip galvanizing metals and metal products; (3) engraving, chasing, or etching metals and metal products (except jewelry; personal goods carried on or about the person, such as compacts and cigarette cases; precious metal products (except precious plated flatware and other plated ware); and printing plates); (4) powder coating metals and metal products; and (5) providing other metal surfacing services for the trade (USDOC, CB 2017).Therefore, the economic contribution of this sector is relatively small, limited and has, therefore, not been directly estimated.

7.5 Current Trends and Outlook: Industry

7.5.1 Regulatory Changes

The pipe coating industry is not regulated like other segments of the natural gas industry, but pipe coating techniques must meet industry standards and specifications as established by PHMSA and recommended by the National Association of Pipe Coating Applicators (NAPCA).

Over the past several years, there have been several natural gas pipeline incidents that have resulted in increased scrutiny on natural gas pipelines, which in turn have forced these pipe operations to replace pipes comprised of older and more compromised materials with newer materials including those with newer and more effective protections. For instance, Atmos Energy in Texas announced in 2018 that it planned to accelerate its pipe replacement activity. (Atmos Energy 2018 Jul 25) This announcement was made in the wake of a fatal explosion caused by gas leaking from corroded pipe (Aspinwall et al. 2018 Mar 25).

Sections 192.455 through 192.477 and Sections 195.557 through 195.561 (Chapter 49) of the Code of Federal Regulations (CFR) list the requirements for external coatings for pipelines transporting natural gas and hazardous liquids:

- Each buried or submerged pipeline must have an external protective coating for external corrosion if the pipeline is:
  - Constructed, relocated, replaced or otherwise changed after the applicable date;
  - Has an external coating that substantially meets allowable coating before the pipeline is placed in service;
  - Is a segment that is relocated, replaced, or substantially altered.
- All pipe coating must be inspected just prior to lowering the pipe into the trench or submerging the pipe, and any damage discovered must be repaired.
- Allowable coating materials for external corrosion control include material that:
  - Is designed to mitigate corrosion of the buried or submerged pipeline;
  - Has sufficient adhesion to the metal surface to prevent under film migration of moisture;
  - Is sufficiently ductile to resist cracking;
  - Has enough strength to resist damage due to handling and soil stress;
  - Is supportive of any supplemental cathodic protection;
  - If the coating is an insulating type, has low moisture absorption and provides high electrical resistance.

Regulations for cathodic protection systems are also included in Sections 192.465, 195.563, and 195.567. A cathodic protection system must be installed for all buried or submerged facilities to mitigate corrosion that might result in structural failure. A cathodic protection system must be installed no later than one year after construction has been completed. Electrical test leads used for corrosion control are required for all buried or submerged pipelines or segments of pipeline, except for offshore pipelines. Requirements for how to test are described in the code.

External Corrosion Control

The aforementioned regulations require pipeline operators to conduct annual tests on any buried or submerged pipe to determine cathodic protection adequacy. Operators must also inspect, every three years, any bare pipe that is not cathodically protected and study leak records for that pipe to determine if additional protection is needed. Whenever buried pipe is exposed for any reason, the operator must examine the pipe for evidence of external corrosion. If active corrosion is found, the area should be reviewed for leak and analysis of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.

Internal Corrosion Control

Pipeline operators may not transport hazardous liquid or carbon dioxide (CO_2) that would corrode a pipe or other components of a pipeline system unless it has investigated the corrosive effect of the hazardous liquid or CO_2 on the system and has taken adequate steps to mitigate corrosion. If corrosion inhibitors are used to mitigate internal corrosion, these inhibitors should be used in sufficient quantity to protect the entire part of the system. Monitoring equipment must be examined twice a year to determine the effectiveness of inhibitors or the extent of any corrosion.

All removed pipe segments must have their internal surfaces inspected for corrosion. If the pipe is generally corroded such that the remaining wall thickness is less than the minimum thickness required by the pipe specification tolerances, the adjacent pipe must also be inspected. Corroded pipe must be replaced with pipe that meets industry requirements. If the pipe is not replaced, based on the actual remaining wall thickness, the operating pressure must be reduced to be commensurate with the limits on operating pressure or the corroded pipe must be repaired using a method that reliable engineering tests and analyses show will permanently restore the pipe's serviceability.

Corrosion control information must be maintained, and maps must be kept of cathodically protected pipelines and cathodic protection facilities installed after January 28, 2002. The required information includes a stated number of anodes, records of each analysis, inspection, investigation, review, survey, and test required by the statute in sufficient detail to demonstrate the adequacy of corrosion control measures or to indicate that corrosion requiring control measures do not exist.

7.5.2 Trends

There are a number of industries that rely heavily on transportation mediums, such as pipelines. These industries include the oil and gas industry (exploration and production) and utilities (natural gas transportation and distribution utilities, water utilities). Thus, historic trends and the future outlook for pipeline coating will be, in large part, a function of the demand for new pipelines and their needs. Over the past several years, those needs have been driven by the need for new pipes, that in turn are a function of (a) pipeline retirements and replacements and (b) load growth for natural gas and water utilities. Since the middle part of the last decade, these needs have been supplemented by unconventional crude oil and natural gas production, particularly natural gas production, that has been highly concentrated in the Appalachian part of the Atlantic seaboard. Over the past few years, this growth has been supplemented by a small but important level of growth in pipelines that are being designed to assist, in part, moving natural gas to the Atlantic coast for export purposes at the region's liquefied natural gas (LNG) facilities.

As noted earlier, the pipe coating industry has evolved from the use of relatively simple natural resource-type coatings to more effective and sophisticated fusion-bonded epoxies and polypropylene coatings all of which, themselves, have arisen due to advances in chemistry associated with reforming natural gas and other hydrocarbons. Pipe coating companies, in order to be competitive and profitable, are always looking for lighter, more effective, more efficient and least-costly material types to apply to various types of pipes.

Safety has been an overriding concern for all aspects of the crude oil and natural gas pipeline industry over the past decade. Several high-profile natural gas pipeline failures that have arisen over the past two decades, such as the Merrimack Valley explosion in 2018 and the aforementioned Atmos explosion, have increased public policy scrutiny on all aspects of the natural gas pipeline industry (discussed in the prior regulatory subsection). This has increased pipeline replacement activities across the entire industry, particularly for pipelines that are composed of cast iron, wrought iron and bare steel. Most of these material types are associated with natural gas distribution mains and not longer-haul natural gas transmission systems although there have been some replacements that arisen over the past two decades.

In addition, some industry sources note that technology and environmental trends are pushing product innovation to meet client needs. For instance, when selecting pipe materials for deepwater installations, fatigue is a critical element that must be considered (Mohr 2020). Also, the installation of export lines and flowlines is an expensive and risk-intensive procedure. For instance, one company, Tenaris, uses a double jointing method, where line pipe is pre-assembled at the mill, then coated with anti-corrosion or thermal insulation. (Tenaris) The pipe and materials arrive at the site ready to be installed, which decreases offshore welding time significantly. Even the anti-corrosion anode pads can be attached before applying protective coatings, thereby reducing installation time even further (Tenaris 2007).

7.5.3 Outlook

As the oil and gas industry continues to push the boundaries of exploration, the pipe coating industry will need to be able to adapt and innovate to changing needs. Most of the developments in pipe coating technologies are found through a specific company's research and development. The largest companies have the greatest amount of capital and funds to conduct this type of research. For example, Tenaris is one of the world's leading suppliers of pipe and has research centers in Argentina, Italy, Japan, and Mexico (Tenaris 2019).

The outlook for the pipe coating industry is strong, yet also competitive because companies vie for market share while trying to keep pace with advances in technology. The market for steel pipe is highly competitive, with primary competitive factors being price, quality, services and technology (Tenaris 2019 Apr 5). Industry participants must focus on timely and efficient applications and offer solution-based services. Research and development will continue to play a major role in the pipe coating industry, particularly as environmental regulations become more stringent and the oil and gas industry moves into deeper waters.

7.6 Current Trends and Outlook: East Coast

7.6.1 Trends

Business is strong for some of the pipe coating facilities in the Atlantic impact region states. Dura-Bond Industries, for instance, cut its staff by 30 percent during the 2008-2009 recession, but has since opened two additions to its operations: a pipe coating facility in Duquesne, PA in 2013 and a steel pipe mill in McKeesport, PA in 2018 (Davidson and Hansen 2012; Norris 2018 Sep 24). Dura-Bond is in the midst of a $400 million contract with Atlantic Coast Pipeline LLC to produce and coat steel pipe for a 550-mile pipeline project that will bring natural gas to Virginia and North Carolina (Norris 2016). However, the outlook for Dura-Bond's operations, will be a function of these, and similar major natural gas and other hydrocarbon projects. The success and expansion of these projects will define the market outlook for pipe coating companies. Many of these major natural gas projects are not without their respective problems.

7.6.2 Outlook

As natural gas production in the Marcellus shale region continues to expand, so will business for these coating facilities. The probable increase in unconventional natural gas production from the Marcellus Shale areas will likely increase the amount of natural gas transported in this area, potentially past levels that rival (conventional) prolific supply basins like the GOM. In addition, the undeveloped eastern portion of the Marcellus Shale could extend as far east as parts of Virginia, eastern Pennsylvania, and Maryland, possibly creating new onshore resources and pipeline investments.

Expanded natural gas production will also facilitate the development of natural gas pipelines that move commodity to the east coast for export to other places around the globe, particularly western and central European markets. There are currently three LNG export facilities located along the Atlantic coast from as far north as Boston to as far south as Elba Island, Georgia. These facilities currently have 4.27 billion cubic feet per day (Bcf/d) of regasification capacity (import capacity) and 0.765 Bcf/d of liquefaction (export) capacity.(PHMSA 2019b) There is also 0.36 Bcf/d of project capacity liquefaction developments or expansions across these facilities. (EIA 2020a) It is highly likely that many of these facilities will need new pipeline interconnections to source natural gas for export purposes.

The continued boom in regional natural gas production benefits pipe coating companies in the region and will likely continue to benefit these companies as long as this production continues. MJ Painting Contractor Corp., for instance, headquartered in Olean, NY, attributes its recent success to the natural gas boom in the Atlantic (Appalachian) region. Since 2002, the company has increased its workforce from 6 to 50 employees and has steadily become more involved in the natural gas industry (Miller 2019 Jul 14). In 2017, the company coated 700 miles of pipeline from Michigan to West Virginia and, in 2019, it announced plans to add a new management office near Pittsburgh in order to better serve the Tri-state pipeline in areas of Pennsylvania, West Virginia, and Ohio as well as other regional energy businesses (Miller 2017 Jan 15; Miller 2019 Jul 14).

Replacing aging natural gas pipeline systems, particularly at the local distribution company, or LDC level, is another important and growing source of business for many regional pipe coating companies. As noted earlier, cast iron, wrought iron, and unprotected (uncoated) steel pipes are the most susceptible to corrosion. Cast and wrought iron natural gas transmission and distribution pipes were mainly installed in the Northeast and Mid-Atlantic regions of the US over 60 years ago and are still in use today, at least at the distribution level.

Although the amount of iron and bare steel pipeline has declined significantly in recent years, to the point where 22 states have completely eliminated these types of natural gas distribution lines in their territories, there is still much to be done (PHMSA 2019 Sep 20). New Jersey, New York, Massachusetts, and Pennsylvania account for half of all the cast iron pipe in the US; Pennsylvania and New York are among four states that account for half of all the country's unprotected steel pipe (USDOE 2017). Please see Table 26 and Table 27 for reference.

Table 26. Miles of cast and/or wrought iron gas distribution mains in Atlantic states, 2009–2018

State	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
CT	1,566	1,542	1,509	1,467	1,426	1,381	1,349	1,298	1,251	1,221
DC	430	428	425	419	418	415	412	411	409	406
DE	107	104	96	91	86	82	76	71	65	61
FL	313	297	253	232	211	203	168	149	123	66
GA	128	55	26	12	5	4	5	4	2	2
MA	4,066	3,990	3,901	3,792	3,691	3,433	3,315	3,194	3,049	2,925
MD	1,446	1,441	1,422	1,399	1,378	1,350	1,318	1,275	1,222	1,164
ME	61	62	59	56	51	48	45	42	39	36
NC	0	0	0	0	0	0	0	0	0	0
NH	154	147	140	134	125	119	112	103	86	81
NJ	5,302	5,215	5,138	5,044	4,881	4,788	4,586	4,369	4,143	3,911
NY	4,738	4,640	4,541	4,396	4,254	4,086	3,960	3,615	3,420	3,175
PA	3,243	3,184	3,260	3,221	3,115	3,008	2,901	2,804	2,661	2,532
RI	885	878	875	859	831	806	769	754	730	700
VA	605	558	480	406	333	293	264	241	203	188
Total	**23,045**	**22,541**	**22,125**	**21,527**	**20,806**	**20,017**	**19,281**	**18,330**	**17,401**	**16,467**

Source: USDOT, PHMSA.

Table 27. Miles of bare steel gas distribution mains in Atlantic states, 2009–2018

State	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
CT	214	208	195	186	174	165	156	152	146	139
DC	30	29	28	28	28	27	25	24	23	23
DE	33	29	26	20	23	17	12	8	6	6
FL	1,361	1,452	1,303	1,224	1,135	946	805	842	616	562
GA	399	339	247	127	80	71	51	45	30	29
MA	2,103	2,007	1,902	1,780	1,698	1,638	1,566	1,462	1,349	1,288
MD	396	380	361	338	308	283	259	233	210	184
ME	3	2	2	2	2	1	1	0	0	0
NC	46	41	38	34	30	22	17	11	7	7
NH	2,007	1,903	1,821	1,708	1,556	1,444	1,333	1,219	1,011	588
NJ	7,663	7,471	7,246	6,903	6,516	6,353	6,138	5,708	5,498	5,152
NY	8,608	8,435	8,091	8,086	7,649	7,448	7,208	6,946	6,711	6,420
PA	423	391	392	346	320	296	266	241	224	199
RI	10	10	10	10	10	9	6	4	4	4
VA	486	739	669	611	575	535	497	451	426	404
Total	**23,782**	**23,436**	**22,332**	**21,402**	**20,103**	**19,256**	**18,340**	**17,346**	**16,263**	**15,003**

Source: USDOT, PHMSA (2020).

Leaks and breaks caused by corrosion can lead to environmental harm and can cost companies and customers millions of dollars from lost product. Many utilities have addressed this issue by instilling pipeline replacement programs that are meant to accelerate the identification of leaks and repair or replace the pipes with new, modern materials such as plastic or coated steel pipes. For example, Atlanta Gas Light recently completed its 15-year Pipeline Replacement Program in 2013 that enabled the company to replace over 2,700 miles of bare steel and cast-iron natural gas pipeline in Georgia (Atlanta Gas Light n.a.).

7.7 Factors Impacting East Coast Development

Many of the existing pipe coating facilities in the Atlantic impact states are in the Appalachian region, while the rest are situated along the coast. Under a limited or moderate development scenario, it is likely that coated pipe would come from these existing facilities supplemented with pipe originating in the GOM region, particularly Louisiana and Texas. The resources pulled from the GOM are largely a function of potential development speed. The faster the development of the offshore Atlantic region, the more likely pipe coating needs will be supplemented by GOM capacity.

Although there seems to be an increasing demand for distribution and transportation pipelines in the Atlantic region, modern materials could cause a decline in business for coating facilities. High density polyethylene (HDPE) pipe and reinforced thermoplastic pipe (RTP) are attractive alternatives to steel due to the numerous qualities that make it more cost-effective (Nummi 2016 May 3):

- Light-weight;
- Rustproof, break-resistant, and corrosion-free;
- Able to withstand harsh chemical environments;
- Flexible and able to expand with pressure surges.

These plastic pipes have been used in oil and gas exploration for years and have become increasingly popular in other aspects of the natural gas industry. Nearly 97 percent of distribution pipelines in the US were made of plastic or steel at the end of 2018 (PHMSA 2019 Sep 20). This trend could cause the need for pipe coating to greatly diminish, leaving pipe coating facilities in a less lucrative position. As for now, pipeline replacement programs could help maintain a steady business for these facilities since connecting new plastic pipe to already existing pipe may not be feasible or effective.(PHMSA 2017) Therefore, the replaced sections of pipeline are most likely composed of steel that will still need coating to protect it from corrosion. Unfortunately for coating facilities, it is only a matter of time until all the iron and unprotected steel pipes are completely replaced.

Offshore construction may encourage some expansion for coating facilities as more utilities seek energy resources within the Outer Continental Shelf. Offshore pipes will most likely be where much of the coating business comes from going forward because of the saltwater and deep-pressure elements that come with being on the sea floor. Plastic pipes are not yet durable enough to combat these extreme environments, so steel pipelines built offshore will need to be coated for extra protection.

However, under a limited offshore development scenario, it is most likely that pipe coating services would be provided by the GOM region. Coated pipe would be shipped or delivered by rail or truck to Atlantic impact regions. Industry consolidation and economy of scale associated with large coating operations may offer further support for this outcome. At this point, we do not anticipate any new pipe coating or fabricating facilities being developed along the Atlantic. It is likely that existing regional facilities may see some expansion. As in the case of MJ Painting Contractors Co., some are showing indications of increased orders given the rise in Marcellus production and new pipeline projects bringing gas from the Rockies into the Midwest and Appalachian area (MJ Painting 2019b; Miller 2017 Jan 15). As for offshore projects, however, it is unlikely that Atlantic coating facilities will inherit as much business as those located in the GOM region. Offshore pipeline development in the US is still banned along the Atlantic Coast, and it is unclear if or when that part of the region will be accessed.

8. Natural Gas Processing and Storage

8.1 Description of the Industry and Services Provided

8.1.1 Natural Gas Processing

Natural gas is produced from a reservoir rock, and includes a mixture of light hydrocarbon gases, impurities, and liquid hydrocarbons. Natural gas is found below the earth's surface in three principal forms:

- **Associated gas**: This is found in crude oil reservoirs, either dissolved in the crude oil, or combined with crude oil deposits. Associated gas is produced from oil wells along with the crude and is separated from the oil at the head of the well.
- **Non-associated gas:** This is found in reservoirs separate from crude oil – its production is not a result of the production of crude oil. It is produced by natural gas wells and is commonly referred to as "gas-well gas" or "dry gas." Today about 70 percent of all US natural gas produced is non-associated gas (USEIA 2019 Nov 4).
- **Gas Condensate**: This form is a hydrocarbon that is neither true gas nor true liquid. It is not a gas because of its high density, and it is not a liquid because no surface boundary exists between gas and liquid. Gas condensate reservoirs are usually deeper and have higher pressures, which pose special problems in the production, processing, and recycling of the gas for maintenance of reservoir pressure.

The composition of the raw natural gas extracted from producing wells depends on the type, depth, and location of the underground deposit and the geology of the area. The quality and quantity of components in natural gas varies by the field, reservoir or location from which the natural gas is produced. Natural gas composition can vary, but it is primarily composed of methane (the lightest hydrocarbon component) and ethane. Methane is what is commonly thought of as "pipeline quality" natural gas and is what is transmitted and distributed to end users.

Figure 91, provides a break-down of a "typical" natural gas stream which, in addition to methane and ethane, is also comprised of varying degrees of small hydrocarbon molecules. These molecules will become liquid at normal atmospheric pressure and are thus known collectively as natural gas liquids (NGLs).

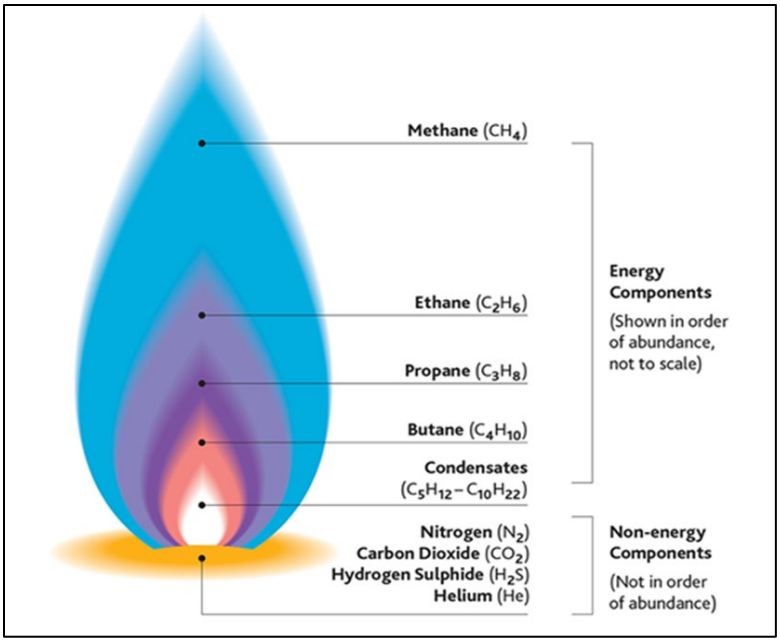

Figure 91. Components of natural gas.

Source: (Colson 2012 Feb 22).

Gas processing occurs at plants and facilities that are typically co-located with natural gas pipelines, or a series of natural gas pipelines and compression units. Natural gas processing also is centrally located near large amounts of natural gas production. The natural gas process removes the impurities and contaminants and separates out other commercially valuable hydrocarbons. Typical contaminants that must be removed from the gas stream include water, hydrogen sulfide, carbon dioxide, nitrogen, and helium.

Figure 92 provides a schematic of how the gas processing function fits into overall field operations. Hydrocarbons that are produced at the field level are usually separated at the lease. Casinghead gas, associated gas, and, in some instances, non-associated natural gas (depending upon its field quality) are moved from the field to a centralized location where a major gas processing plant is located.

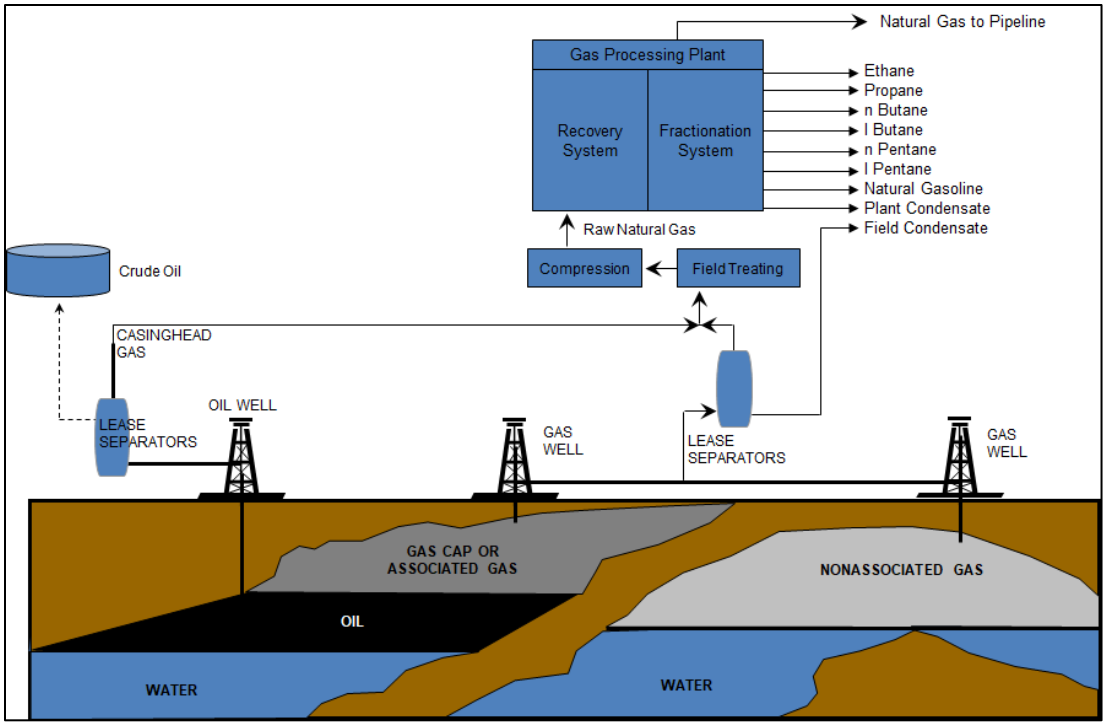

Figure 92. Natural gas production, gathering and processing.

Source: Author's Construct.

A schematic of the various stages in which gas is processed is provided in Figure 93. As noted earlier, the first step in the process at the field level is separation of oil and natural gas. The second and third steps are associated with the water separation process. The fourth step removes various types of contaminants like hydrogen sulfide ("H_2S") and carbon dioxide ("CO_2"); the fifth step removes nitrogen ("N"). The last step removes methane, or "pipeline quality natural gas" from the remaining stream. Natural gas liquids ("NGLs") are then fractionated at a co-located fractionation unit or sent in the form of what is known as "Y-grade" NGLs to a centralized fractionation unit to be separated into individual NGLs like ethane, propane, butane, etc. "Y-grade" is also referred to as the "raw make" or unfractionated blend of NGLs or liquified petroleum gasses ("LPG").

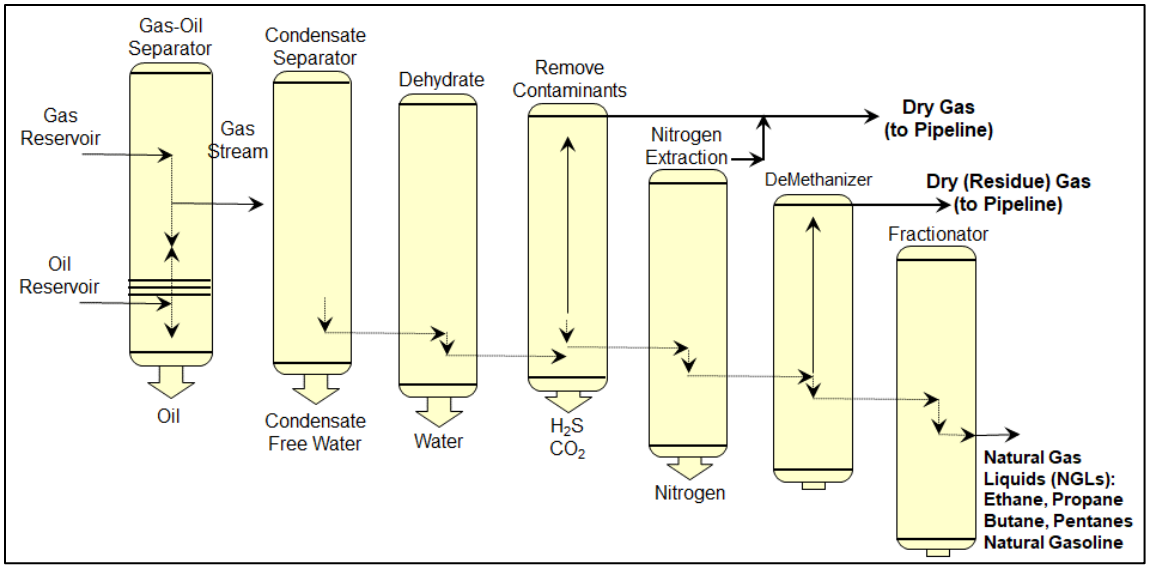

Figure 93. Natural gas processing schematic.

Source: US Energy Information Administration (USEIA 2006 Jan 20).

8.1.1 Natural Gas Storage

Natural gas underground storage plays an important role in the US natural gas value chain and is a key part of the component of the industry. Underground storage is a capacity investment that facilitates market efficiency and reduces need for larger capacity investments in pipeline systems to “hold” natural gas when that gas is not needed.

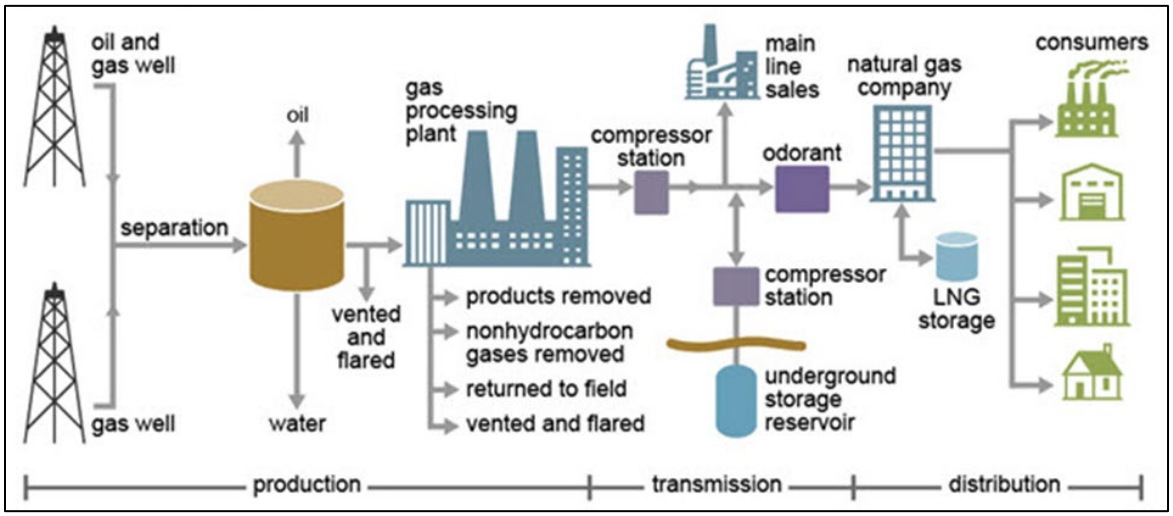

Figure 94. Natural gas production and delivery.

Source: US Energy Information Administration (USEIA 2019 Dec 6).

Without storage facilities, pipeline operators would need to construct additional pipelines, and/or larger pipelines, to meet peak localized demands during winter months. Shippers and other market participants would have to pay capacity fees to utilize these assets that would more than likely sit idle for large periods of the year. The benefit of using storage instead of expensive pipeline capacity is passed along to customers through lower rates and more reliable service. Overall, storage serves three important physical and commercial functions that include: (1) assuring reliable supplies; (2) assisting in risk management; and (3) and increasing natural gas market efficiencies and profitability.

Reliability is the first and most important physical (as opposed to commercial) function of natural gas storage in order to assure that gas is available when needed. Natural gas storage serves two primary reliability functions: (1) to meet seasonal demands for gas (base-load storage to pull out in winter months); and (2) to meet short-term peaks in demand (peaking storage for sudden, usually weather-related spikes in winter demand). Peaks in natural gas demand can range from a few hours to a few days.

Underground natural gas storage facilities are typically "filled" during what is commonly referred to as the "injection season," typically between April through October of any given year. During the spring and summer months, natural gas demand tends to be relatively lower, and excess natural gas production is placed into underground storage facilities during this time to be used later, during the peak fall and winter heating season months. This "withdrawal season" tends to run between the months of November to March.

The second important function of natural gas storage is to reduce the volatility of natural gas costs to end users. Natural gas prices can be exceptionally volatile and, prior to the shale revolution, were second only in volatility to crude oil prices. Storage represents a physical risk management tool that allows a large buyer, like a natural gas distribution utility, to make advance, more steady purchases of natural gas, hopefully at lower or more stable prices, and use that gas during periods when prices are more volatile, like the winter heating season. It is important to note that the goal here is not "profit" from the storage of natural gas so much as it is to secure a stable and fixed price natural gas to avoid the ups and downs often seen in natural gas commodity markets.

Lastly, profitability serves as an important third function for natural gas storage. Underground storage gives energy marketers and other market participants the ability to make profits by effectively "buying low and selling high" and using underground storage to capture the profits associated with seasonal or locational price differentials. This "arbitrage" can often take place across time (buying in the summer at lower price on a speculative belief that winter prices will be extremely high) or across different geographic areas that may have physical delivery constraints.

8.2 Typical Facility Characteristics

8.2.1 Natural Gas Processing

Natural gas processing facilities can be located both onshore and offshore. Onshore gas processing facilities can be located at the wellhead, or at a "hub" location that is between many fields and usually several pipeline systems. Natural gas is extracted from the wellhead and transported to a processing plant through a network of small-diameter, low pressure, pipelines often referred to as "gathering" lines (NaturalGas.org 2013). While many of these gas processing facilities may be of a moderate size, very large centrally located facilities, like the ones of the Gulf Coast, can have capacities that are over Bcf/d. Over the past decade, natural gas processing facilities have been placed on production platforms and moved to offshore deep-water locations.

The central and western Gulf of Mexico is the hub for nearly all offshore natural gas leasing and development activity where many production structures operate in waters up to 6,000 feet deep with several more operating around depths of 10,000 feet or more. In 2018, offshore oil and natural gas production in the Federal Gulf of Mexico accounted for about 16% of total US crude oil production and about 3% of total US dry natural gas production (USEIA 2019 Feb 14).

Fractionation is an important part of natural gas processing which separates NGLs and LPGs into their individual components. Fractionation units are often co-located at natural gas processing facilities, but there are also instances where these fractionation units are located on an independent, stand-alone basis.

Natural gas processing is part of the mid-stream portion of the natural gas value chain including gathering, storage, processing and NGL separation, distribution and marketing. Midstream firms vary in terms of their particular business focus with some concentrating on just a few aspects of the business while others span the entire sector. Firms that focus on transportation tend to pipeline companies that receive revenues from tariffs and other fees they collect from users of their facilities.

Enterprise Product Partners ("Enterprise" or "EPP") operates the largest midstream energy asset network in the US and includes: natural gas gathering, treating, processing, transportation and storage; NGL transportation, fractionation, storage, and export and import terminals (including those used to export LPG and ethane); crude oil gathering, transportation, storage, and export and import terminals; petrochemical and refined products transportation, storage, export and import terminals, and related services; and a marine transportation business that operates primarily on the US inland and Intracoastal Waterway systems (U.S Securities and Exchange Commission 2019a Dec 31). EPP's core activities are in natural gas processing along the Gulf Coast, the Permian basin, and the Rockies with total processing capacity of 11.91 Bcf/d. EPP has a considerable level of other mid-stream assets that include approximately 50,000 miles of pipelines; 260 MMBbl of storage capacity for NGLs, crude oil, petrochemicals, and refined products; 14 Bcf of natural gas storage capacity, and 1.2 MMBbl/d of fractionation capacity (U.S Securities and Exchange Commission 2019a Dec 31).

Targa Resources Corporation ("Targa" or "TRC") is another major industry mid-stream player owning 8,900 miles of natural gas gathering pipelines to feed its 46 natural gas processing plants (US Securities and Exchange Commission 2019 Dec 31). In 2019, Targa processed an average of 4.4 Bcf/d of natural gas and produced an average of 505.4 MBbl/d of NGLs. The company's natural gas processing capacity spans the Gulf Coast, the Permian basin, Williston basin, and the midcontinent.

DCP Midstream is one of the largest processors of natural gas and producers of NGLs in the US In 2019, DCP processed 4.9 Bcf/d of natural gas and produced 417 MMBbl/d of NGL (U.S Securities and Exchange Commission 2019b Dec 31). The company has 5,650 miles of NGL pipeline with a throughput capacity of 860 MMBbl/d. This means that 860 million barrels of NGL can flow through the pipes each day. Most of these pipelines bring product processed in the Permian Basin and Denver-Julesburg Basin to fractionation facilities and petrochemical users in Mont Belvieu and GOM region of Texas. DCP owns or operates 44 natural gas processing plants located in Michigan, the Permian Region, Midcontinent (south central Oklahoma) and the South, which includes facilities along coastal Texas.

8.3.2 Natural Gas Storage

There are three main types of underground natural gas storage facilities that include depleted oil and gas reservoirs, salt caverns and aquifers. A diagram of each storage type is provided in Figure 95. Each type of storage facility has its own physical characteristics that include porosity, permeability, and retention capability. Equally important is the fact that each type of underground natural storage facility also has its own economic characteristics that include capacity development costs, location, deliverability rates and cycling capability.

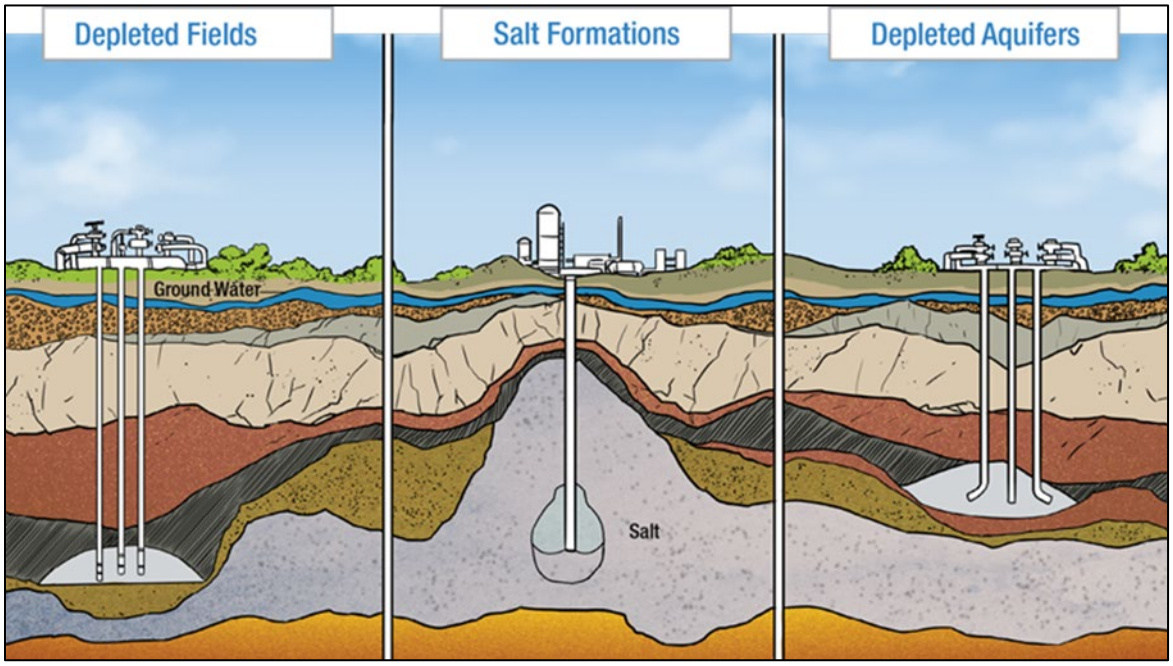

Figure 95. Types of underground natural gas storage facilities.

Source: (DanaEnergy 2019).

Table 28 summarizes the differences in storage characteristics (differences in deliverability, cycling, development costs, etc.) to help explain the current make-up of underground storage in the US.

Table 28. Characteristics of natural gas storage facilities

Type of Storage Facility	Number of Active Fields	Injection Period (days)	Withdrawal Period (days)	Injection and/or Withdrawal Flexibility	Cushion to Working Gas Ratio	Development Cost
Depleted Reservoir	320	200–250	100–150	Low	Cushion: 50–80%	Low
Aquifer	46	200–250	100–150	Low	Cushion: 50%	High
Salt Cavern	38	20–40	10–20	High	Cushion: 20–30%	High

Source: US Energy Information Administration (USEIA 2020a May 30).

The middle columns in Table 28 help to describe the deliverability flexibility of each storage type. This flexibility is defined by a facility's injection capabilities; that is, the speed at which a given storage type can be "filled" or "withdrawn." Those facilities that can be filled or pulled from quickly can often have more flexibility than other types of underground natural gas storage facilities.

Injection flexibility is becoming an increasingly important characteristic for underground storage facilities. Quick delivery times are much more important in today's competitive markets than they were in past decades where storage service deliverability was limited to steady seasonal requirements.

First is the advent of LNG facilities that often need to draw on large volumes of natural gas to liquefy for export purposes. A single LNG tanker, for instance, can hold up to nine Bcf in total gas volume. Likewise, it is often the case that many LNG facilities along the GOM are still receiving gas imports and re-sending those to other places of the world. Thus, in a similar fashion, storage helps "absorb" those very large import volumes that may be offloaded in a matter of days.

Second, the increasing importance of natural gas power generation also enhances the flexibility and injection requirements of underground natural gas storage. Over the past two decades, increases in natural gas demand have come primarily from the power generation sector. More and more power generation is being converted from coal, and in some cases, nuclear, to natural gas. These power generators can have high "cycling" needs for natural gas: that is, the need ramp up power generation to meet increasing demand due to weather or other electrical system deliverability issues.

The overall cost and performance characteristics of underground storage facility types helps to explain, from a big picture perspective, the distribution of their size and location. Overall, depleted reservoirs are the most common type of natural gas storage facility and are often used as a form of "baseload" storage medium. Here, baseload storage means that this storage type is used to hold large amounts of natural gas to be withdrawn on a more steady, methodic basis say than on a "cycling" or "as needed" basis. Reservoir storage is concentrated in areas that have both the need and the underground geological capability. Large amounts of reservoir storage are in the upper mid-west (Michigan), as well as in older areas of historic natural gas production like the Appalachian basin, the mid-continent region, and the Gulf Coast. These facilities, while lacking in flexibility, are very cost-effective to develop (NaturalGas.org 2013) Regions that do not have the ability to storage natural gas underground, like in New England, often rely on other types of peak storage such as small-scale LNG.

The last two columns in Table 28 indicate the capital cost requirements for each type of storage facility. The second to last column highlights the base gas requirements by facility type which can serve as an important driver of overall development costs. Those storage facilities that use less base or "cushion gas" can often be cheaper to develop. Cushion (or base) gas is the term used to describe the minimum amount of gas that is needed in an underground storage facility to maintain operating pressures and in the case of salt, maintain cavern integrity (USEIA 2015 Nov 6). Facilities that have large cushion gas requirements can be more expensive to develop since they tie up large amounts of highly valued gas in limited revenue generating activities. Thus, one advantage that salt cavern storage has relative to other storage types is that it typically requires considerably less cushion gas. However, salt's advantage relative to reservoir storage has to be balanced against its increased initial capital development cost much like the cost of reservoir storage, which has higher base gas requirements, needs to be balanced against its lower capacity (capital) development costs.

Reservoir storage is a relatively low-cost form of underground natural gas since little sub-surface investment is required. In fact, in some instances, older investments at the facilities, such as wells, gathering lines, and transmission lines can be repurposed to support some underground natural gas storage activities. Aquifers and salt caverns are both relatively expensive facilities to develop. Aquifer storage often requires additional infrastructure that is not commonly used in other types of underground storage facilities. Like other types of storage facilities, wells must be drilled along with inter-facility pipelines, dehydration facilities, and usually some compression to move the gas from the facility into the long-line pipeline system. In addition, "collector" wells are often employed to capture natural gas that escapes from the aquifer (NaturalGas.org 2013).

Aquifers are rarely used forms of natural gas storage and are commonly located in the mid-west. Aquifers are natural water reservoirs that can also be used for natural gas storage. They are porous, permeable rock formations found below the ground. An aquifer can be used for natural gas storage if the formation is covered with an impermeable cap rock (USEIA 2015 Nov 6). The geology of aquifers may be similar to depleted reservoirs, however their use in gas storage may require more base gas and greater monitoring of injection and withdrawals (USEIA 2015 Nov 6).

Aquifer storage can require additional infrastructure that is not commonly used in other types of underground storage facilities. Like other types of storage facilities, wells must be drilled along with inter-facility pipelines, dehydration facilities, and usually some compression to move the gas from the facility into the long-line pipeline system. Aquifers can also require unique dehydration equipment. In addition, "collector" wells are often employed to capture natural gas that escapes from the aquifer (NaturalGas.org 2013).

The primary disadvantage of the salt cavern, like aquifers, is the high capital cost of development. The leaching or mining process required to develop a salt cavern involves additional capital investments such as the development of a brine handling system (pipes, pumps, electrical), an injection well that is first fitted out for brine handling (mining) operations, and then converted to facilitate storage service. Several integrity tests must also be conducted in order to ensure cavern and well stability. Salt cavern construction is more expensive than depleted field conversions when measured on a capacity basis, but faster cycling ability reduces the per-unit cost injections and withdrawals (USEIA 2015 Nov 6). Salt caverns have very high withdrawal and injection rates and require lower levels of base gas, which is in comparison to reservoirs and aquifers.

Developing a salt cavern formation within a salt dome or salt bed involves dissolving and extracting salt from the deposit by pumping water into the formation, as shown in Figure 96. The process used for creating salt storage caverns is commonly known as "salt cavern leaching" or "solution mining." Under this type of process, salt is dissolved creating a concentrated brine solution, which, in turn, is pumped out through an injection well that is developed in many ways like a typical oil and gas well.

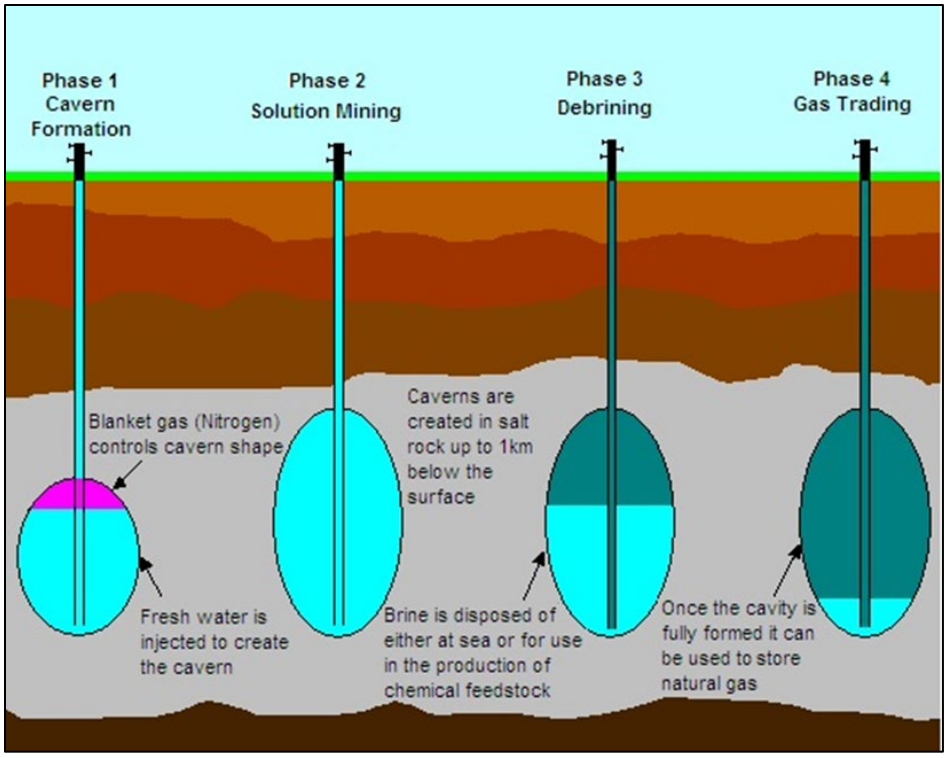

Figure 96. The solution mining process.

Source: (CNG Services 2019).

While salt cavern leaching can be expensive, it creates a highly valuable underground storage facility that has very high deliverability. An additional advantage is that salt caverns typically require a much lower level of base (or cushion) gas than reservoir or aquifer-based storage. However, salt caverns tend to be smaller than depleted gas reservoirs and aquifers resulting in smaller levels of overall storage capacity. For this reason, salt caverns are commonly not used for baseload storage requirements. Salt caverns do, however, have higher deliverability rates making them very attractive for cycling and/or peaking purposes, particularly during emergency periods or periods of unexpectedly high demand.

8.3 Geographic Distribution

8.3.1 Natural Gas Processing

Figure 97 outlines the distribution of the capacity and concentration of natural gas processing plants across the United States. As of 2017, there were 479 processing plants across the United States, with the most concentrated sources located along the GOM, in the Appalachian region, the west Texas/mid-continent region that includes the Permian basin, and the Rockies.

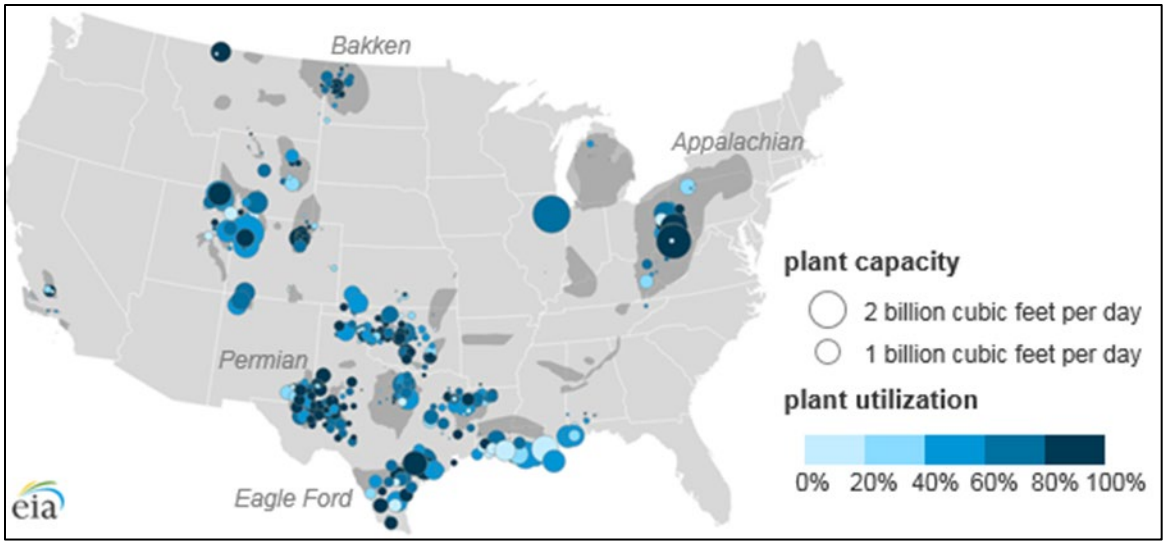

Figure 97. Concentration of natural gas processing plants across the United States.

Source: US Energy Information Administration (USEIA 2019 Feb 14).

Table 29 provides state-specific detail on natural gas processing facilities, capacity and throughput for the year 2017. Pennsylvania is the only state within the Atlantic Region that has natural gas processing plants with a total number of 10 most of which have been developed to process natural gas produced from the unconventional Marcellus play. The state has over 1,120 MMcf/d of natural gas processing capacity, an average capacity of 112 MMcf/d per processing unit, and a capacity utilization of about 69 percent.

Texas is the leading state in the US with the highest natural gas processing capacity of about 26,593 MMcf/d of capacity, an average capacity of about 151 MMcf/d and capacity utilization of 72 percent. Louisiana has the second highest natural gas processing capacity in the US at 9,344 MMcf /d. Louisiana and Texas accounts for about 45 percent of the natural gas processing capacity in the US.

Table 29. US natural gas processing plants and capacity

State	Number of Plants	Gas Capacity (MMcf/day)	Average Gas Capacity (MMcf/day)	Gas Through-put (MMcf/day)	Average Use Rate (%)
AL	13.0	1,364.0	104.9	542.0	39.7
AR	1.0	12.0	12.0	11.0	91.7
CA	10.0	434.0	43.4	285.0	65.7
CO	38.0	6,632.0	174.5	4,476.0	67.5
IL	2.0	2,102.0	1,051.0	1,634.0	77.7
KS	6.0	1,211.0	201.8	651.0	53.8
KY	2.0	365.0	182.5	150.0	41.1
LA	36.0	9,358.0	259.9	4,588.0	49.0
MI	9.0	101.0	11.2	40.0	39.6
MS	1.0	763.0	763.0	406.0	53.2
MT	5.0	655.0	131.0	629.0	96.0
ND	19.0	1,801.0	94.8	1,431.0	79.5
NM	24.0	3,917.0	163.2	2,402.0	61.3
OH	5.0	2,165.0	433.0	1,355.0	62.6
OK	70.0	7,834.0	111.9	5,764.0	73.6
PA	10.0	1,120.0	112.0	771.0	68.8
TN	1.0	25.0	25.0	12.0	48.0
TX	176.0	27,650.0	157.1	19,174.0	69.3
UT	8.0	1,623.0	202.9	734.0	45.2
WV	15.0	5,504.0	366.9	4,365.0	79.3
WY	28.0	6,116.0	218.4	3,870.0	63.3
U.S Total	**479.0**	**80,752.0**	**4,820.6**	**53,290.0**	**1,326.0**
Atlantic Region	**10.0**	**1,120.0**	**112**	**771.0**	**68.8**

Source: US Energy Information Administration (USEIA 2019 Feb 14).

Mount Belvieu, Texas is the most important and largest US natural gas processing center given its close proximity to major refining complexes, underground storage capacity and access to onshore and offshore transportation. The complex at Mount Belvieu processes NGLs from several supply basins including the Permian basin, Rocky Mountains, Eagle Ford Shale, Mid-Continent, and San Juan Basin.

8.3.2 Natural Gas Storage

Ohio, Michigan, Illinois, and the Gulf Coast areas have the highest concentrations (close to 50 percent) of underground storage capacity, resulting from conducive geology and location of depleted oil and gas reservoirs. Table 30 lists the breakdown of storage type by region. Depleted facilities account for 80 percent of active facilities and approximately 82 percent of working gas capacity in the US 40 percent of depleted reservoir capacity is found in the East; about 20 percent is in the South-Central region; and 25 percent is in the Midwest. In the Midwest, depleted reservoirs are supplemented by storage in groundwater aquifers. The Midwest accounts for 93 percent of aquifer storage capacity. Total of US salt cavern storage capacity is primarily located in the South-Central region, specifically in Texas and Louisiana.

Table 30. Underground natural storage by region, 2018

Region	Depleted Field		Aquifer		Salt Dome		Total
	Number of Facilities	Working Gas Capacity (Bcf)	Number of Facilities	Working Gas Capacity (Bcf)	Number of Facilities	Working Gas Capacity (Bcf)	Working Gas Capacity
Pacific	21	389,171	0	24,600	0	0	413,771
Mountain	26	457,488	3	1,828	0	0	459,316
South Central	63	1,078,455	1	31	34	480,947	1,559,433
East	129	1,094,710	2	1,004	2	5,450	1,101,164
Mid-West	81	846,563	40	283,214	2	2,160	1,131,937
US TOTAL	**320**	**3,866,387**	**46**	**310,677**	**38**	**488,557**	**4,665,621**

Source: US Energy Information Administration (USEIA 2020a May 30).

The Atlantic region accounts for about 19 percent of the number of natural gas storage sites and about 12.4 percent of working capacity in the US However, like natural gas processing, most of these sites are located in the western part of Pennsylvania. In fact, of the states in the Atlantic region that have storage facilities, Pennsylvania accounts for about 63 percent of storage facilities and 74 percent of working gas capacity. All but one of the Pennsylvania storage sites are depleted fields. Maryland and Virginia have one depleted field, each with 18,300 Bcf and 1,400 Bcf of working gas capacity, respectively. Virginia also has one salt cavern, totaling 5,400 Bcf of working gas capacity.

8.4 Scope of Economic Contribution to Regional Economy

8.4.1 Natural Gas Processing

According to the North America Industry Classification System (NAICS), Natural gas processing is included in the category for oil and gas extraction activities (NAICS Code 2111). This classification code also includes exploration for crude petroleum and natural gas; drilling, completing and equipping wells; operation of separators, emulsion breakers, desilting equipment, and field gathering lines for crude petroleum and natural gas; and all other activities in the preparation of oil and gas up to the point of shipment (US Census Bureau Classification Development Branch 2020 Jul 8).

Table 31 shows the contribution of each Atlantic State's oil and gas extraction industry to its own state-level gross domestic product (GDP) and the U.S oil and gas extraction sector. To date, this sector, even with regional unconventional development in Pennsylvania, is small relative to US totals. Pennsylvania's oil and gas GDP makes the largest contribution to its state's overall economy at 1.5 percent. The contributions each Atlantic state makes to total US oil and gas extraction GDP is also small, totaling just 6.2 percent of the US total for oil and gas extraction.

Table 31. Regional and national GDP contribution, and gas extraction sector, 2017

State	Oil and Gas Extraction GDP (Millions in Current $)	Total State GDP (Millions in Current $)	Oil and Gas Extraction GDP as a Percent of Total State GDP (%)	Oil and Gas Extraction GDP as a Percent of Total US Oil and Gas Extraction GDP (%)
CT	0	268,311	0.0	0.0
DC	0	134,043	0.0	0.0
DE	0	70,775	0.0	0.0
FL	43	985,665	0.0	0.0
GA	0	566,474	0.0	0.0
MA	1	540,786	0.0	0.0
MD	1	394,259	0.0	0.0
ME	0	62,040	0.0	0.0
NC	4	538,402	0.0	0.0
NH	0	80,900	0.0	0.0
NJ	21	595,325	0.0	0.0
NY	87	1,604,134	0.0	0.0
PA	11,353	744,290	1.5	6.0
RI	0	58,506	0.0	0.0
SC	1	223,111	0.0	0.0
VA	95	509,373	0.0	0.1
Total Region:	**11,605**	**7,376,392**	**0.2**	**6.2**
Total US	**187,921**	**19,519,424**	**1.0**	**100.0**

Source: US Bureau of Economic Analysis (BEA c2020).

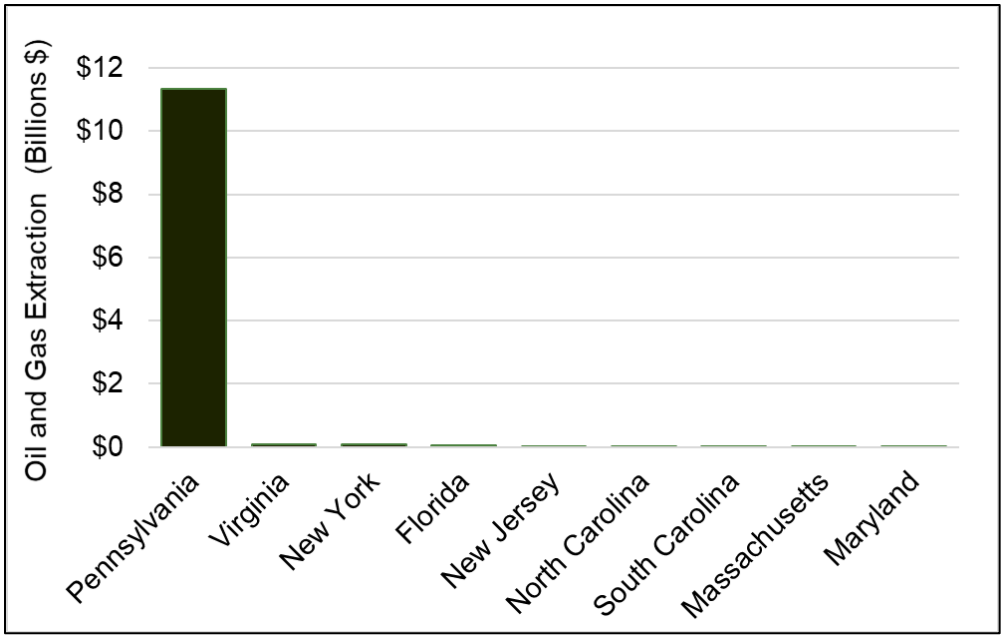

Figure 98. Atlantic region oil and gas extraction GDP shares, 2017.

Source: US Bureau of Economic Analysis (BEA c2020).

Figure 98 compares the oil and gas extraction GDP across the individual Atlantic region states, for 2017. Pennsylvania reports the highest 2017 contribution of oil and gas extraction to GDP relative to any other state in the region at $1.9 billion. This is followed by Virginia and New York, contributing $95 million and $87 million, respectively.

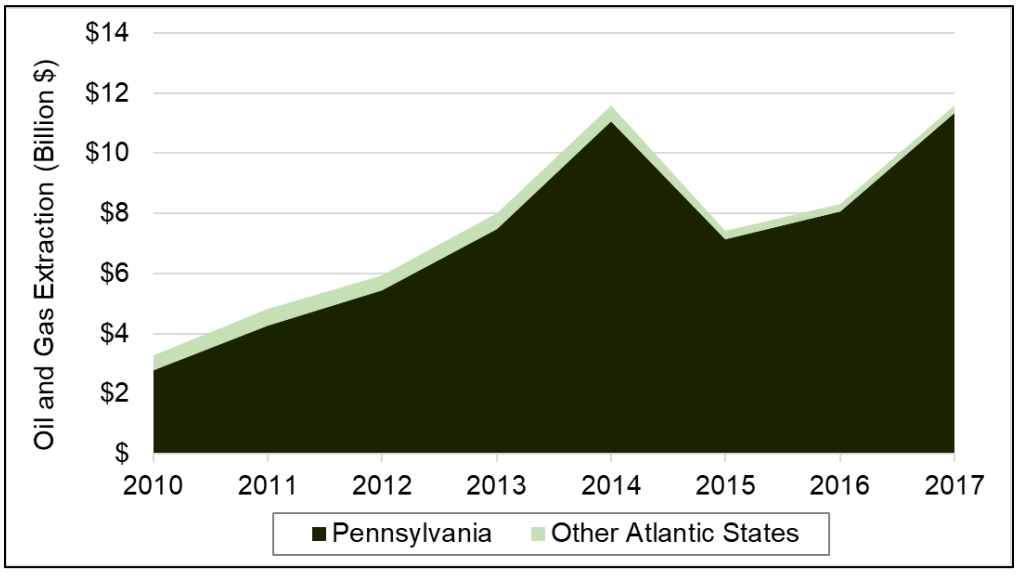

Figure 99. Trends in oil and gas extraction GDP, 2010–2017.

Source: US Bureau of Economic Analysis (BEA c2020).

Figure 99 compares the trends in oil and gas extraction GDP for the highest contributing states in the Atlantic Region from the year 2010 to 2017. Oil and gas extraction GDP in Pennsylvania overshadows any value reported by the region states. Pennsylvania has experienced a steady growth in the oil and gas extraction sector from 2010 until contribution to the state's GDP fell in 2015 Pennsylvania's natural gas processing plants experienced 2 disruptions from 2005 to 2014. This impacted average production of natural gas processing plants by 335 million MMcfd. After 2015, the contribution of the sector to GDP has increased steadily. This pattern is the same for other states like Virginia, New York, and Florida.

Table 32 lists gas and oil extraction employment statistics for the Atlantic region in 2018. Oil and gas extraction activities are an extremely small portion of employment for the Atlantic region, only about .01 percent. The region accounts for about 3.5 percent of total oil and gas extraction employment in the US, with the largest number of people employed in Pennsylvania. This is consistent with the previous sections in this chapter, because Pennsylvania has the most activity in this sector (in the Atlantic region).

Table 32. Regional and national employment contribution, oil and gas extraction sector, 2018

State	Number of Oil and Gas Extraction Jobs (2018)	Total State Jobs	Oil and Gas Extraction Jobs as a Percent of Total State Employment (%)	Oil and Gas Extraction Jobs as a Percent of Total US Oil and Gas Extraction Employment (%)
FL	87	7,635,037	0.00	0.06
MD	5	2,188,298	0.00	0.00
NY	145	8,017,398	0.00	0.10
PA	4,496	5,193,979	0.09	3.16
VA	228	3,188,362	0.01	0.16
Total Region:	**4,961**	**45,966,045**	**0.01**	**3.48**
Total US	**142,363**	**124,551,838**	**0.11**	**100.00**

Source: US Bureau of Labor Statistics (BLS c2020).

Pennsylvania is the largest regional employer in this sector, comprising 91 percent of the region's 2011 natural gas extraction employment. Virginia and New York account for four percent and three percent of oil and gas extraction employment in the region, respectively, and the two remaining states with reliable data account for less than three percent each.

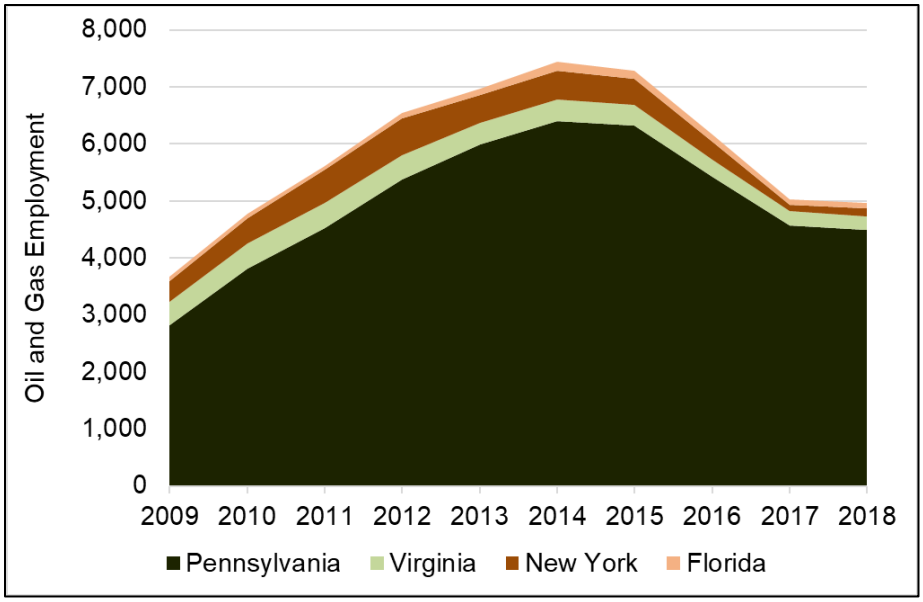

Figure 100. Trends in Atlantic region oil and gas extraction employment, 2009–2018.

Source: US Bureau of Labor Statistics (BLS c2020).

Figure 100 shows the empirical trends in oil and gas extraction employment in the Atlantic region states since 2008. The increase in employment in Pennsylvania after 2009 is attributable to the development of the Marcellus Shale region. Employment in the sector grew by 101.5 percent from 2008. Pennsylvania's growth in employment in the oil and gas sector is consistent with the gross withdrawals from shale gas wells. In 2012, Pennsylvania became the sixth largest state by oil and natural gas employment. After 2012, the number of employees in the sector decreased by 16. 5 percent in 2018.

The rest of the region also experienced a significant percentage increase in oil and gas extraction employment between 2008 and 2012, with Florida being the only state to experience a decrease. Between 2012 and 2018, the region has experienced a decrease in the total number of people employed in the oil and natural gas extraction sector.

Table 33. Regional and national wages contribution, oil and gas extraction sector, 2018

State	Oil and Gas Extraction Wages (Thousands in 2018) ($)	Total State Wages (Thousands in 2018) ($)	Oil and Gas Extraction Wages as a percent of Total State Wages (%)	Oil and Gas Extraction Wages as a Percent of Total U.S Oil and Gas Extraction Wages (%)
FL	6,375	377,741,168	0.00	0.03
MD	366	128,523,234	0.00	0.00
NY	12,682	589,087,033	0.00	0.05
PA	551,653	287,198,234	0.19	2.28
VA	22,760	184,434,708	0.01	0.09
Total Region:	**593,836**	**2,741,857,128**	**0.02**	**2.45**
Total US	**24,217,291**	**7,124,159,437**	**0.34**	**100.00**

Source: US Bureau of Labor Statistics (BLS c2020).

Table 33 provides 2018 wage contribution data for the Atlantic region and the United States and underscores the very small current contribution the Atlantic region plays in the US oil and gas industry. Pennsylvania has the highest concentration of oil and gas wages relative to total state wages of any other state in the region. This, in large part, is due to Marcellus development. Wage contributions of all Atlantic states are small compared to the total state wages and the total US oil and gas sector.

Regional trends are charted in Figure 101. These trends are consistent with several of the others discussed above: namely, that Pennsylvania activity dominates the region and its relatively small current industry contribution.

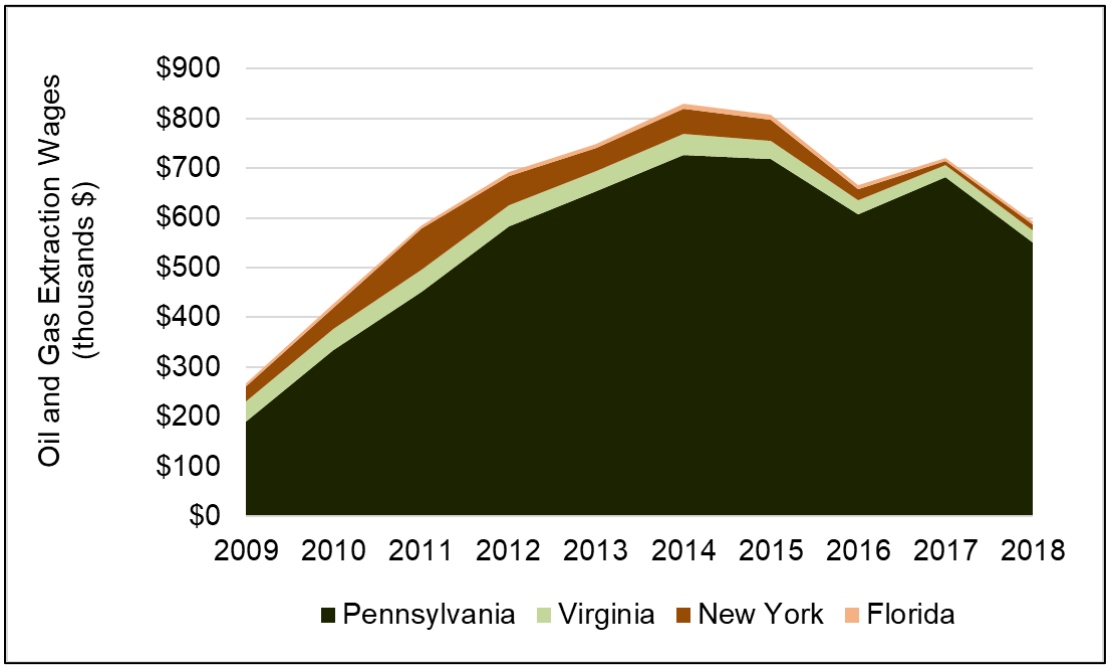

Figure 101. Trends in Atlantic region oil and gas extraction wages, 2009–2018.

Source: US Bureau of Labor Statistics (BLS c2020).

Regional annual wages are provided in Table 34 and shows that Pennsylvania pays the highest annual wage of $122,712. Virginia is a distant second, posting average annual wages of $99,970, followed by New York at $87,314. The table shows that oil and gas average annual wages are considerably higher than the statewide average wage in most Atlantic states. This indicates that, where a state has some oil and gas activity, those workers tend to earn considerably more than the statewide average. Oil and gas wages in the Atlantic region, however, tend to be considerably lower than national average oil and gas annual wage level (close to half the nation average for oil and gas workers). The exception is for Pennsylvania that pays three- quarter the amount paid to most oil and gas workers on an average annual average wage rate basis.

Table 34. Regional and national Average Annual Pay contribution, Oil and Gas Extraction sector, 2018

State	Average Annual Pay (Oil & Gas Extraction) ($)	State Average Annual Pay ($)	Oil & Gas Extraction Avg. Annual Pay as a percent of Total State Avg. Annual Pay (%)	Oil & Gas Extraction Avg. Annual Pay as a Percent of Total US Oil & Gas Extraction Avg Annual Pay (%)
FL	73,274	49,475	1.48	43.07
MD	79,902	58,732	136.05	46.97
NY	87,314	73,476	118.83	51.33
PA	122,712	55,294	221.93	72.14
VA	99,970	57,846	172.82	58.77
Total Region	**28,948**	**59,376**	**48.75**	**17.02**
Total US	**170,109**	**57,198**	**297.40**	**100.00**

Source: US Bureau of Labor Statistics (BLS c2020).

The trend in average annual wage growth over time, as shown in Figure 102 is quite different among Atlantic states. Data from 2008 to 2018 is only available for Pennsylvania, New York, Florida, and Virginia. Each state presents a unique pattern of the average annual wage growth for the oil and natural gas sector. The average annual wages of New York and Florida are quite volatile, likely resulting from the very small size of the employment force in this sector. Pennsylvania shows rising trends in annual wages, likely due to the increase in upstream productivity from the Marcellus shale.

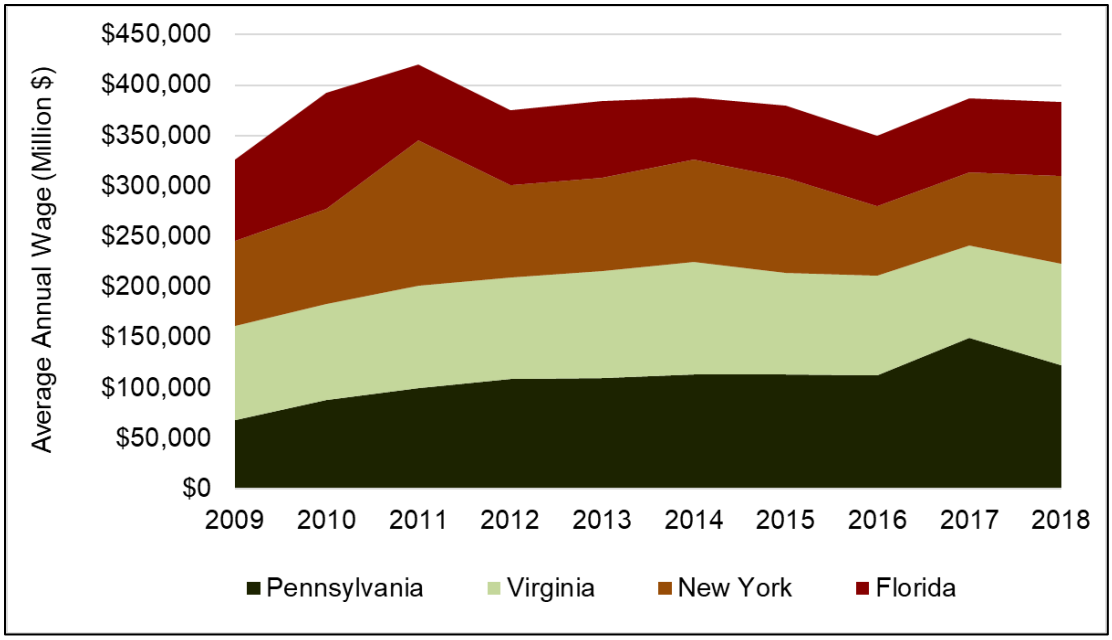

Figure 102. Trends in the Atlantic Region oil and natural gas extraction Average Annual wages shares, 2009–2018.

Source: US Bureau of Labor Statistics (BLS c2020).

8.4.2 Natural Gas Storage

Neither natural gas processing nor natural gas storage have a unique NACIS code. Natural gas storage is included along with a number of related services in the natural gas transportation industry: booster pumping station, natural gas transportation, natural gas pipeline operation and transportation, and natural gas transmission (processing plants to local distribution systems). The US Census explains the reason for this combined coding as, "the storage is usually done by the pipeline establishment and because a pipeline is inherently a network in which all the nodes are interdependent."(US Bureau of Labor Statistics 2020 Jul 31). The GDP, employment and wage statistics reported in the next two sections should be interpreted with this caveat in mind.

Table 35. Regional and national GDP contributions, pipeline transportation sector, 2017

State	Pipeline Transportation GDP (Millions in Current $)	Total State GDP (Millions in Current $)	Pipeline Transportation GDP as a Percent of Total State GDP (%)	Pipeline Transportation GDP as a Percent of Total U.S Pipeline Transportation GDP (%)
CT	327	268,311	0.1	0.8
DC	3	134,043	0.0	0.0
DE	3	70,775	0.0	0.0
FL	103	985,665	0.0	0.3
GA	350	566,474	0.1	0.9
MA	56	540,786	0.0	0.1

State	Pipeline Transportation GDP (Millions in Current $)	Total State GDP (Millions in Current $)	Pipeline Transportation GDP as a Percent of Total State GDP (%)	Pipeline Transportation GDP as a Percent of Total U.S Pipeline Transportation GDP (%)
MD	33	394,259	0.0	0.1
ME	28	62,040	0.0	0.1
NC	87	538,402	0.0	0.2
NH	2	80,900	0.0	0.0
NJ	171	595,325	0.0	0.4
NY	224	1,604,134	0.0	0.5
PA	4,737	744,290	0.6	11.6
RI	6	58,506	0.0	0.0
SC	22	223,111	0.0	0.1
VA	154	509,373	0.0	0.4
Total Region:	**6,304**	**7,376,392**	**0.1**	**15.4**
Total US	**40,976**	**$19,519,424**	**0.2**	**100.0**

Source: US Bureau of Economic Analysis (BEA c2020).

Table 35 shows the contribution of each Atlantic State's pipeline transport industry to its own state-level gross domestic product (GDP) and the U.S pipeline transportation sector. This analysis highlights the sector's impact on the economy of each Atlantic state and the U.S pipeline transportation sector. The pipeline transportations sector makes a very small contribution to the Atlantic region's total GDP. The pipeline transportation GDP of Pennsylvania makes the largest contribution to its state's overall economy at 0.6 percent. The contributions each Atlantic state makes to total US pipeline transportation GDP is also small, totaling 15.4 percent of the pipeline transportation GDP of the entire country.

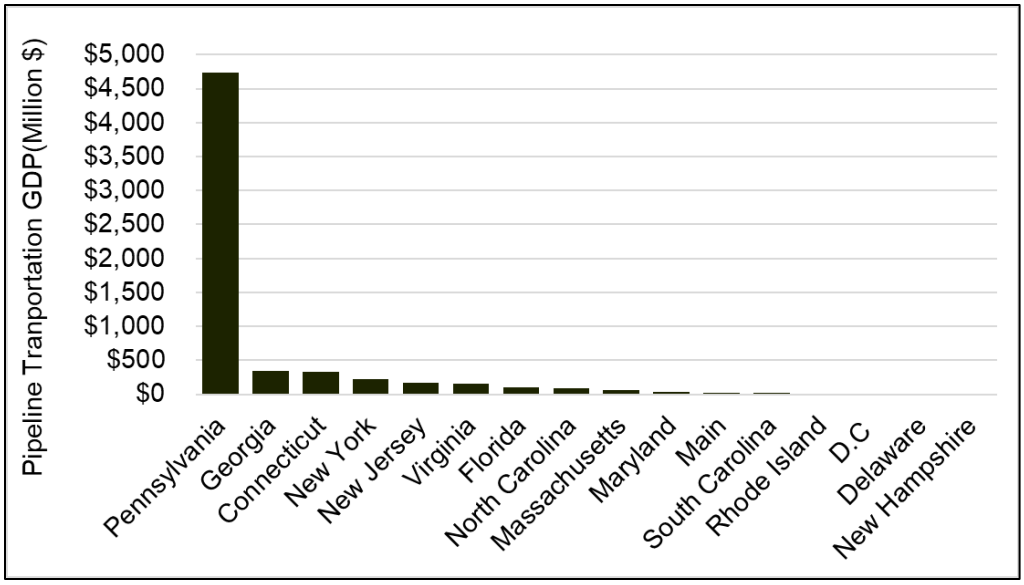

Figure 103. Atlantic region Pipeline Transportation GDP shares, 2017.

Source: US Bureau of Economic Analysis (BEA c2020).

Figure 103 compares the GDP contribution of pipeline transportation across the individual Atlantic region states, for 2017. Pennsylvania reports the highest 2017 contribution of pipeline transportation to GDP relative to any other state in the region at $4.7 billion. This is followed by Georgia and Connecticut, contributing $350 million and $327 million, respectively.

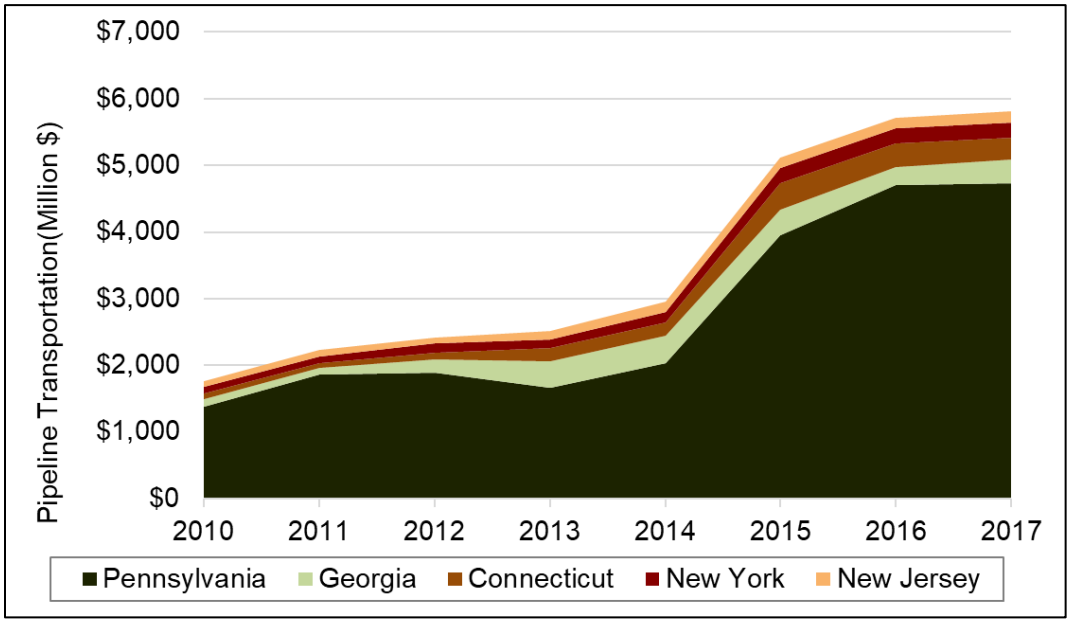

Figure 104. Pipeline Transportation GDP Trend, 2010–2017.

Source: US Bureau of Economic Analysis (BEA c2020).

Figure 104 compares the trends of pipeline transportation GDP for the highest contributing states in the Atlantic Region from the year 2010 to 2017. Again, Pennsylvania's pipeline transportation contribution of GDP has been the highest over the years. The GDP of pipeline transportation in the region has increased by more than a 100 percent between 2010 and 2017.

In the employment sector, contributions of each state's total pipeline transportation to the employment sector are relatively small in comparison to the total employment in each of the states in the Atlantic region. Table 36 shows that, none of the states in the Atlantic region have pipeline transportation employment totals that are over one percent of the overall statewide employment totals. Although Pennsylvania has the majority of pipeline transportation employment in the region, it makes up only 0.04 percent of the total employment in the states.

Table 36. Regional and national employment contributions, Pipeline Transportation sector, 2018

State	Number of Pipeline Transportation Jobs (2018)	Total State Jobs	Pipeline Transportation Jobs as a percent of Total State Employment (%)	Pipeline Transportation jobs as a Percent of Total US Pipeline Transportation Employment (%)
FL	193	7,635,037	0.00	0.66
NY	276	8,017,398	0.00	0.94
PA	1,857	5,193,979	0.04	6.30
VA	359	3,188,362	0.01	1.22
Total Region	**2,685**	**45,966,045**	**0.01**	**9.11**
Total US	**29,463**	**124,551,838**	**0.02**	**100.00**

Source: US Bureau of Labor Statistics (BLS. c2020)

As shown below in Figure 105, pipeline transportation in the Atlantic region has not been steady over the years. After 2013, the region has experienced an increase in number of jobs in the pipeline transportation sector, with a high of 2,492 number of jobs in 2018. Since 2009, number of jobs in the pipeline transportation sector has increased by 29 percent, with the largest increase occurring in 2014. In 2014, regional sector employment increased by 12 percent.

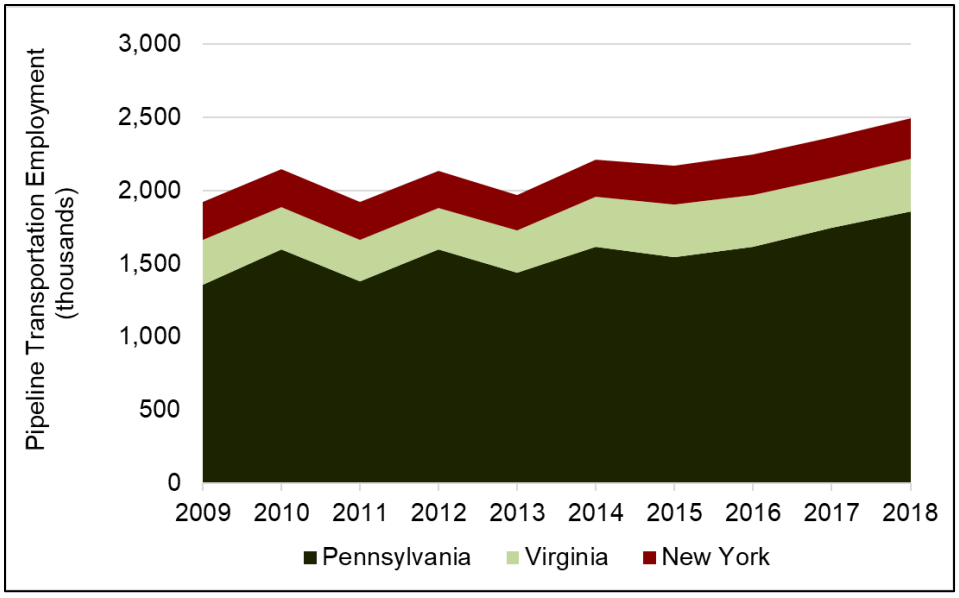

Figure 105. Trends in Atlantic region pipeline transportation employment, 2009–2018.

Source: US Bureau of Labor Statistics (BLS. c2020)

Regional wage contributions, provided in Table 37, follow trends like employment levels discussed earlier with the regional totals dominated by the Pennsylvania which has the largest share of transportation pipeline miles. The Atlantic region accounts for about seven percent of pipeline transportation wages in the US and 0.01 percent of the total wages in the region. Trends in pipeline transportation wages are presented in Figure 106.

Table 37. Regional and national wage contributions, pipeline transportation sector, 2018

State	Pipeline Transportation Wages (Thousands $)	Total State Wages (Thousands $)	Pipeline Transportation Wages as a percent of Total State Wages (%)	Pipeline Transportation Wages as a Percent of Total US Pipeline Transportation Wages (%)
FL	20,217	377,741,168	0.00	0.52
NY	26,452	589,087,033	0.00	0.69
PA	178,858	287,198,234	0.06	4.64
VA	40,437	184,434,708	0.02	1.05
Total Region	**265,964**	**2,741,857,128**	**0.01**	**6.90**
Total US	**3,857,272**	**7,124,159,437**	**0.05**	**100.00**

Source: US Bureau of Labor Statistics (BLS. c2020)

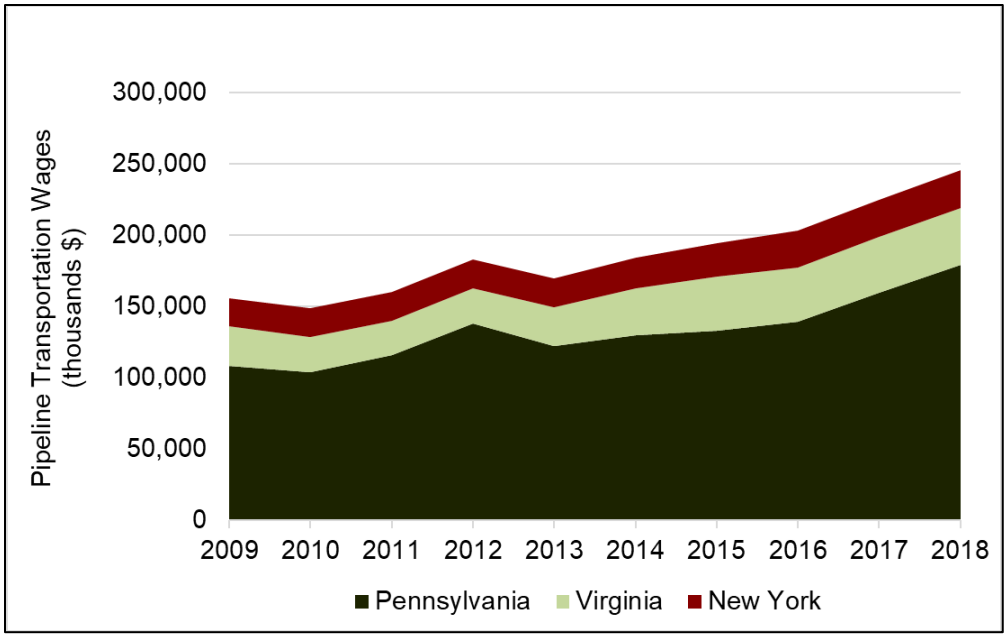

Figure 106. Trends in Atlantic region pipeline transportation wages, 2009–2018.

Source: US Bureau of Labor Statistics (BLS. c2020).

Table 38 provides a comparison of the average annual wages paid to employees in the pipeline transportation sectors of the Atlantic impact area. The annual wages for pipeline transportation sector employees in each state in the region are considerably higher, in fact orders of magnitude higher than the average in-state wage. This is not surprising and is consistent with industry trends in other parts of the country. Virginia reports the highest average annual wage in the region at $112,585 per year for a pipeline transportation company employee. In Pennsylvania, the average annual wage for pipeline transportation is $96,307 which is almost double (174 percent) the average annual wage for Pennsylvania in general. In Florida, average annual wage for pipeline transportation is over 200 percent higher than the state average. However, average annual pipeline transportation wages in the region are below the US pipeline transportation average of roughly $131,000 per year.

Table 38. Regional and national average annual pay contributions, Pipeline Transportation sector, 2018.

State	Pipeline Transportation Average Annual Pay ($)	State Average Annual Pay ($)	Pipeline Transportation Avg. Annual Pay as a percent of Total State Avg. Annual Pay (%)	Pipeline Transportation Avg. Annual Pay as a Percent of Total U.S Pipeline Transportation Avg. Annual Pay (%)
FL	104,569	49,475	211.36	79.87
NY	95,695	73,476	130.24	73.09
PA	96,307	55,294	174.17	73.56
VA	112,585	57,846	194.63	85.99
Total Region	**102,289**	**59,376**	**172.27**	**78.13**
Total US	**130,921**	**57,198**	**228.89**	**100.00**

Source: US Bureau of Labor Statistics (BLS. c2020).

Trends in regional average annual wages for regional pipeline transportation employees are provided in Figure 107. Over the past 10 years, average annual wage in the Atlantic region have been increasing at an average rate of 6.7 percent.

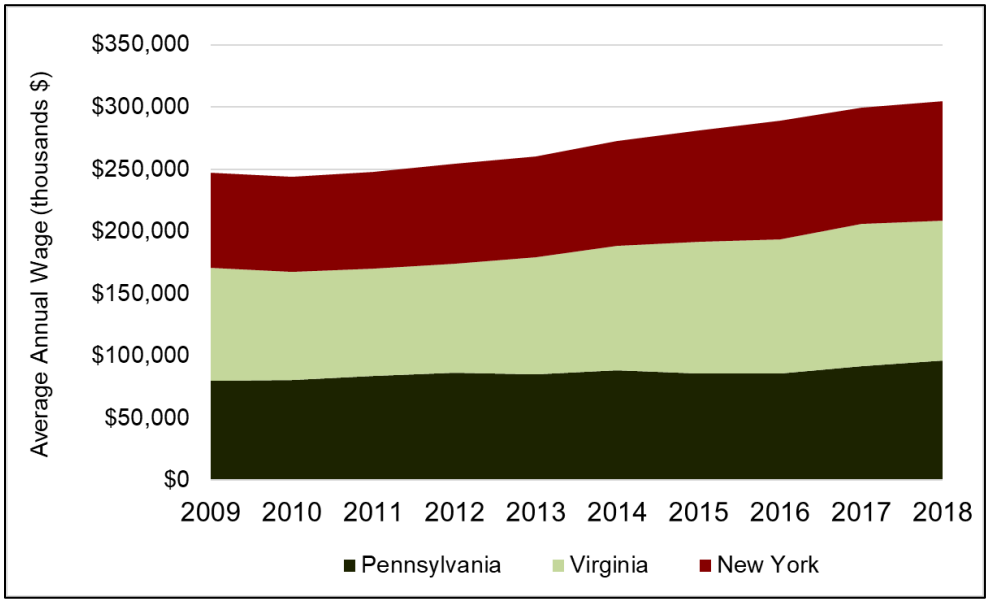

Figure 107. Trends in Atlantic region pipeline transportation average annual pay, 2009–2018.

Source: US Bureau of Labor Statistics (BLS. c2020).

8.5 Current Trends

8.5.1 Natural Gas Processing

The EIA does not collect continuous information on natural gas processing capacity on a consistent basis. It has, over recent years (starting in 2014), collected capacity information every two to three years. Recent natural gas processing facility and capacity information was compiled, and is available for 2012, 2014, and 2017, across these three separate data points, spanning a five-year period, and are provided in Figure 108.

Recent trends in the number and size of natural gas processing facilities over the past several years has become more concentrated. The number of processing plants by the year 2012 was 525. By 2014 this number increased to 551 and decreased to 479 by the year 2017. However, the processing capacity has seen an increase over the five-year period while, at the same time, the number of processing plants decreased indicating an increase in the average processing capacity per facility.

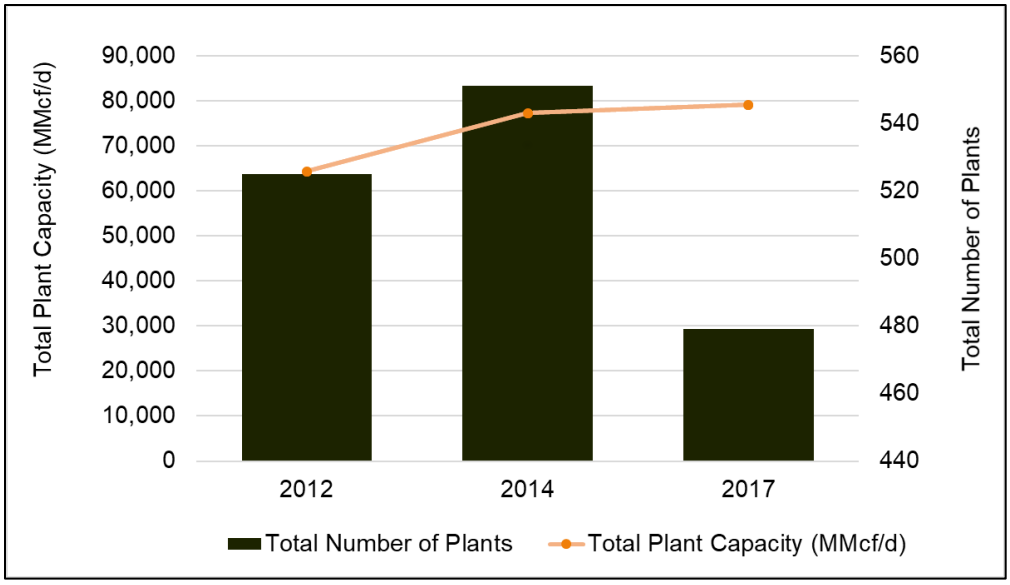

Figure 108. US natural gas processing plants and capacity, 2012, 2014, and 2017.

Source: US Energy Information Administration (USEIA 2019 Jan).

Figure 109 shows the change in natural gas processing capacity by state, between 2014 and 2017. The largest decrease in capacity comes from Louisiana and Wyoming and, in the case of Louisiana, is very likely a reduction in operable capacity dedicated to processing offshore natural gas production activity. Texas, West Virginia, and North Dakota showed the largest increase in natural gas processing capacity and throughput between 2014 and 2017. The increase in Texas' gas processing capacity is due to considerable amount of associated natural gas coming from both the Permian basin and Eagle Ford shale plays. In West Virginia, increases in the utilization of existing plants led to an increase in throughput from 2014 to 2017 that exceeded its increase in processing capacity.

There was an increase in natural gas processing capacity in Pennsylvania from 2014 to 2017, although the number of processing plants decreased by one within that period. A significant portion of Pennsylvania is underlain by the Marcellus Shale, which is one of the world's largest natural gas fields, containing over 500 trillion cubic feet of natural gas. In 2013, Pennsylvania became the second largest natural gas-producing state and has remained in that position, with Texas being the leading state. In 2018, natural gas production in Pennsylvania reached 6.2 Tcf.

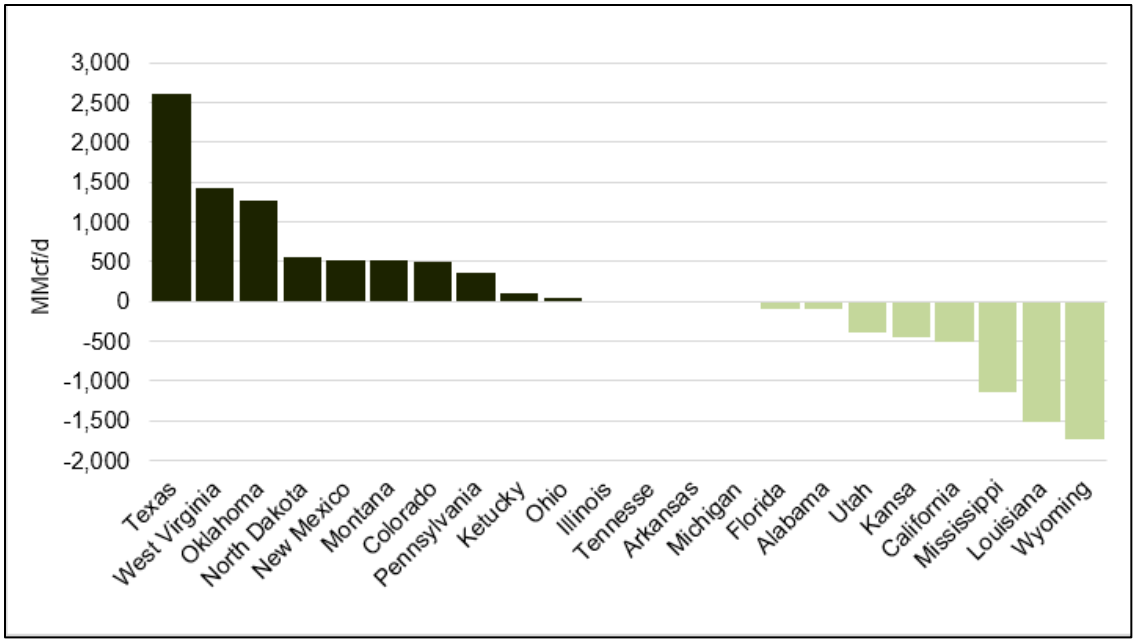

Figure 109. Change in US natural gas processing capacity, 2014–2017.

Source: US Energy Information Administration (USEIA 2019 Jan).

Figure 110 shows the recent trends in natural gas processed volumes in the Atlantic Region versus other domestic natural gas producing regions. This chart underscores many of the same trends seen earlier in the analysis of recent natural gas processing capacities. Due to the low number of processing plants in this region, volume of processed natural gas is very low, compared to the volume of processed natural gas in other regions of the country.

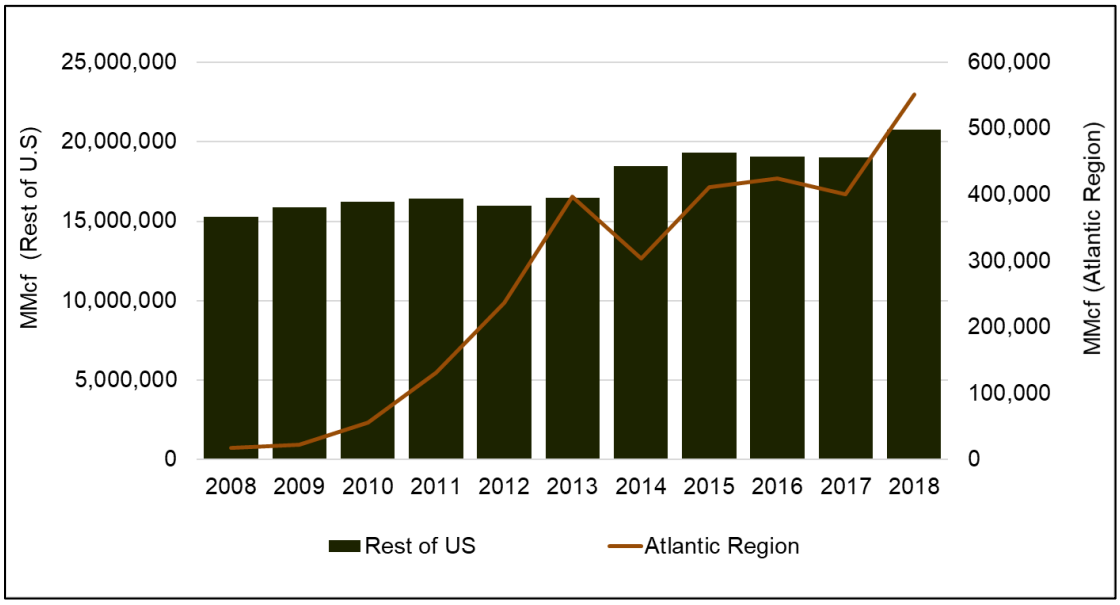

Figure 110. Natural gas volume processed, Atlantic Region and US.

Source: US Energy Information Administration (USEIA 2019 Jan).

Figure 111 provides a similar illustration of natural gas processing growth in specific areas over the past decade across a range of natural gas producing states. Texas, which has a historically large level of natural gas processing has seen volumes increase by 64 percent, in large part due to increases in the Permian and Eagle Ford basins. As a result of the discovery of the Marcellus shale, Pennsylvania saw more than a 2,800 percent increase in natural gas processing volumes. States with large volumes of processed natural gas like Louisiana and Arizona saw a decrease by 71 percent and 2.7 percent respectively over the ten- year period.

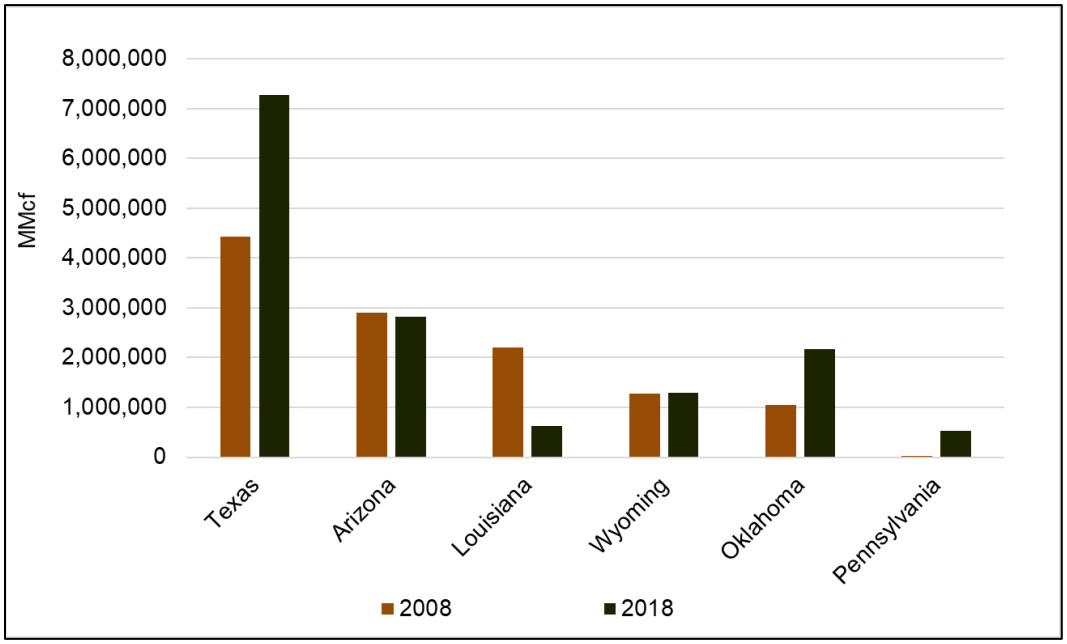

Figure 111. Natural gas volume processed by state, 2008 compared to 2018.

Source: US Energy Information Administration (USEIA 2019 Jan).

8.5.1 Natural Gas Storage

Figure 112 shows the trends in underground natural gas storage working gas capacity development over the past decade. Underground natural gas storage capacity has consistently grown from a total level of around 4.2 trillion cubic feet (Tcf) in 2008, to about 4.8 Tcf in 2017 and fell slightly in 2018. Most of this new storage capacity is salt cavern based and designed to keep pace with the increasing volumes and cyclical uses for new unconventional natural gas being produced from shale formations.

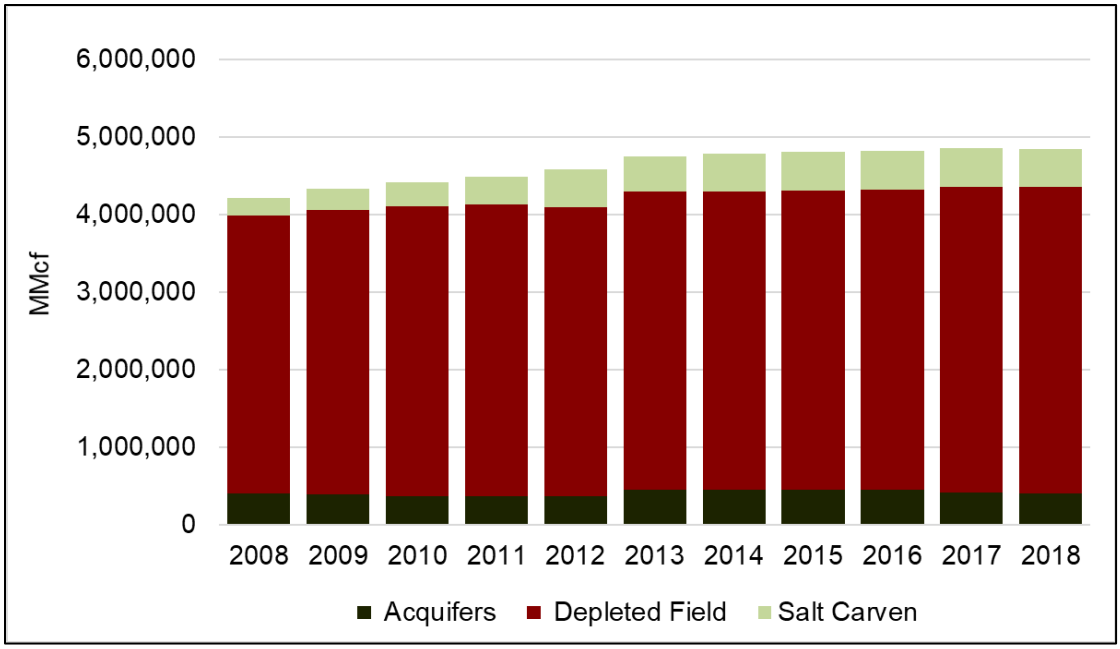

Figure 112. US Natural gas storage working gas capacity, 2008–2018.

Source: US Energy Information Administration (USEIA 2020a May 30).

Table 39 shows a comparison of the underground storage capacity by state. Michigan has the greatest underground storage capacity, making up about 14.7 percent of the total underground storage capacity in the US. This is followed by two GOM states, Texas and Louisiana, making up 11.7 percent and 9.6 percent of the total underground storage capacity in the US Also notable are the collectively significant underground natural gas storage capacities of Pennsylvania (fourth), and California. The Atlantic region makes up 12.4 percent of the total underground natural gas storage capacity.

Table 39. US natural gas storage working gas capacity by state, 2018

State	Underground Storage Capacity (Bcf)	Storage Capacity as a Percentage of Total US Storage Capacity (%)
MI	683,820	14.66
TX	545,640	11.69
LA	449,172	9.63
PA	427,601	9.16
CA	373,236	8.00
IL	303,613	6.51
WV	268,626	5.76
OH	253,750	5.44
MS	204,013	4.37
MT	197,477	4.23
OK	195,582	4.19
NY	127,487	2.73
KS	122,982	2.64
KY	107,596	2.31
WY	74,605	1.60
CO	72,554	1.56
NM	59,738	1.28
UT	54,942	1.18
AL	33,150	0.71
IN	33,108	0.71
WA	24,600	0.53
MD	18,300	0.39
OR	15,935	0.34
AR	8,894	0.19
VA	5,400	0.12
MN	2,000	0.04
TN	1,800	0.04
US Total	**4,665,621**	**100.00**

Source: US Energy Information Administration (USEIA 2020a May 30).

Only four states in the Atlantic region –Pennsylvania, Virginia, New York, and Maryland–have natural gas storage facilities. Figure 113 provides additional, subregion trends on underground natural gas storage trends along the Atlantic. The chart shows storage capacity development in the Atlantic states has not seen any significant change over the years. From 2008 through 2018, storage capacity in Pennsylvania increased by two percent.

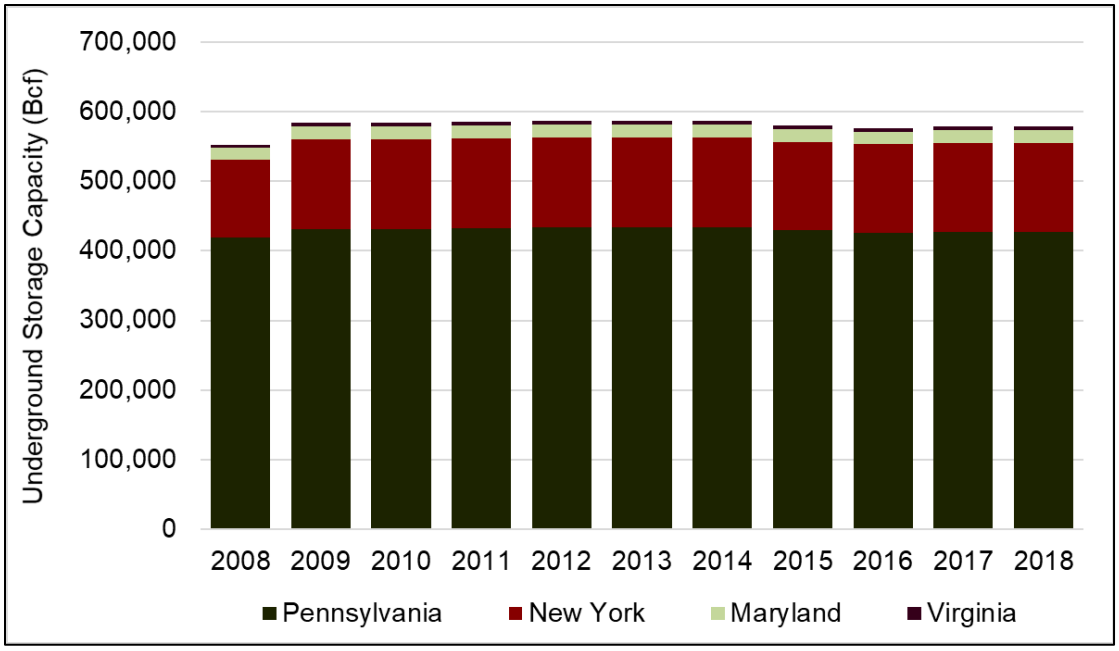

Figure 113. Atlantic states natural gas storage working gas capacity trend, 2008–2018.

Source: US Energy Information Administration (USEIA 2020a May 30).

8.5.3 Market Trends

Unconventional natural gas production has had considerable impacts on natural gas processing and NGL supplies throughout the US and increasingly, around the globe. NGL market trends over the past decade have been driven by the processed unconventional natural gas production coming from basins that tend to produce "richer" or "wetter" natural gas. On the NGL supply side, two primary forms of natural gas production are impacting natural gas processing volumes and NGL supplies: (1) non-associated natural gas production and (2) associated natural gas production.

Non-associated natural gas production comes from wells that are primarily drilled to produce natural gas along, not a combination of crude oil and natural gas. The early unconventional wells drilled in the Barnett, Haynesville and Fayetteville shale plays, and ultimately the Marcellus shale, are primarily designed for non-associated natural gas production. Over time, as the oil and gas industry discovered that unconventional technologies could be extended to other types of unconventional shales that were more "liquids" rich such as the Eagle Ford, Bakken and the Permian.

Over the last decade, an increasing amount of natural gas that has been produced in unconventional basins around the US comes from associated natural gas production (rather than non-associated natural gas wells) and this natural gas production tends to be "richer" in nature relative to historic natural gas production averages. The increasing emphasis on associated gas production has positively impacted natural gas processing and the development of abundant NGL supplies.

NGL supplies come from three sources: (1) natural gas processing volumes (also referred to as "gas plant volumes"); (2) refinery production of liquefied petroleum gases ("LPGs" which are the same as NGLs and include such liquids as propane, butane, ethane, to name a few) and (3) imports from other countries. Over the past several years, NGL supplies have grown considerably, particularly those originating from the gas plant volumes identified earlier.

Figure 114, for instance, compares NGL supply trends focusing only on those supplies originating from natural gas processing facilities (gas plant) and those from refineries (LPGs): imports, which have been relatively small, and decreasing over time, are excluded. Over the past years, NGL supplies originating from processed natural gas (gas plants) have grown rapidly, particularly relative to refinery supplies. NGL supply growth originating from gas processing plants has grown at an average annual rate of 10 percent per year since 2010.

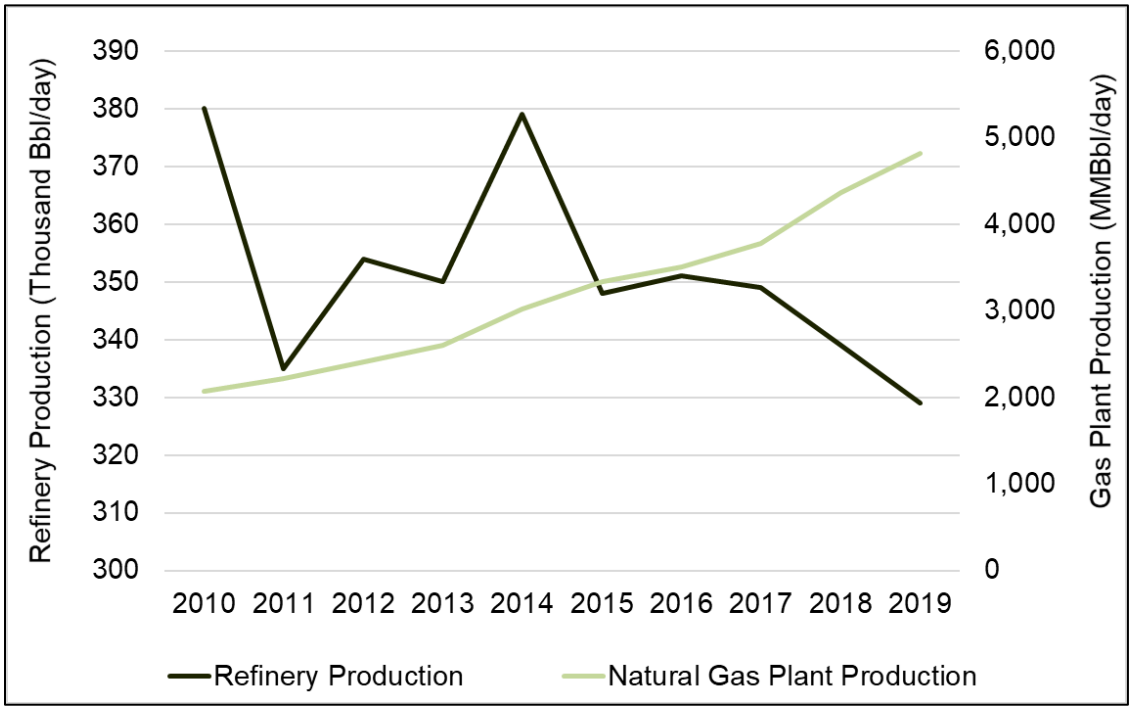

Figure 114. NGL production trend, 2010–2019.

Source: US Energy Information Administration (USEIA 2020b Jun 30).

NGL demand has also expanded to meet the growing low-cost and abundant supply volumes which, as established earlier, are derived in large part from processed unconventional natural gas production. A good portion of the new NGL demand comes from and will continue to come from US chemical industry manufacturing, a large portion of which is located along the GOM. The chemical industry uses these NGLs (and LPGs) as feedstocks for production purposes. The recent unconventional revolution, that has help facilitate the production of local cost commodity natural gas (methane) and NGLs is largely responsible for the industrial "renaissance" that has arisen over the past decade.

The American Chemistry Council ("ACC"), for instance, estimates that as much as $200 billion in new chemical industry capital investment has arisen in large part due to new, ubiquitous, and low-cost supplies of natural gas and NGLs (ACC, 2018). In March of 2017, the American Chemistry Council reported a $179 billion capital investment of 294 chemical manufacturing projects. Figure 115 shows the capital investment trends included in the 2018 study sponsored by the ACC. On average, between 2011 and 2018, the ACC estimates as much as $25 million per year, on average, has been invested in local economies in the upper Midwest, Appalachia, and, primarily along the GOM.

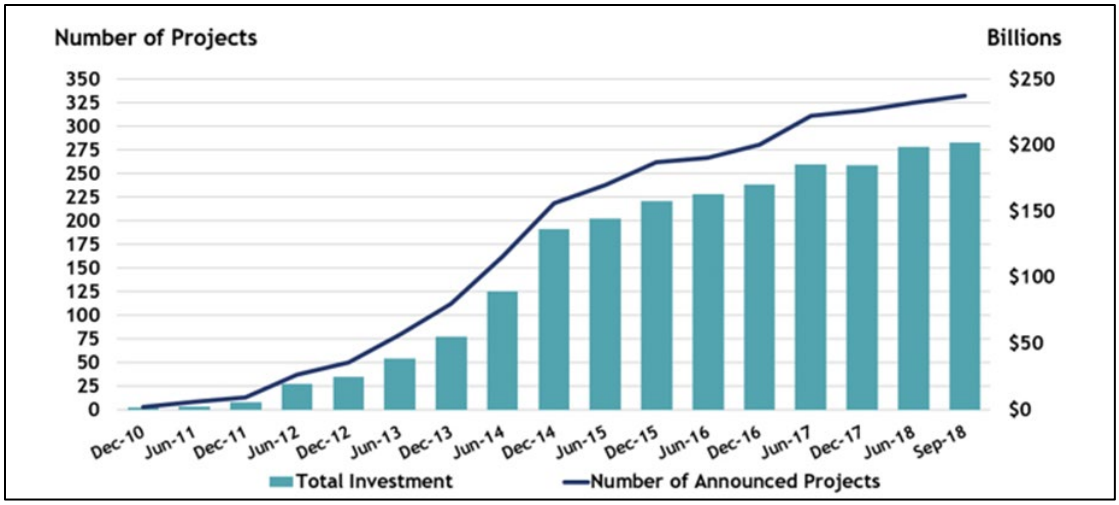

Figure 115. Chemical industry investments from shale gas, cumulative.

Source: (American Chemistry Council, ACC 2018).

Lastly, despite the growth of domestic chemical industry demand, NGL supply has exceeded demand for the past several years and is expected to be in an "excess" position for some time. This has created a number of opportunities to sell NGLs via exports much like methane in today's liquefied natural gas ("LNG") markets. Figure 116 below shows that NGL exports have grown by as much as 32 percent per year, on average, over the last ten years.

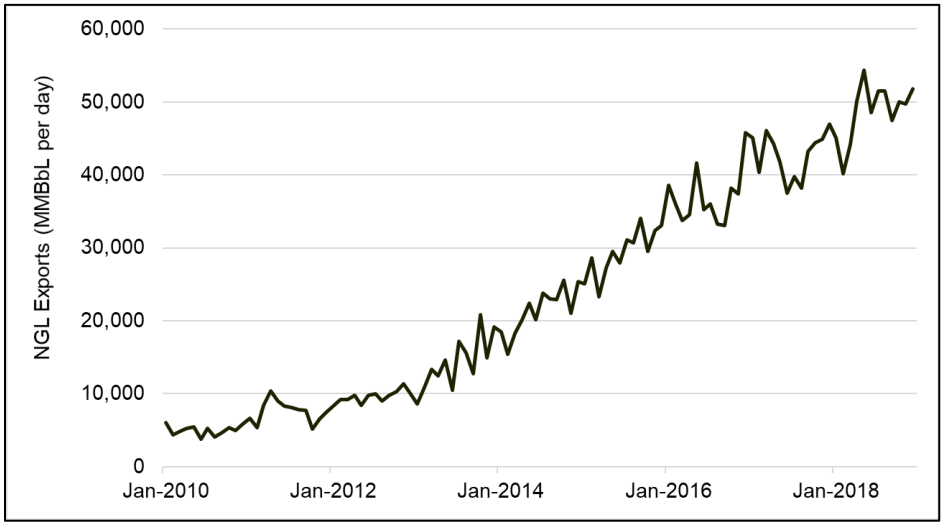

Figure 116. Trend of US export of NGLs.

Source: US Energy Information Administration (USEIA 2020b Jun 30).

NGL pricing sends strong signals the market about the profitability of extracting relatively rich natural gas and separating NGLs from the overall gas stream. Figure 117 shows the recent trends in NGL pricing, on a composite basis, and compares those prices to pipeline quality natural gas (methane) traded on the Henry Hub.

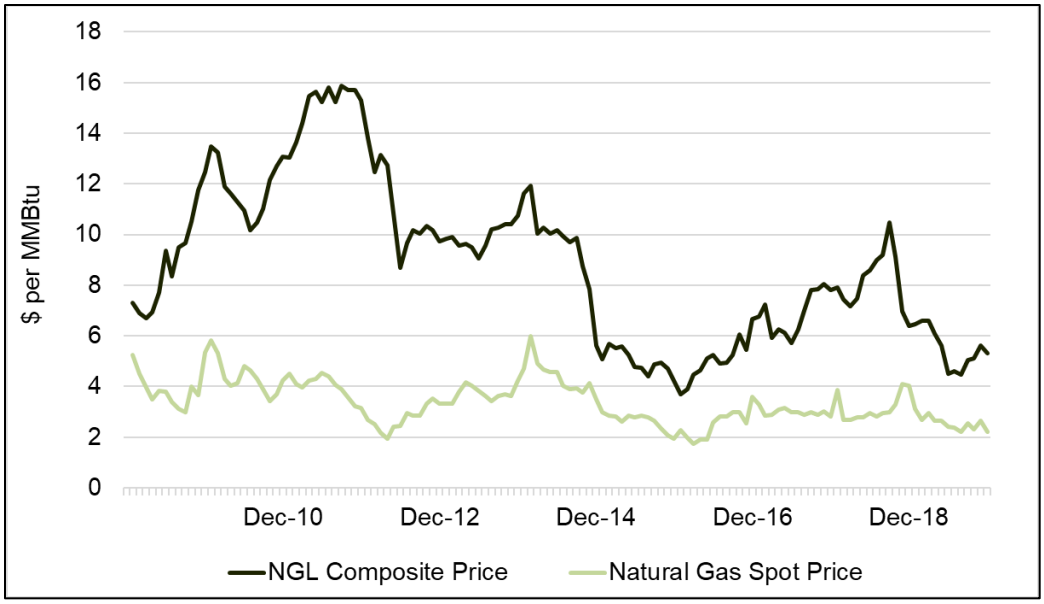

Figure 117. Natural gas spot price and NGL composite price.

Source: US Energy Information Administration (USEIA 2020a Jun 30).

NGL price trends, standardized on a MMBtu basis, have shown more volatility than standard natural gas traded at the Henry Hub. Prices for natural gas, for instance, have been relatively flat and range-bound between $4.50 per MMBtu and $2.00 per MMBtu. Composite NGL prices, by contrast, have traded between a high of $16 per MMBtu and a low of $4.00 per MMBtu. The "margin" of NGL prices to natural gas prices mostly arose during the 2009 to 2014 time period when crude oil prices were very high. Those differentials collapsed with the crude oil price collapse in 2014 but have since started to build again, particularly 2017 and 2018.

As noted earlier in this chapter, underground storage serves a very important commercial, in addition to reliability function. Storage's important commercial functions include serving as a physical hedge against volatile natural gas commodity prices. The presence of volatility also creates profit opportunities for marketers that are willing to assume risk by speculating or arbitraging commodity price differences. Historically, the presence of commodity price volatility, and risk, that unleashes underground storages' intrinsic and extrinsic value. The problem for storage in more recent time periods has been the elimination of this natural gas commodity pricing volatility. The large levels of almost ubiquitous natural gas supplies created by the unconventional shale revolution has effectively stripped natural gas commodity pricing volatility away, substantially reducing the value of underground natural gas storage.

Figure 118 shows natural gas pricing trends over the past three decades that closely correspond to three different pricing periods. The first period covers the late 1990s up to the winter of 2000-2001. This can be thought of as the golden age of natural gas when supplies were affordable, yet, during this time, prices were still volatile. Natural gas commodity prices averaged $2.79 per MMBtu during this time period. The second period runs through the 2000s and the high natural gas prices that existed during this period were greatly exaggerated by the tropical activity of the middle part of the decade. During this second pricing trend, natural gas prices averaged about $6.24 per MMBtu. The last pricing period, which is more contemporaneous with current markets, and reflects the post-shale revolution period, has seen prices fall, on average, to $3.38 per MMBtu.

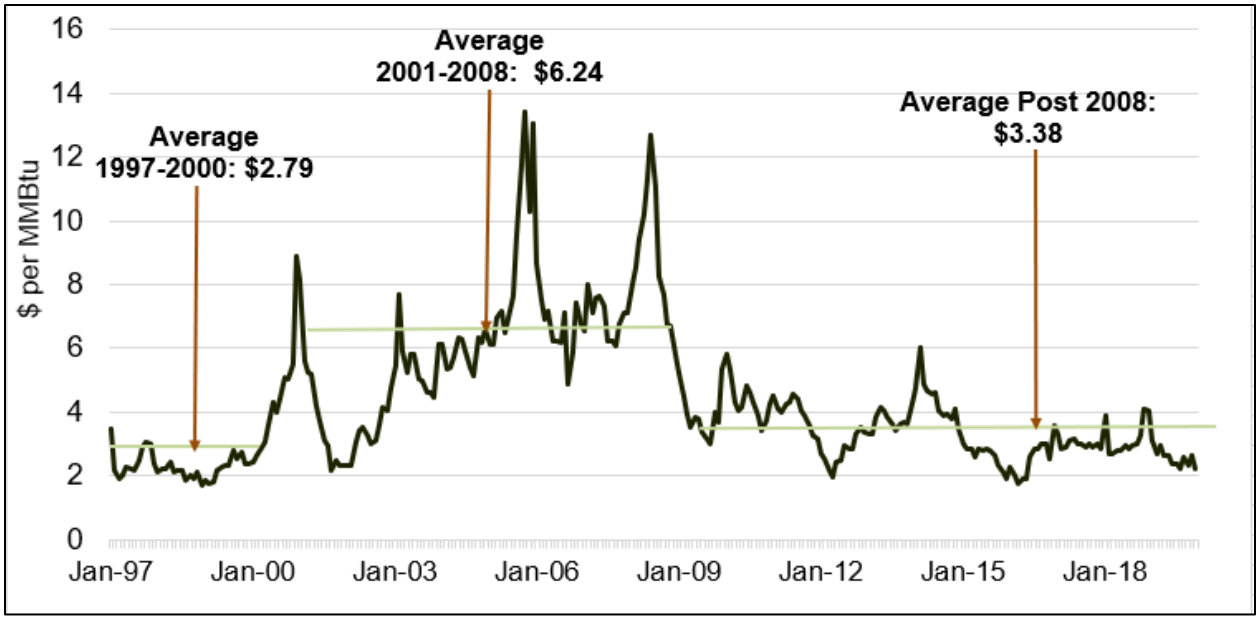

Figure 118. US natural gas price trends.

Source: US Energy Information Administration (USEIA 2020a Jun 30).

The diminution of natural gas pricing volatility is important for understanding recent trends, and ultimately the near-term outlook for storage development. Reliability-related storage functions have been and continue to be important. However, the need for additional reliability-based storage is not large, particularly considering the very slow growth of US natural gas demand. More importantly, the need for storage as a physical hedge is significantly reduced since lower natural gas pricing volatility means the pricing differentials between the spring/summer injection season, and the fall/winter withdrawal seasons is considerably smaller than historic trends. Likewise, gone are the days where super spikes of natural gas commodity prices happened on an almost regular and consistent basis during the winter heating season. While pricing spikes do happen, their magnitudes are considerably lower than historic experiences also reducing profitability opportunities with natural gas storage.

8.6 Current Outlook

The amount of natural gas production, level of natural gas in storage will continue to affect natural gas prices, from the supply side of the market. The outlook for natural gas processing will continue to be tied to many of the same trends and factors discussed above, most of which have been a function of the unconventional revolution of crude oil and natural gas production.

First, and foremost, natural gas processing will be driven by the location and quality of natural gas produced throughout the US The production of natural gas will continue to be dominated by unconventional natural gas production. Production of natural gas is expected to grow from by 1.9 percent annually from 2020 to 2025 (USEIA 2020 Jan 29). This growth is considerably slower than the average annual growth rate from 2015 to 2020, which was 5.1%. Natural gas production is expected to continue increasing, particularly in the Appalachian basin, thus continued development of the infrastructure to move them and the facilities to process them are vital. Figure 119 shows a forecast of natural gas production levels over the next 30 years. Based on studies, US dry natural gas production increases as a result of continued development of tight and shale resources, which accounts for 90% of dry natural gas production in 2050 (USEIA 2020 Jan 29).

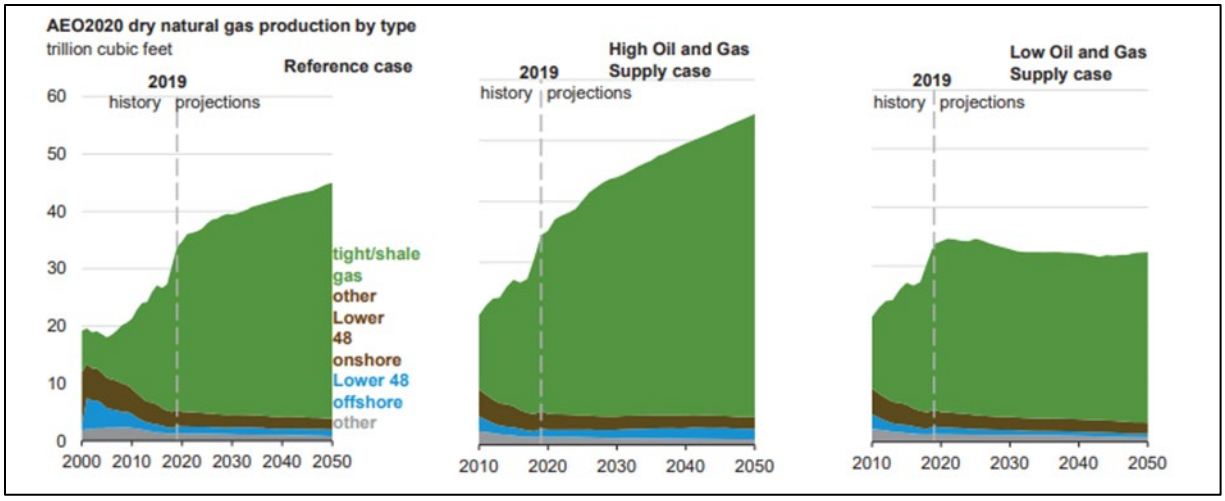

Figure 119. Dry natural gas production by type.

Source: US Energy Information Administration (USEIA 2020 Jan 29).

Natural gas processing capacity will be maintained and expanded in areas seeing constant or increasing unconventional natural gas production, while those regions seeing decreasing natural gas production will likely see a contraction on the base level of legacy capacity that exists in-region. The US is expected to add around 17,533 MMcfd of gas processing capacity during the forecast period from 86 planned and announced gas processing plants, between 2019 and 2023, with a total processing capacity of 20,545 MMcfd, by 2023. The growth in gas processing capacity is driven by booming shale gas production and increasing demand of natural gas, from the industrial and power generation sector.

Natural gas demand plays an important role in incenting natural gas underground storage capacity development. Higher levels of natural gas demand, particularly during winter peaking months, usually requires additional storage capacity to assure reliable peak season deliveries. Natural gas demand growth, however, is anticipated to be relatively tepid over the next decade, mitigating the need to develop a considerable larger level of underground storage capacity. Figure 120 shows the increasing demand pattern for natural gas by the various demand sectors. Industrial and electric power will continue to drive the growth of natural gas consumption while residential and commercial sectors remain relatively flat. Although production is forecast to grow at a slower rate to 2025, it still grows faster than demand. This could lead to decreasing prices and an increase in volumes of export.

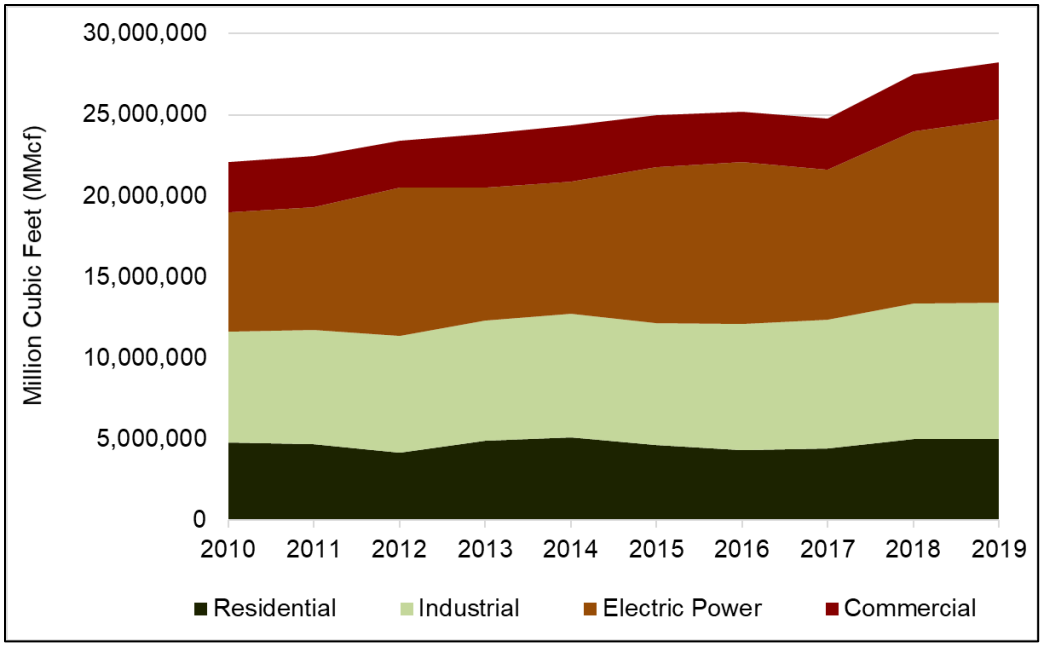

Figure 120. US natural gas demand forecast, by sector.

Source: US Energy Information Administration (USEIA 2020b May 30).

NGL (and LPG) demand will influence the attractiveness of (1) producing in liquids rich regions and (2) continuing to separate large liquid volumes. The NGL sector is highly responsive to market signals-investments in production, transportation, and consumption. Demand over the next few years, much like that shown in the trends earlier, will be driven by industry needs, particularly in the chemical sector. This sector is an integral factor in determining prices, especially prices of ethane. Chemical sector demand, which is currently being configured to meet growing export opportunities, and will be driven by global economic activity, particularly in Asia. However, the growth in NGL production is dependent on the development of transportation avenues, ethane crackers and markets for the NGL(Interstate Natural Gas Association of America, INGAA 2014 Mar 18). The shipment of NGLs can be extremely difficult, and they are expensive to handle, store and transport compared to other refined products because they require high pressure and low temperature to maintain their liquid state (Kinder Morgan 2018 Mar). These require a heavy level of capital investment.

The Interstate Natural Gas Association of America ("INGAA") prepares an annual forecast for a wide range of US natural gas and NGL infrastructure development. The analysis breaks down a variety of infrastructure types from gathering lines, to long-haul pipelines, to storage, and includes NGL processing capacity and pipeline development. This analysis, conducted by ICF Consulting, also includes an outlook for natural gas and NGL production. Table 40 is replicated from the 2018 INGAA natural gas infrastructure outlook on the addition of NGL pipeline capacity, by region. The analysis clearly shows that about half of the NGL expected pipeline capacity in the US will be located in the Southwestern region of the country with the balance being dispersed across other regions.

Table 40. NGL Pipeline capacity added by region (MMBbl per day)

Originating Region	2017	2018	2019–2020	2021–2025	2026–2030	2031–2035	Total 2018–2035	Average Annual 2018–2035
US and Canada	0.5	0.9	1.8	0.4	0.4	-	3.6	0.2
US	0.3	0.8	1.5	0.4	0.3	-	3.1	0.2
Canada	0.1	0.1	0.3	-	0.1	-	0.5	0
Central	-	0	0.2	-	-	-	0.3	0
Midwest	-	0.3	0.2	0.3	-	-	0.8	0
Northeast	0.1	0.3		-	-	-	0.3	0
Offshore	-	-	-	-	-	-	-	-
Southeast	-	-	-	-	-	-	-	-
Southwest	0.3	0.2	1	0.1	0.3	-	1.6	0.1
Western	-	-	-	-	-	-	-	-
Alaska	-	-	-	-	-	-	-	-

Source: (ICF 2018 Jun 18).

Table 41 examines total projected capital expenditures in various types of natural gas infrastructure to 2035. These projections come from the afore referenced INGAA outlook. The outlook forecasts anticipated cumulative capital expenditures, by natural gas infrastructure category, to 2035 and is provided in constant (inflation adjusted) dollars. INGAA anticipates as much as $7.2 billion in new natural gas gathering and processing investments (processing is not provided on individual basis). Gathering and processing investments ranks third and accounts for about 19 percent of the total infrastructure investment. Most of that investment, over $5 billion, is anticipated to be located in the Southwest and the northeastern US (Marcellus).

Table 41. Projected annual CAPEX by region and category, through 2035 (Million 2016 $)

	Central	Midwest	Northeast	Southeast	Southwest	West	Offshore	Alaska	Canada	US & Canada
Surface and Lease Equipment	1,019	14	305	22	2,607	101	7,505	9	745	12,326
Gathering and Processing	986	82	2,445	8	2,710	38	18	9	945	7,241
Oil, Gas and NGL Pipelines	1,204	1,322	3,414	2,183	3,259	66	1	-	1,657	13,107
Oil and Gas Storage	19	21	48	62	128	-	-	-	93	372
Refining and Oil Products Transport	75	70	21	72	205	87	-	1	-	532
Export Terminals	-	-	285	3,576	477	1	-	-	114	4,454
Total Midstream Investment	**3,303**	**1,509**	**6,518**	**5,924**	**9,388**	**294**	**7,523**	**18**	**3,555**	**38,031**

Source: (ICF 2018 Jun 18).

8.6.1 Factors Impacting Atlantic Coast Development

The need for natural gas processing in the Atlantic Region will depend on which wet and sour gas volumes are anticipated to be produced from offshore areas. Assuming gas processing is needed, which is likely given the increased use of shale gas, for example, many of the same factors influencing gas transportation will be important, including:

a. Location: gas processing facilities will be located as close to production as economically feasible.
b. Volumes: production volumes will influence the processing capacity.
c. Commercial factors: the ability to store, transport, and market the natural gas liquids processed from the gas stream will be important in determining facility configuration.

The development of new storage infrastructure could help customers maintain service reliability while at the same time managing commodity price volatility. A number of natural gas storage facilities have been identified in the Atlantic region; most of which are depleted reservoirs. It is likely that reservoir-based storage will continue to be the more common facility used to support offshore production given its base-load nature. Gas storage will likely be developed in this area in the future to support new production volumes. Some characteristics that will be important in future development include:

a. Location: gas storage will likely be located in proximity to new areas of production, but exact location decisions will be a function of both the ultimate location of production and the geological capabilities of creating underground storage.
b. Capacity: the size of a storage facility will be a function of the perceived volumes available to be stored from the Atlantic OCS and the commercial consideration of the developer. There could be trade-offs between a single large storage facility and a larger number of smaller facilities.
c. Deliverability: type of cavern and size of injection well will be driven by deliverability goals and the location and number of proximate pipelines and potential storage customers.

9. Liquefied Natural Gas

9.1 Description of the Industry and Services Provided

Liquefied Natural Gas (LNG) is natural gas converted to liquid form by cooling it to a temperature of -256°F, the point at which gas becomes liquid. This process allows natural gas to be transported from an area of abundance to an area where it is needed for commercial purposes. Once the LNG arrives at its destination, it is either stored as a liquid or converted back to natural gas and delivered via pipeline to end-users. Liquefying natural gas is not a new process or technology; it is simply a process by which the physical properties of natural gas, primarily methane, are altered in order to transport the commodity from markets where it is abundant to those more limited in supply (Dismukes 2008). Within the scope of Atlantic OCS exploration, LNG liquefaction has the potential to provide producers with valuable flexibility by providing access to markets that cannot be accessed by pipeline.

The natural gas price controls and production shortages of the late 1960s led many US energy planners to look at alternative sources of natural gas to meet domestic energy needs. The energy crisis of the 1970s provided the impetus for the first generation of LNG regasification facilities in the US During this period, four LNG facilities (known as the “legacy” facilities) were developed in various locations (Figure 121) in the eastern US for the express purpose of importing natural gas. Three of these LNG regasification facilities (Everett, MA; Cove Point, MD; and Elba Island, GA) are located within the potential impact area for future East Coast offshore oil and gas activity. Also, in recent years, the regasification facilities in Cove Point, MD and Elba Island, GA have added liquefaction capacity and begun producing LNG for export. The operation of these facilities increases demand for natural gas on the East Coast and gives nearby producers access to foreign LNG markets.

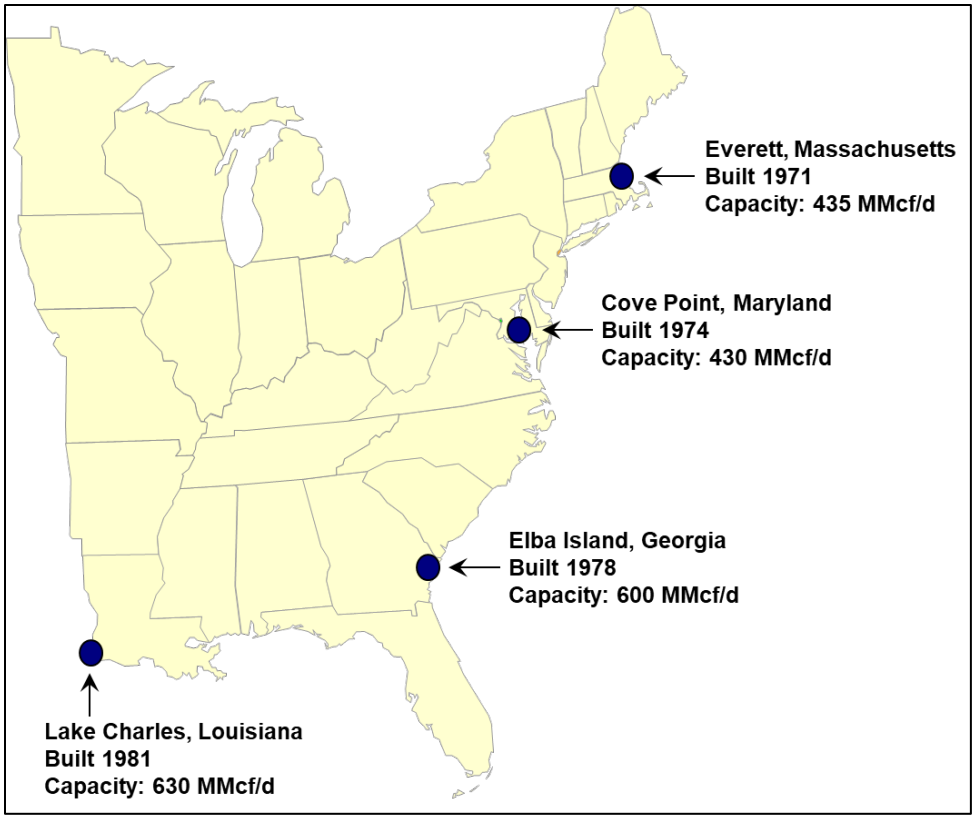

Figure 121. Initial US LNG terminals and original capacity.

Source: (Dismukes 2004 Apr 14).

Despite the growth of LNG regasification in the late 1970s, policies, markets and the underlying economics of natural gas production changed relatively quickly and left these newly developed facilities economically stranded for 20 years. In fact, two of the facilities shut down (Cove Point and Elba Island), while the other two experienced low utilization (Everett and Lake Charles) (Herbert-Burns et al. 2009). It was not until the early part of 2000 that the dynamics of US natural gas supply and demand led to renewed interest in natural gas imports and the re-activation of these legacy LNG regasification facilities. In 2002, FERC issued what became known as the "Hackberry Decision," granting preliminary approval for the construction of the first LNG regasification facility in over 20 years. The facility, originally developed by Dynegy (now owned by Sempra Energy), is located in Hackberry, Louisiana, hence the name of the important FERC decision (EIA c2020).

Forecasted growth in natural gas usage, with limited domestic supply capabilities, was the primary factor motivating developers into the construction of a new generation of LNG regasification facilities. By the early to mid-2000s, the size of the US natural gas market was anticipated to increase substantially. At the time, the DOE forecasted that US natural gas imports (primarily through LNG regasification) would need to grow by as much as 50 percent by 2030 (EIA 2007 May). Imported natural gas (LNG) was anticipated to come from the prolific conventional reserves around the world, which, at that time, were estimated to be around 6,200 trillion cubic feet (Tcf) (EIA 2007 May).

The renaissance of LNG regasification development was short lived. High natural gas prices and supply disruptions created by the tropical activity during the 2004 and 2005 hurricane seasons along the Gulf Coast led to significant natural gas drilling activity, particularly exploratory drilling for unconventional natural gas resources found in various shale plays in Texas, Louisiana, the mid-continent areas of the US, and in the mid-Atlantic region west of the Appalachian Mountains. More significantly, advances in and the combination of two existing technologies, horizontal drilling and hydraulic fracturing gave producers the ability to economically produce gas trapped in shale rock and other tight formations. As a result, US production began to increase in 2007-2008. Today, the US has 2,829 Tcf of technically recoverable reserves thanks to these new unconventional sources (EIA 2020 Feb 4).

This immediate change in the US natural gas outlook has turned domestic LNG investment interests away from the importation of natural gas and towards exports. Both the legacy and recently developed LNG regasification facilities have already changed their configuration from a focus on natural gas imports, to one concentrated on natural gas exports to Europe, Asia and India. However, the shift to natural gas exports will require considerable new equipment investment. Any increase to US natural gas supplies, either unconventional or conventional (like production likely to arise from any future lease sales off the Atlantic seaboard), will increase the opportunities for US natural gas exports. The Atlantic seaboard in particular is well positioned to serve Western and European markets.

9.2 Typical Facility Characteristics

The LNG “value chain” shown in Figure 122 is made up of the various stages of natural gas production, transportation, conversion, storage, and delivery. The first part of the value chain consists of the exploration and production process, where natural gas wells are drilled, reserves are developed, and production begins. Natural gas production is delivered, usually by pipeline, to a facility dedicated to the second part of the value chain: liquefaction. Liquefication facilities process and convert natural gas to a liquid through a super-cooling process. On-site insulated tanks serve as intermediate storage facilities before the gas is transported internationally. This intermediate storage helps to regulate the flow of natural gas since it cannot be transported in its liquid form in a continuous state.

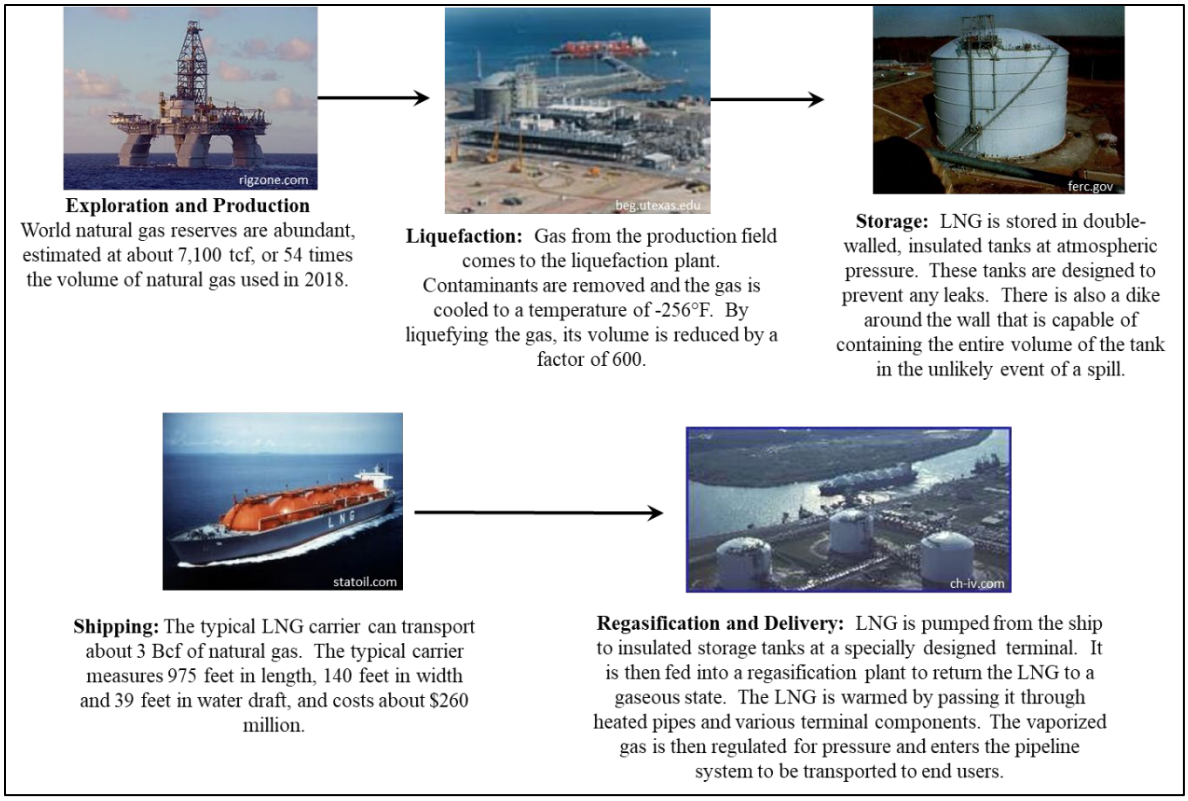

Figure 122. LNG supply chain.

Source: (Kelkar 2008; Foss 2012; EIA 2019 Sep 24; Daiss 2019 Oct 10; EIA 2020 Apr 17).

The next part of the LNG value chain is composed of transportation, usually through specialized ships that have their own insulated storage to keep the gas in its cooled and liquefied state until it is delivered to its destination market. Any gas that naturally regasifies during the transport process (known as "boil-off") is used as transportation fuel during the trip. Tankers are large and can typically hold as much as 3.8 Bcf of natural gas, although tankers today are being constructed to move as much as 5.8 Bcf of natural gas (Daiss 2019 Oct 10). As of 2019, there were more than 500 LNG carriers worldwide (GIIGNL 2019).

The last step in the LNG value chain is made up of the "regasification" process which gradually heats the imported LNG on a steady and controlled basis and then delivers that natural gas to local destination markets or intermediate storage for future delivery to end-users. On-site insulated tanks can also serve as intermediate storage facilities at the regasification location to regulate the potentially intermitted flow of imported LNG. Likewise, these tanks can hold liquid natural gas waiting to be exported to various places around the globe.

To date, all the LNG facilities developed along the Eastern seaboard or the Gulf Coast are comprised of regasification facilities. The other components of the LNG "value chain" (production, liquefaction, and transportation) originate in other locations depending upon the source of the natural gas. As will be discussed later, several facilities originally developed as regasification locations have invested heavily to give the facilities full liquefaction capabilities. These types of investments will allow these facilities to both import or export gas based upon US and global market conditions. This is a unique feature of LNG facilities in the US, particularly those along the Atlantic seaboard and along the GOM.

Figure 123 presents a general schematic of the LNG regasification process. The process does not differ much between onshore and offshore receiving terminals used across the US The first step of the regasification process consists of unloading LNG from ships into a series of intermediate storage tanks. The physical process of offloading the LNG cargo usually takes about 12 hours but can vary depending on the capacity of the regasification facility (Elengy c2020). The typical capacity for an onshore facility ranges between 1 Bcf per day to 4 Bcf per day. For an offshore facility, the typical capacity ranges from 0.5 Bcf per day to 1.5 Bcf per day (FERC 2020a).

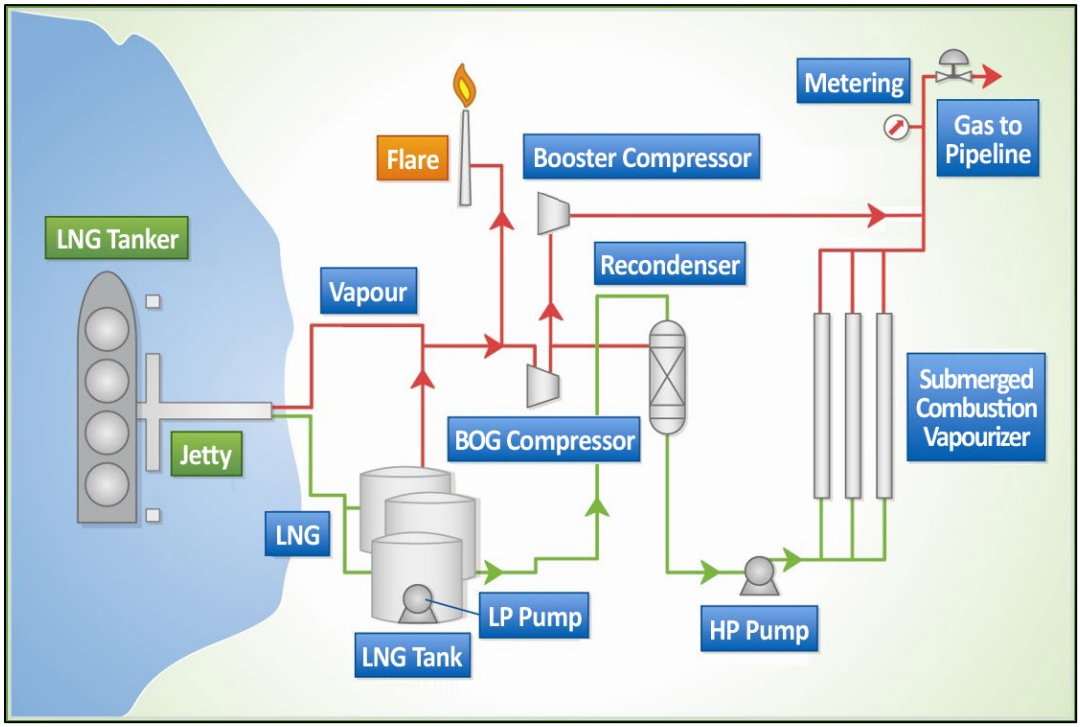

Figure 123. Receiving terminal: LNG gas flow.

Source: (Canaport LNG c2020).

When gas is required, pumps inside the storage tanks transfer LNG for the next step in the regasification process, where it is heated or vaporized. The primary method is to use heat treaters or vaporizers to warm the gas and convert it from a liquid to a gaseous state. From there, the gas is injected into large interstate and/or intrastate pipelines for delivery to markets (end-users) or intermediate storage facilities that are commonly used for domestic natural gas production. Any boil-off associated with the LNG in storage is captured in boil-off gas (BOG) compressors, where it is compressed and then combined with gas from the vaporizers to feed into pipelines for delivery to end-users or intermediate storage facilities.

Two types of regasification facilities, offshore and onshore facilities, are currently in operation or development along the Atlantic Coast. Onshore regasification facilities have existed for over 40 years, while the offshore facilities were developed more recently, the first on the Atlantic Coast beginning operations in 2008 (Excelerate Energy c2020). The primary difference between onshore and offshore facilities tends to be the capacity levels of the facilities. Onshore LNG regasification facilities are typically located at or near major ports, where LNG tankers arrive and unload their cargoes. Because of their port locations, these LNG regasification facilities are referred to as “marine” facilities. Homeland security concerns, however, have led to greater interest in locating these regasification facilities further offshore away from what are usually densely populated areas around coastal and port areas.

Offshore facilities are a newer type of regasification facility that have had little historic application even though they tend to utilize many of the same types of technologies and equipment facilitated by their onshore counterparts. The following lists some of the various types of offshore LNG regasification and liquefaction facilities proposed over the past several years.

A **Gravity-Based Structure (GBS)** consists of two large concrete caissons that are floated to the site and lowered to rest on the sea floor. LNG carriers offload cargoes into storage tanks on the GBS. The topside of the GBS houses vaporizers and other equipment to warm the LNG and return it to its gaseous state. The gas is then transported by subsea pipeline to processing facilities on land for delivery to end-users. The Adriatic LNG terminal (Figure 124) was the first offshore GBS facility constructed. It began operations in 2009 in water depths of 95 feet (29 meters) off the coast of Venice, Italy and has a regasification capacity of 283 Bcf per year (Adriatic LNG c2020; Adriatic LNG c2020). The facility also includes two LNG storage tanks with a total working capacity of 8.8 MMcf (Mangia and Carlesimo 2013 Apr). There are currently no GBS facilities operating in the US

Figure 124. Adriatic LNG terminal.

Source: (Adriatic LNG c2020).

At a **Buoy or Energy Bridge**, specially designed regasification vessels dock with a subsurface buoy that is permanently anchored offshore. The LNG is returned to its gaseous state onboard the regasification vessel and delivered to the buoy. As shown in Figure 125, the natural gas is then sent through the submerged turret-loading (STL) buoy and flexible rise to a subsea pipeline. The offshore pipeline brings the gas onshore and delivers it to end-users. Built in 2008, the Northeast Gateway Deepwater Port is an LNG import facility consisting of two STL buoys that support the docking of specially designed regasification vessels. Located 13 miles (21 kilometers) from shore in Massachusetts Bay, the Northeast Gateway Deepwater Port is able to deliver natural gas back to land at a rate of up to 600 MMcf per day through a series of subsea pipelines (Excelerate Energy c2020).

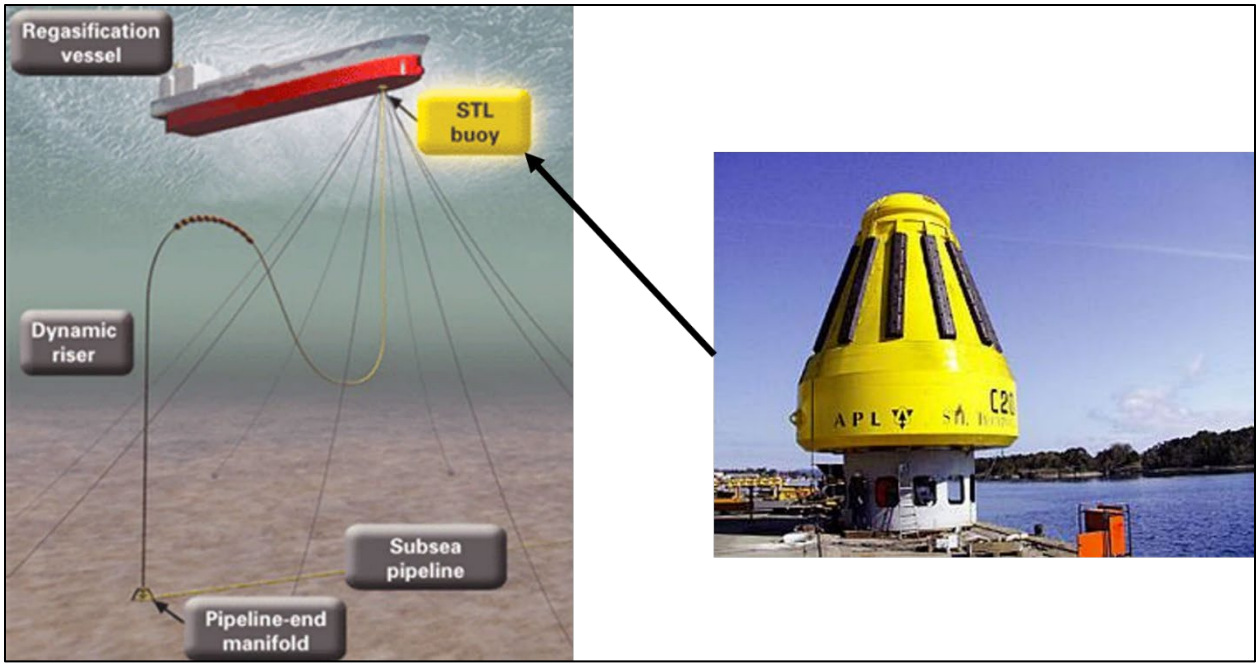

Figure 125. Buoy used for LNG regasification.

Source: Oil & Gas Journal (OGJ 2004 Apr 12).

Floating Storage and Regasification Units (FSRU) are floating regasification systems where the vaporizer, storage, and other equipment is housed on the vessel itself. The vessel tethers to a buoy-based system during the regasification process. The tether connects the ship and vaporization equipment to the subsea pipeline system. Regasified LNG (i.e. natural gas) is then delivered to end-user markets or intermediate storage. When the offload is complete, the ship can leave the system to obtain additional cargoes. The FSRU system would be permanently moored to a tether system and would serve as an intermediate station for offloading LNG. Figure 126 shows one of the two FSRUs moored at the Northeast Gateway Deepwater Port waiting for an LNG carrier to transfer LNG over so it can be regasified and delivered to shore through the buoy and pipeline system.

Figure 126. Floating storage and regasification unit at the Northeast Gateway Deepwater Port.

Source: (Excelerate Energy c2020).

Floating Production, Storage, and Offloading (FPSOs) or **Floating Liquefied Natural Gas (FLNGs)** participate in the production of natural gas. While FPSOs are mainly used for oil production and storage, FLNGs are mobile vessels focused on the production, liquefaction, storage, and transfer of LNG. The FLNG is stationed directly above a natural gas field and collects natural gas through risers (Figure 127). The gas is processed, treated, and liquefied onboard the vessel and then stored in the hull. The FLNG then offloads the LNG onto a smaller LNG carrier so it can be delivered to onshore regasification facilities or to an FSRU, where it is then transferred back to shore (Gallagher 2018 Aug 24).

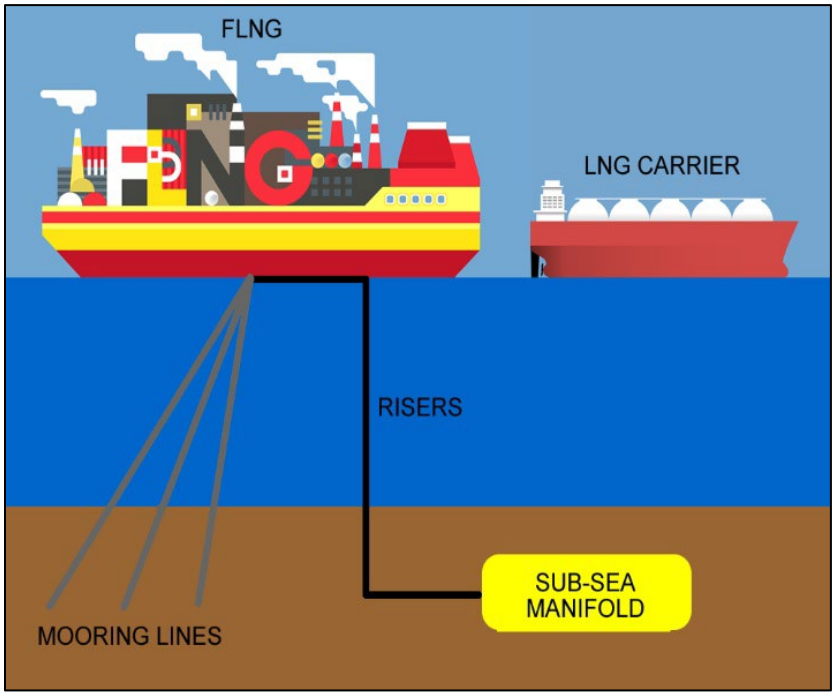

Figure 127. Floating liquefied natural gas vessel.

Source: Oil & Gas IQ (Gallagher 2018 Aug 24).

FLNG vessels have only just recently entered the market. The world's first FLNG to start producing was the Petronas 1 near Malaysia in December 2016 (Connolly 2019 Nov 20). As of May 2020, there are only three operational FLNG vessels in operation, the most recent of which is Shell's *Prelude* off the coast of western Australia, which shipped its first LNG cargo in 2019. With a length of 1,601 feet (488 meters), *Prelude* is the largest floating structure ever built (Figure 128) and can produce 3.6 mtpa of LNG (Shell c2020). In addition to these, 22 more FLNGs are expected to be operational by 2022 (Connolly 2019 Nov 20).

Figure 128. Shell's FLNG, *Prelude*.

Source: (Shell c2020).

9.3 Geographic Distribution

LNG is not a new means for transporting natural gas from, within, and to the US In addition to the large, recently developed marine terminals designed to import LNG, there are numerous small domestic LNG liquefaction and regasification facilities typically used by local distribution companies (LDCs) as a form of storage that can be tapped during peak winter use periods to shave very high weather-related surges in natural gas demand usage (also known as a "peak shaving" resource).

Most LDC peak-shaving facilities have a regasification unit attached, but not all have a liquefaction unit. Facilities without regasification equipment are known as "satellite" facilities and must rely upon tank trucks to deliver LNG from other production or transportation terminal areas. Figure 129 and Figure 130 provide maps with the location of several different types of LNG facilities located throughout the country. As shown in the figures, over half of the LNG facilities in the US are located in states on the Atlantic Coast, where the majority (65 percent) are peak-shaving facilities.

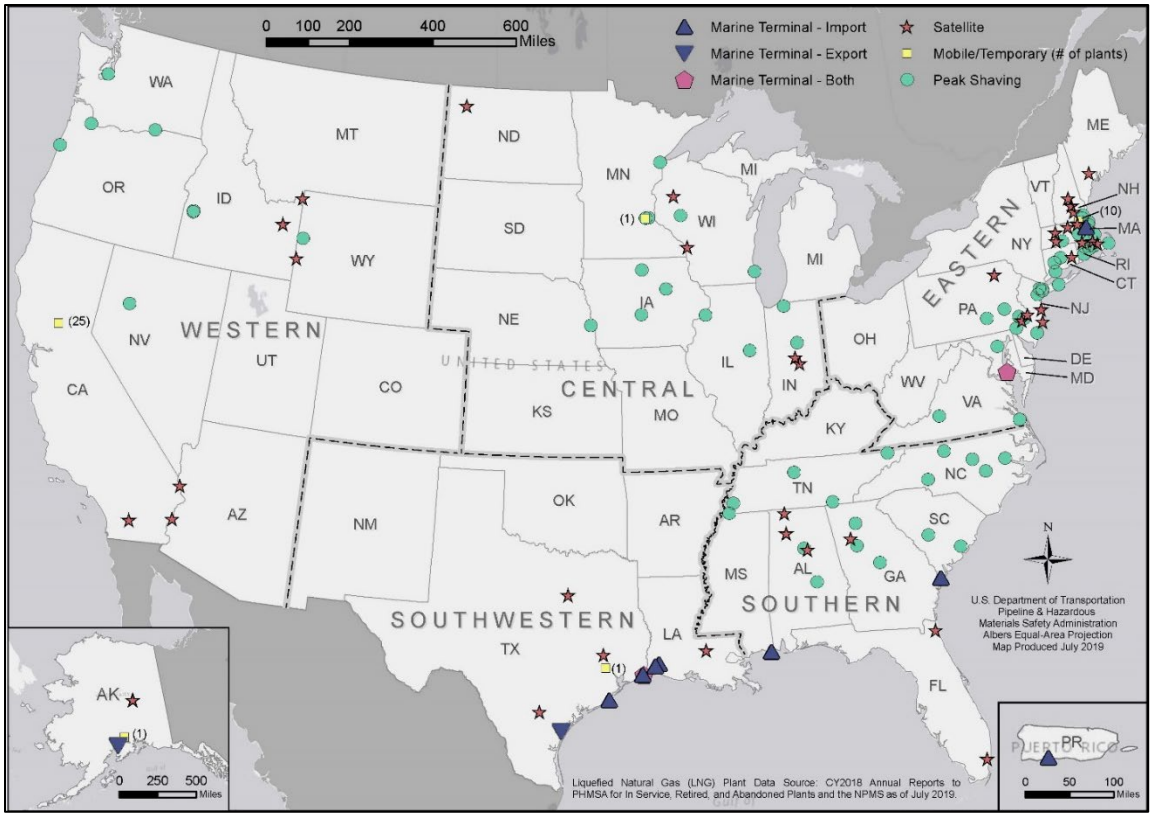

Figure 129. Onshore US LNG facilities.

Source: Pipeline and Hazardous Materials Safety Administration (PHMSA 2019c).

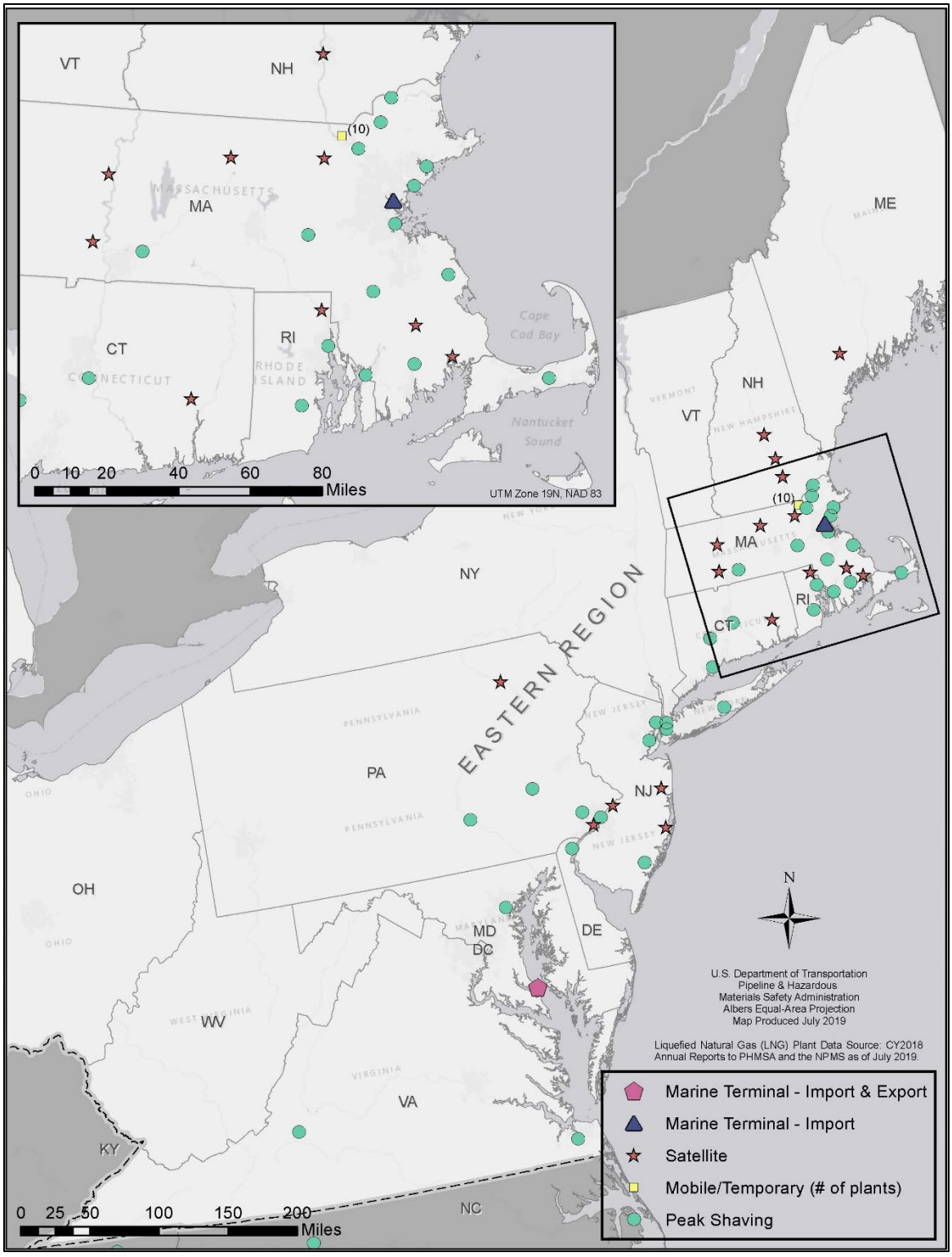

Figure 130. Onshore Northeastern US LNG facilities.

Source: Pipeline and Hazardous Materials Safety Administration (PHMSA 2019d).

New facility investment and development over the past several years has focused almost exclusively on the large marine terminals located primarily along the GOM and the eastern seaboard, including the potential Atlantic area for future offshore oil and gas activities.

Figure 131 provides an expanded view of the currently active LNG import facilities located in North America. All four legacy LNG facilities are still active, and each has had significant capacity expansions and upgrades over the past ten years. An additional seven facilities are also now in operation. These facilities are included in the figure below. Approximately 12 Bcf/d of capacity has been developed at these new "greenfield" LNG facilities.

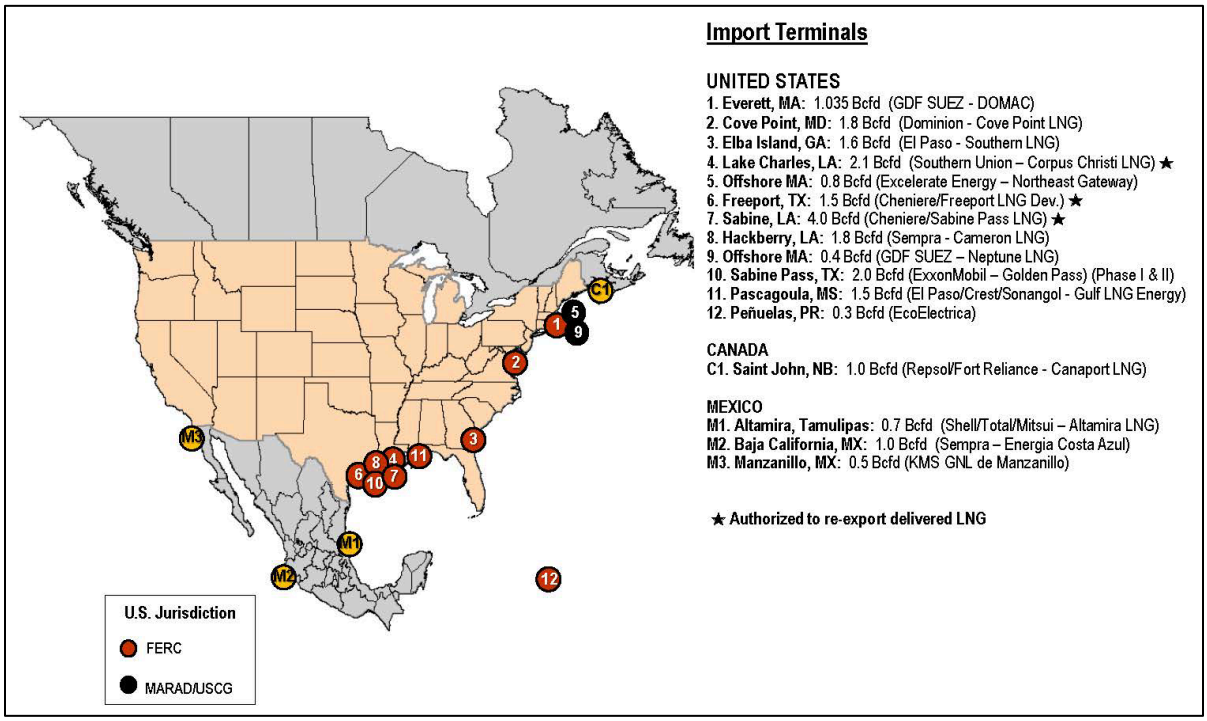

Figure 131. Existing North American LNG import terminals as of March 2020.

Source: Federal Energy Regulatory Commission (FERC 2020a).

There was one formerly operational facility, the Gulf Gateway Energy Bridge, that was retired in 2012. The Gulf Gateway Energy Bridge, developed in 2005, was the world's first deepwater LNG port and was located 116 miles (187 kilometers) off the south coast of Louisiana in 298 feet (91 meters) of water with the capability to deliver approximately 3 Bcf of regasified LNG into the pipeline grid through the Sea Robin and Blue Water subsea systems at a rate of about 500 MMcf per day (Excelerate Energy c2020). However, this facility was exclusively an import facility, and the advent of increased US shale-based natural gas supplies ultimately forced the facility's early retirement in 2012. In addition, the facility's owner, Excelerate Energy, noted that, in 2008, Hurricane Ike had caused significant damage to both pipeline systems that serviced the Energy Bridge, and that neither pipeline had been able to return to its prior level of service or provide adequate capacity. Importantly, the Gulf Gateway Energy Bridge itself was not damaged by Hurricane Ike (Excelerate Energy 2011 Apr 13).

Combined, the eleven active US LNG regasification facilities account for 18.5 Bcf/d of import capacity, which, if fully used, could supply up to 23 percent of total US annual natural gas demand of 82 Bcf/d (EIA 2020 Apr 7). Though LNG facilities located along the GOM were originally developed to take advantage of the region's unique and extensive set of natural gas infrastructure and large users, Atlantic-based LNG regasification facilities were developed almost exclusively as a needed source of supply primarily for residential and commercial end-use markets which are both larger and have higher heating-based requirements than the Gulf Coast.

Five of the eleven facilities reside on the Atlantic coast, totaling 5.6 Bcf/d or 30 percent of total US LNG regasification capacity. These five facilities are spread across the Atlantic region and are located in Everett, Massachusetts; off the coast of Massachusetts Bay, Massachusetts; in Cove Point, Maryland; and on Elba Island, Georgia.

The Everett, MA facility (Figure 132) is the longest operating LNG import facility of its kind in the US Located on the Mystic River, approximately three miles north of Boston, the Everett LNG terminal was the first ever built in the US and has continuously operated since its completion in 1971 (Engie c2020). The facility was built and owned by an ENGIE subsidiary until 2018 when it was bought by Exelon (Exelon c2020). It connects to two interstate pipeline systems that deliver natural gas to almost every gas utility in New England (Engie c2020). The facility is also the sole source of natural gas supply for Massachusetts's largest electric generating station, also owned by Exelon. The Everett LNG terminal has a baseload send-out capacity of 0.7 Bcf/d and a peak send-out capacity of 1.0 Bcf/d. Its relationship with the Mystic Generating Station nearby makes Everett the only LNG terminal in the US that imports LNG on a regular basis (EIA 2018 Apr 19). In 2019, Everett accounted for approximately 68 percent of all US LNG imports by receiving terminal (US DOE 2020).

Figure 132. Everett, MA LNG terminal.

Source: (The Boston Globe 2017 Aug 12).

The Cove Point, Maryland facility is located on the Chesapeake Bay just south of Baltimore. Built by Consolidated Natural Gas Company and the Columbia Gas System in the 1970s, it received its first LNG shipment in 1978 (Dominion Energy c2020). The facility had an original peak send out capacity of 430 MMcf per day and a storage capacity of 5 Bcf (FERC 2014; Dismukes 2004 Apr 14). However, after just two short years of operation the terminal was shut down in 1980 due to unfavorable market conditions. In 1988, Consolidated sold its interest in Cove Point to Columbia, who in turn sold the terminal to Williams in 2000 (Dominion Energy c2020). Dominion purchased Cove Point from Williams in 2002 for $217 million. At the time, the facility was used for storage and employed 25 people (Dominion Energy 2020 Aug 1). Dominion reactivated the facility and received its first LNG shipment at Cove Point in the summer of 2003. In 2006, Dominion began a capacity expansion project at the facility. The expansion was finished in 2009 and increased the facility's import capacity from 1 Bcf/d to 1.8 Bcf/d. Storage capacity at the facility was also increased from 7.8 Bcf to 14.6 Bcf (FERC 2018 May 4).

Today, Cove Point (Figure 133) not only exports natural gas, but also receives LNG from various locations including Trinidad, Nigeria, Norway, Venezuela, and Algeria (Dominion Energy c2020). In 2018, the terminal began liquefying natural gas and commercially exporting LNG – a project that Dominion spent $4 billion to complete. Since then, Cove Point has delivered over 4 billion gallons of LNG to more than 20 countries (Bloomberg 2019 Nov 15; Bloomberg 2019 Nov 15). The facility can liquefy up to 750 MMcf/d of natural gas that is sourced from the Marcellus and Utica shale plays (EIA 2018 Mar 8). It is the largest LNG export facility on the East Coast and the second largest in the continental US. With the completion of the liquefaction project, Cove Point became the first facility in the US that can perform all the functions of an LNG facility, including importing, exporting, vaporization and send-out, and liquefaction (Bloomberg 2019 Nov 15).

Figure 133. Cove Point liquid natural gas facility.

Source: (S&P Global 2018 Apr 10).

Elba Island (Figure 134) is an LNG import terminal located on an island in the Savannah River, next to the South Carolina border, near Savannah, Georgia. The terminal was built by Southern LNG, a part of the El Paso Corporation, to supply natural gas to the growing population and industrial base of the southeastern US The facility was brought online in 1978, but, like Cove Point, the Elba Island facility was soon shuttered in 1982 (USDOE, OFE 2016). After almost 20 years, in 2001, market conditions had changed enough to reopen the terminal, in addition to adding five new storage tanks with a peak send-out capacity of 675 MMcf/d and a baseload send-out capacity of 446 MMcf/d (SEC 2001; Landers 2019 Jul 18).

The Elba Island facility went through several more expansions and changes that eventually led to its acquisition by Kinder Morgan as part of a 2011 deal in which Kinder Morgan bought the terminal's parent company, El Paso Corporation (SEC 2011). Additionally, the facility's operations grew to where Elba Island now has a storage capacity of 11.5 Bcf and a peak vaporization send-out capacity of 1.76 Bcf/d (Kinder Morgan c2015). In 2016, Elba Island was authorized by FERC to begin another expansion project. The $2 billion project included the construction of an export facility and ten small-scale liquefaction units capable of producing 2.5 million tons per year of LNG by processing natural gas at a rate of 350 MMcf/d (Magill 2019 Oct 4). These units use a new technology developed by Royal Dutch Shell called Movable Modular Liquefaction System (MMLS), in which the units are preassembled at a manufacturing plant, are quickly bolted together, and can be moved from one site to another as required (Lewis c2019). The export terminal was completed in 2019 and sent out its first shipment later that year, making Elba Island one of the newest LNG export facilities in the US (EIA 2019 Oct 17).

Figure 134. Elba Island liquid natural gas facility.

Source: (Chapa 2019 Dec 16).

The two newest LNG import facilities on the East Coast are dual buoy systems located off the coast of Massachusetts. The Northeast Gateway Deepwater Port, owned by Excelerate Energy (which owned the first offshore system in the GOM), began operations in 2008 thirteen miles from the coast in Massachusetts Bay. It has a dual submerged turret-loading buoy system and a 16-mile (26-kilometer) pipeline that connects it to the major subsea HubLine pipeline operated by Algonquin Gas Transmission (Excelerate Energy c2020). It is capable of delivering up to 600 MMcf of natural gas per day but has had years where it hasn't imported any LNG at all, mainly from 2011-2014 and again in 2017 and 2018 (Excelerate Energy c2020; Northeast Gas Association c2020). The Neptune Deepwater Port is owned by Engie and is located approximately ten miles off the coast of Gloucester, Massachusetts. It was mainly designed as a supplement to the company's main import facility in Everett, Massachusetts, capable of injecting about 0.4 Bcf/d into the state's pipeline system (Engie c2020). However, it has not been active since its completion in 2010. Over the years, the facility has been authorized by MARAD to suspend operations several times, citing unfavorable conditions that are impacting Neptune's ability to import LNG. The most recent suspension period became effective in June 2018 and extends until mid-2022 (Northeast Gas Association c2020).

Though these facilities still represent a significant source of potential natural gas supply, recent development and production of natural gas in the various shale-producing regions of the US has changed the importance and attractiveness of coastal marine-based LNG facilities. These, and many other large LNG facilities, have gained, or are currently seeking, licenses to export what is becoming a glut of diverse, stably-priced, and affordable, domestic natural gas supply for foreign market consumption.

9.4 Scope of Economic Contribution to Regional Economy

LNG facilities are extremely capital intensive yet employ relatively few workers. Research has found that, on average, approximately 111 workers are employed per Bcf/d of regasification capacity. Given this limited number of employees, and the fact that employment data for LNG facilities tends to not be released due to data disclosure purposes, an estimate based on this average is provided in Table 42 below.

Table 42. Estimated number of employees by LNG facility

Facility	Capacity (Bcf/d)	Estimated Employees
Everett, MA	1.04	115
Cove Point, MD	1.80	200
Elba Island, GA	1.60	178
Lake Charles, LA	2.10	233
Northeast Gateway, Offshore MA	0.80	n.a
Freeport, TX	1.50	167
Sabine Pass, LA	4.00	444
Hackberry, LA	1.80	200
Neptune, Offshore MA	0.40	n.a
Sabine (Golden Pass), TX	2.00	222
Pascagoula, MS	1.50	167

Source: Federal Energy Regulatory Commission (FERC 2020a).

LNG facility development, as well as expansions, lead to considerable economic benefits for the communities in which they are built. For example, at its peak, approximately 4,500 workers were employed during the liquefaction capacity development at the Cove Point facility, with the number of permanent jobs doubling to 200 employees. The project also used 800 miles of wire and fiber, 80 miles of piping, and 20,000 tons of steel, much of which came from in-state businesses and industries. The export terminal investment was $4.4 billion and generated more than $500 million in export revenue in 2018. Additionally, Calvert County, where the facility is located, received over $50 million in taxes and other payments from Dominion, the owner of the facility, in 2019 (Rector 2019 Mar 20).

As the US continues to produce vast amounts of natural gas, especially in the shale plays located in the Northeast, there could be additional LNG facility developments and expansions. Should this development arise, it will likely boost local economies through job creation, tax payments, and supply purchases.

9.5 Current Trends

Historically, LNG imports have represented a small share of overall US natural gas supply. The overwhelming majority of US gas supplies used to meet demand have come from producing fields in the lower 48 states. The limited amount of natural gas that has been imported into the country, outside of LNG, has been from pipeline imports from Canada. Figure 135 shows the overall natural gas import trends over the past three decades.

The left axis graphs total imports and pipeline imports as a percent of total US consumption (the difference between the two series being LNG). The right side of the figure shows the share of LNG as a percent of total consumption. Due to a decline in domestic gas production and a substantial increase in natural gas prices, LNG imports rose significantly in the early 2000s and peaked in 2007 to a high of 17 percent of total imports (the remainder coming from pipelines) and 3.3 percent of total US consumption. This was an increase of over 4,000 percent from the low of 1995. However, those shares have fallen considerably since then, and, today, LNG imports have returned to levels comparable to the 1990s before the era of the US natural gas supply "bubble."

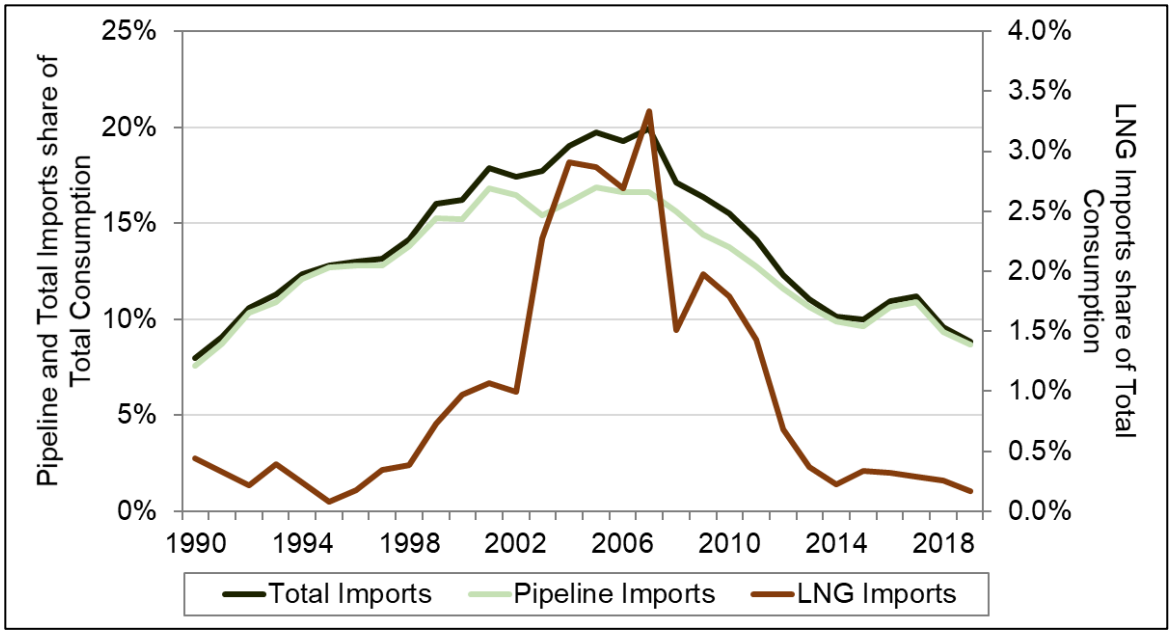

Figure 135. US natural gas imports as a percent of total consumption, 1990–2019.

Source: Energy Information Administration (EIA 2020a Mar 31).

Figure 136 shows historic LNG imports per Atlantic Coast facility since the mid-1990s. The left side of the graph measures total LNG imports (in Bcf), and the right side compares those imports to trends in Henry Hub natural gas prices (i.e., wholesale prices). The graph shows the increase in imports from all three original terminals starting in 2003, after Cove Point restored operations. The import trend increased considerably when natural gas prices began their climb in 2000, though it slowed during 2005 and 2006 due to European and Asian competition. Since then, imports into all US facilities have decreased considerably, although the East Coast facilities have suffered less than those along the GOM. Today, LNG imports through these facilities are approximately 90 percent lower than their peak in 2007.

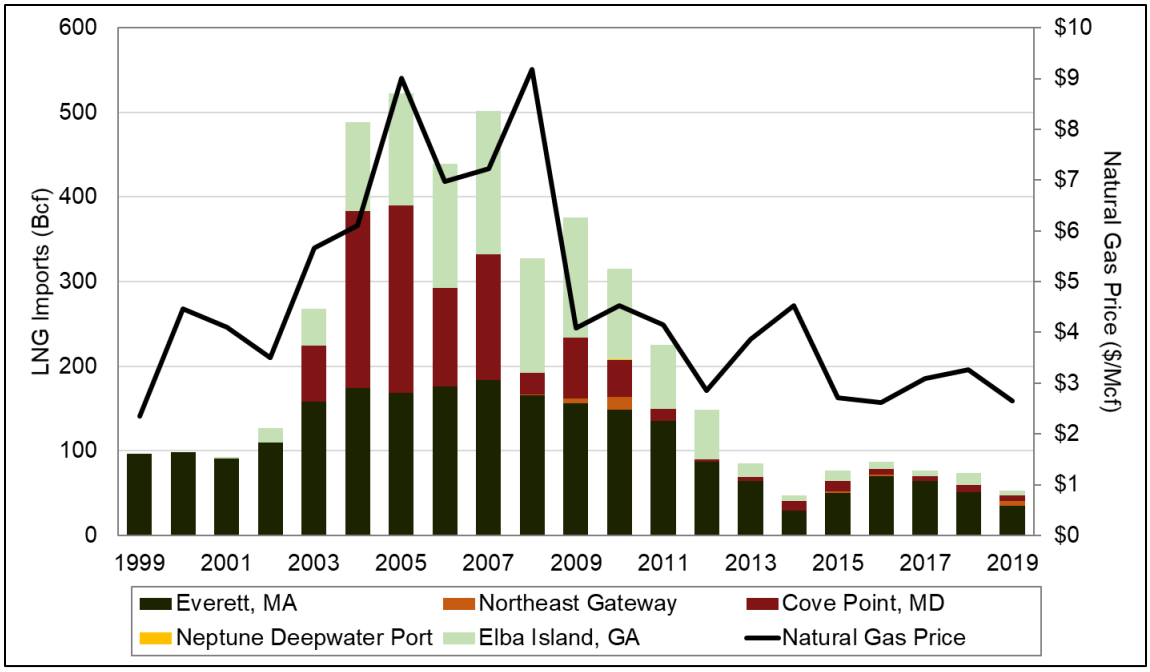

Figure 136. LNG imports and natural gas price.

Source: Energy Information Administration (EIA 2020a Mar 31; EIA 2020 Apr 22).

The need to import LNG has become nearly non-existent thanks to upgraded "fracking" techniques and the shale revolution of the past decade. As seen in Figure 137, there is a strong inverse relationship between LNG imports and domestic natural gas production.

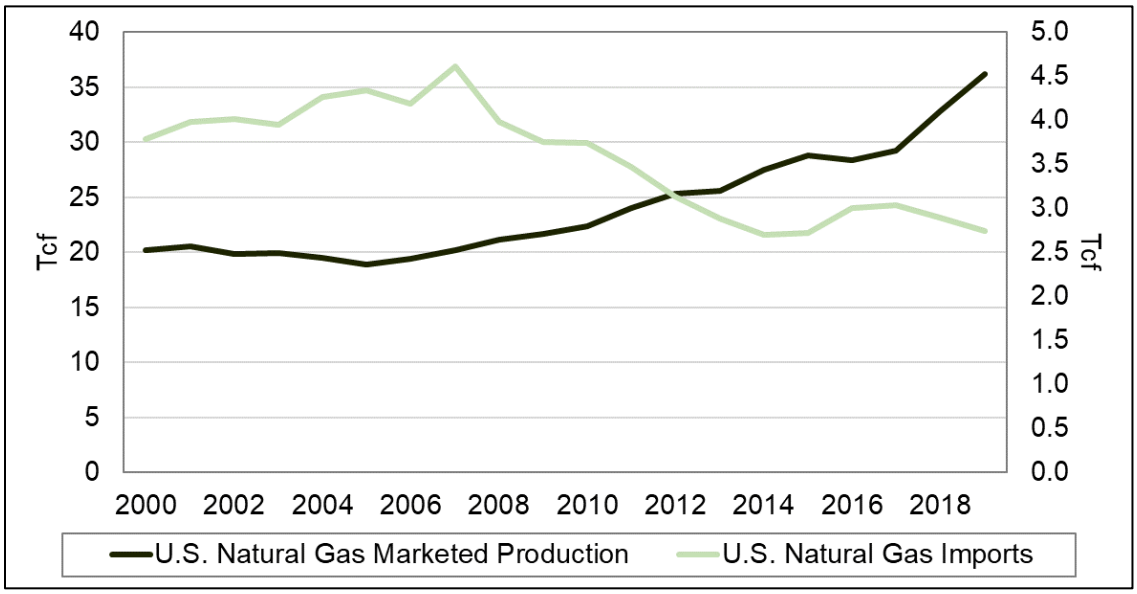

Figure 137. Total US natural gas marketed production and natural gas imports.

Source: (EIA 2020a Mar 31; EIA 2020b Mar 31).

Some of the LNG import facilities described earlier have become entirely reconfigured to support the growing natural gas export market (Figure 138). Only the LNG facilities located in Kenai, Alaska and Corpus Christi, Texas were constructed to export LNG exclusively, although the Kenai location has not exported LNG since 2015 (Paul 2019 Feb 12). Aside from the Kenai facility, all these export terminals were constructed within the last five years, starting with the Sabine Pass, Louisiana facility in February 2016. Together, they account for nearly 9 Bcf/d of export capacity (Chapa 2019 Sep 16).

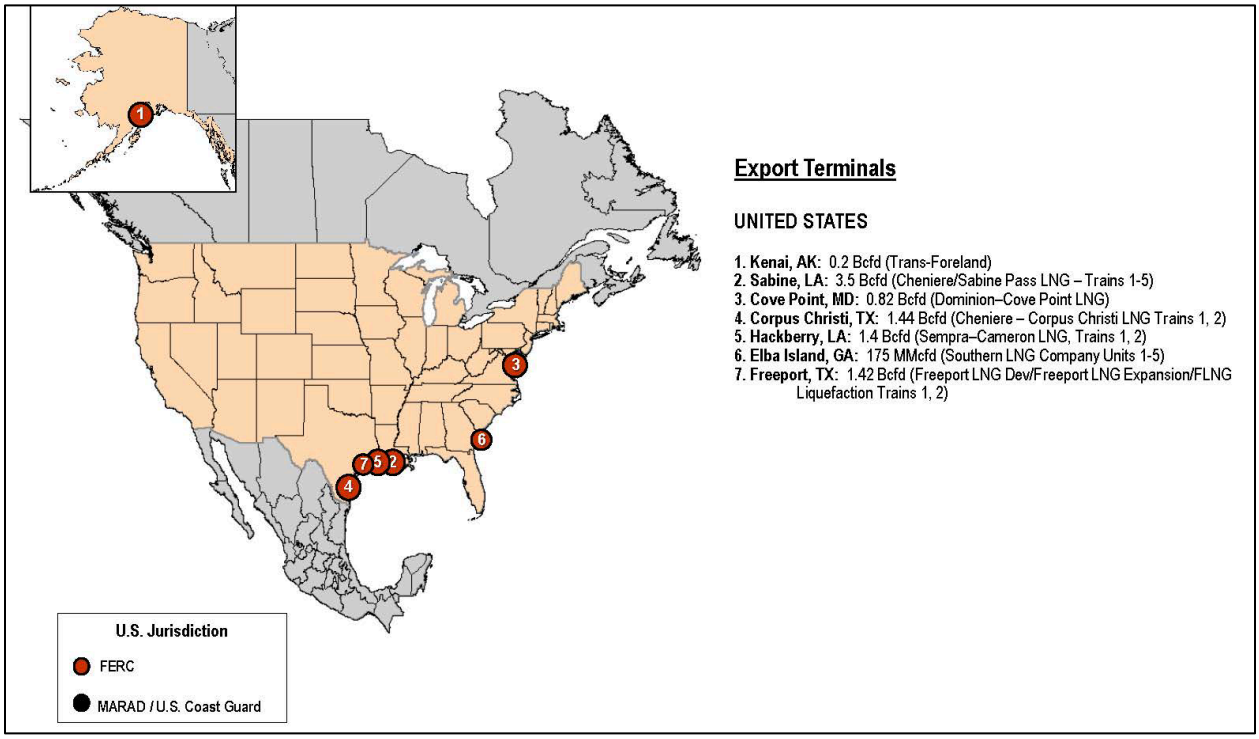

Figure 138. Existing North American LNG export terminals as of March 2020.

Source: Federal Energy Regulatory Commission (FERC 2020b).

The Natural Gas Act of 1938 requires a potential natural gas exporter to attain prior authorization from the US Department of Energy's (DOE) Office of Oil and Gas Global Security and Supply, Office of Natural Gas Regulatory Activities. Section 3(a) of the Natural Gas Act, sets forth the statutory criteria for review of the instant export application:

> [N]o person shall export any natural gas from the United States to a foreign country or import any natural gas from a foreign country without first having secured an order of the [Secretary of Energy] authorizing it to do so. The [Secretary] shall issue such order upon application, unless after opportunity for hearing, [he] finds that the proposed exportation or importation will not be consistent with the public interest. The [Secretary] may by [the Secretary's] order grant such application, in whole or part, with such modification and upon such terms and conditions as the [Secretary] may find necessary or appropriate (USDOE, OFE 2011).

The DOE export application review and balances domestic natural gas needs against natural gas export opportunities to assure that exports do not threaten domestic natural gas needs. Any natural gas export application must also be consistent with the DOE's policy of promoting competition in the marketplace by allowing parties to negotiate their own trade arrangements. In addition, the National Environmental Policy Act (NEPA) requires the DOE to consider any environmental effects of its proposed decision (USDOE, OFE 2011).

By April 2020, 23 different companies had been approved to export domestically produced LNG to both free trade agreement (FTA) and non-free trade agreement (non-FTA) countries. Twelve had only been authorized for FTA exports, while only one had been approved to exclusively export to non-FTA countries (USDOE 2020 Apr 27). Altogether, these approved applications have a total export capacity of over 66 Bcf/d.

Current LNG facilities interested in exporting natural gas will likely be required to make significant capital investments, primarily in the form of liquefaction equipment that physically converts domestically produced natural gas. The dramatic increase in natural gas reserves that has arisen over the past several years currently places the US at 475 Tcf of proven resources (Figure 139). This increase in reserves has, in turn, fueled a nearly 80 percent increase in natural gas production since 2000. As a result, US natural gas exports have also skyrocketed by over 1,800 percent since then, which helped the US become a net exporter of natural gas for the first time in its history in 2017 (Clemente 2020 Mar 22).

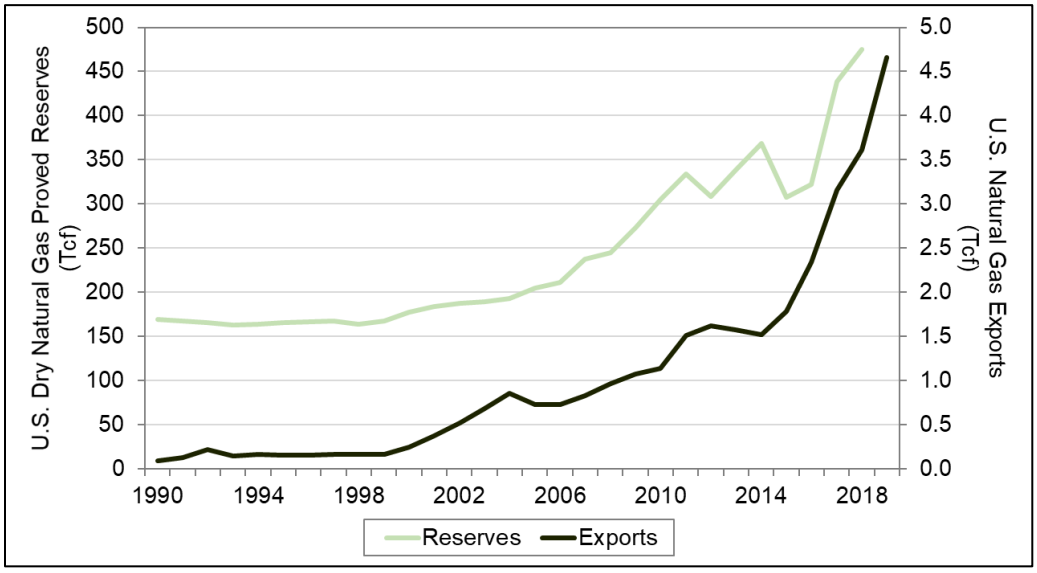

Figure 139. US natural gas reserves and exports.

Source: Energy Information Administration (EIA 2019 Dec 12; EIA 2020a Apr 30).

Today, the US is one the of the top five largest exporters of natural gas in the world and the third largest LNG exporter in the world after Qatar and Australia (CIA 2017; IEA 2019 Jun). Of the currently six operating export terminals in the US, those located in the GOM region accounted for over 87 percent of LNG exports in 2019 (Cocklin 2020 Mar 19). Cove Point's new export terminal has made it the largest exporter on the East Coast and one of the top three exporters in the country (Figure 140). The Elba Island terminal just recently finished construction in 2019, making it the second operational export terminal in the Atlantic region. Overall, these six facilities exported over 1.8 Tcf of LNG to 34 different countries in 2019 (EIA 2020b Apr 30).

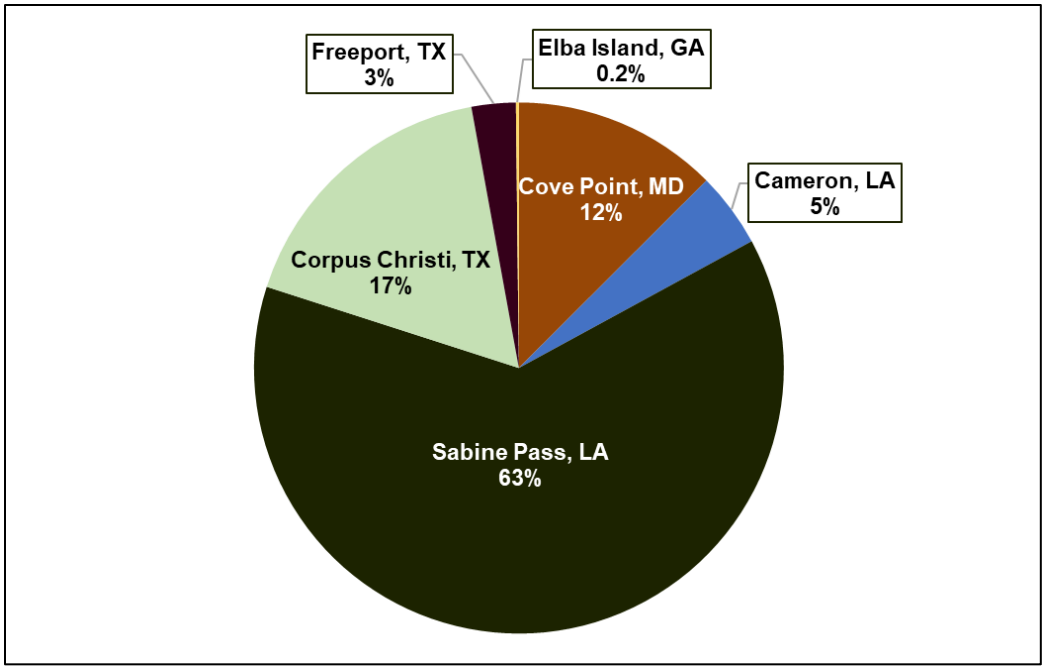

Figure 140. LNG exports by exit point, 2019.

Source: Energy Information Administration (EIA 2020b Apr 30).

9.6 Current Outlook

Natural gas, including LNG traded in world energy markets, will likely be a highly preferred energy resource in the near future given its environmental attributes, particularly in emerging economies throughout the world. Figure 141 provides a forecast of international energy demand. Overall, world energy demand is expected to increase some 120 quadrillion BTUs (quads) by the year 2035, where 64 percent of that increase will be met with renewable energy resources and 21 percent, or roughly 26 quads, will be met with natural gas. The next closest competing energy resource will be oil at 13 percent, while coal use is anticipated to actually decrease by two percent by the year 2035.

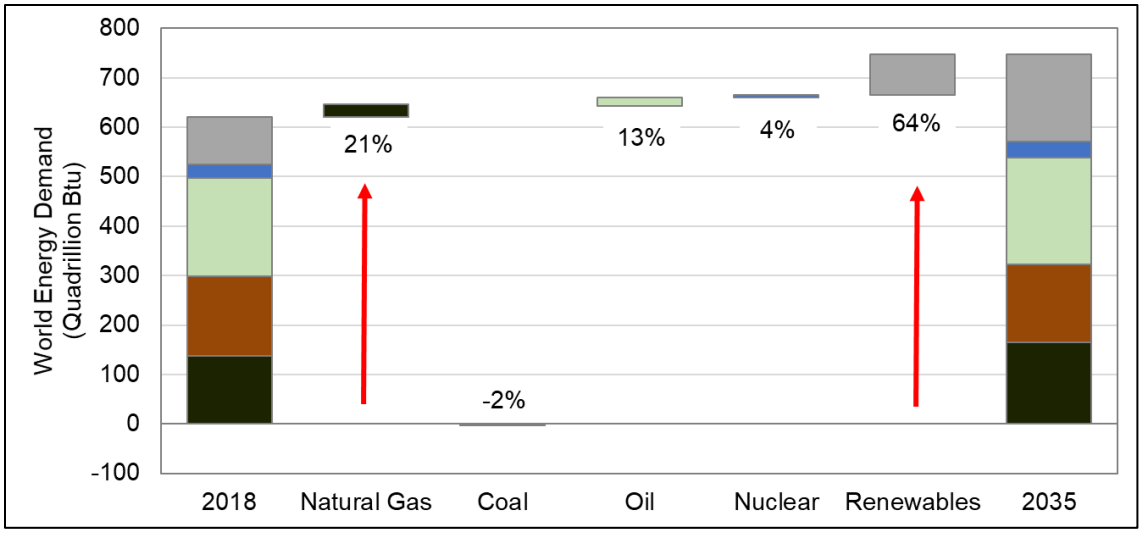

Figure 141. Total world energy growth by fuel type, 2018-2035.

Source: Energy Information Administration (EIA 2019 Jan).

Countries will continue producing natural gas to meet this expected demand, and LNG exports will become even more important as countries who produce more than they consume (such as the US) sell off their remaining supply to other countries. Already LNG accounts for nearly one-third of total US natural gas exports, and it is expected to continue growing over the next five years, eventually making the US the largest LNG supplier worldwide, as shown in Figure 142 (Caldwell 2019 Jun 10).

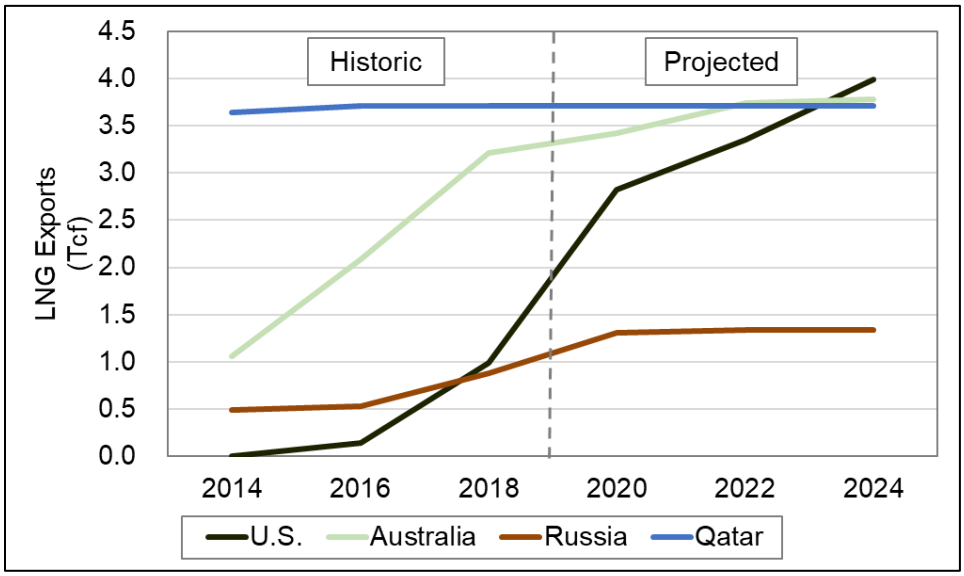

Figure 142. Historic and projected LNG exports by top four countries, 2014–2024.

Source: International Energy Agency (IEA 2019 Jun).

As of March 2020, FERC has approved 23 applications seeking the ability to export natural gas, several of which have already begun construction (see Figure 143). If all these projects become operational, it would increase US exporting capacity by over 33 Bcf/d. However, only two of these projects are located along the Atlantic Coast: (1) an expansion to the Elba Island facility that is currently being built; and (2) a small terminal in Jacksonville, Florida that has been approved but has not yet started construction (FERC 2020b).

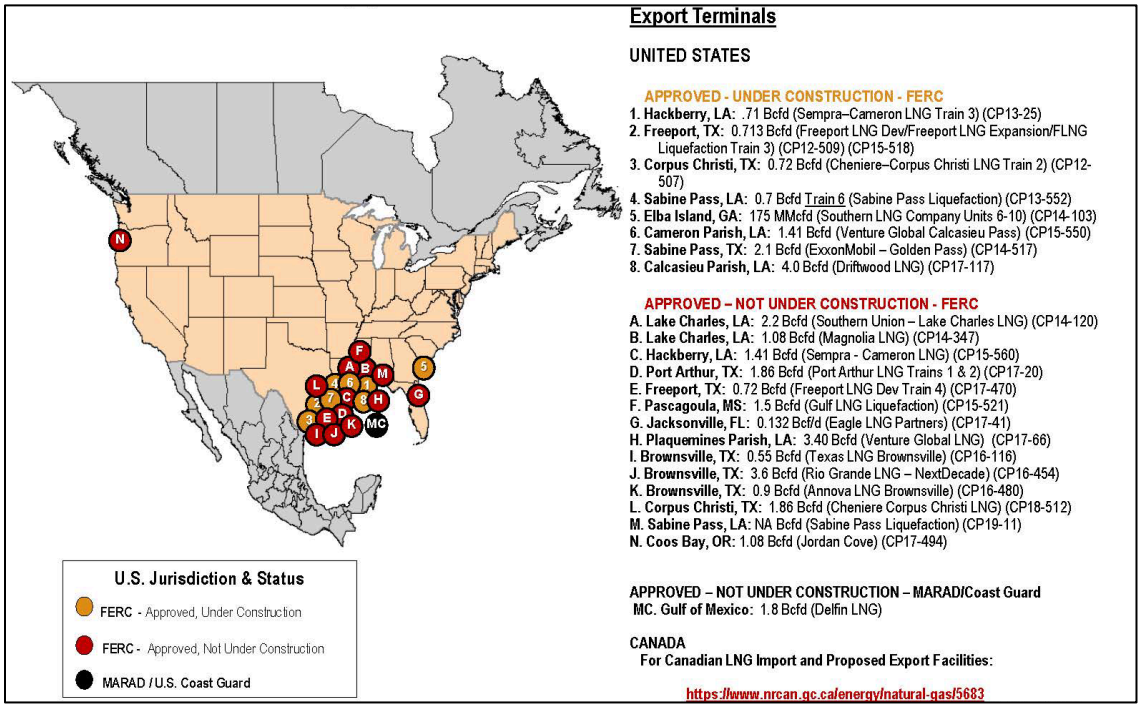

Figure 143. Approved North American LNG export terminals.

Source: Federal Energy Regulatory Commission (FERC 2020b).

The likelihood of all this LNG export capacity being developed is very low because all require longer-term contracts that secure as much as two-thirds of the total project capacity (Chapa 2019 Sep 20). As of 2020, the over-development of export capacity around the world, makes rapid domestic export capacity development unlikely. However, there is a healthy degree of interest in developing this capacity should the underlying market conditions justify the development.

However, environmental concerns about emissions, particularly greenhouse gas (GHG) emissions, will be an important factor in encouraging continued, if not increased, natural gas usage around the globe in the next decade, particularly in developing countries that have relatively high emission rates and increasing economic growth opportunities. Figure 144 shows that China, India, and many other Pacific Rim countries have some of the highest GHG emissions in the world. Many of these countries are signees of the 2015 Paris Climate Agreement and will have strong incentives to reduce emissions in order to maintain their global emissions reductions commitments (United Nations 2015 Dec 12). These GHG emissions could, in large part, be mitigated through fuel switching away from coal and towards natural gas.

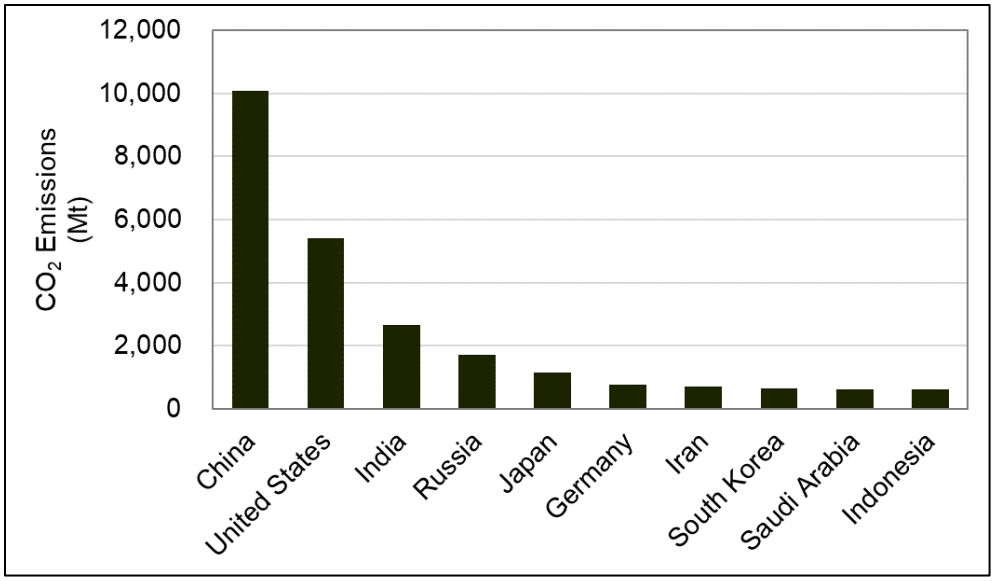

Figure 144. World CO_2 emissions by top ten countries, 2018.

Source: World Resources Institute (Levin and Lebling 2019 Dec 3).

As shown in Figure 145, however, nearly a quarter of the world's projected energy consumption is expected to be met by renewable resources by 2035. Natural gas is a cleaner option to coal and petroleum and is currently one of the most abundant and cheapest fuel sources in the world, which is why it has become so widely used. But, as the world grows more concerned with decreasing GHG emissions, it is likely that this growth in natural gas consumption, and consequently production, will eventually flatten and remain relatively constant in the long-run as renewable technologies, including storage, become more advanced and oil and coal continue to be phased-out.

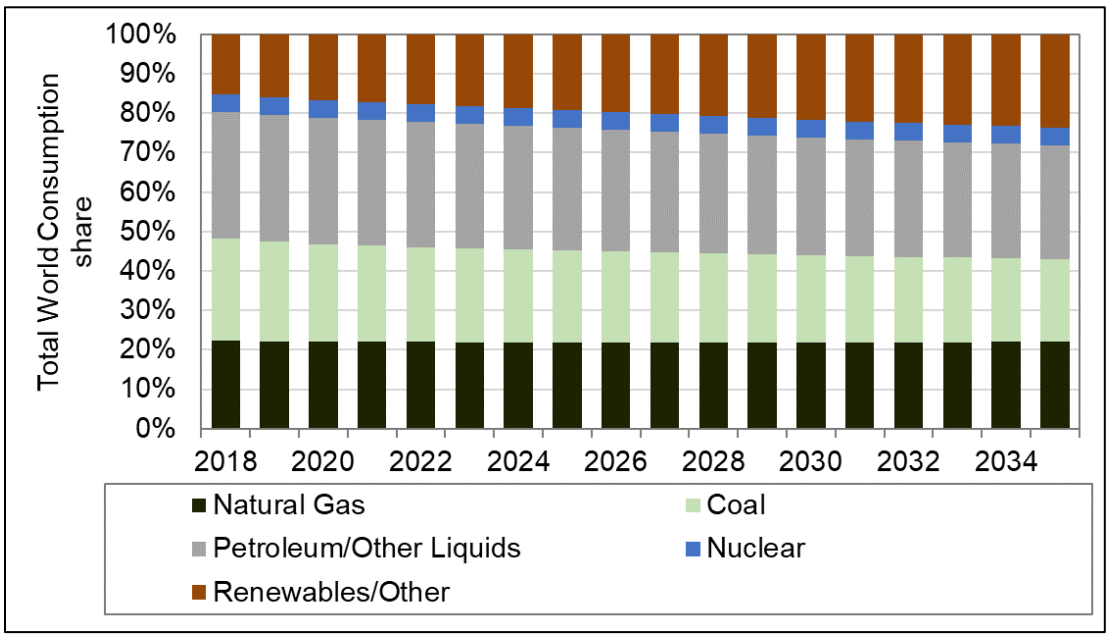

Figure 145. Share of total world consumption by fuel type, 2018–2035.

Source: Energy Information Administration (EIA 2019 Jan).

9.6.1 Factors Impacting East Coast Development

One source of potential LNG growth on the Atlantic Coast is the continuous exploration and production of shale gas in the Marcellus and Utica basins located in the Appalachian region of the US (Figure 146).

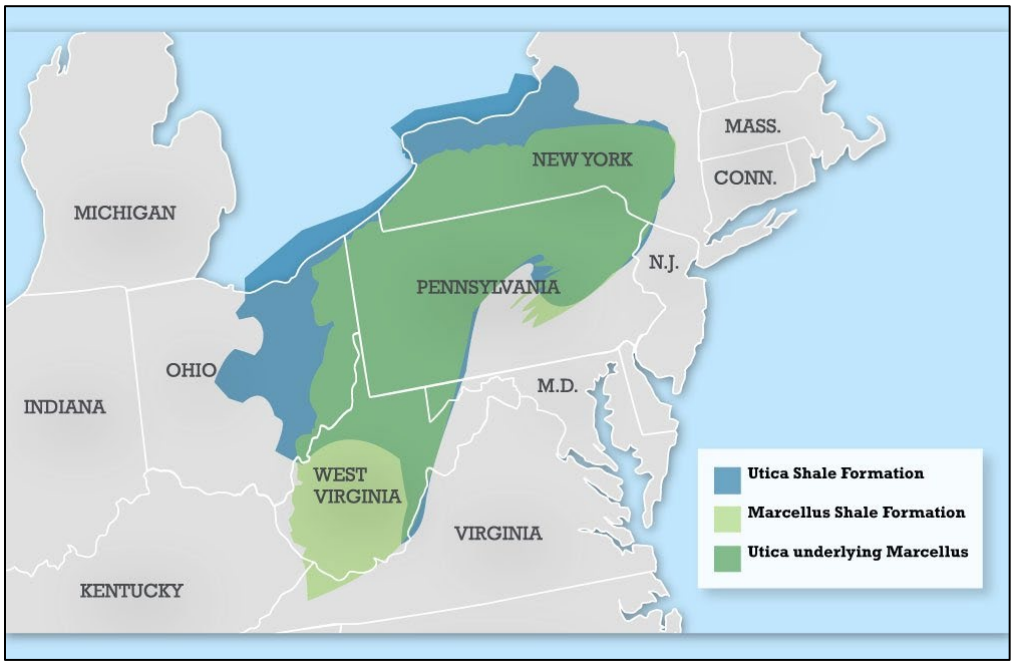

Figure 146. Marcellus and Utica shale formation map.

Source: (Marcellus Shale Coalition c2019).

Drilling in the Marcellus and Utica basins began in 2003 and 2010, respectively, in Pennsylvania, West Virginia, and Ohio. The Marcellus covers approximately 95,000 miles (152,888 kilometers) from New York to Kentucky, while the Utica spans about 60,000 miles (96,561 kilometers) across Ohio, Pennsylvania, West Virginia, and New York. By the end of 2017, more than 13,100 wells had been drilled across these areas (EIA 2017 Dec 4). As seen in Figure 147, this region has been driving the growth of US natural gas production since 2012, which could have a major impact on the LNG industry along the East Coast.

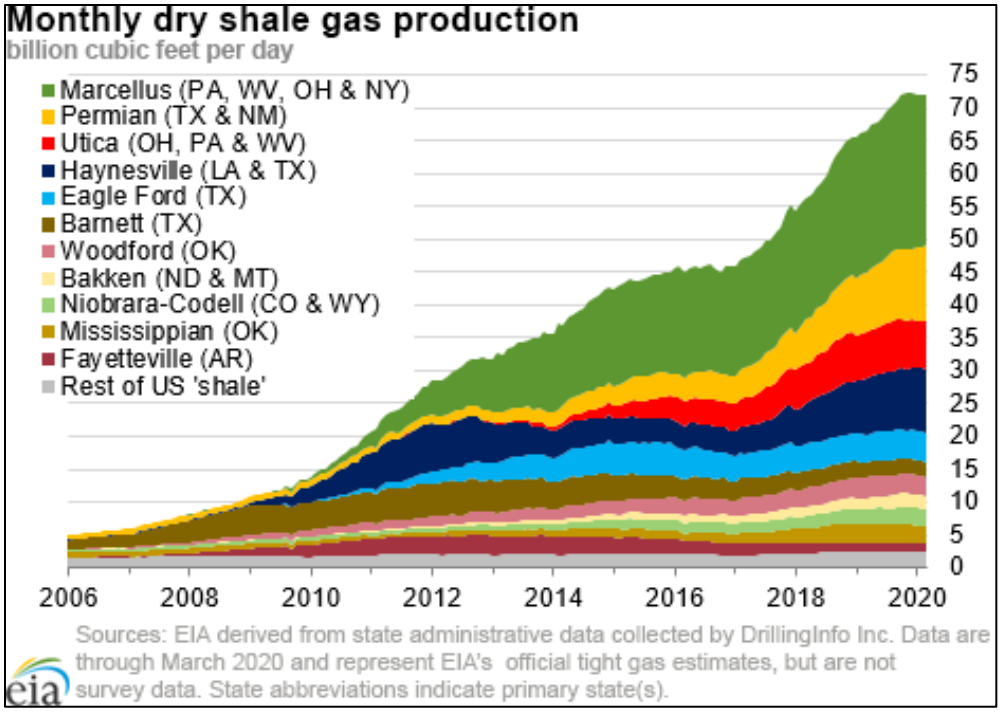

Figure 147. Dry shale gas production by shale play.

Source: Energy Information Administration (EIA 2020 Apr 16).

For example, a new LNG export terminal has been proposed in New Jersey in an effort to take advantage of the vast quantity of natural gas being produced in these nearby shale plays. The project, developed by Delaware River Partners, was approved by the Delaware River Basin Commission (DRBC) in June 2019 to be built along the Delaware River near Paulsboro, New Jersey (Figure 148). The project would receive natural gas, produced in the Marcellus basin and liquefied at a proposed liquefaction plant in Wyalusing, Pennsylvania, by train, where it would then transfer the LNG via a $96 million, 1,600-foot long pier to service tankers for export. The facility would not provide bulk storage of LNG or manufacture any liquids but would act strictly as an exporting location (Duchneskie 2019 Jul 23; Hurdle 2020 Mar 4).

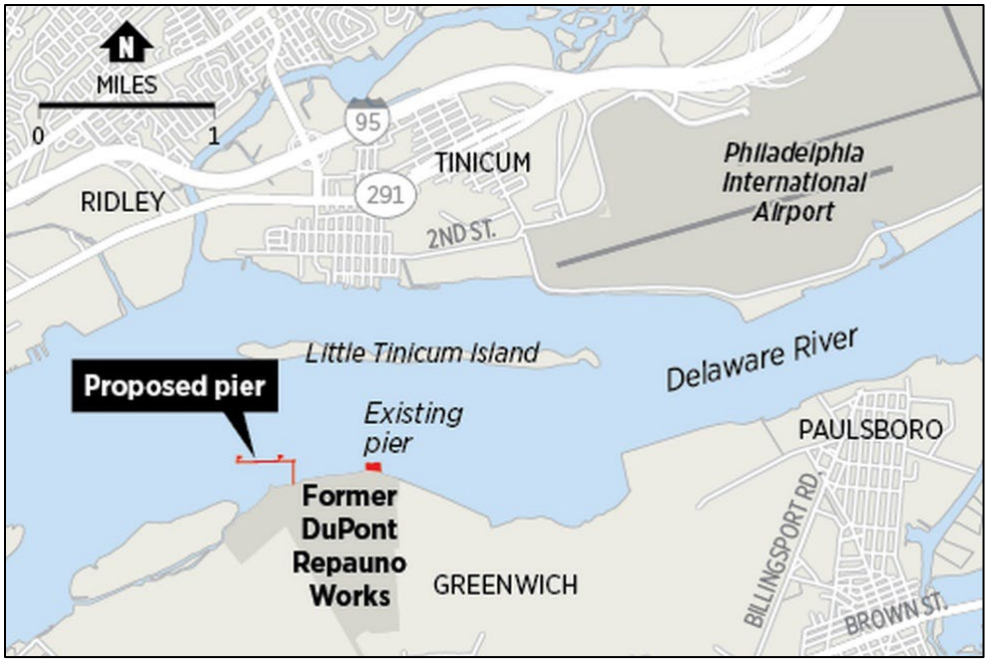

Figure 148. Location of proposed New Jersey LNG terminal.

Source: The Philadelphia Inquirer (Duchneskie 2019 Jul 23).

Although the project was unanimously approved by the DRBC in 2019, it has faced some backlash by local environmental groups and is currently in the process of a "quasi-judicial hearing" due to complaints that the DRBC did not allow enough time for public comments on the proposal, and that the Army Corps of Engineers failed to conduct a full environmental impact study before issuing a permit (Hurdle 2020 Mar 4; Hurdle 2020 Apr 27). As such, it is undetermined whether this project will come to fruition. However, it is likely not the last of its kind that will be proposed in the Atlantic coastal region as more companies will have incentive to follow suit so long as natural gas production continues and market conditions remain favorable.

The recent trend to reduce GHG emissions and create a more environmentally friendly world could also have major impacts on the LNG industry and its development on the East Coast, both directly and indirectly.

One instance of an indirect affect is a recent rule implemented by the International Maritime Organization (IMO) to tighten its restrictions on how much sulphur oxides (SO_x) ships can emit. The main type of fuel used to power ships' engines is heavy oil that is derived as residue from crude oil distillation. The crude oil contains sulphur, which is emitted by a ship after the oil is burned off in its engines. According to the IMO, SO_x are known to cause respiratory issues and lung disease in humans and can lead to acid rain, which can harm crops, forests, and the oceans (IMO c2020). The IMO first instated regulations to reduce SO_x emissions from ships in 2005 under Annex VI of the MARPOL Convention. Under this rule, ships operating outside designated emission control areas (ECAs)[5] were required to limit the sulphur content of their fuel oil to 3.50% m/m (mass by mass), and those operating inside ECA's were limited to 0.10% m/m (IMO c2020). However, on January 1, 2020, the IMO cut the allowed emissions for ships outside ECAs down even further to 0.5% m/m.

Now, in order to comply with these new regulations, ships will be forced to change how they operate. Some may limit air pollutants by installing exhaust gas cleaning systems ("scrubbers"), which remove SO_x from ships' engines and allow them to keep using heavy fuel oil to operate. Others, however, may opt to switch fuels completely to those that contain little to no Sulphur such as LNG and biofuels (IMO c2020). By the end of 2018, 143 LNG-powered ships were already in operation with another 135 on order (Keller 2019 Feb 2). With the IMO's new restrictions in place, that number could substantially rise as ships are forced to find alternatives to crude oil.

As more ships turn to LNG for fuel, LNG bunkering infrastructure will expand as well. LNG bunkering is when LNG is transferred to a vessel to be used as fuel. The most common way to refuel these vessels is through hoses from either a shoreside facility, truck, or a small LNG bunker ship or barge (Figure 149) (ABS 2017). In early 2019, there were only six bunkering vessels in operation worldwide. By 2020, however, this number had doubled to twelve, with 27 more on order or under construction. The Port of Jacksonville is currently the only site on the Atlantic Coast that hosts LNG bunkering, but there is potential for more ports in this area to begin offering similar services as the need grows (The Maritime Executive 2020 Feb 12).

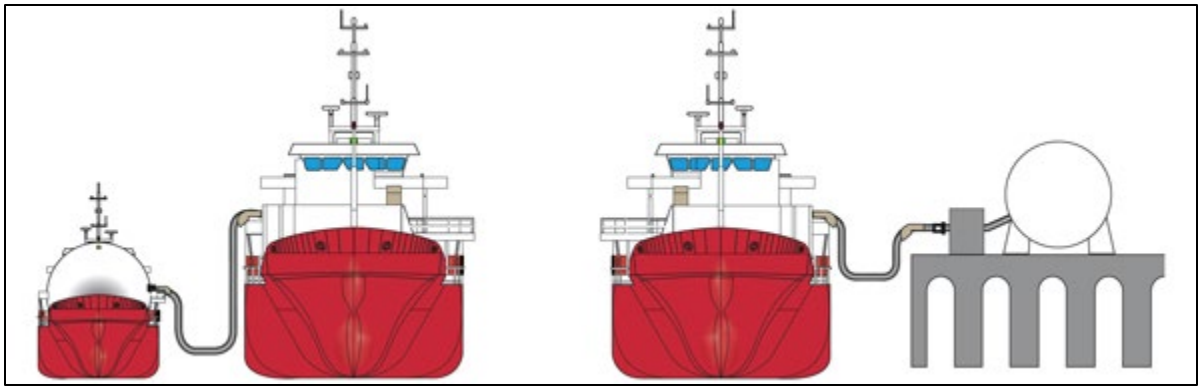

Figure 149. LNG bunkering by ship and shoreside facility.

Source: (KLAW LNG c2020).

[5] ECAs are sea areas in which stricter controls are established to minimize airborne emissions. The currently established ECAs are located around the Baltic Sea area, North Sea area, North American area, and United States Caribbean Sea area (IMO c2020).

Q-LNG Transport, for example, has placed orders for two LNG bunkering barges to provide ship-to-ship LNG fueling, where at least one is expected to fuel cruise ships based in Port Canaveral, and possibly Miami, Florida. Though the plans are still in the initial stages, the LNG is expected be sourced from the Elba Island terminal nearly 230 nautical miles away. If LNG bunkering operations continue to expand, it is likely that they will be developed near existing LNG terminals like Q-LNG's planned projects. Table 43 lists the top 20 container shipment ports in the US and their proximity to existing LNG terminals. Twelve of these ports are less than 230 nautical miles away from an LNG terminal, and distances between LNG terminals and smaller East Coast ports are not much greater. Provided that this distance of 230 nautical miles is economically viable for sourcing and barging, LNG for vessel bunkering could be within reach of every East Coast and GOM port in the US (CRS 2019a). Therefore, the Atlantic Coast could see a spike in LNG bunkering infrastructure expansion as more vessels become reliant on LNG.

Table 43. Top 20 US Container Ports (2017) and Nearby LNG Terminals

US Port	Total Trade (TEUs)	Closest LNG Terminal Location	Distance to LNG Terminal (nautical miles)
Los Angeles, CA	6,189,161	Ensenada, MX	145
Long Beach, CA	5,009,490	Ensenada, MX	140
New York, NY	4,767,279	Cove Point, MD	330
Savannah, GA	3,162,898	Savannah, GA	In port
Norfolk, VA	2,189,485	Cove Point, MD	100
Houston, TX	2,018,254	Freeport, TX	75
Charleston, SC	1,725,784	Savannah, GA	80
Oakland, CA	1,666,100	Ensenada, MX	490
Tacoma, WA	1,278,298	Ensenada, MX	1,290
Seattle, WA	987,151	Ensenada, MX	1,280
Jacksonville, FL	817,242	Jacksonville, FL	In port
Port Everglades, FL	791,849	Jacksonville, FL	280
Miami, FL	768,028	Jacksonville, FL	310
Baltimore, MD	702,897	Cove Point, MD	60
New Orleans, LA	406,439	Pascagoula, MS	80
Philadelphia, PA	362,811	Cove Point, MD	290
Mobile, AL	250,575	Pascagoula, MS	60
San Juan, PR	212,583	Peñuelas, PR	115
Boston, MA	211,193	Everett, MA	In port
Wilmington, DE	197,089	Cove Point, MD	270

Note: TEU = twenty-foot equivalent unit. These figures include only loaded containers and empty containers that involve a freight charge. Mileage figures are approximate.

Source: Congressional Research Service (CRS 2019a).

Another factor that could affect LNG development on the Atlantic Coast is the US increasing interest in wind generation. Offshore wind (OSW) farms often operate in ECAs, where installation and maintenance vessels need to meet the SO_x limit set forth by the IMO. LNG's low cost and low sulphur emissions make it a perfect fuel choice for vessels needed to establish wind farms. Therefore, LNG bunkering infrastructure would need to be built nearby to easily refuel these vessels. GustoMSC, a company that specializes in designing and engineering mobile offshore units and equipment, is in the process of creating LNG-powered ships specifically designed to install and maintain OSW farms. ENSIS is one such vessel optimized for the installation of large monopiles (Figure 150). Equipped with a heavy-duty crane, its multi-purpose nature will also enhance the installation of jacket-type foundations and a wide range of other offshore construction activities (GustoMSC c2020).

Figure 150. ENSIS offshore wind installation vessel.

Source: Power & Energy Solutions (PES Essential 2017).

With multiple OSW farms already online, and more than a dozen already planned for the Atlantic OCS in the near future, these ships may become more commonplace, intertwining LNG's fate with that of wind power.

10. Refineries

10.1 Description of the Industry and Services Provided

There are few, if any, uses of crude oil in its natural state. The petroleum refining industry is dedicated to the processing of crude oil and other crude oil-based feedstocks into usable fuels and products. The US refining industry is almost as old as the commercial crude oil and natural gas industry itself. The first refinery in the US, for instance, was developed and began refining operations in 1861 near Titusville, Pennsylvania, adjacent to the site where Edwin Drake and W.A. Smith discovered the first producing oil field. The wood-fired distillery (or "still") worked on a batch method that took three days and produced only kerosene and no other refined products. (Wisdom et al. 1998; Uhl 1984 Feb 1).

The petroleum refining process is comprised of a variety of physical and chemical operations that have been developed over the past hundred years. In the 1860s, petroleum development was almost exclusively oriented towards finding illumination substitutes that were portable, clean burning, and could be developed from an abundant feedstock. Kerosene was seen as a valuable competitor to other forms of early illumination that included whale oil, beeswax, other agricultural products, and early manufactured gas and early natural gas systems.

Early kerosene refineries used a process that simply involved heating or "boiling" the mixture to various temperatures to extract one product, kerosene, for clean burning, uniform-quality fuel for lighting purposes. Today, the refining process produces a large number of end products through a range of processes, including heating, distilling, and catalytic conversions. As illustrated in Figure 23 below, a 42 US gallon barrel of crude oil provides around 44.5 gallons of different petroleum products, such as gasoline, diesel fuel and heating oil, jet fuel, and liquefied petroleum gas (EIA 2019a Dec 14).

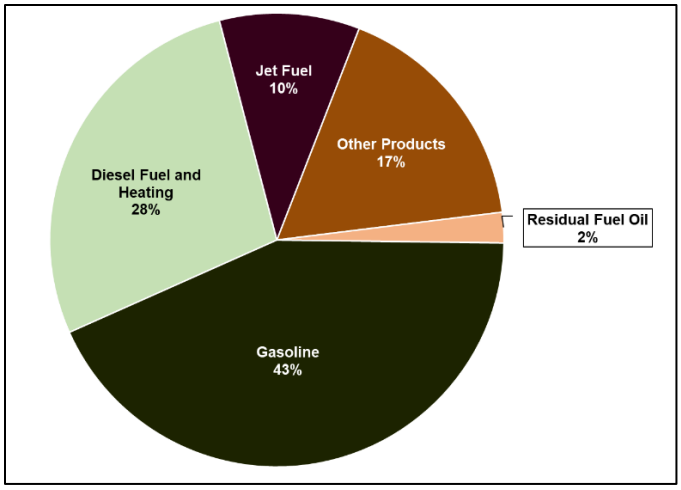

Figure 151. Products made from a barrel of crude oil (Percentage of Yield).

Source: US Energy Information Administration (EIA 2019a Dec 14).

10.2 Typical Facility Characteristics

Differences in crude oil composition and consistency have led to the development of different types of refineries. Crude oil input quality is an important factor in defining the scope of a refinery's operations and refining processes. Crude oil is not uniform or homogeneous in quality and can vary in gravity and sulfur content (EIA 2017 Sep 21). Each characteristic will determine the degree of additional processing, treatment, capital investment, and profitability needed to develop a given slate of refined product yields.

The gravity of any given crude oil stream is an important characteristic. A crude oil stream can be either heavy (low gravity), light (high gravity), or somewhere in between. A heavy crude oil input, with relatively low gravity, is typically thicker, does not flow well, and is usually associated with a higher carbon-to-hydrogen ratio than a crude stream that is considered light. Heavier crude oils, typically produced and imported from such places as Canada and Mexico (as seen below in Figure 25), are also known to contain a high level of carbon residues, asphaltenes, sulfur, nitrogen, and heavy metals (EIA 2019b Dec 14). Historically, some refineries in the US have used very heavy crude oils from places such as Venezuela, and to a lesser extent, Saudi Arabia (EIA 2019b Dec 14). Recently, however, geo-political strains in Venezuela, and US responses to these conditions, have restricted US imports from Venezuela (Kemp 2019 Feb 12).

Figure 25, for instance, shows the historic trends in crude oil feedstocks for US refineries. These trends show considerable increases in heavier crude streams from places like Canada and Mexico, with decreasing imports from such places as Venezuela (as noted earlier), Iraq, and other collective places around the globe.

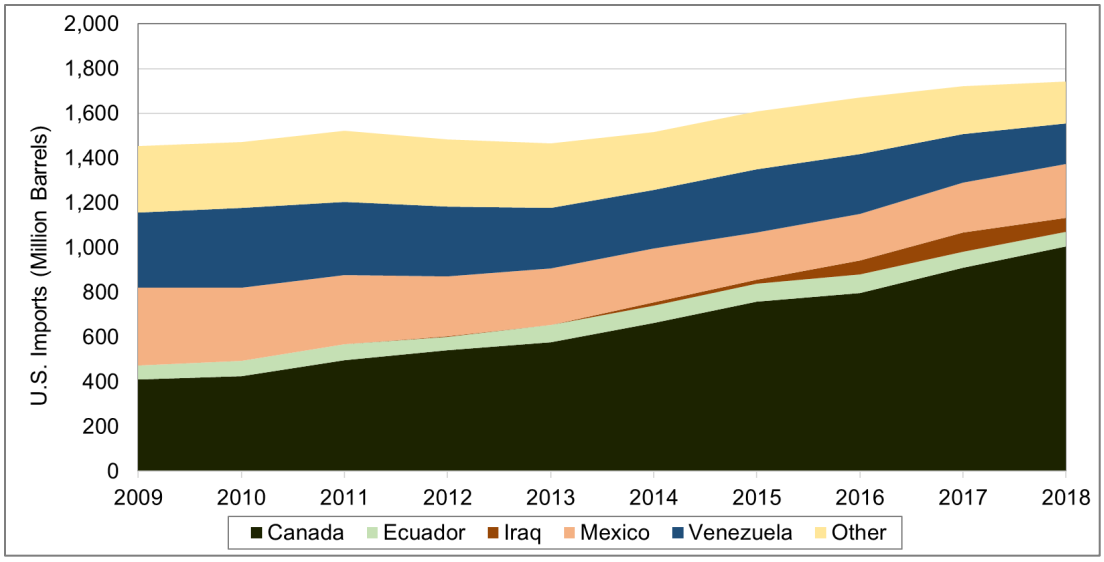

Figure 152. US Imports of Heavy Crude Oil, 2009–2018.

Source: US Energy Information Administration (EIA 2019b Dec 14).

Note: Heavy crude oil defined as crude oil with an API gravity of <=27.

Sulfur content is a second and important qualitative difference in crude oil that can impact refining configurations. The refining industry refers to crude oil feedstocks that have relatively lower sulfur concentrations as being "sweet," while those with higher sulfur contents as being "sour." Generally, "sweet crudes" are considered to be those that contain less than 0.5 percent sulfur by weight, while high sulfur, or "sour" crudes typically have a sulfur content of 0.5 percent or higher. High sulfur crudes are more corrosive than their "sweeter" counterparts, making them more expensive to handle and process. Over the years, various regions' crude oil production has been named by its qualitative difference, such as Heavy Louisiana Sweet, West Texas Intermediate, and Wyoming Sour.

Unique product blends and regulatory requirements, such as those restricting the sulfur content of various types of fuels, can also impact the configuration of a modern refinery. The geographic needs for various refined products, the availability of inputs, export and distribution capabilities, input cost characteristics, and historic evolution can also be important determinants that have led to the development of certain refineries in various locations of the country. Today, these factors tend to be more important in decisions associated with maintaining or expanding existing facilities than in developing new ones since no new modern greenfield refinery has been developed since the Garyville, Louisiana refinery started operations in 1976 (Fluor 2019 Dec 14).[6]

[6] Although no new modern greenfield refinery has been built since 1976, Meridian Energy Group is currently in the process of developing a new modern greenfield refinery in Belfield, North Dakota, which it hopes to put in operation by 2023 (Meridian Energy Group Inc. 2019 Dec 14). This refinery is anticipated to have a capacity of 60,000 barrels per day and is anticipated to be comprised of a $1.0 billion capital investment (McEwen 2019 Feb 15)

While each individual refinery can differ, some common operations occur at most facilities. For instance, the initial phase of most refining processes begins with the heat separation of the crude oil components through a series of distillation towers. This distillation process is a modern variation of the boiling processes used by refineries over one hundred years ago during the industry's evolution in the Appalachian region of the US Today's modern distillation towers, however, are much more complicated and use individually calibrated temperatures and pressures to separate various unique types of fuels from crude oil inputs.

Crude oil entering the distillation tower is separated into various vapor and liquid mediums using heat generated from furnaces that can reach temperatures as high as 800 degrees Fahrenheit. The vaporized portion of the crude oil input rises through the tower condensing into different products as the temperature falls. The heavier, liquid portion of the crude remains at the bottom of the distillation tower (Valero 2015).

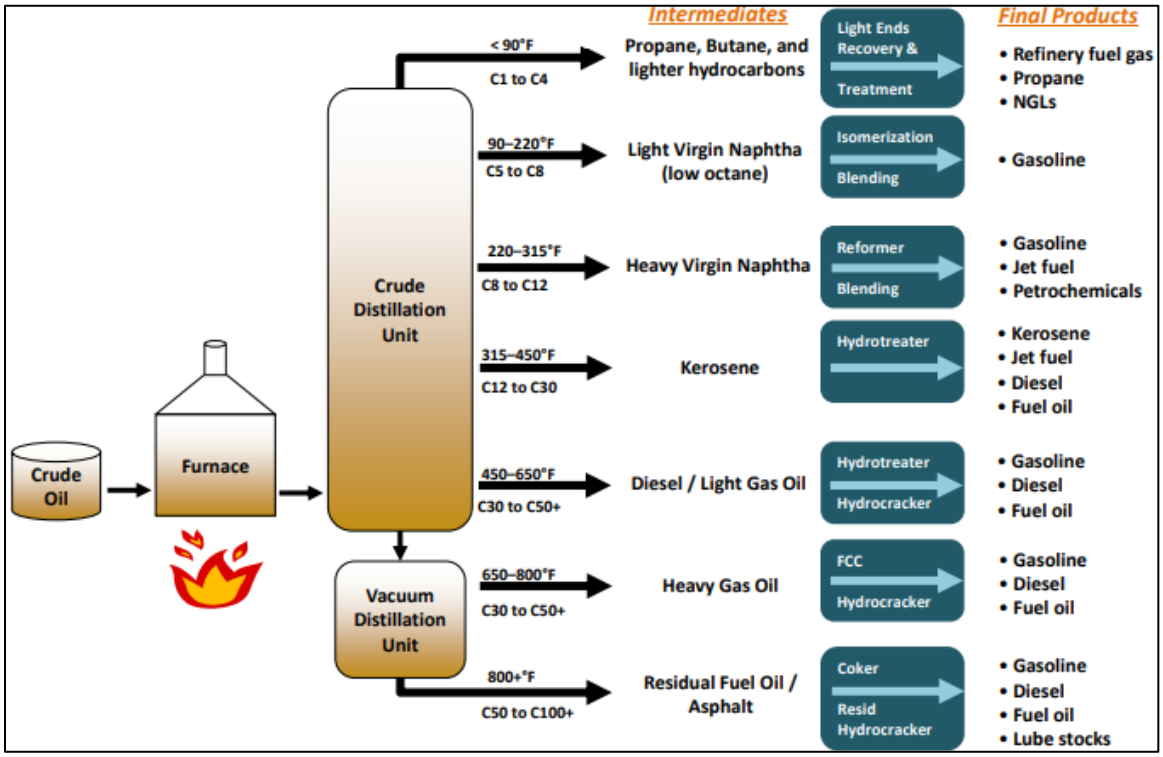

Figure 153. Distillation process and yield schematic.

Source: Valero (Valero 2015).

A schematic of how distillation towers separate products from gases at the top, to very heavy, viscous liquids at the bottom, is presented in Figure 153. The thick liquids remaining at the bottom of the distillation tower are considered unfinished and usually require further processing (Valero 2015). Yield refers to the relative percentage of each type of separated component, or product streams, produced through the primary distillation process. This percentage will vary depending on the composition of the crude being processed.

The heaviest hydrocarbons, having the highest boiling points, remain at the bottom of the distillation tower and can be further processed through an additional distillation process that takes place under vacuum. The resulting materials from vacuum distillation can be further processed into lubricating oils and other products through another process known as solvent extraction. Various types of solvents can also be used to separate impurities, non-lubricating types of oils, or various waxes from the various hydrocarbon mixes that are produced from the primary distillation process (Lloyd Minister 2019 Dec 14).

An important and secondary form of refining is commonly referred to as the "cracking" process. During the cracking process, intermediate hydrocarbon blends, commonly a byproduct arising from the distillation process, are exposed to various catalysts under controlled heat and pressure. This process produces additional refined products. The most commonly refined products that arise from the cracking process include gasoline, liquefied petroleum gas (LPG), unsaturated olefin compounds, cracked gas oils, cycle oil, light gases, and solid coke. The cracking process leads to the separation of a class of liquid hydrocarbons known as naphthenes, which are often used as solvents and diluents, olefins (ethylene, propylene and butylene), and parrafins (AIP 2017 Sep 1). With additional treatment (reformation), these intermediate refined products (commodity chemicals) can be important building blocks for a wide range of petrochemical products, including:

Ammonia	Guitar strings	Ping-Pong paddles
Antiseptics	Heart valves	Plastic beverage containers
Bubble gum	Ice chests	Roller-skate wheels
Crayons	Insect repellant	Sneakers
Denture adhesive	Life preservers	Synthetic fibers
Eyeglass frames	Liquid detergent	Telephones
Fertilizer	Mascara	Tobacco pouches
Floor polish	Paint	Volleyballs

A refinery's ability to create inputs (primarily LPGs) that are used in the commodity chemical production process is an important aspect of a given refinery's importance, size (in terms of distillation capacity), and profitability. Refineries that are integrated with broader chemical operations allow for input hydrocarbons to be optimized across a wide range of refined products and commodity chemicals. These chemical operations are usually co-located or located in very close proximity to the refinery. The development of both refining and chemical operations allows large energy companies, like BP, Shell, or ExxonMobil, to maximize their operations and profitability. This is one reason why refineries along the Gulf Coast are relatively large integrated facilities, while those along the Atlantic seaboard (particularly in the mid-Atlantic region), tend to be smaller, more stand-alone units.

Reforming is another important function that can occur during the refining process. The reformation process converts naphthenes into products that can be used as petrochemical inputs or components of high-octane gasoline. An additional refining process known as isomerization separates paraffins, or single-chained hydrocarbons, into isoparrafins to create a product more readily processed into other outputs and to be more effective in fuel blends (AIP 2017 Sep 1). Alkylation is a refining function that produces isoparrafins from the bonding of olefins and isobutene (Fahim et al. 2009). Furthermore, a process known as polymerization creates large hydrocarbon molecules from smaller, lighter, chains under exposure to heat, pressure, and catalysts to yield a high-octane gasoline component polymer gasoline (AIP 2017 Sep 1).

10.3 Geographic Distribution

The Atlantic seaboard is included in the US Department of Energy's PADD District 1.[7] According to Energy Information Administration (EIA), PADD District 1 is home to eight refineries[8] with approximately 1.2 million barrels per day (MMBbls/d) of refining capacity. PADD District 1 (as illustrated in Table 44) is a relatively evenly balanced refining region in that it accounts for six percent of the total number of refineries and seven percent of total US refining capacity. These relative shares differ from the Gulf Coast (PADD 3), which accounts for only 42 percent of the total refineries in the US, but 53 percent of total US refining capacity. PADD 1 also differs from the midwestern US (PADD 4), which accounts for 12 percent of all US refineries, but only four percent of total US refining capacity (EIA 2019 Jun 21).

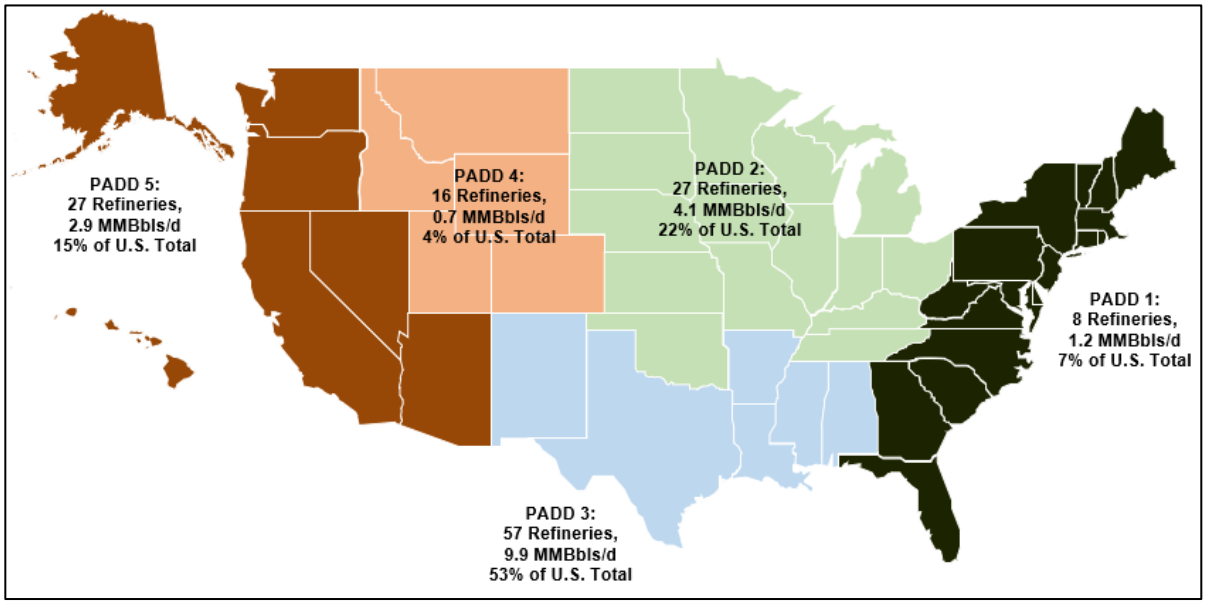

Figure 154. Number and capacity of US refineries, as of January 1, 2019.

Source: US Energy Information Administration (EIA 2019 Jun 21).

Atlantic region refineries in PADD 1 are also relatively close to the average size for a typical US refinery. The US currently has over 18.8 MMBbls/d of total refining capacity located at 135 refineries, for an average refinery size of about 139 thousand barrels per day (MBbls) of capacity. PADD 1 refineries have an average size of about 153 MMBbls/d of capacity, smaller than a large modern Gulf Coast facility of

[7] The five regions referred to as "Petroleum Administration for Defense Districts" or "PADDs" were created during World War II to facilitate oil allocation for defense purposes. Though the original PADDs were abolished in 1946, they were re-activated during the Korean War and taken over by the US Department of the Interior (Oil and Gas Division) and then later by the US Department of Energy.

[8] Though EIA reports eight refineries in PADD 1, there are technically only six refineries in the Atlantic region. One of the refineries included within EIA's PADD 1 data is located in West Virginia. Another facility, meanwhile, is listed as operational; however, it is actually no longer operational as of December 2019 (Philadelphia Energy Solutions).

over 173 MBbls/d of capacity, but larger than a refinery in the western US that averages about 106 MBbls/d of capacity.

Table 44 lists the six Atlantic refineries, provides the state in which they operate, and their operating capacities. A map illustrating similar information is provided in Figure 155. The table underscores the wide range of refineries located in the region, ranging from the exceptionally small American Refinery Group facility (11 MBbls/d) to the moderately sized Phillips 66 facility in New Jersey (at 258.5 MBbls/d of operating capacity).

Table 44. Study area refineries as of January 2019

	Facility	State	Operating Capacity (Barrels per calendar day)
1	Delaware City Refinery	DE	182,200
2	Paulsboro Refining Co LLC	NJ	160,000
3	Phillips 66 Co-Bayway Refinery	NJ	258,500
4	Monroe Energy LLC-Trainer Refinery	PA	190,000
5	American Refining Group Inc	PA	11,000
6	United Refining Co	PA	65,000
Total			**866,700**

Source: US Energy Information Administration (EIA c2019).

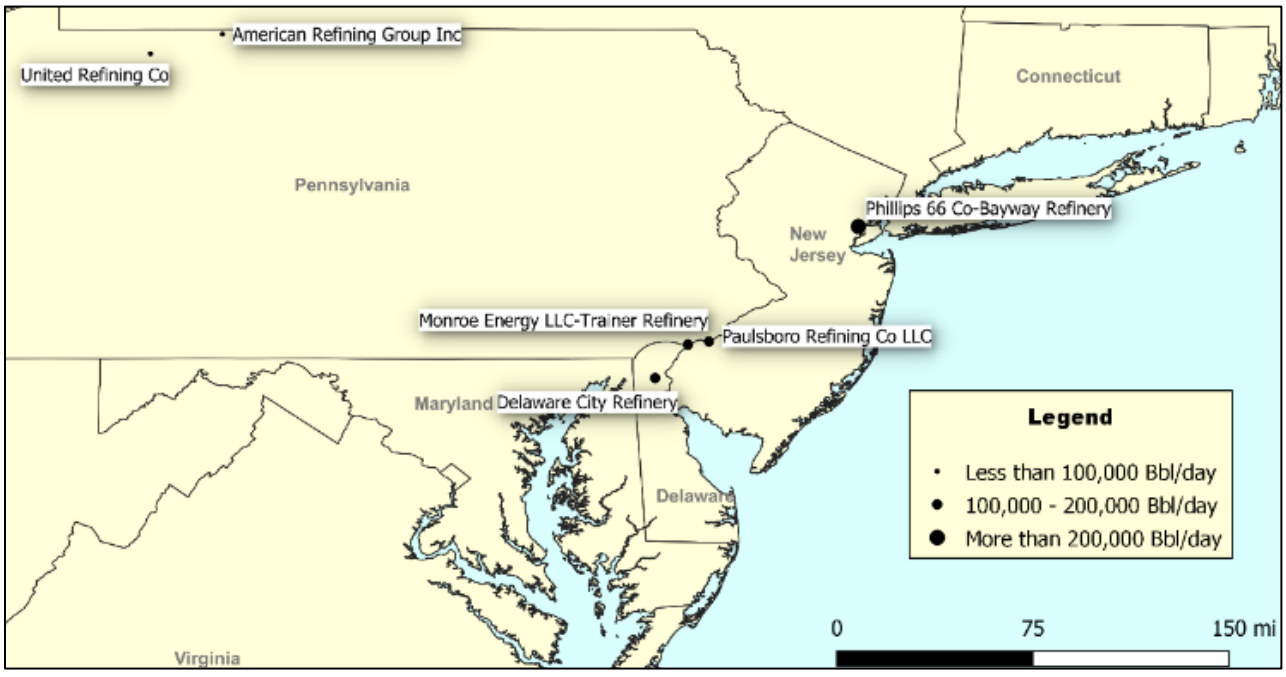

Figure 155. Study area refineries.

The following summarizes the characteristics of each operating refinery.

- Phillips 66's Linden, New Jersey facility was built in 1909 and has a total capacity of 258,500 barrels per day. The facility reports approximately 800 employees, and is the largest refinery on the East Coast (EIA c2019; Phillips 66 c2019). The Phillips refinery processes mainly light, low-sulfur crude from Canada and West Africa, and produces mostly transportation fuels, as well as petrochemical feedstocks, residual fuel oil, and home heating oil. In addition, this refinery is one of the few in the region that maintains an onsite polypropylene plant, which produces over 775 million pounds of polypropylene per year. Products are delivered to customers on the East Coast by pipeline transport, barges, railcars, and tank trucks (Phillips 66 c2019). The Phillips refinery can process up to 258.5 MBbls/d, with naphtha or reformer feed and diesel fuel being the main outputs at 65.5 and 108 MBbls//d, respectively (EIA c2019).
- The Paulsboro, New Jersey refinery is owned by PBF Energy and has a total capacity of 160 MBbls/d (EIA c2019). The Paulsboro refinery employs approximately 475 workers (GCCOC c2018), and is located on 950 acres in southern New Jersey on the Delaware River, 15 miles (24 kilometers) south of Philadelphia. The refinery processes a variety of medium and heavy sour crude oils, and produces gasoline, home heating oil, and jet fuel, as well as lubricant base oils and asphalt (PBF Energy c2019). Much of the jet fuel production supplies the Philadelphia International Airport (GCCOC c2018).
- PBF Energy's second Atlantic refinery, located in Delaware City, Delaware, has a total operating capacity of 182.2 MBbls/d (EIA c2019) and is located on 5,000 acres on the Delaware River (PBF Energy c2019). The Delaware City refinery reports around 560 employees (Hurdle 2018 Feb 2) and is one of the more complex refineries in the region, refining high sulfur crude oils (PBF Energy c2019). PBF Energy purchased the facility from Valero Energy in 2010. Valero Energy had idled the facility in November 2009, reporting at the time that it was losing an estimated $1 million per day due to reduced gasoline demand (Reuters 2011 Apr 29). PBF Energy restarted the facility in October 2011 (PBF Energy 2011 Oct 7).
- In April 2012, Delta Airlines (Monroe Energy) acquired a refinery in Trainer, Pennsylvania from ConocoPhillips in order to offset the risk of higher jet fuel prices (Mouawad 2012 Apr 30). The Monroe Energy refinery is located on the Delaware River (Mouawad 2012 Apr 30), and has a total capacity of 190,000 barrels per day (EIA c2019). The Monroe Energy facility processes mainly light, low sulfur crude oil, and produces mostly transportation fuels such as gasoline and diesel (Mouawad 2012 Apr 30).
- American Refining Group's refinery is located on 131 acres in Bradford, Pennsylvania (American Refining Group c2019) and has a capacity of 11,000 barrels per day, making it the smallest refinery on the East Coast (EIA c2019). This refinery processes mostly light sweet paraffinic crude that is purchased from the unconventional basins in the Appalachian region (Pennsylvania, Ohio, New York, and West Virginia). The Bradford refinery produces wax, lubricant base oils, gasolines, and fuels (American Refining Group c2019). Employment at the refinery has grown from 165 in 1997 to approximately 350 at present day (American Refining Group 2017 Mar 4).
- United Refining Co.'s refinery in Warren, Pennsylvania has been operational for over 100 years (United Refining Company c2019). It is located in northwest Pennsylvania and has a capacity of approximately 65,000 barrels per day (EIA c2019). United Refining does not offer any public estimates on the number of workers that are directly employed at the Warren, PA facility.

10.4 Scope of Economic Contribution to Regional Economy

The East Coast refining sector is relatively small in comparison to (a) each of its component state's overall value-added and (b) the economic contribution made by the refining sector relative to the US GDP. On a regional basis (Atlantic region), Delaware's refining GDP makes the largest contribution to its home state's overall economy of 0.8 percent. Pennsylvania refineries, meanwhile, have the second largest refinery operating capacity in the region, yet only contribute seven-tenths of one percent to the state's overall GDP. These statistics, as well as other summary economic contributions, are provided in Table 45.

New Jersey, with the largest regional refining share (48 percent), makes the second-largest contribution to the regional refining sector value-added of 32 percent; and total US refining sector value-added of 2.3 percent. However, the state accounts for only 2.2 percent of total US refining capacity. Similarly, Delaware, which makes a larger relative contribution to its own economy, makes a relatively smaller contribution to the economic output of the overall US refining sector.

Table 45. Regional and national value-added (GDP) contribution, refinery sector, 2017

State	Refining GDP (Millions in Current $)	Total GDP (Millions in Current $)	Refining GDP as a Percent of Total State GDP (%)	Refining GDP as a Percent of Total US Refining GDP (%)
DE	548	70,775	0.8	0.4
NJ	2,917	595,325	0.5	2.3
PA	5,538	744,290	0.7	4.3
Total Region:	**9,003**	**1,410,389**	**0.6**	**7.0**
Total US	**128,348**	**19,519,424**	**0.7**	**100.0**

Source: US Bureau of Economic Analysis (BEA c2020).

Figure 156 charts the total economic contribution, in terms of value-added that the refining sector makes in the eastern seaboard states with refineries. Pennsylvania reports the highest refinery value added relative to any other state in the region at $5.5 billion per year. This amounts to 62 percent of all regional value added. New Jersey, with nearly $3.0 billion in the annual value of its refinery output, accounts for 32 percent of the value of the region's refinery output. Delaware, meanwhile, comprises a much smaller share of the region's refinery output.

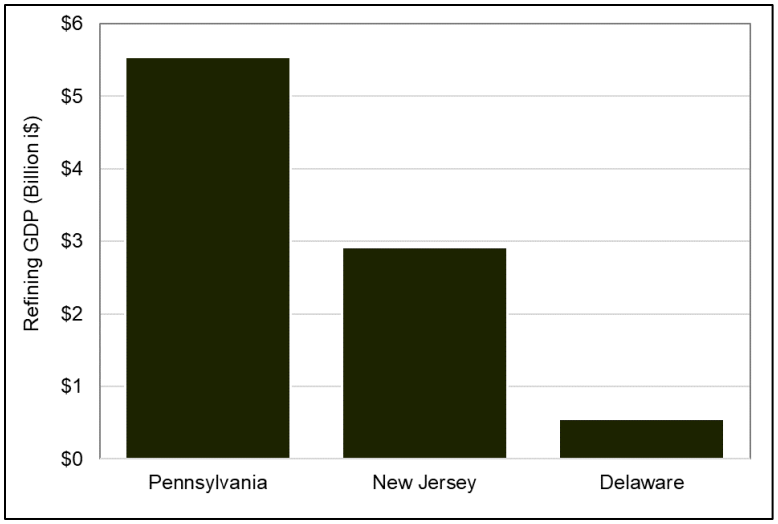

Figure 156. Regional refinery value-added (GDP) contributions, 2017.

Source: US Bureau of Economic Analysis (BEA c2020).

Figure 157 examines the regional trends in refining value-added relative to the "crack spread,"[9] as a measure of gross profitability, reported over the past two decades. The chart shows that regional refinery value-added contributions are highly correlated, albeit lagged, relative to crack spreads. For instance, an initial increase in market crack spreads after the 2005 tropical seasons led to an increase in mid-Atlantic value-added contributions peaking at close to $12 billion by 2008. The chart shows a second surge in regional refining value-added around 2014, following the post-recession crude oil price and crack spread run up after 2010.

[9] A crack spread is a general measure of refined product profitability as reflected in the price of crude oil inputs relative to refined product outputs. A "3:2:1 crack spread" is one of the more commonly reported forms of crack spreads and represents the commodity-priced cost of purchasing 3 barrels of crude oil and selling 2 barrels of gasoline and 1 barrel of distillates on futures markets.

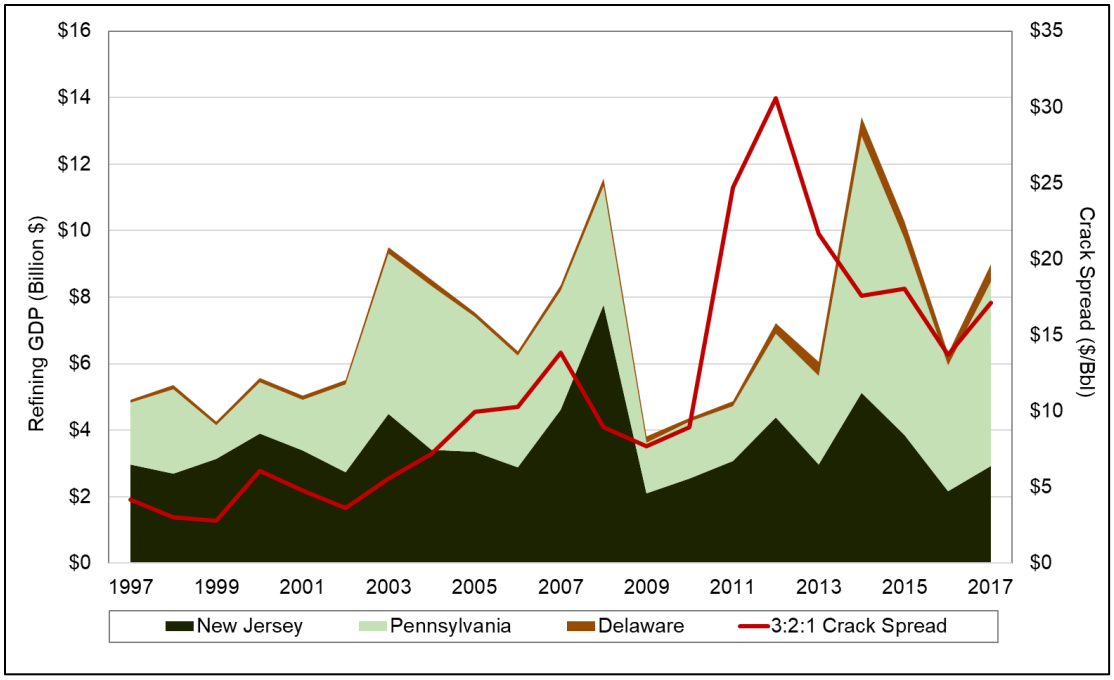

Figure 157. Trends in Atlantic region refining GDP.

Source: US Bureau of Economic Analysis (BEA c2020).

Table 46 and Figure 158 show that each state's total refinery employment contributions are very small in comparison to the total employment in the region. None of the states in the Atlantic region have refinery employment totals that are over 0.20 percent of the overall statewide employment totals. Refining employment in Delaware represents the highest contribution, at 0.15 percent. On a regional basis, however, both New Jersey and Pennsylvania have the highest share of total refinery employment.

Table 46. Regional and national employment contribution, refinery sector, 2018

State	Number of Refining Jobs (2018)	Total State Jobs (2018)	Refinery Employment as a Percent of Total State Employment (%)	Refinery Employment as a Percent of Total US Refinery Employment (%)
DE	560	384,332	0.15	0.80
NJ	1,396	3,472,611	0.04	2.00
PA	2,079	5,193,979	0.04	2.98
Total Region	**4,035**	**9,050,922**	**0.04**	**5.78**
Total US	**69,798**	**124,551,838**	**0.06**	**100.00**

Note: Refining data for New Jersey is from 2017; data for 2018 was unavailable.

Source: US Bureau of Labor Statistics (BLS c2020); (Hurdle 2018 Feb 2).

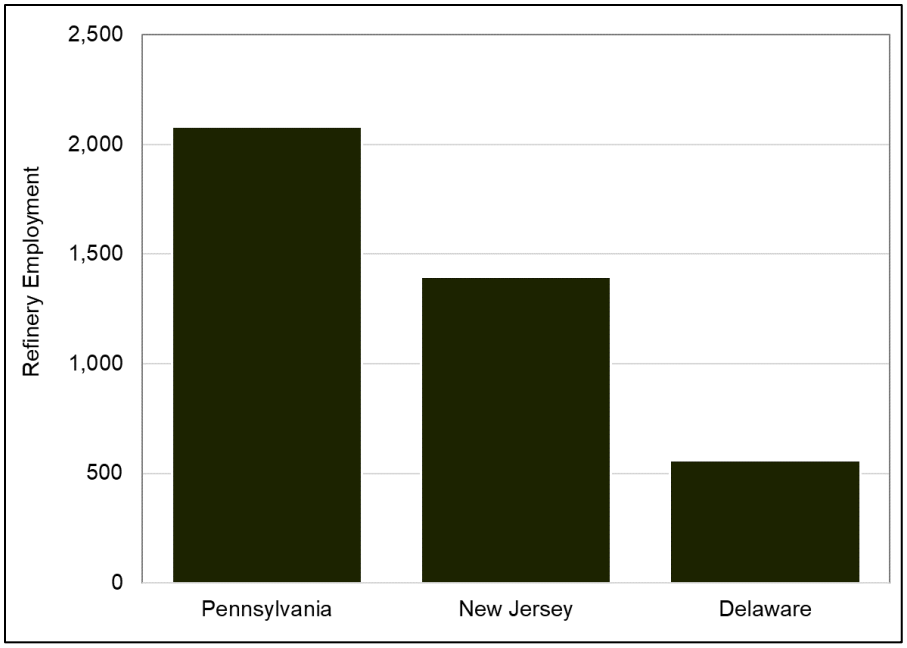

Figure 158. Atlantic region refinery employment shares, 2018.

Note: Employment data for New Jersey is from 2017; data for 2018 was unavailable.

Source: US Bureau of Labor Statistics (BLS c2020); (Hurdle 2018 Feb 2).

Over the past decade, regional refinery employment has declined moderately in states along the Atlantic coast, both on a nominal basis, and relative to overall US trends. New Jersey and Pennsylvania reported over 4,500 refinery jobs in 2009 but, as of 2018, provided only 3,455 jobs in the refining sector. This trend is highlighted in Figure 158 and Figure 159.

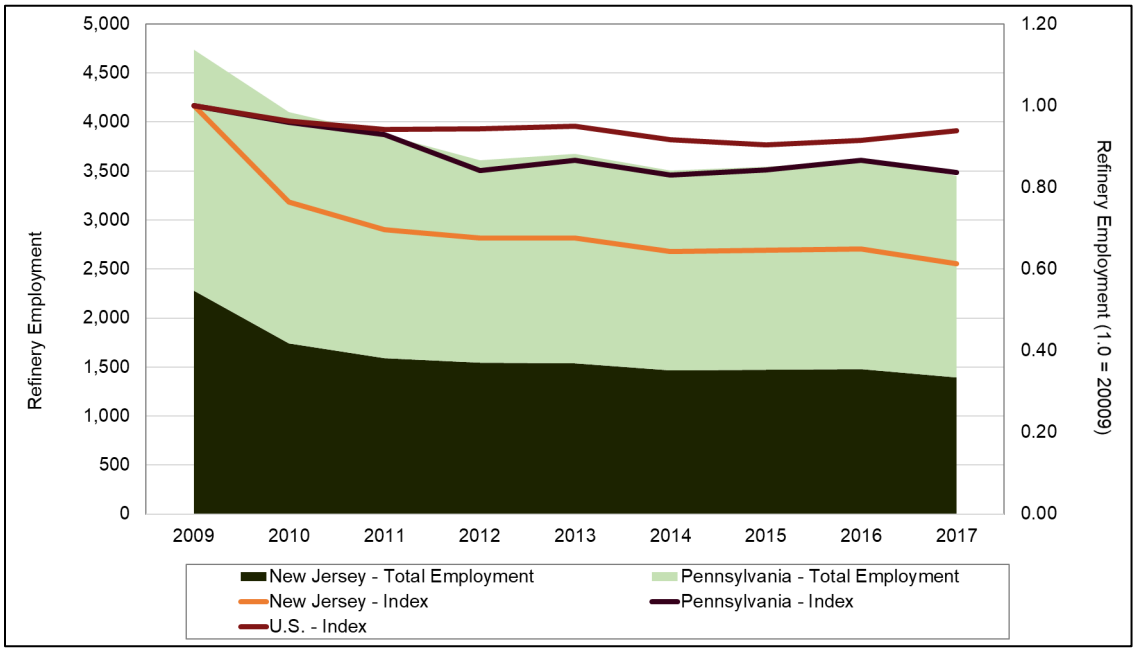

Figure 159. Trends in Atlantic region refinery employment, 2009–2017.

Note: A complete set of data was not available for Delaware.

Source: US Bureau of Labor Statistics (BLS c2020).

Regional wage contributions, provided in Table 47, follow trends similar to employment levels. The regional totals are dominated by the states with the largest shares of refining capacity (New Jersey and Pennsylvania). The regional shares of total wages paid by Atlantic coast refineries are provided in Figure 160.

Table 47. Regional and national wages contribution, refinery sector, 2018

State	Refining Wages(Millions in 2018 $)	Total State Wages (Millions in 2018 $)	Refinery Wages as a Percent of Total State Wages (%)	Refinery Wages as a Percent of Total US Refinery Wages (%)
DE	NA	21,785	NA	NA
NJ	191.0	226,946	0.08	1.91
PA	265.3	287,198	0.09	2.66
Total Region	**456**	**535,930**	**0.09**	**4.58**
Total US	**9,973**	**7,124,159**	**0.14**	**100.00**

Notes: (1) Refining data for New Jersey is from 2017; data for 2018 was unavailable. (2) N.A. is “not available.”

Source: US Bureau of Labor Statistics (BLS c2020).

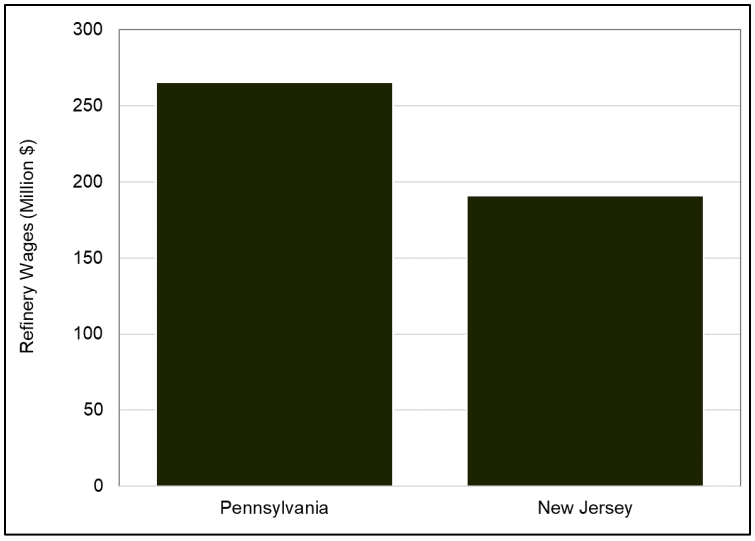

Figure 160. Atlantic region refinery wage shares, 2018.

Notes: (1) Refining data for New Jersey is from 2017; data for 2018 was unavailable; (2) A complete set of data was not available for Delaware.

Source: US Bureau of Labor Statistics (BLS c2020).

From 2009 to 2017, refinery wages in the Atlantic region (and the US as a whole) held steady for the most part. Wages in Pennsylvania increased slightly, while wages in New Jersey declined by a small amount (Figure 161).

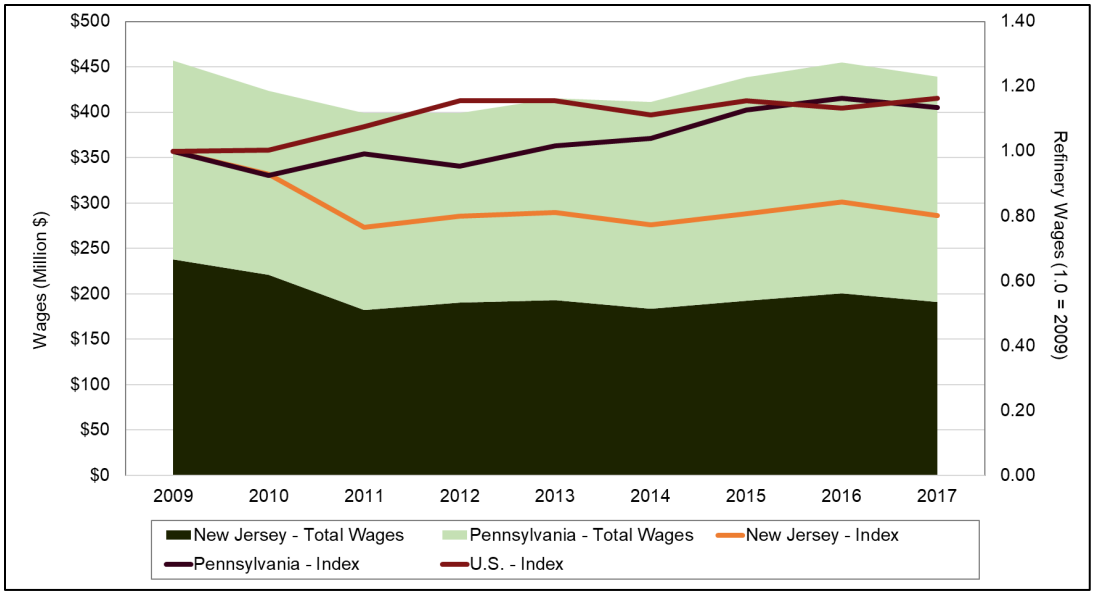

Figure 161. Trends in Atlantic region refining wages, 2009–2017.

Note: A complete set of data was not available for Delaware.

Source: US Bureau of Labor Statistics (BLS c2020).

Table 48 provides a comparison of the average annual wages paid to employees in the refining sectors of the Atlantic region. The annual wages for refinery employees in New Jersey and Pennsylvania are considerably higher, in fact orders of magnitude higher than the average in-state wage. This result is consistent with national trends that show the refining sector, at a national level, to pay wages that are considerably higher than the US national average.

The last column provided in Table 48 compares each state's average annual refinery wage to the US average annual refining wage of $134,867. Generally, average annual refinery wages in the region are below the US refinery average. Pennsylvania, with the second highest share of refining capacity in the region, has wages that are 89 percent of the US average.

Table 48. Regional refinery and national average annual wage comparisons, 2017

State	Average Annual Pay (Refining) ($)	Average Annual Pay (All) ($)	Refinery Avg. Annual Pay as a Percent of Total State Avg. Annual Pay (%)	Refinery Avg. Annual Pay as a Percent of Total US Refinery Avg. Annual Pay (%)
DE	NA	55,780	NA	NA
NJ	136,848	63,705	214.8	101.5
PA	120,557	53,673	224.6	89.4
Total Region	**128,703**	**57,719**	**223.0**	**95.4**
Total US	**134,867**	**55,338**	**243.7**	**100.0**

Note: N.A. is "not available."

Source: US Bureau of Labor Statistics (BLS c2020).

Trends in regional average annual wages are provided in Figure 162. The trends show that, in general, average annual wages for refinery employees have been increasing moderately across the East Coast, and the US as a whole.

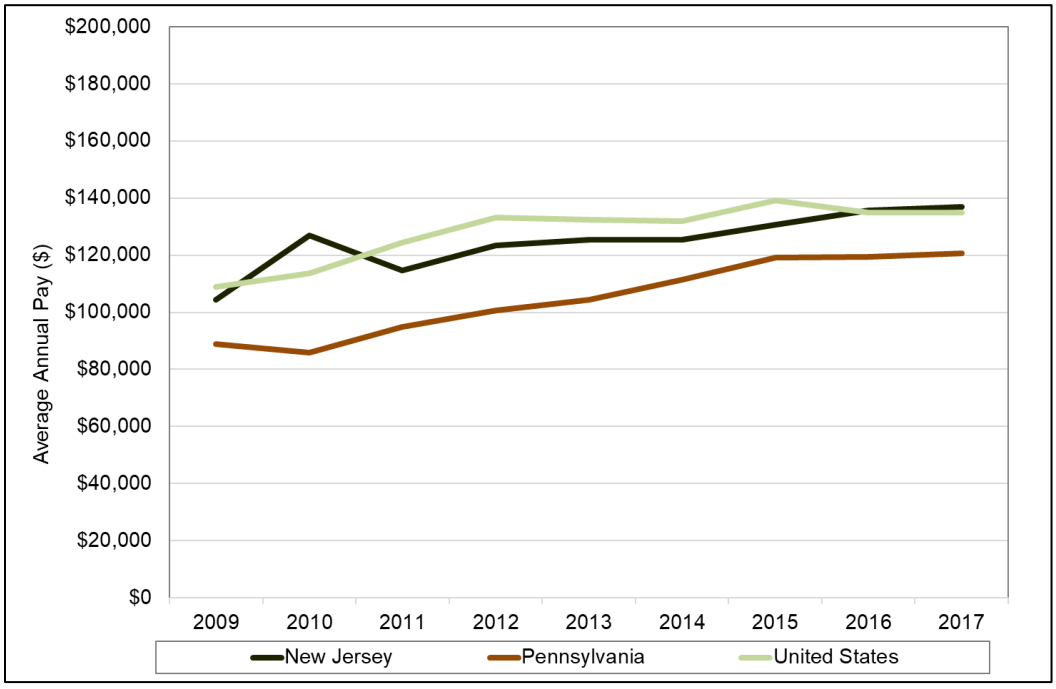

Figure 162. Trends in Atlantic region refinery average annual wages, 2009–2017.

Note: A complete set of data was not available for Delaware.

Source: US Bureau of Labor Statistics (BLS c2020).

10.5 Current Trends

The last several years have seen a dramatic shift of events in US energy markets. The emergence of unconventional crude oil production in the US has, and continues to have, considerable impacts on global and domestic energy markets, including refined product markets. The unconventional revolution has helped transform the US from being a net importer to a net exporter of petroleum products, including refined products.

These new opportunities, however, have not come without a few challenges and obstacles. Some of the factors that have influenced refined product trends, positively and negatively, over the past decade include:

- Capacity flows
- Regulatory changes
- Fluctuating crude oil and refined product markets
- Changes in US refined product demand
- Alternative transportation fuel standards
- The emergence of the US energy export market

10.5.1 Capacity Flows

Figure 163 shows that over the past decade, PADD 1 refineries have contracted both in terms of the number of facilities (from 15 in 2009 to eight in 2019) and overall operable capacity (from 1.7 MMBbls/d to 1.2 MMBbls/d). For the most part, the refineries that were closed over the past decade have been smaller, less used and less efficient than those remaining in operation. For instance, the average size of the refineries shut down over the past decade is 71 MBbls/d compared to the average distillation capacity of active refineries at 135 MBbls/d. The further explanation for these contractions in both refineries and capacity will be provided later in trends section of this chapter.

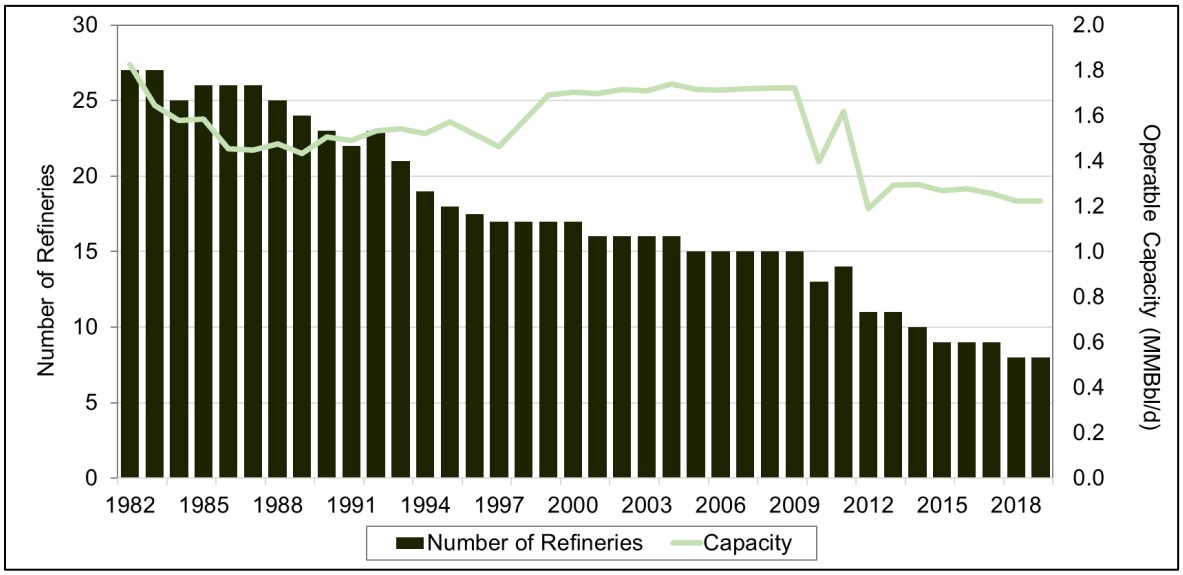

Figure 163. PADD 1 Refineries.

Source: US Energy Information Administration (EIA 2019 Jun 21).

The contraction of Atlantic refineries stands in contrast to national trends. Figure 164 shows that overall US refining capacity over the past decade, for instance, has grown from 17.7 MMBbls/d to 18.8 MMBbls/d, or by 6.0 percent. The active number of refineries for the US is down, relative to a decade ago, but only down by 8.8 percent on a national average basis.

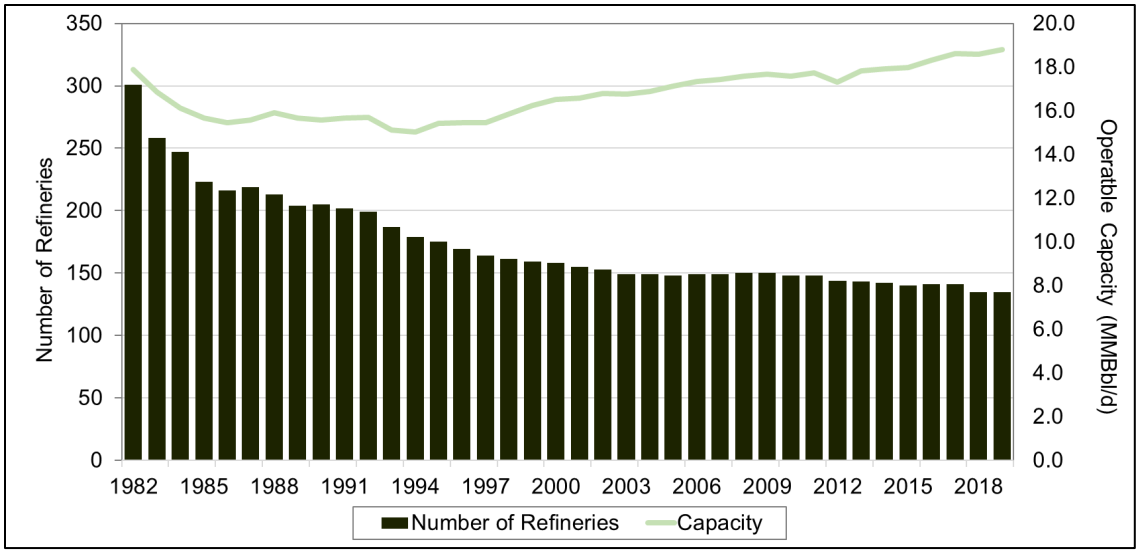

Figure 164. US Refineries.

Source: US Energy Information Administration (EIA 2019 Jun 21).

US refineries in general, and refineries along the eastern seaboard, have preserved total operating capacity and met US refined product needs through a trend often referred to in the industry as “capacity creep.” This arises through the concentration and expansion of refining capacity at existing facilities rather than the investment in new greenfield sites. Figure 165 shows the capacity creep and increased average refinery size for both refineries along the eastern seaboard and the US average. In 1982, the year with the largest number of refineries in both the East Coast and the US, an average-sized refinery was 68 MBbls/d (East Coast) and 59 MBbls/d (US). Today, average refinery capacity is 153 MBbls/d (East Coast) and 139 MBbls/d (US).

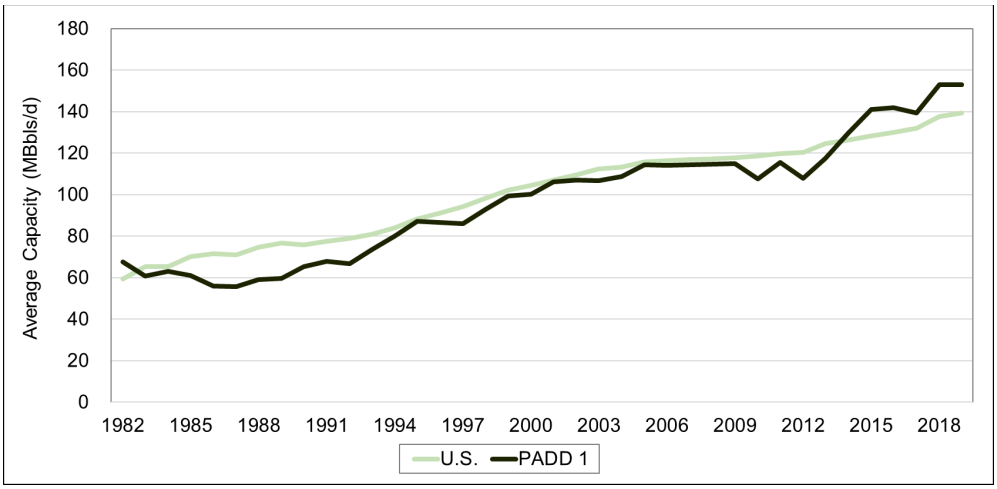

Figure 165. Historic trends in average operable capacity (PADD 1 v. US).

Source: US Energy Information Administration (EIA 2019 Jun 21).

Major oil companies, typically comprised of the super-majors that have integrated oil and gas operations from production to distribution, control a large majority of total US refining capacity. In the US, major oil companies own approximately 95 percent of all refining capacity, while independent oil refining companies own approximately five percent. This differs slightly along the broader East Coast region, where majors control 91 percent of all operable capacity and independents control nearly nine percent of the region's refining capacity (see Figure 166).

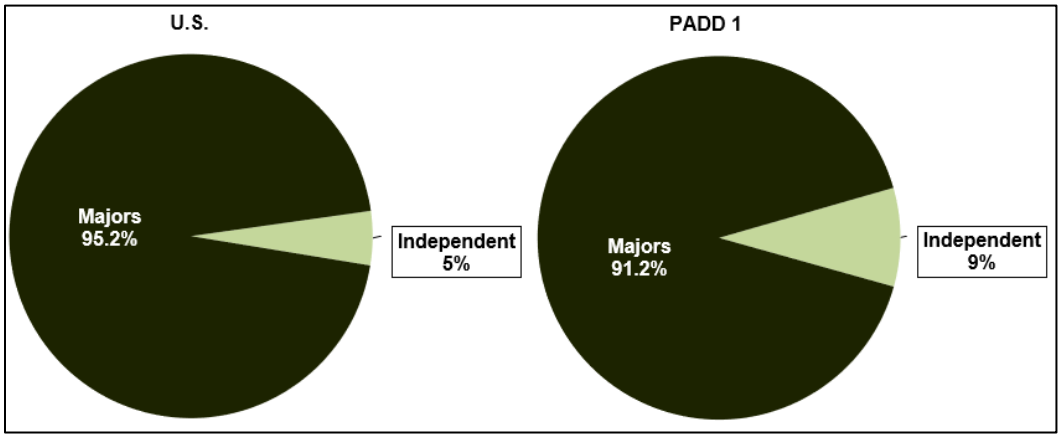

Figure 166. Average ownership shares.

Source: US Energy Information Administration (EIA c2019).

10.5.2 Regulatory Changes

Air emission regulations, and their changes over the past decade, have had considerable impacts on refineries across the US, including those on the eastern seaboard. Many of these changes were adopted to reduce local ozone concerns and to reduce smog and nitrous oxides (NOx).

Approximately thirty years ago, the Clean Air Act Amendments of 1990 (CAAA) tightened emissions standards for automotive tailpipe emissions (EPA 1999). The regulatory changes coming from the EPA in response to this legislation saw two different phase-ins. The first phase-in is referred to as the "Tier 1" guidelines, where the EPA set NOx standards for passenger automobiles at 0.6 grams per mile (gpm); a 40 percent reduction from the previous 1981 standard (EPA 1999).

The second set of EPA air emission standards for refined fuels, referred to as "Tier 2" standards were adopted in 1999 and reduced NOx emission standard further to 0.07 gpm for both cars and light-duty trucks (EPA 1999). These standards were implemented from 2004 through 2009, and later extended to include heavier vehicle categories (DieselNet 2019). The Tier 2 standards also included regulations on sulfur levels in gasoline and diesel fuel quality (DieselNet 2019). The regulatory changes that were initiated by the EPA are shown in Figure 167, and required a reduction in average gasoline sulfur standard down to 120 parts per million (ppm) beginning in 2004. In 2005, this average standard was reduced to 30 ppm. The EPA also established rules for highway diesel, setting the maximum sulfur level at 15 ppm beginning in 2006 (DieselNet 2019).

Most recently, in March of 2014, the EPA issued its Tier 3 standards, which set a new standard of 10 ppm sulfur in gasoline on an annual average basis starting in January 1, 2017 (EPA 2014 Mar 1). This new standard, as well as previous standards, are illustrated below in Figure 167.

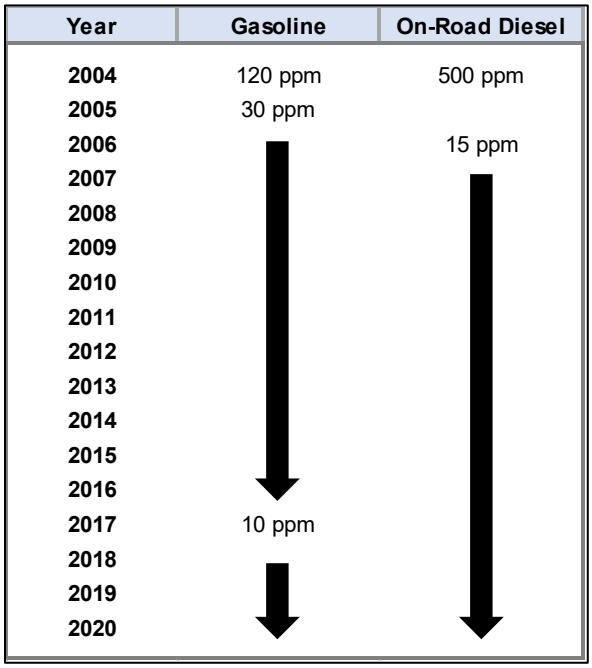

Figure 167. EPA regulations, sulfur fuel specifications.

Source: (EPA 2014 Mar 1; DieselNet 2019).

Fuel use standards have also changed considerably, particularly over the past decade. In July 2011, for instance, the Obama Administration and 13 different automotive manufacturers, representing close to 90 percent of the auto sales in the US, reached a historic agreement to aggressively increase fuel efficiency standards for cars and light trucks (The White House 2011 Jul 11). The new fuel efficiency standards called for a reduction of five percent per year, from 2017 to 2025, for cars. For pick-ups and light-duty trucks, meanwhile, fuel efficiency standards were reduced by 3.5 percent per year, from 2017 to 2021, and by five percent per year, from 2022-2025 (The White House 2011 Jul 11).

10.5.3 Fluctuating Crude Oil and Refined Product Prices

Crude oil prices are historically volatile and perhaps one of the more volatile commodities that are traded on exchanges throughout the world. Past and current crude oil prices fluctuate as market conditions change. Over the past decade, crude oil trends have reflected the successes in US unconventional production and the impact this production has on global markets.

Figure 168 below, for instance, shows two distinct pricing trends over the past decade. Early in the decade, immediately after the global financial meltdown of 2008–2009, crude oil prices were high, and supplies were dominated by some of the same producing basins that have influenced markets in modern times. OPEC-based production in Saudi Arabia and the Persian Gulf, for instance, continued to dominate world markets. US production during that time period was around five MMBbls/d and comprised around six percent of global markets.

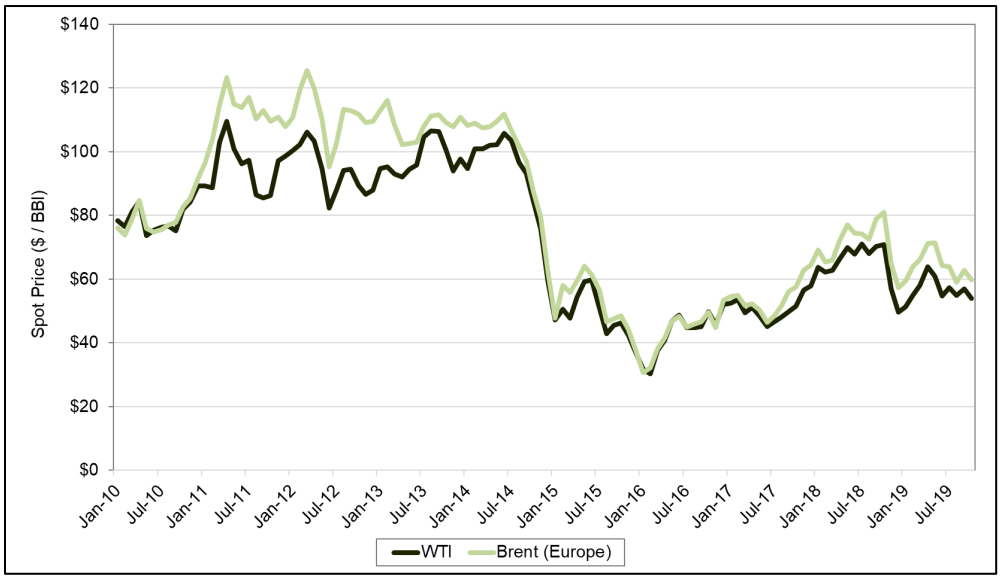

Figure 168. Monthly crude oil spot prices.

Source: US Energy Information Administration (EIA 2020 Mar 2).

However, the gradual emergence of US unconventional reserves, starting in 2010, began to threaten OPEC oil market hegemony. US shares of total world oil production began to rise from a typical position of around six percent to over 10 percent. US crude oil production began to surge in the middle part of the decade coupled with Saudi attempts to "flood" the market in 2014 in order to drive out blossoming US gains. These supply actions are seen clearly in Figure 169 since, in 2014, OPEC supply strategies resulted in a "tanking" of global crude oil markets with prices (WTI and Brent) falling by over 50 percent.

OPEC actions, and the corresponding price fall of 2014, did little to stop US unconventional production, and operators began to re-negotiate service company contracts, reduce costs, and increase drilling and production efficiencies through a variety of means that included longer horizontal segments and the drilling of more wells per field. The net result of these actions was that US producers not only were not driven out of the market, but continued to increase production to levels in 2019 that exceed 13 MMBbls/d. OPEC, under Saudi leadership, has learned, since this time, that its best move is to strategically contain prices in the $60/Bbl to $70/Bbl range; effectively calling a détente between its members and US unconventional production.

US gasoline customers have been a large beneficiary of the dramatic decreases in crude oil prices that began in 2014. Gasoline and other refined product prices follow trends in crude oil markets and, prior to 2014, refined product prices, including gasoline, were exceptionally high and volatile.

Figure 169, for instance, highlights the direct relationship between crude oil prices and retail gasoline prices. From 2010 until 2015, retail gasoline fluctuated between $2.00 and $3.25 per gallon. Then, in January 2015, the price of gasoline fell to less than $2.00 per gallon, and fell once again, in February 2016, to approximately $1.33 per gallon. Since 2017, however, prices have stabilized and generally hovered between $2.00 and $2.50 per gallon. Throughout this time, retail gasoline prices closely followed crude oil price fluctuations.

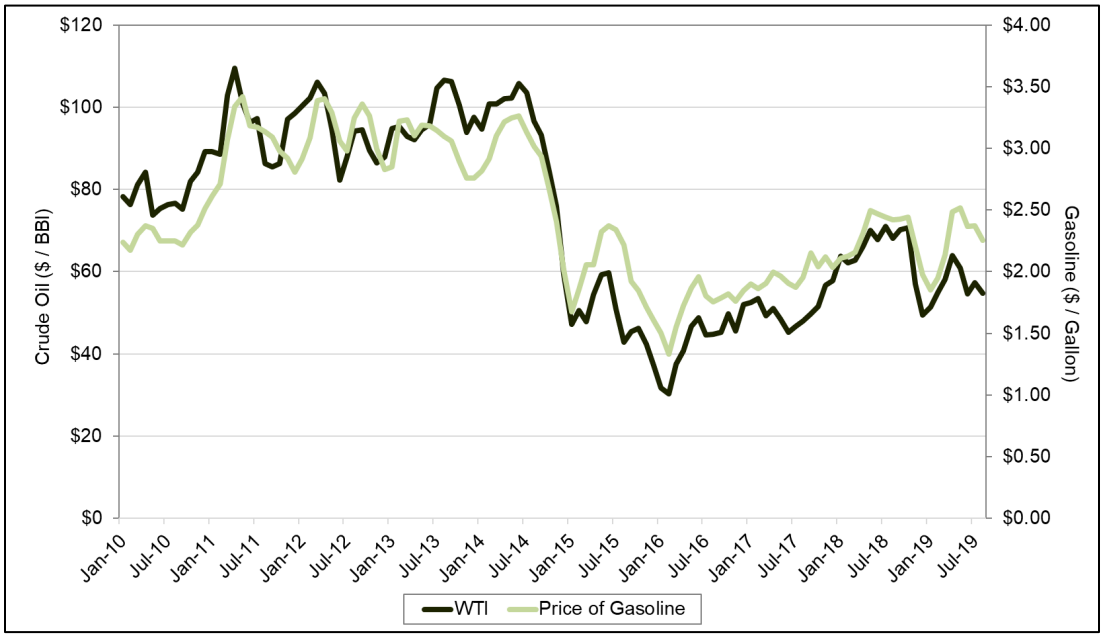

Figure 169. Monthly crude oil spot and retail gasoline prices.

Source: US Energy Information Administration (EIA 2020 Mar 2; EIA 2020 Mar 11).

10.5.4 Refined Product Demand

Gasoline demand is commonly thought of as being relatively price inelastic. In other words, large changes in price do not tend to result in large changes in retail gasoline demand. Over time, that price elasticity can increase, in absolute terms, as substitutes and alternatives arise. Yet, despite these relationships, changes in gasoline prices can have impacts on gasoline demand. Figure 170, for instance, shows the strong inverse relationship between gasoline demand and prices. As prices increased throughout the early part of the decade, gasoline demand started to fall from its previous highs in 2006 which peaked about around 9.6 MMBbls/d. High gasoline prices (owing to high crude oil prices), the economic recession of 2008 and 2009, and other policy and structural changes in US energy markets (such as the increasing availability of alternative fueled vehicles) have all had lasting impacts on gasoline demand.

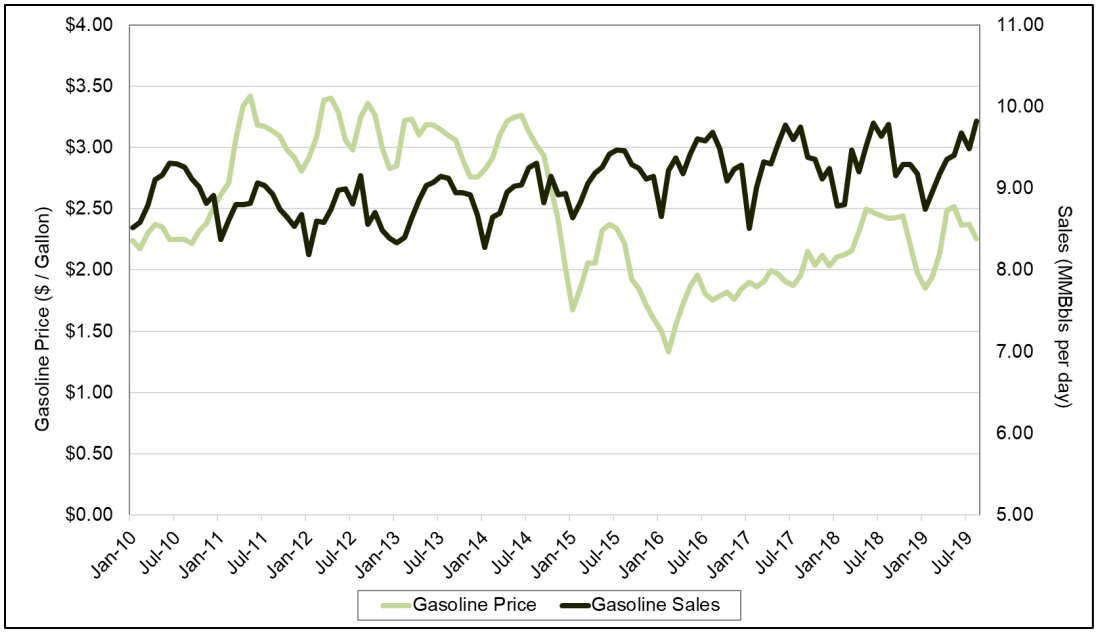

Figure 170. US Gasoline prices and demand, 2010–2019.

Source: US Energy Information Administration (EIA 2020 Mar 2; EIA 2020 Mar 16).

Gasoline demand began its free fall in early 2010 during the onset of the earlier-referenced economic recession, the most severe economic downturn in the post WWII era. US retail gasoline demand numbers bottomed out at around 8.27 MMBbls/d in 2014, the time in which gasoline prices also began to plummet in response to the OPEC crude oil supply actions attempting to drive out US unconventional production. Overall US gasoline demand (and prices) have flat lined since 2015. Overall average U.S gasoline prices remain around 2.00 per gallon, whereas retail gasoline demand has remained flat at around 9.3 MMBbls/d.

This flattening of US retail gasoline demand has had important implications for the US refining sector. Consider that gasoline demand peaked in 2006 immediately after the tropical seasons of 2004 and 2005 pummeled the highest concentration of refining capacity in the US (i.e., the Gulf of Mexico). Many refining companies and integrated majors attempted to expand their operating refining capacities to meet what they thought would be continued expanded retail gasoline demand.

Consider, as an example, that in 2006, the Motiva refinery in Port Arthur, Texas reported a total operating capacity of 285 MBbls/d, which was ultimately expanded to 607 MBbls/d; the largest refinery in North America (EIA c2019; EIA c2006). Likewise, the Marathon refinery in Garyville, Louisiana, the youngest refinery in the US, and the last greenfield refinery project to come on-line, reported an operating capacity of 245 MBbls/d in 2006, only to expand that capacity to its present day capacity of 564 MBbls/d (EIA c2019; EIA c2006).

The significant change in US retail gasoline demand, therefore, left many US refineries, particularly those along the Gulf Coast, in a precarious position of having considerable excess capacity relative to current demand. Many refineries were able to export that excess product, which, as will be seen later, contributed to the surge in US refined product exports. The decrease in retail gasoline demand also changed the relative economics of the continued operations of many refineries, particularly those along the Atlantic seaboard. As noted earlier, between 2010 and 2019, some five refineries in the Atlantic region were closed, resulting in a contraction of some 33 MBbls/d of regional refining capacity. These contractions were driven, in large part by these facilities' operating efficiencies and competitiveness in the face of rapidly contracting US refined product demand.

10.5.5 Alternative Fuels Standards

High crude oil prices of the last decade motivated several new federal and state policies promoting alternative fuels, particularly biofuels, that could be added to existing gasoline stocks. The 2005 Energy Policy Act (EPAct 2005), for instance, established an initial set of guidelines for biofuel blending in the US EPAct 2005 required four billion gallons of biofuel blending in 2006 before steadily increasing from that level to 7.5 billion gallons of biofuel by 2012 (Schnepf and Yacobucci 2013).

The Energy Independent and Security Act of 2007 (EISA) mandated a series of alternative fuel blends under what is referred to as the "Renewable Fuel Standard" (RFS) program (Schnepf and Yacobucci 2013). The EISA required the use of nine billion gallons of biofuel blending or use in 2008, increasing to a goal of 36 billion gallons by 2022, with at least 16 billion gallons consisting of cellulosic biofuels and with a cap of 15 billion gallons for corn-starch ethanol (Schnepf and Yacobucci 2013).

The EPA manages the RFS program by setting annual biofuel standards for refineries, fuel blenders, and importers of gasoline and diesel fuels. Such biofuel standards are expressed as a percentage of the biofuels that must be contained within transportation fuel. Each refinery's RFS mandate is known as its Renewable Volume Obligation (RVO), which is equal to the product of the EPA's annual RFS standard (across each of the four different biofuel categories) and the firm's annual fuel sales (CRS 2019b).

The RFS is a tradable credit-based system of renewable identification numbers (RINs). RINs are attributed to renewable fuel, and may be submitted for compliance, traded, or banked for future use (CRS 2019b). Refineries that do not produce enough renewable fuels are required to acquire RINs in order to meet their RVOs and comply with the RFS program (Schnepf and Yacobucci 2013). Over the past decade, RINs have become an increasingly significant compliance cost for refineries.

The RFS policy has been criticized by several refineries as likely driving up costs for themselves and US consumers (PBF Energy 2019). In January 2018, the largest and oldest refinery on the East Coast filed for bankruptcy, and in the filing, Philadelphia Energy Solutions, the refinery's owner, cited RFS compliance costs as the primary contributor to the company's financial despair (United States Bankruptcy Court 2018):

> "The RFS Program requires refiners to blend "biofuels" such as ethanol into the gasoline and diesel fuels they produce and sell in the United States or, if they are unable to do so, to purchase compliance credits known as Renewable Identification Numbers ("RIN") instead of blending. PESRM's ability to blend biofuels is very limited because its position in the fuel distribution chain limits its ability to sell blended gasoline and diesel fuel and capture the RINs needed for compliance with the RFS Program. Specifically, the substantial majority of transportation fuel produced at the Refining Complex is sold neat (unblended) at the refinery gate and delivered into markets in the Central Atlantic and Northeast regions of the US through pipelines that the Debtors do not own and that will not accept blended gasoline. As a result, PESRM must purchase RINs for compliance from market participants that blend biofuels (typically large integrated oil companies and companies that own retail gasoline stations) or from companies that trade in RINs for profit. Significant penalties and fines can be assessed by EPA for failure to comply. Unlike a tax, the amount paid by PESRM for RINs is not remitted to the government but generates profits for the sellers of the RINs. This unpredictable, escalating, and unintended compliance burden has cost the Debtors $832 million since their commencement of operations in September 2012 and, on an annual basis, the Debtors' expense associated with complying with the RFS Program is twice their annual payroll, nearly one and one-half times their annual average capital expenditures, four times their interest expense, and now represents their single largest expense after crude oil. The effect of the RFS Program on the Debtors' business is the primary driver behind the Debtors' decision to seek relief under the Bankruptcy Code" (United States Bankruptcy Court 2018).

PBF Energy, which owns two East Coast refineries and 39.5 percent of total refining capacity in the Atlantic region, has also been impacted by the compliance costs of the EPA's RFS mandates.

In 2017, PBF Energy acquired a products terminal next to its Toledo, Ohio refinery in order to increase its output of biofuel production and reduce its RFS compliance costs (RFA 2017 Nov 2). That same year, Pennsylvania Governor Tom Wolf wrote letters to President Donald Trump and EPA Administrator Scott Pruitt, requesting that the EPA's RFS mandate be no greater than 9.7 percent of annual gasoline demand (Wolf 2017a; Wolf 2017b). In his letter to the EPA Administrator (Mr. Pruitt), Governor Wolf explained that the merchant refiners in the Northeast were most negatively impacted by RFS compliance costs and that the refiners in Pennsylvania are "struggling to remain operational given the current and proposed volume requirements" (Wolf 2017b).

PBF Energy noted in its own 2018 Annual Report that "market prices of RINs have been volatile and may harm our profitability" (PBF Energy 2019). The "volatile" and "escalating" prices of RINs, as touched upon by both PBF Energy and Philadelphia Energy Solutions, are highlighted below in Figure 171.

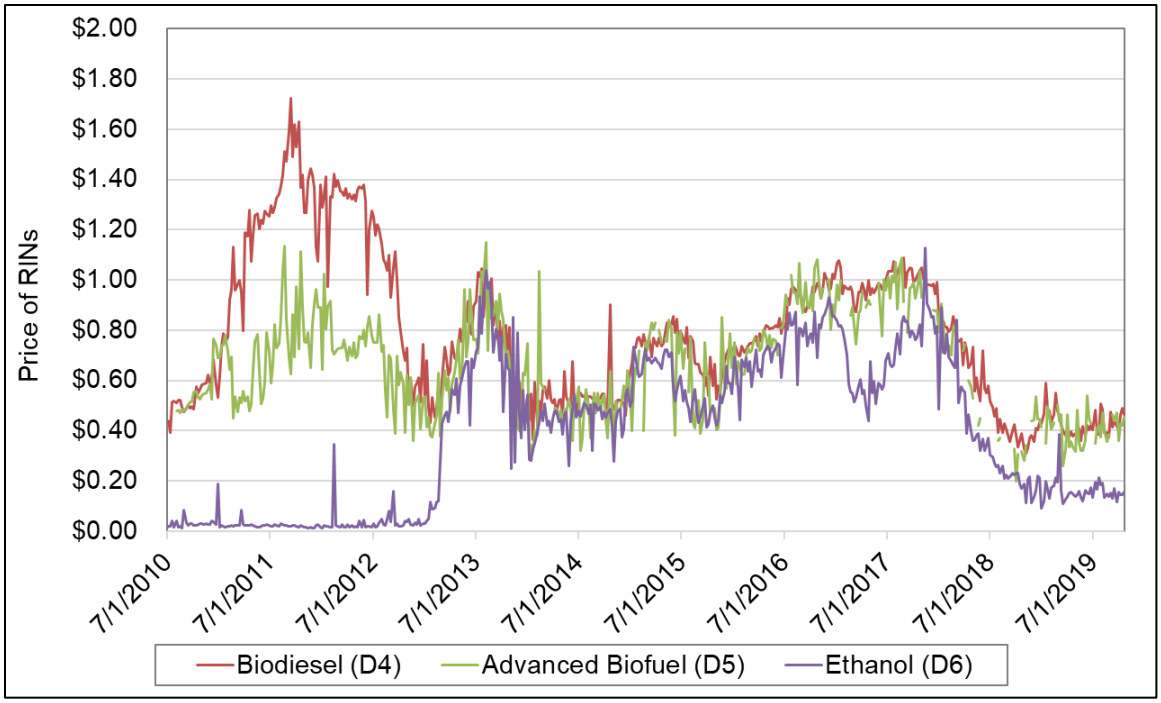

Figure 171. Price of RINs, 2010–2019.

Source: US Environmental Protection Agency (EPA 2018 Sep 20).

In the US, the practical limit of ethanol as a mixture within fuel is 10 percent; this is known as the "blend wall." Blended fuels that contain ethanol mixtures of greater than 10 percent can cause corrosion in automobile engines, and because of this, the majority of gas stations in the US do not sell fuels with higher ethanol blends, such as E15, which contains between 10.5 and 15 percent ethanol (Pirrong 2018).

Over the past decade, the EPA's RPS standards for ethanol have surpassed the 10 percent threshold, even though, for all intents and purposes, the practical cap is 10 percent. As a result, the market for RINs has been volatile and characterized by dramatic price increases, which has, in turn, caused financial distress for refineries, particularly those along the East Coast (Pirrong 2018).

Figure 172 illustrates the quantity of blended ethanol as a percentage of the total quantity of supplied finished gasoline. For much of the last decade, the percentage of blended ethanol has been near, or in excess of, the blend wall of 10 percent (Pirrong 2018).

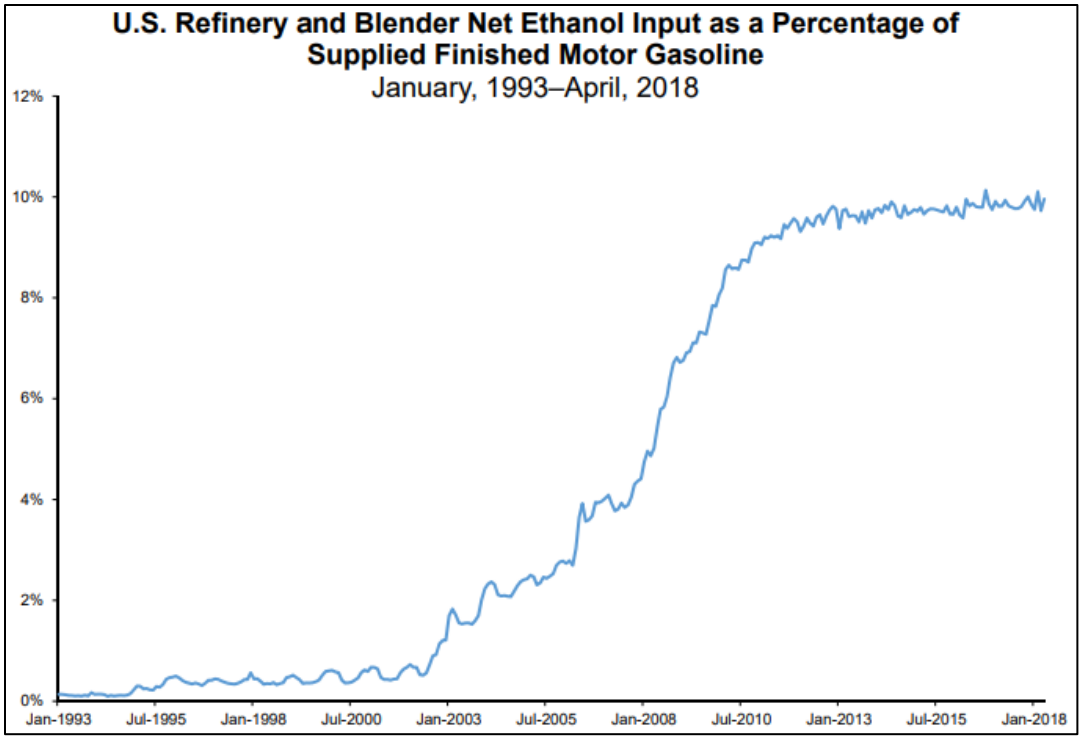

Figure 172: Ethanol as a Percentage of Finished Motor Gasoline.

Source: (Pirrong 2018).

The results of the RFS program are also demonstrated by Figure 173 and Figure 174. Figure 173 highlights the historic change in annual renewable fuel refining capacity and installations throughout the US The chart shows a dramatic increase over the past five years.

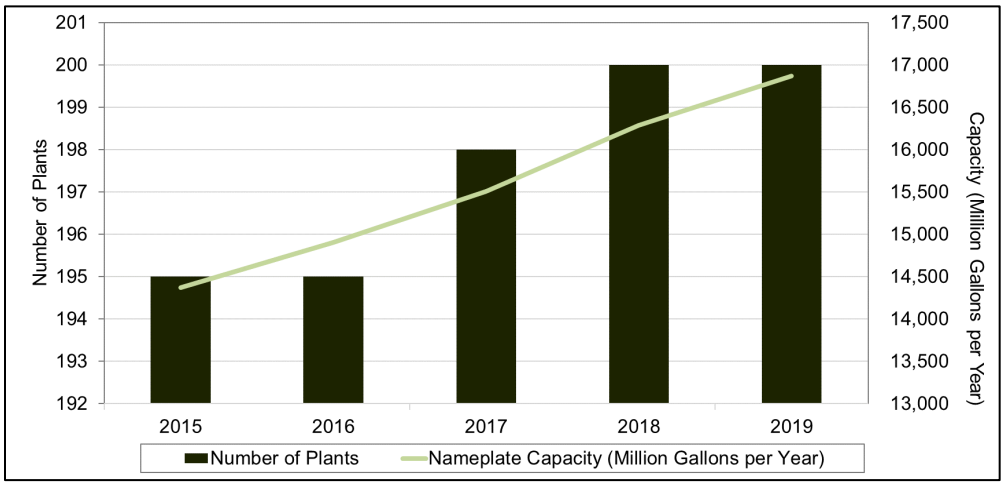

Figure 173. US fuel ethanol industry plants and production capacity.

Source: US Energy Information Administration (EIA 2019 Jan 1).

Figure 174, meanwhile, highlights US ethanol production, in billion gallons, over the past decade. Since 2009, US production of ethanol has grown by 46.8 percent. These new ethanol production levels have had an immediate and important impact on traditional refining operations, particularly profitability, as more and more capacity has been displaced by new biofuel capacity.

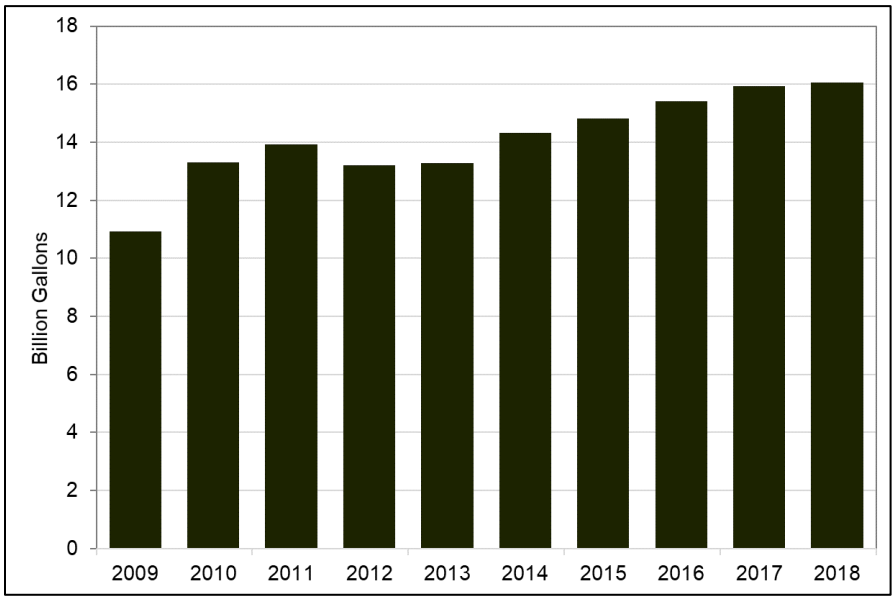

Figure 174. US fuel ethanol production.

Source: Renewable Fuels Association (RFA 2019).

Biofuels are not the only new transportation fuel competing with traditional petroleum-based fuels. The past several years have seen an increase in the advocacy and promotion of a wide range of other transportation fuel sources, particularly with regard to electric vehicles.

Figure 175 illustrates the dramatic increase in US sales of plug-in electric vehicles (PEVs) from 2011 to 2017. During that seven-year span, annual sales of PEVs increased by more than 1000 percent. One factor which largely contributed to this growth were the subsidies granted to buyers of such vehicles.

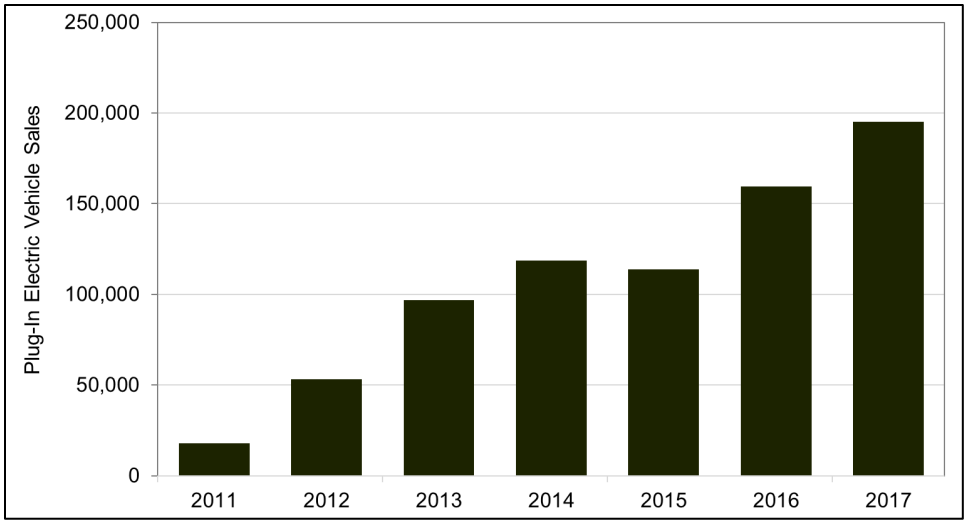

Figure 175: US PEV Sales, 2011–2017.

Source: US Department of Energy, Alternative Fuels Data Center (DOE c2019).

10.5.6 Exports

In recent years, another factor that has impacted refineries has been the United States' termination of its ban on crude oil exports. In December 2015, the US lifted its ban on crude oil exports, which had been in place since the Arab oil embargo in the mid-1970's. The effects of this policy are reflected in Figure 176, Figure 177, and Table 49.

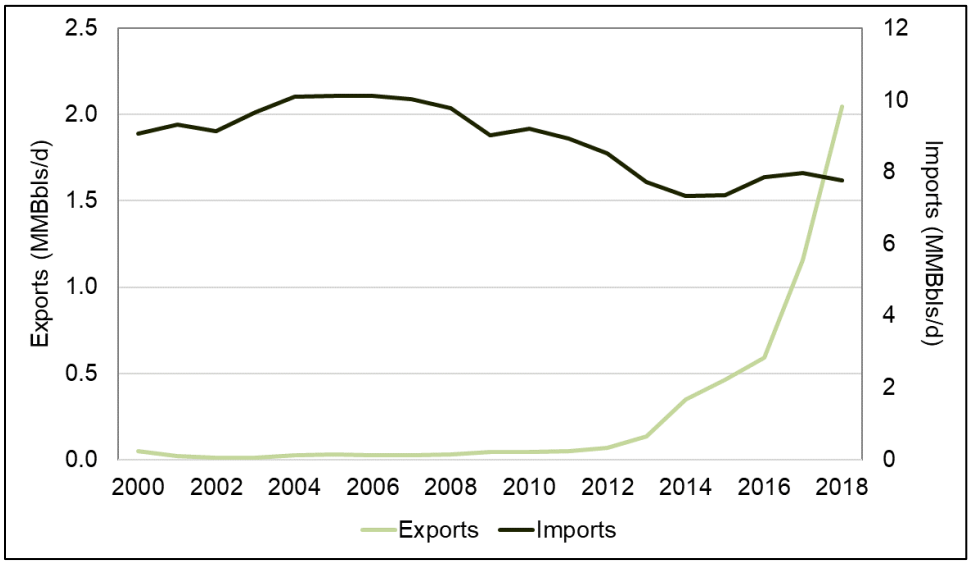

Figure 176. Imports compared toxports, 2000–2018.

Source: US Energy Information Administration (EIA 2020a Jan 31; EIA 2020b Jan 31).

Figure 177 illustrates the price differential between domestic crude oil and international crude oil. Since the US ban on crude oil exports was lifted in 2015, the gap between domestic and international crude oil prices has narrowed (Pirrong 2018).

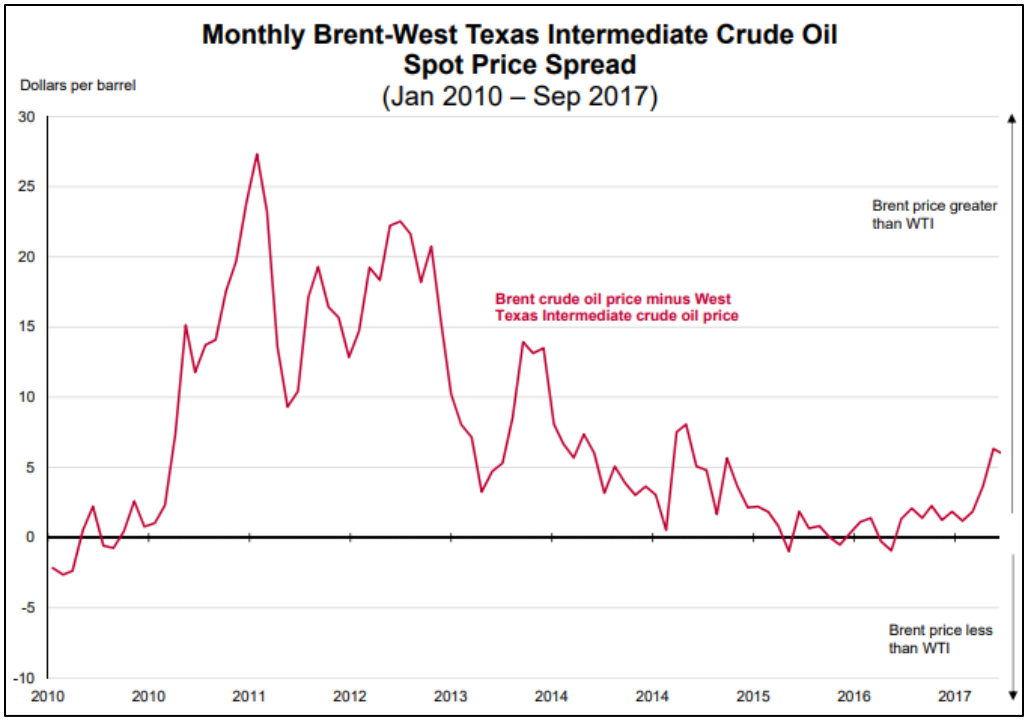

Figure 177. Domestic compared to International Price Differential.

Source: (Pirrong 2018).

As the price differential between domestic crude oil and international crude oil narrowed, the cost advantage provided to East Coast refineries began to dissipate. Also, refineries along the Gulf Coast began exporting greater quantities of their production internationally, which in turn meant fewer shipments of crude oil to the Atlantic region (Pirrong 2018). Table 49 illustrates this trend below.

Table 49. PADD 1 Shipments, 2014–2018

Year	Shipments from PADD 3 to PADD 1 (thousand barrels)	International Imports of Crude Oil to PADD 1 (thousand barrels / day)
2014	42,160	7,825
2018	33,166	10,222
Change (%)	**-21**	**31**

Source: US Energy Information Administration (EIA 2019 Jun 21; EIA c2019).

10.6 Current Outlook

The factors that that have impacted US refineries over the past decade, most notably the emergence of unconventional crude oil production and the rise of US crude oil exports, will continue to shape the refinery sector in the years ahead. Additionally, there will be an emerging set of issues that will affect the industry as well. Some of the most notable issues, both present and forthcoming, that are anticipated to impact refineries include:

- Energy export opportunities;
- Emerging transportation technologies;

- Public policies curtailing fossil fuel use;
- Regional-specific factors;

10.6.1 Energy Export Opportunities

Though refineries along the Eastern seaboard are facing significant challenges, the overall US refining industry appears to be in a somewhat favorable position, especially with regards to the available export opportunities. The previous section of this chapter detailed the recent increases in US crude oil exports, which followed the US's 2014 termination of its ban on crude oil exports. Over the next decade, the EIA anticipates that this growth in exports of crude oil will continue. By the end of 2021, the EIA estimates that US crude oil exports will grow to 2.4 MMBbls/d, and by the end of 2025, the EIA estimates that US exports will grow to 2.5 MMBbls/d. Such projections are illustrated in Figure 178.

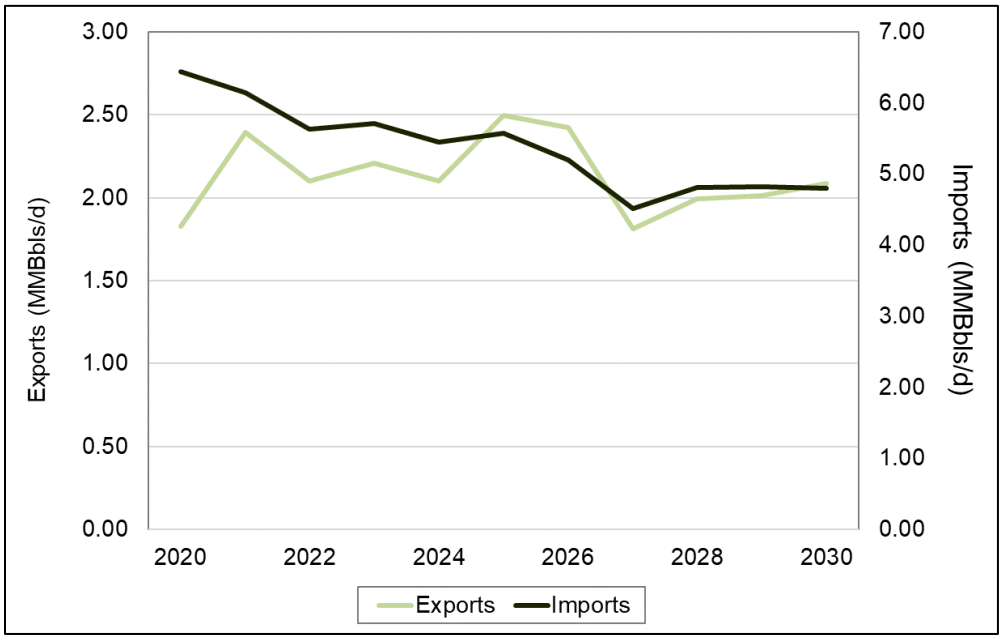

Figure 178: Outlook: Net Crude Exports and Imports (2020–2030).

Source: US Energy Information Administration (EIA 2020a Jan 31; EIA 2020b Jan 31)

Figure 179, presented below, outlines the range of outcomes for US exports of crude oil exports and imports that can be expected over the next thirty years. Under a scenario of high oil prices, it is anticipated that the US could become a net exporter of crude oil. However, under the reference case, the US can be expected to stay at the same relative level that it is at currently with regard to exports and imports of crude oil.

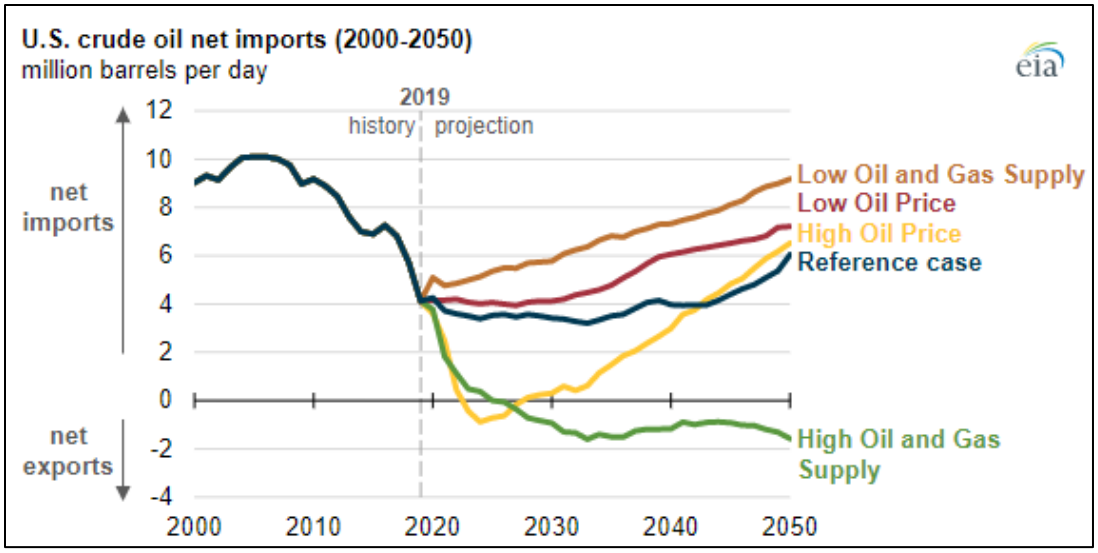

Figure 179: Outlook: Net Crude Exports and Imports (2020–2050).

Source: US Energy Information Administration (EIA 2020a Jan 31; EIA 2020b Jan 31)

Additionally, if all of the LNG applications currently filed with the Department of Energy were to come online, US liquefaction capacity would exceed 60 Bcf per day by 2025 (Figure 180).

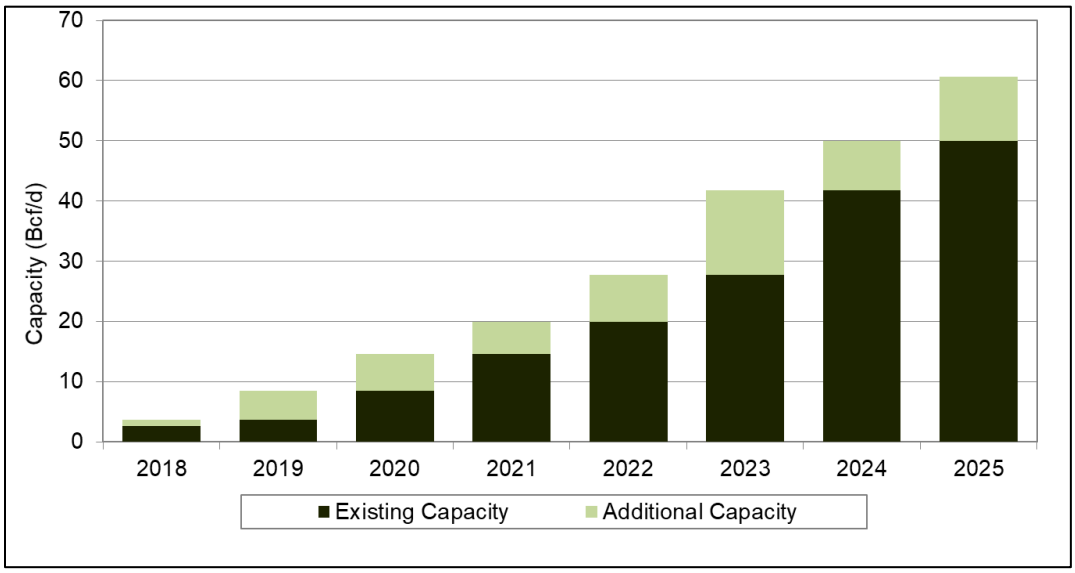

Figure 180: Outlook: Net Crude Exports.

Source: US Energy Information Administration (EIA 2020b).

10.6.2 Emerging Transportation Technologies

In the years ahead, one issue that will significantly impact the US refining industry comprises the emergence of new transportation technologies. The following discussion focuses on the emerging technologies that are anticipated to impact the manner in which individuals move across cities and countries and the types of fuels that the transportation industry relies upon.

Figure 181 outlines the EIA's projection of electric vehicle sales over the next thirty years. By 2030, the EIA anticipates that electric fuel vehicles will comprise 5.0 percent of new vehicle sales. By the end of 2050, meanwhile, the EIA anticipates that annual sales of electric vehicles will surpass 1.8 million and 11.2 percent of total annual sales.

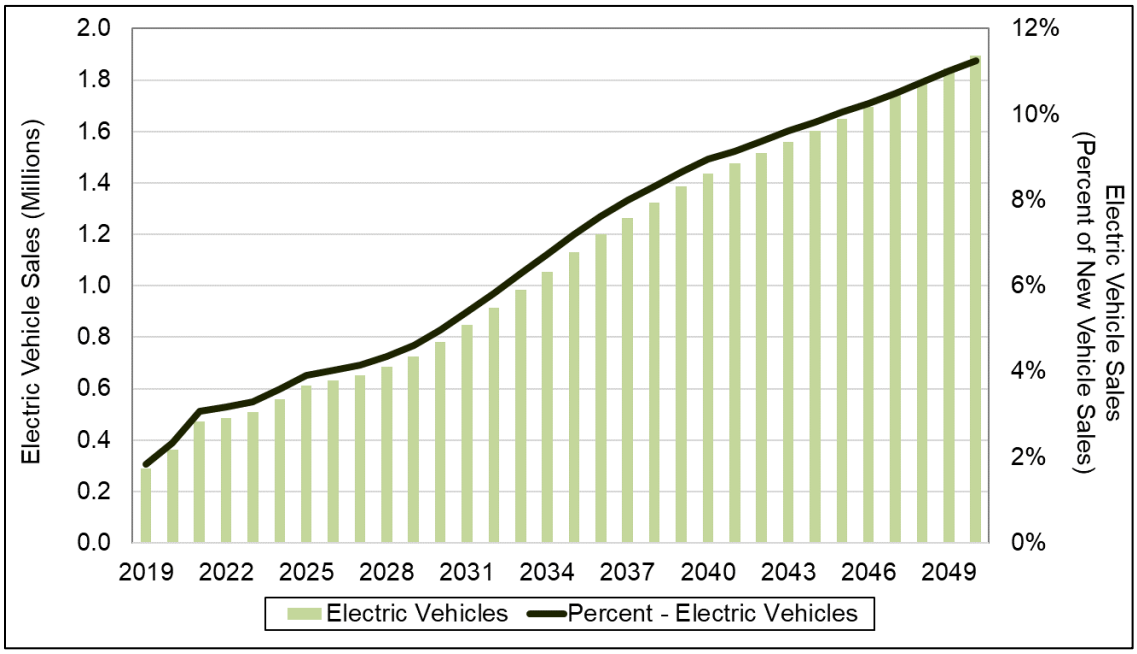

Figure 181: Outlook: Electric Vehicle Sales

Note: This includes sales of plug-in hybrids and gasoline/electric hybrids.

Source: US Energy Information Administration (EIA c2020).

Such EIA estimates should be viewed in a conservative light. In its 2010 Annual Energy Outlook, EIA projected that US sales of all-electric vehicles would amount to only 497 vehicles from 2011 to 2019 (EIA c2010). In contrast, over 879,000 all-electric vehicles were sold in the US during this time (DOE c2019). This discrepancy is illustrated in Figure 182.

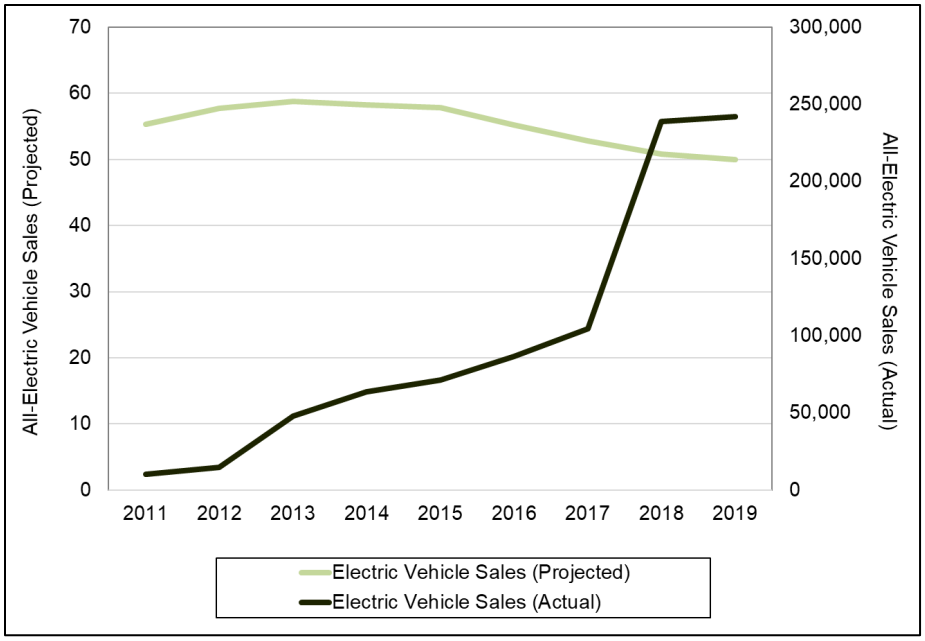

Figure 182: All-Electric Vehicle Sales (2011–2019).

Source: US Department of Energy, Alternative Fuels Data Center (DOE c2019); US Energy Information Administration (EIA c2010).

Another emerging technology that will impact fuel consumption over the coming years is that of autonomous vehicles and ride sharing. Figure 183 outlines Boston Consulting Group's forecast of autonomous vehicles through 2035. According to the consulting firm, sales of fully autonomous vehicles will grow to $6 billion by 2025 and to $38 billion by 2035 (Mosquet et al. 2015)..

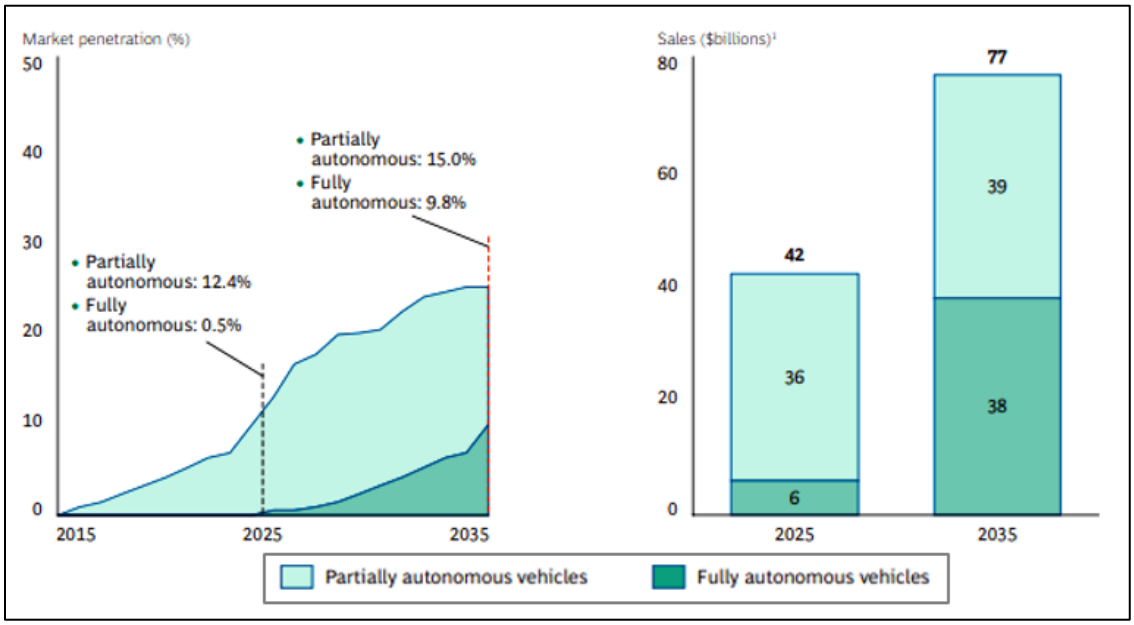

Figure 183: Outlook: Autonomous Vehicles

Source: Author's construction from Boston Consulting Group (Mosquet et al. 2015).

The intersection of the "sharing economy" and the transportation sector is not only visible via the expansion of vehicle ride sharing services, such as Uber and Lyft, but also via the bike-sharing revolution. Figure 184 highlights the staggering growth in bike-sharing and scooter-sharing in the US from 2010 to 2018. In 2010, approximately 321,000 trips were taken via bike-sharing services. In 2018, US citizens made approximately 84 million trips via bike sharing and scooter sharing services (NACTO c2018).

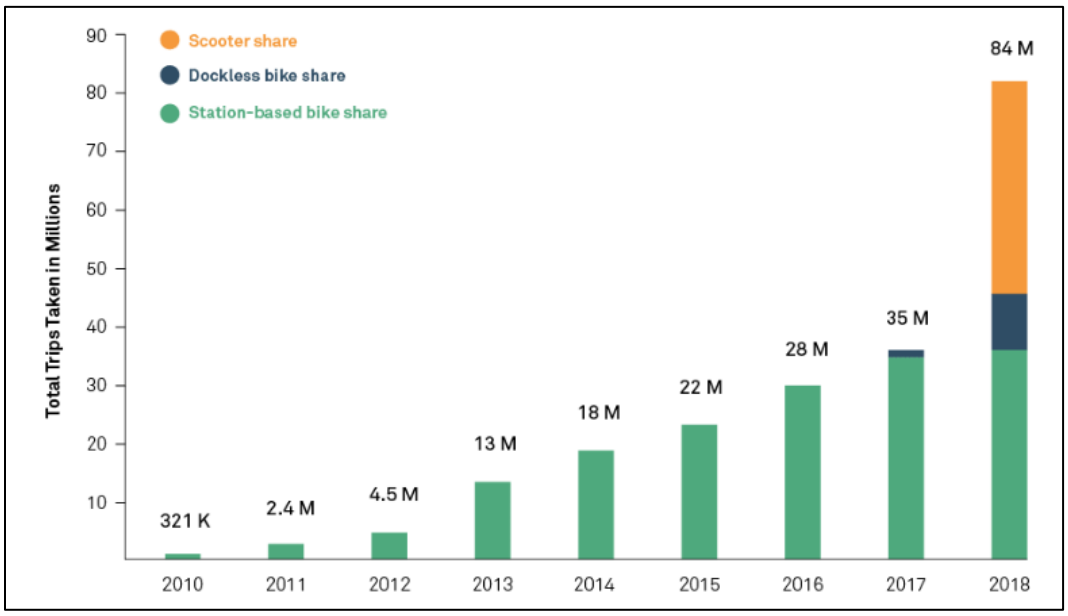

Figure 184: Bike-sharing and scooter-sharing the US

Source: National Association of City Transportation Officials (NACTO c2018).

According to McKinsey & Company, approximately half of all passenger miles comprise trips of less than eight miles, and these are the trips which are likely to be cannibalized by "micromobility" services in the years ahead. McKinsey & Company estimates that bike-sharing and scooter-sharing services may one day comprise as much as 15 percent of all trips under eight miles (Heineke et al. 2019 Jan 1).

10.6.3 Public Policies Curtailing Fossil Fuel Use

The previous subsection of this chapter examined the manner in which refineries have been impacted by public policies, such as alternative fuel standards and the EPA's environmental standards. Looking ahead towards the years ahead, one can expect that such policies, and additional ones, will continue to shape the refinery sector.

In addition to the issues discussed previously, one issue that is garnering political attention is that of fracking. Major candidates for the US Democratic presidential nomination, including Joe Biden and Bernie Sanders, have proposed plans that would limit, or ban altogether, hydraulic fracking in the United States (Johnson 2020 Mar 3).

Bernie Sanders, who proposed a national ban on fracking, has also proposed a ban on oil exports. However, it is unclear at this time whether Biden would support a similar proposal (Gardner and Volcovici 2020 Mar 9).

10.6.4 Factors Impacting East Coast Development

The future of PES remains uncertain. The company plans to sell the complex to real estate developer Hilco Redevelopment Partners, who may redevelop the property for other purposes, while the company's unsecured creditors had pushed for a sale to Industrial Realty Group LLC, whose purchase might have left open an avenue to resumption of refining operations (Maykuth 2020 Jan 23). With little hope for a resumption of refining operations at PES, refining capacity on the Atlantic coast has taken a major blow, and challenges also lie ahead for the remaining refineries.

Delaware City Refinery was recently fined $70,000 for air pollution violations (Lauria 2020 Jan 27). The violations were the result of a fire in February 2019 that sent over 6,000 lbs. of pollutants into the air. This is in addition to the pollution-related $950,000 settlement the refinery reached with the Delaware Department of Natural Resources and Environmental Control in July 2019 (Baker 2019 Jul 12).

Meanwhile, the Monroe Energy refinery in Trainer, PA, has seen its parent owner, Delta, trying to sell off part or all of its stake in the facility (Renshaw and Resnick-Ault 2019 Feb 1). The company had purchased the refinery in 2012 in hopes of lowering its own fuel costs, but acquisition costs had since made East Coast refineries an undesirable asset. However, the closure of PES did cause an increase in refining margins, so the refinery may appear to be a more attractive investment going forward (Dhillon 2019 Jul 5).

11. Petrochemical Plants

11.1 Description of the Industry and Services Provided

When natural gas is processed and crude oil is refined, the resulting non-fuel components are typically used as a feedstock in the production basis for petrochemicals. This process is illustrated in Figure 185.

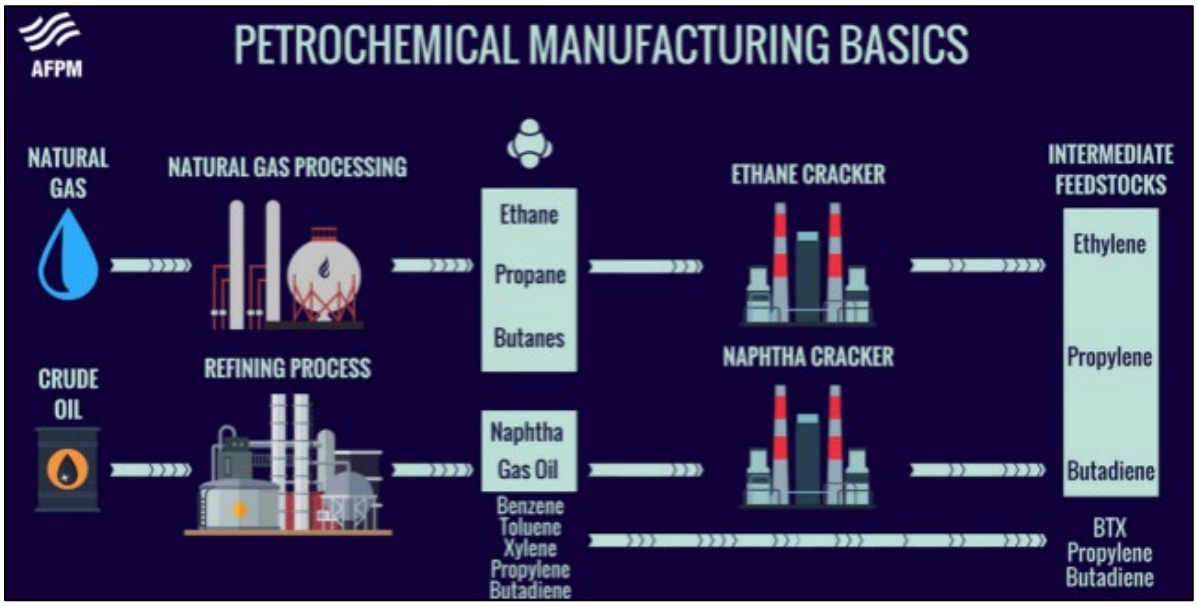

Figure 185. Petrochemical manufacturing basics.

Source: American Fuel & Petrochemical Manufacturers (American Fuel & Petrochemical Manufacturers 2017).

The transformation of raw hydrocarbons into intermediate and final chemical products requires chemical, physical, and biological separation and synthesis processes. These processes expend large amounts of energy for heating (heat, steam), cooling, or electrical power. Separations play a critical role and account for a significant percent of both capital and operating costs.

The industrial organic chemical sector includes thousands of chemicals and hundreds of processes that are based upon a set of building blocks (petroleum-based feedstocks), which are combined in a series of reaction steps to produce both intermediate and end-products. Important petrochemical processes include (Waddams 1969):

1. Distillation. A technique of separation that makes use of the difference in volatility or boiling points of different components in input stream or combination of input streams. The use of successive vaporization and condensation processes (into higher and lower temperatures and successive extractions) separates the input streams into progressively lighter or heavier portions.

2. Solvent Extraction. Input streams using this process are separated through the use of some liquid component with solvent or solvent-type characteristics. This operation is used for the separation of components by types, for example, the separation of aromatics from paraffins.

3. Crystallization. This process runs various different input streams or solutions through a filter or centrifuge that, in turn, are subjected to exceptionally cold temperatures, freezing certain components, that can be separated and recovered from those components of less value or interest.

4. Absorption. Under this process a component of a gas or vaporized input mixture is separated by selective absorption, usually in a liquid solvent. The operation is commonly carried out in a packed tower.

5. Adsorption. This process utilizes certain highly porous materials (e.g., activated charcoal, silica gel) which can condense various components vapors on their surface for potential extraction and recovery. In some instances, adsorption can be operated selectively, and can remove one component from a mixture or input stream.

6. Cracking. This process typically breaks down large hydrocarbon molecules into molecules of lower molecular weight through the absence of air, by high temperature alone or by combination of high temperature and catalytic activity.

7. Reforming. This refers to processes that use heat and usually a catalyst to transform hydrocarbons into other hydrocarbons or mixtures of hydrocarbons and oxides of carbon, with air or steam taking part in the reaction.

8. Alkylation. This is usually the reaction of a hydrocarbon, such as an alkane or aromatic, with an olefin using an acid or other catalyst.

9. Isomerization. Process that rearranges atoms within a particular molecule and is commonly applied to the conversion of a normal paraffin to the isoparaffin.

10. Polymerization. A polymer results from a catalyst being employed to form very large molecules from small molecules.

11.1.1 Primary Petrochemicals

Primary petrochemicals are the chemicals produced directly from the refining of crude oil and the processing of natural gas. There are three broad categories of primary petrochemicals: aromatics, olefins, and synthesis gas. Aromatics include xylene, toluene, and benzene, and are produced by reforming. Olefins include ethylene, propylene, and butadiene, and are produced by cracking. Finally, synthesis gas is made from methane and used in the production of methanol and ammonia. Figure 186 below provides an illustration of the feedstock and resulting primary petrochemicals.

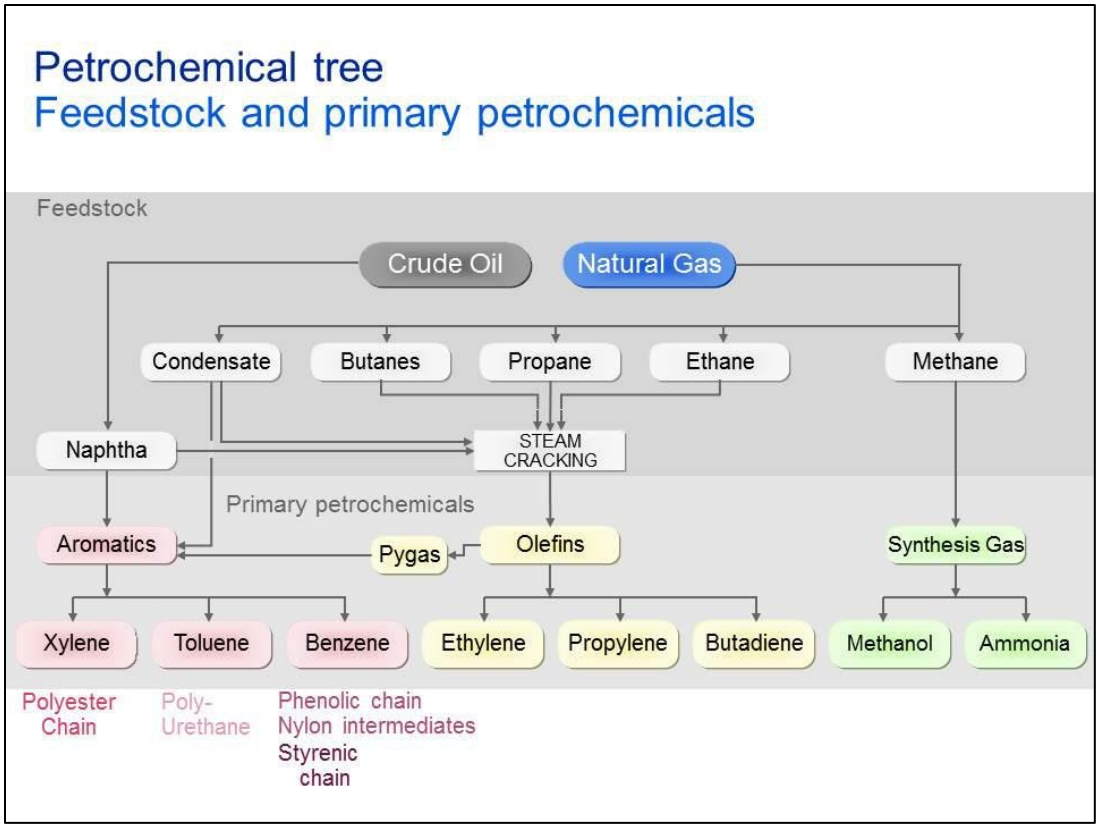

Figure 186. The relationships among feedstock and primary petrochemicals.

Source: ABB, Inc. (Devold 2016 Figure 23).

11.1.2 Supply Chain

The petrochemical industry is highly diverse. Like the refining industry, it produces a large number of outputs. However, the inputs it accepts are equally diverse. These inputs may be used as reactants, processing aids, or manufacturing aids in petrochemical production. The outputs of these processes may be sold or used as inputs in additional processes. Figure 187, Figure 188, and Figure 189, provide examples of the series of intermediate petrochemicals that are used to convert the primary petrochemicals to end-use products.

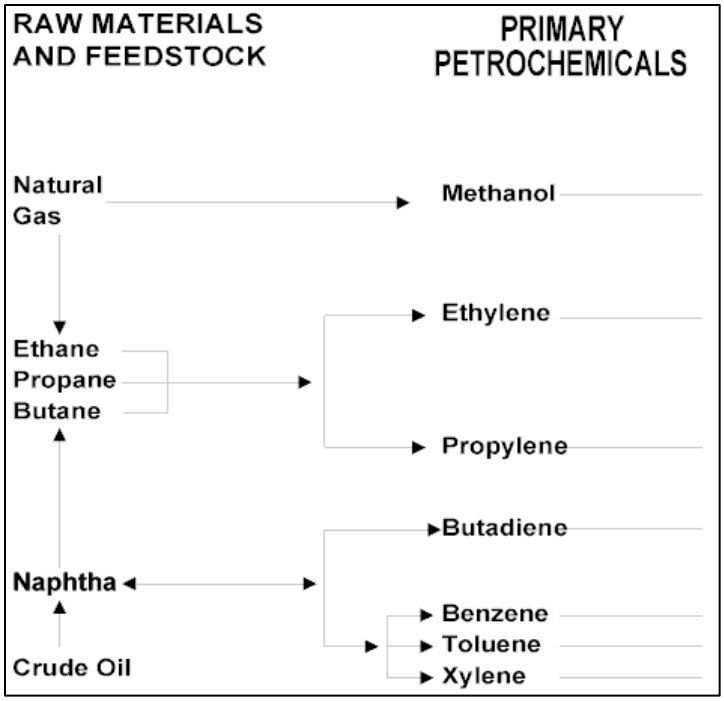

Figure 187. Relationship between feedstock and the primary petrochemicals.

Source: Elmhurst College Virtual Chembook (Ophardt c2003).

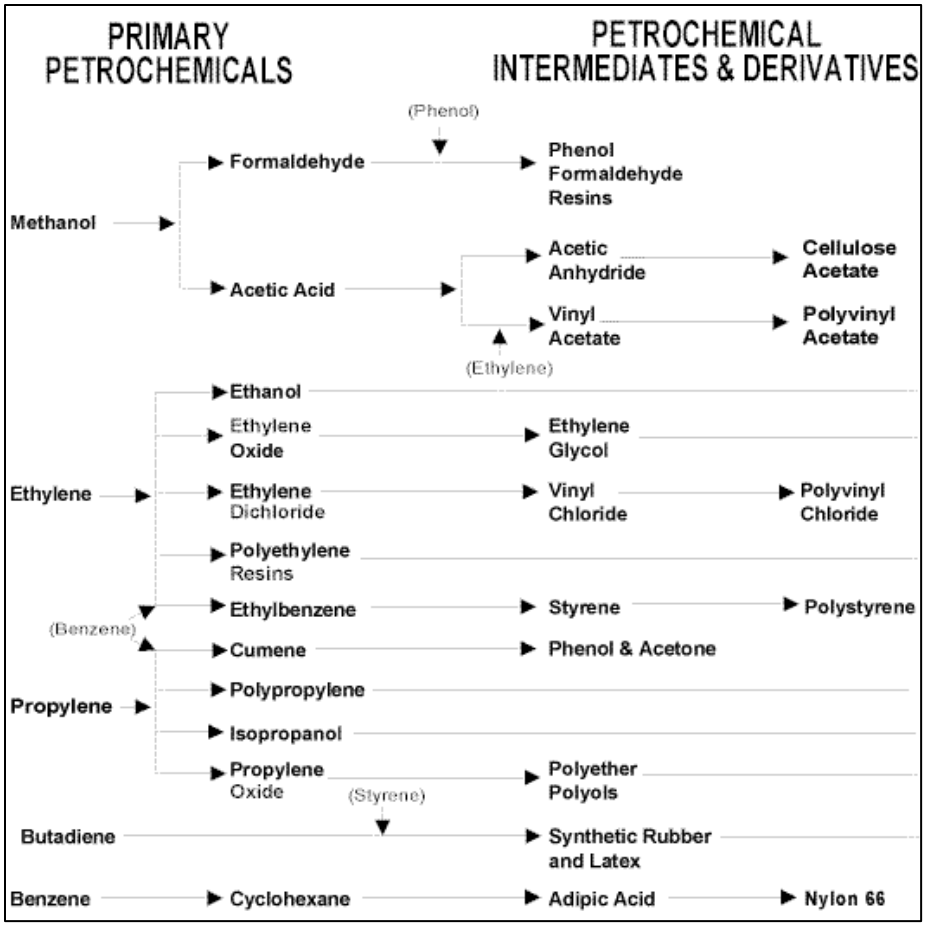

Figure 188. Relationships among the primary petrochemicals and petrochemical intermediates and derivatives.

Source: Elmhurst College Virtual Chembook (Ophardt c2003).

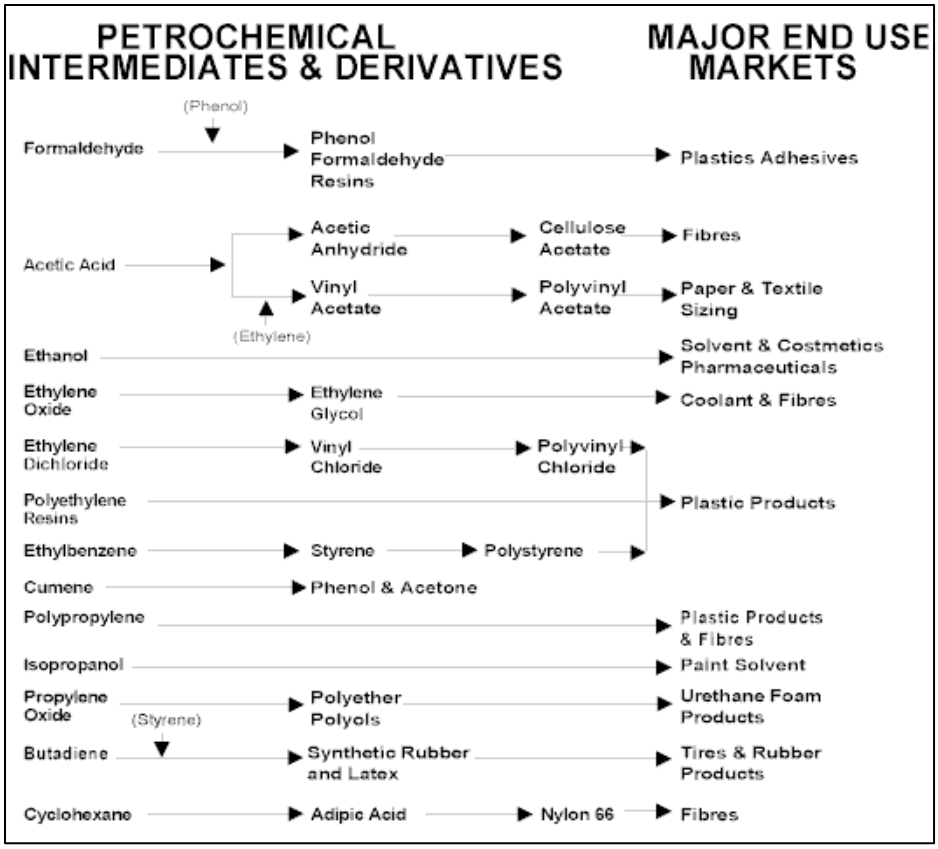

Figure 189. End-use products derived from petrochemicals.

Source: Elmhurst College Virtual Chembook (Ophardt c2003).

For example, Advansix Resins & Chemicals in Philadelphia, Pennsylvania, imports the petrochemical cumene, which is derived from the elementary petrochemical benzene. Cumene is then used to form cumene hydroperoxide, which is used as a reactant to create the plant's primary product, phenol, as well as a coproduct, acetone (Advansix c2020). Figure 190 illustrates the phenolic chain, which begins with benzene and ultimately produces nylon, resins, and polycarbonate.

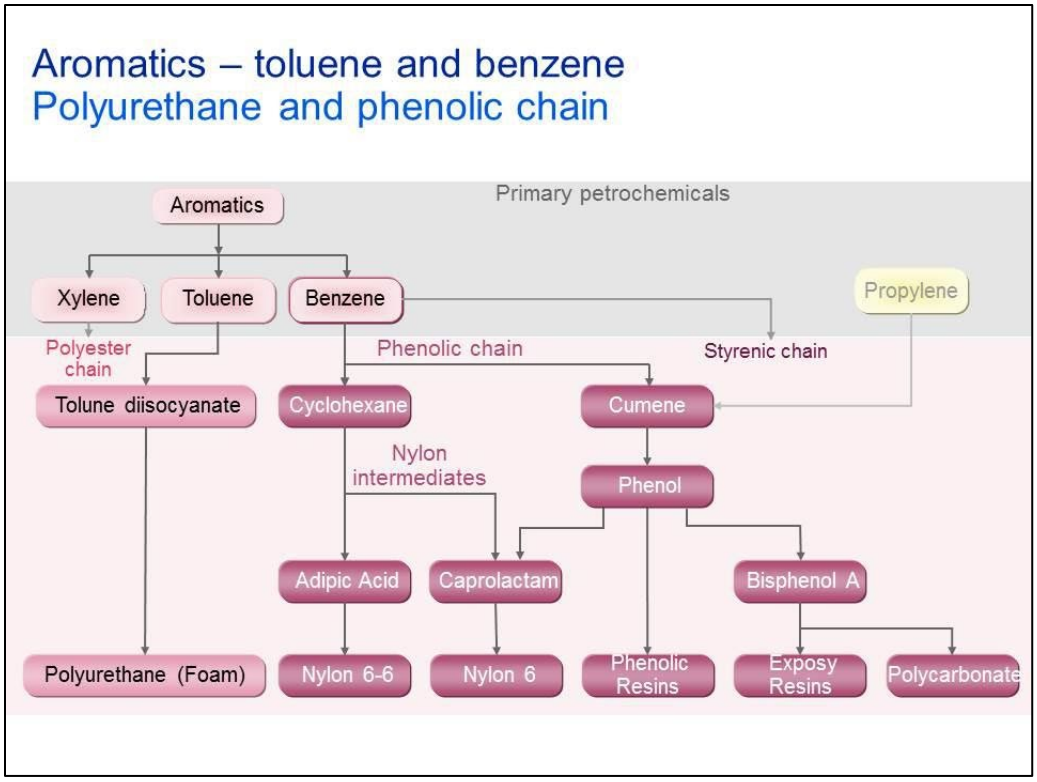

Figure 190. Petrochemical intermediates: polyurethane and phenolic chain.

Source: ABB, Inc. (Devold 2016 Figure 25).

Not all chemicals involved in these production processes are reactants, either. They may instead be used as process or manufacturing aids. For example, BP's Cooper River plant, which is located in South Carolina, uses cobalt, manganese, and n-butyl alcohol as catalysts in the reactions that convert p-xylene to its primary product terephthalic acid (BP 2020a). Figure 191 illustrates the polyester chain, including the process carried out by the Cooper River plant. When the primary petrochemical finally reaches its end-use, xylene will ultimately be used to produce polyester fibers and resins.

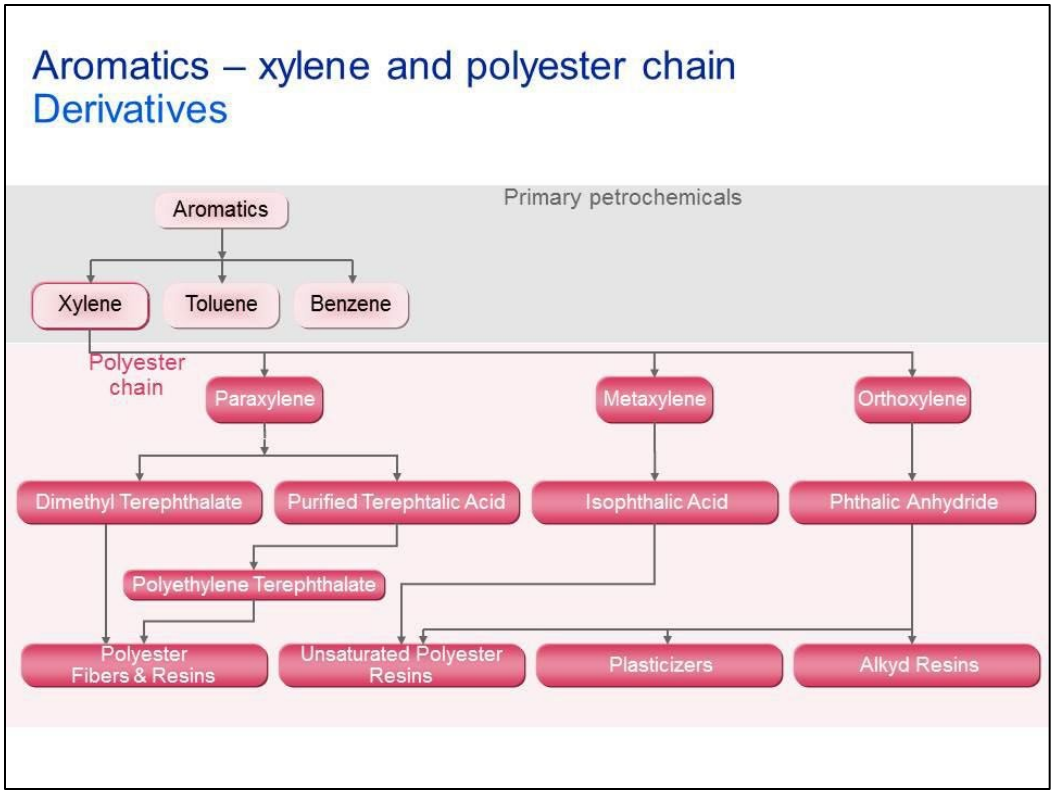

Figure 191. Petrochemical intermediates: polyurethane and phenolic chain.

Source: ABB, Inc. (Devold 2016 Figure 24).

Finally, petrochemicals may be used to enhance other products produced by the plant. The Delaware-based Delaware City Refinery, for instance, lists cumene as being used for this purpose. Cumene is likely used in this context as a component in gasoline blending (American Chemistry Council 2017). Figure 192 provides an illustration of the petrochemical industry's place in the hydrocarbon supply chain.

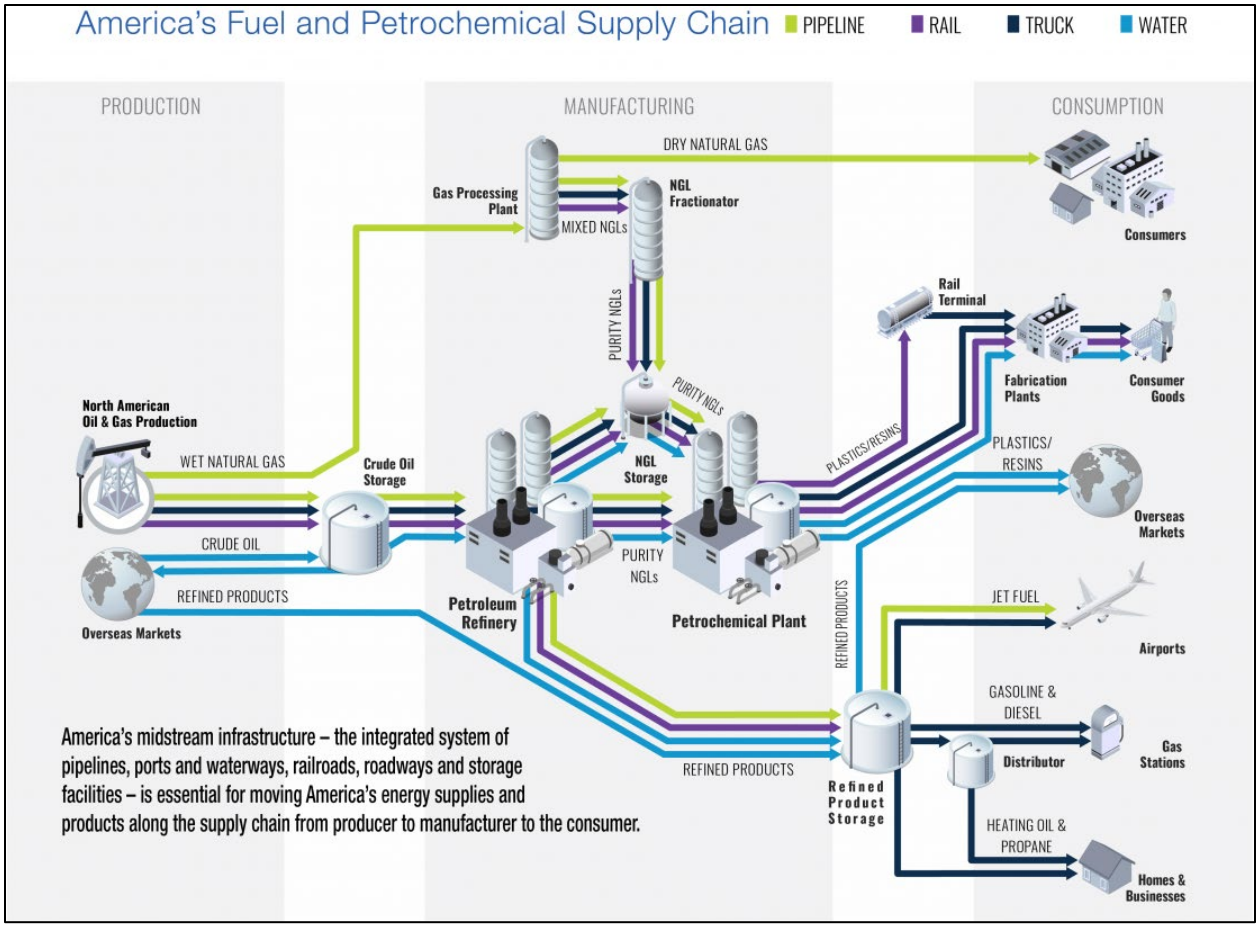

Figure 192. Petrochemical supply chain.

Source: American Fuel & Petrochemical Society (American Fuel & Petrochemical Manufacturers 2018).

11.2 Typical Facility Characteristics

The petrochemical industry is somewhat amorphous and can be difficult to define, particularly around the boundaries. The upstream side of the business is one that is typically defined by the production and primary use of very aggregate crude oil and natural gas byproducts. As one moves downstream, industries and facilities that combine petrochemical manufacturing and other organic chemistry-based industries, such as plastics, synthetic fibers, agricultural chemicals, paints and resins, and pharmaceuticals, are usually included.

Quite often, companies owning and operating facilities in this industry largely consist of a) petroleum companies who have broadened their interests into chemicals; b) chemical companies who buy petroleum raw materials; and c) joint ventures between chemical and petroleum companies. For instance, BP owns the Cooper River Chemicals plant in South Carolina. The co-location of chemical and refining operations can create efficiencies and synergies that keep many of these facilities operational in an otherwise mature high-cost environment that defines North American and European operations.

Petrochemical plants are usually located in areas with close proximity to raw materials (petroleum-based inputs) and multiple transportation routes including rail, road, and water. For example, Advansix's Philadelphia phenol plant used to source cumene from the nearby Philadelphia Energy Solutions refinery prior to the refinery's closure (Advansix 2019 Jun 24). As noted earlier, it is not uncommon for large integrated oil and gas companies that own refineries to have nearby chemical plant affiliates to take advantage of particular waste streams that would offer the chemical plant a potential competitive advantage relative to siting on a "stand-alone" basis.

Most petrochemical complexes include plants that manufacture any combination of primary, intermediate, and end-use chemical products. Changes in market conditions and technologies are often reflected over time as input and product slates are changed. In general, petrochemical plants attempt to run in an "optimized" fashion by attaining the cheapest manufacturing costs and producing the largest level of output while taking advantage of any and all co-locational synergies. Product slates and system designs are carefully coordinated in order to optimize the use and output of chemical by-products and to use steam, heat, and power as efficiently as possible.

11.3 Geographic Distribution

11.3.1 Petrochemical Facilities in the Study Area

Fourteen petrochemical facilities have been identified in the study area. The petrochemical facilities are those listed in the EPA Toxic Release Inventory database as having either NAICS code 342110 (Petroleum Refineries) or NAICS code 325110 (Petrochemical Manufacturing). Refineries are included in this group because they produce primary petrochemicals. Table 50 and Figure 193, Figure 194, provide the name and location of petrochemical facilities within the study area.

Table 50. Petrochemical plants in study area.

Facility	Location
Advansix Resins & Chemicals LLC	Philadelphia, PA
Albemarle Corp	Blair, PA
American Refining Group Inc	Mckean, PA
BP Chemical Co - Cooper River Plant	Berkeley, SC
Cherokee Pharmaceuticals LLC	Northumberland, PA
Crown Point International LLC	Gloucester, NJ
Delaware City Refinery	New Castle, DE
Monroe Energy LLC-Trainer Refinery	Delaware, PA
Paulsboro Refining Co LLC	Gloucester, NJ
Phillips 66 Co-Bayway Refinery	Union, NJ
Sunoco LLC-Race Fuels	Delaware, PA
United Refining Co	Warren, PA

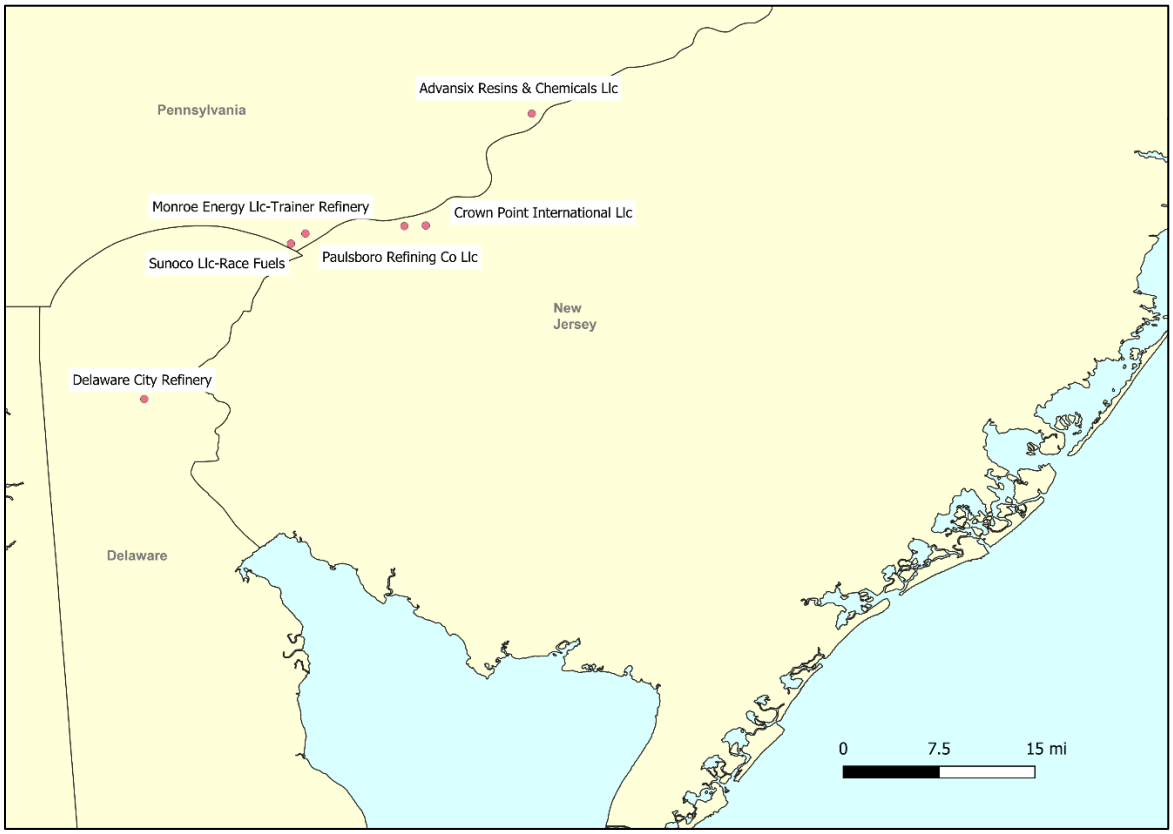

Figure 193. Petrochemical plants in Delaware, southern New Jersey, and southeastern Pennsylvania.

Figure 194. Petrochemical plants in Pennsylvania and northern New Jersey.

11.4 Scope of Economic Contribution to Regional Economy

Unfortunately, the manufacturing of petrochemical products constitutes too granular an industry to obtain industry-specific data. However, economic data can be obtained for the manufacture of chemical products as a whole. This may also be an appropriate measure, as it includes manufacturing of other chemical products whose development may use petrochemicals in some manner.

As of 2018, the chemical manufacturing industry overall (NAICS industry code 325) provides nearly 300,000 jobs within the study area (BLS 2019 May). While the BLS does not track state-level wages by industry, it does track state-level wages by occupation. Table 51 shows national employment for the top 10 largest occupations in the chemical manufacturing industry both within the industry, and across all industries. These ten occupations comprise about 43 percent of workers in the chemical manufacturing industry. The largest occupation in the industry is “Chemical Equipment Operators and Tenders,” and almost 90 percent of all workers employed in this occupation work in the chemical manufacturing industry.

Table 51. National employment figures for top ten occupations in the chemical manufacturing industry as of May 2019.

Occupation	Chemical Manufacturing	All Industries	Share of workers (%)
Chemical Equipment Operators and Tenders	76,610	85,730	89
Packaging and Filling Machine Operators and Tenders	56,060	387,710	14
Mixing and Blending Machine Setters, Operators, and Tenders	44,500	109,190	41
First-Line Supervisors of Production and Operating Workers	34,420	603,060	6
Chemists	28,320	83,250	34
Inspectors, Testers, Sorters, Samplers, and Weighers	28,050	57,3730	5
Industrial Machinery Mechanics	23,380	387,200	6
Chemical Plant and System Operators	22,220	26,690	83
Chemical Technicians	22,120	65,430	34
Laborers and Freight, Stock, and Material Movers, Hand	19,290	2,948,460	1

Source: Bureau of Labor Statistics (BLS 2019 May).

For five of the occupations shown in Table 51, more than 30 percent of workers are employed by the chemical manufacturing industry. Table 52 provides the median annual income for these occupations in each state within the study area as of May 2019. Chemists and chemical plant and system operators consistently earn more than the state medium. However, it should be noted that only 34 percent of chemists in the nation work in the chemical production industry.

Table 52. Median annual earnings for major occupations in the chemical manufacturing industry as of May 2019.

State	Chemical Equipment Operators and Tenders ($)	Mixing and Blending Machine Setters, Operators, and Tenders ($)	Chemists ($)	Chemical Plant and System Operators ($)	Chemical Technicians ($)	All Occupations ($)
CT	41,660	40,670	82,520	55,600	48,580	48,530
DE	65,670	39,620	103,670	70,770	65,440	40,900
DC	n/a	n/a	126,050	n/a	58,310	74,340
FL	39,750	33,890	59,220	59,590	45,030	35,850
GA	37,790	38,470	82,870	52,210	46,510	36,930
ME	44,980	50,150	60,810	n/a	45,460	38,370
MD	45,680	40,130	114,600	66,010	53,370	45,970
MA	46,600	40,440	89,280	56,680	52,900	50,200
NH	42,810	42,000	69,580	n/a	45,640	41,490
NJ	47,310	42,430	89,830	75,900	53,720	45,000
NY	47,260	38,060	75,590	54,090	49,840	46,680
NC	46,900	34,850	73,510	44,580	51,510	36,910
PA	45,980	38,630	68,660	60,550	45,550	39,490
RI	40,280	42,300	91,180	n/a	48,330	44,170
SC	46,050	40,500	69,290	50,210	44,060	34,690

Source: Bureau of Labor Statistics (BLS 2019 May).

11.5 Current Trends

As mentioned in the previous sector, petrochemical data is too granular to obtain useful economic data, so the chemical industry as a whole must be considered instead.

11.5.1 Gross Domestic Product

Figure 195 provides a look at real GDP for the study area as a percentage of the comparable total for the country as a whole on an annual basis from 1997 through 2017. At its peak, the study area comprised over 48 percent of the country's chemical products manufacturing GDP. However, after 2002, the regional industry began rapidly declining as a percentage of the country's chemical manufacturing industry. By 2017, its share of the industry was just 32.7 percent. In contrast, the region's share of the country's total GDP has declined slowly and gradually. In 1997, this share was 36.6 percent, and by 2017, it had only declined to 34.3 percent (BEA 2020 Apr 7).

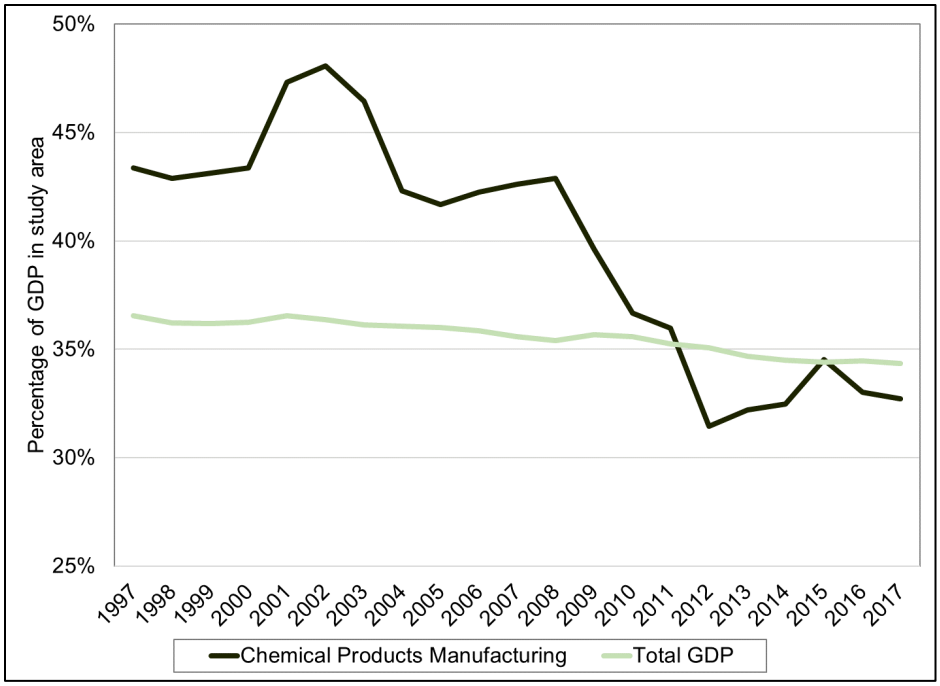

Figure 195. Share of national real GDP in study area for chemical manufacturing industry and total GDP, 1997–2017.

Source: Bureau of Economic Analysis (BEA 2020 Apr 7).

Figure 196 provides another perspective on the drastic decline of the chemical manufacturing GDP in the study area. Note that in the aftermath of the 2007 financial crash, the national chemical manufacturing GDP declined from $372.9 billion in 2007 to $303.4 billion in 2012, a decline of 18.6 percent. Over the same period, chemical manufacturing GDP for the study area declined from $158.9 billion in 2007 to $95.4 billion in 2012, a decline of 40 percent (BEA 2020 Apr 7). The study area's chemical industry was hit especially hard by the Great Recession compared to the national chemical industry.

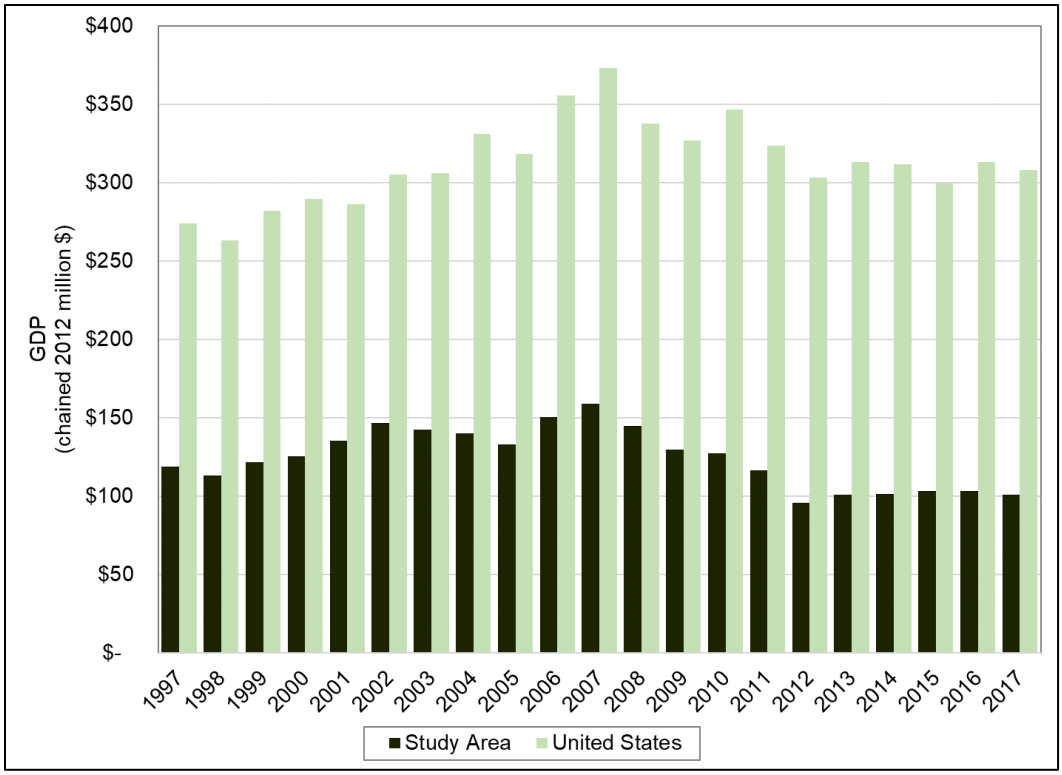

Figure 196. Chemical manufacturing industry real GDP for study area and United States, 1997–2017.

Source: Bureau of Economic Analysis (BEA 2020 Apr 7).

11.5.2 Employment

Employment tells a similar, though less drastic, story to that of GDP. Figure 197 presents the chemical industry and total employments for the study area as percentages of their national counterparts. Again, chemical products manufacturing employment in the study area has fallen dramatically as a percentage of chemical products manufacturing employment for the country as a whole, from 40.2 percent in 1998 to 33.7 percent in 2018. The study area's share of total employment was 33.4 percent in 1998 and actually increased to 34.4 percent in 2018 (BEA 2019 Sep 24).

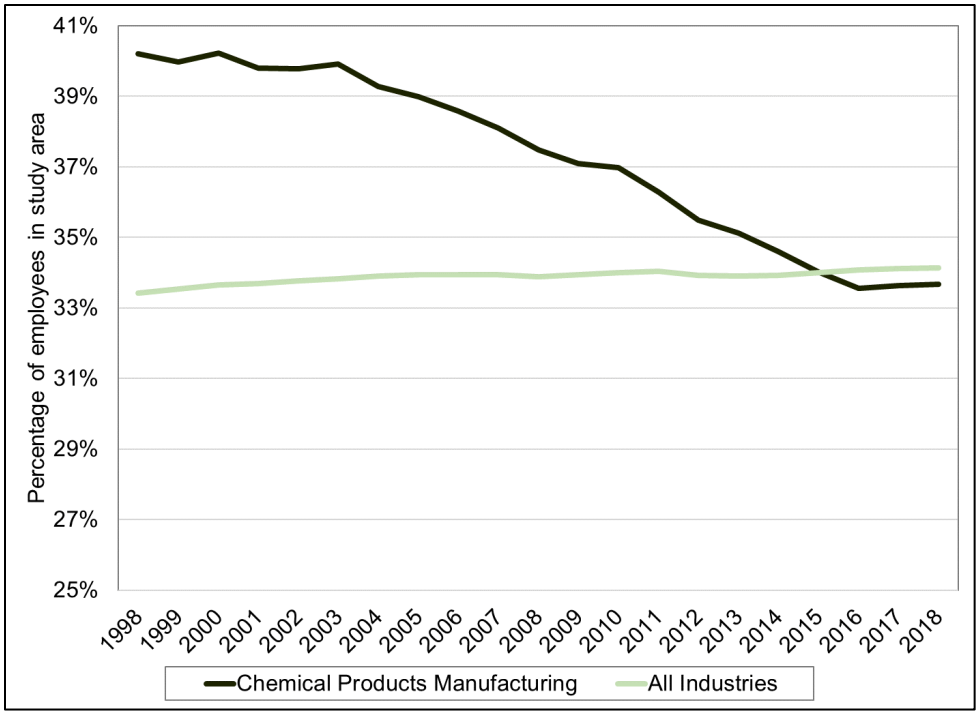

Figure 197. Share of national employment in study area for chemical manufacturing industry and in total, 1998–2018.

Source: Bureau of Economic Analysis (BEA 2019 Sep 24).

The decline in chemical products manufacturing employment in the study area as a share of industry employment across the country is better explained in Figure 198, showing the number of full- and part-time employees in the industry from 1998 through 2018. It is clear that starting in 2012, national employment in the chemical products manufacturing industry began to recover, increasing by 6.9 percent from 817,900 jobs in 2012 to 874,100 in 2018. Meanwhile, industry employment within the study area has been flat. Over the same period, chemical products manufacturing employment in the study area has only increased by 1.4 percent from 290,355 jobs in 2012 to 294,295 jobs in 2018 (BEA 2019 Sep 24).

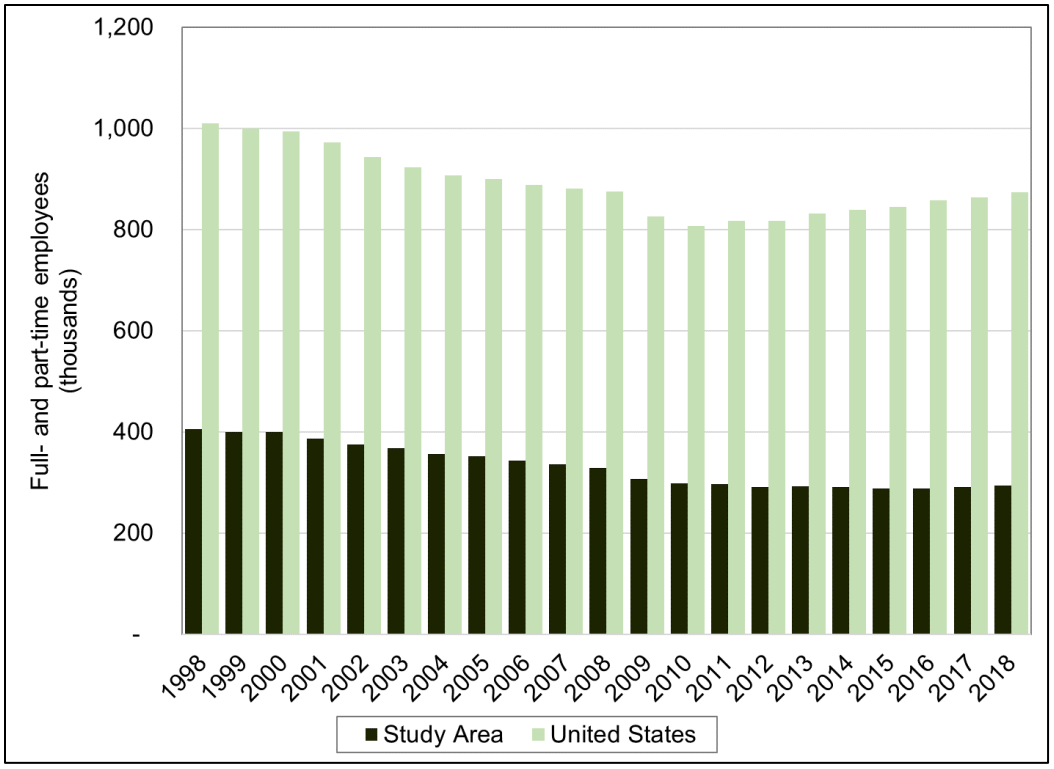

Figure 198. Chemical manufacturing industry employment for study area and United States, 1998–2018.

Source: Bureau of Economic Analysis (BEA 2019 Sep 24).

11.5.3 Regulatory Changes

As with all chemicals, petrochemicals in the United States are regulated under the Toxic Substances Control Act (TSCA). The TSCA bans the manufacture and importation of chemicals which are not included in a defined TSCA "inventory". In 2016, the TSCA was amended by the Frank R. Lautenberg Chemical Safety for the 21st Century Act. This act requires the EPA to evaluate existing chemicals using risk-based assessments. It also provided for increased transparency for chemical information (EPA 2016 Jun 9).

This update has facilitated EPA risk evaluations of several chemicals, including petrochemicals and other chemicals used in petrochemical facilities. For example, two of the first ten chemicals to be evaluated under the act, dichloromethane and tetrachloroethylene, are handled by facilities within the study area. The EPA released its final risk evaluation for dichloromethane, which both Albemarle Corp and Cherokee Pharmaceuticals list as a processing aid, finding that its commercial and industrial use as a processing aid presents an unreasonable risk of injury to health (EPA 2020: 5).

Additional chemicals handled by facilities within the study area are also undergoing risk evaluations. These include 1,3-butadiene, dibutyl phthalate, formaldehyde, and phthalic anhydride (EPA 2020 Apr 1). These chemicals are either imported into the facilities, or they are produced onsite. The ban of manufacture or importation of these chemicals could impact petrochemical facility operations.

11.6 Current Outlook

11.6.1 Industry Outlook

Table 53. Projected employment and output across all industries and in the chemical manufacturing industry. below shows the BLS projected employment and output changes from 2018 to 2028 across all industries, as well as for the chemical manufacturing industry, and the basic chemical manufacturing subindustry, which includes petrochemical manufacturing. Output for these industries is projected to grow more slowly than the economy as a whole, while employment is projected to decline.

Table 53. Projected employment and output across all industries and in the chemical manufacturing industry.

	Employment (thousands of jobs)			Output (chained 2012 billion $)		
Industry	**2018**	**2028**	**Annual Change (%)**	**2018**	**2028**	**Annual Change (%)**
All industries	161,038	169,436	0.5	33,242	40,045	1.9
Chemical manufacturing	838	808	-0.4	814	951	1.6
Basic chemical manufacturing	153	142	-0.7	310	351	1.3

Source: Bureau of Labor Statistics (BLS 2019 Nov 8).

11.6.2 Factors Impacting East Coast Development

Petrochemical industry factors for the East Coast relate to the availability of chemical process inputs as well as waning demand for certain products as companies in the region look to shift from petroleum towards renewables.

The availability of cheap shale gas in the Appalachian region provides potential for the further development of the study area's petrochemical industry through increased cracking activities to produce olefins such as ethylene, propylene, and butadiene. In fact, this access to cheap gas may give it a cost advantage over Gulf Coast petrochemical facilities. According to a 2020 DOE report, IHS Markit has estimated that "when compared with the Gulf Coast, identical greenfield manufacturing facilities in Appalachia could produce polyethylene for 23 percent less, ammonia/urea for 12 percent less, propylene for 10 percent to 11 percent less, and methanol for 26 percent less (DOE 2020: 30)." Shell is currently constructing a new petrochemical plant in Potter Township, Pennsylvania. The plant will process ethane from shale gas and use it to produce 1.6 million tons of polyethylene per year. The plant will employ over 600 people (Shell).

In addition to the gas reserves of the Marcellus shale, the region also has access to oil reserves in a portion of the Utica and Point Pleasant formations under eastern Ohio and northwestern Pennsylvania (Enomoto et al. 2019). Figure 199 shows the location of the oil and gas assessment units in these formations. Shale oil from these formations could supply the production of aromatics and derivatives. In 2019, Ohio produced 28 million barrels of oil, 24.9 million of which was produced through horizontal drilling (Ohio Department of Natural Resources 2020 May 28).

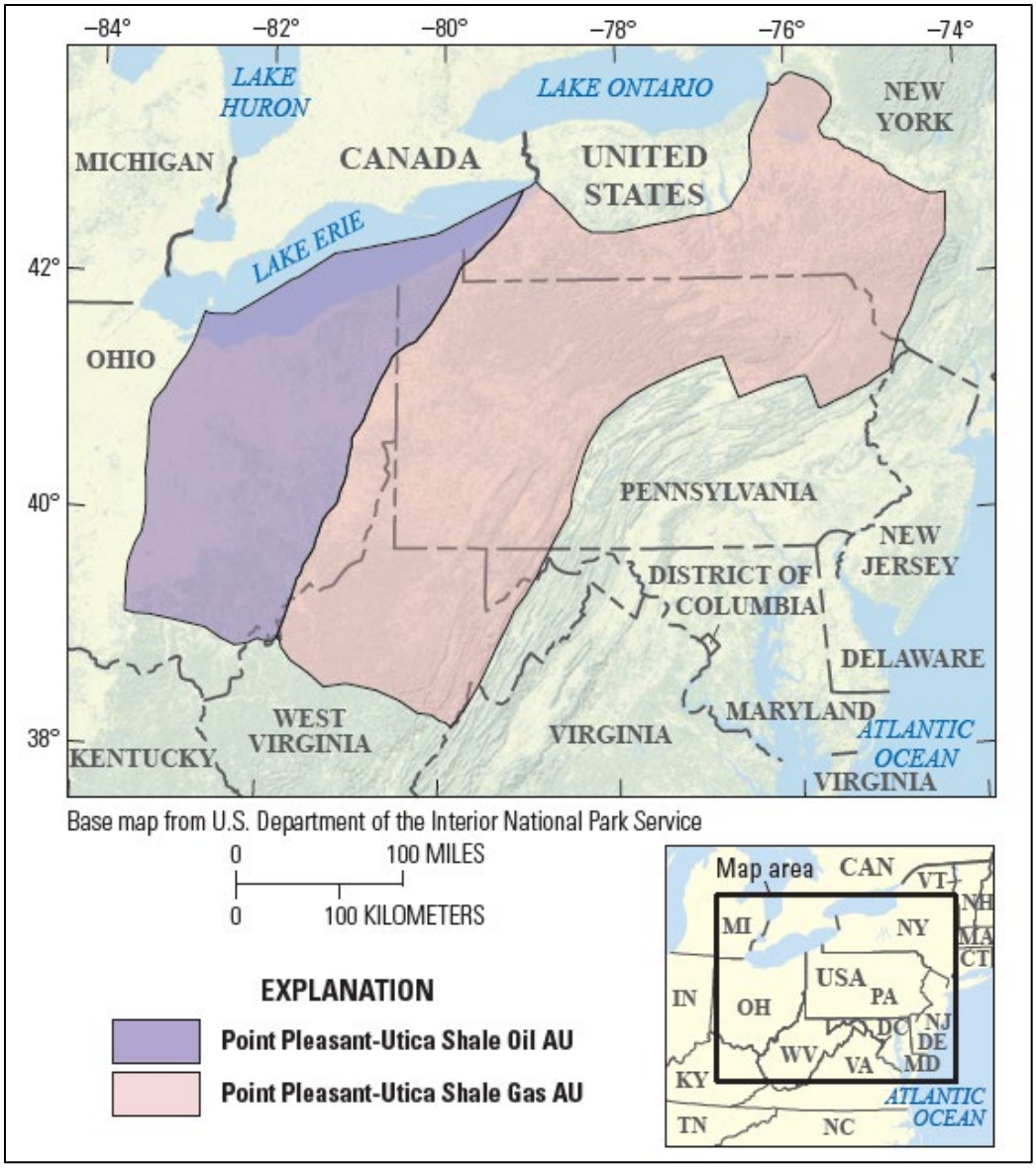

Figure 199. Point Pleasant-Utica Shale map.

Source: United States Geological Survey (Enomoto et al. 2019 Figure 1).

Negative impacts on the study area's petrochemical industry include supply issues due to the recent closure of Philadelphia Energy Solutions (PES) and the movement of certain major players in the petrochemical industry toward renewable energy.

As mentioned earlier in this chapter, PES was a major supplier of cumene to the Advansix phenol plant. Advansix estimated in its 2019 10-K filing that the closure of PES caused $4 million in unfavorable impacts to its third-quarter pre-tax income, and $6 million in unfavorable impacts to its fourth-quarter pre-tax income. It also estimates an unfavorable impact of $10 million to $15 million to pre-tax income for 2020 (SEC 2020 Feb 21).

BP has owned the Cooper River chemical plant since 1998 when it merged with the plant's owner Amoco (BP 2020b). However, as part of its shift toward a focus on renewable sources of energy, BP agreed to sell its petrochemical assets to Ineos, including the Cooper River plant (Tullo 2020 Jun 29; Wren 2020 Jun 29).

12. Electric Power

12.1 Description of the Industry and Services Provided

Electricity is an integral part of modern life in most developed countries and is used for lighting, running appliances, electronics, and for heating and cooling purposes. Electricity is essential to factories, commercial business, and some recreational facilities. Electricity is also an essential input for the industries located in the Atlantic region that could support offshore oil and gas activities.

Electricity is delivered to end-users via regulated electric utilities. These electric utilities are responsible for ensuring safe, economic, and reliable electricity to the consumers in their service territories. Electric utilities can be investor-owned utilities (or "IOUs"), publicly owned (or "munis"), cooperatives (or "coops"), or Federal utilities.

There are also several categories of non-utility market participants in the electricity industry that go beyond utilities. For instance, power marketers are wholesale "middle-men" that purchase electricity from physical or contractual sources, and then resell that electricity to other market participants, often utilities. These power marketers are not required to own or operate electric generation assets.

In addition, there are over 3,800 nonutility power producers (or generators) that sell their electricity into wholesale markets. These nonutility producers are often referred to as independent power producers (IPPs) that produce and sell power on the wholesale market at non-regulated rates. The IPPs do not have franchised service territories and are not typically "rate-regulated" like many utilities. Last, there are also a set of generators that are co-located at industrial facilities that take advantage of these facilities' byproduct thermal energy to "co-produce" or "cogenerate" electricity. These facilities are often referred to as "combined heat and power applications" (CHP) and are highly efficient sources of electricity (EIA 2019).

Electric utilities have historically been regulated monopolies and have pre-defined market service territories within which they are the exclusive providers of what was referred to as vertically-integrated service. The retail operations of IOUs and some rural cooperative providers are regulated by the state in which they operate. Over the past few decades, competition has been introduced in the power generation sector and a certain degree of competition retail service has been allowed, particularly among the Atlantic states. The introduction of retail competition, however, is based entirely on state policy and is predominantly introduced via state legislation. There are currently no federal mandates for retail competition.

Electricity is a relatively homogeneous commodity and is typically differentiated only by customer types (as a rough proxy for size) and, in some instances, on the type of service quality (i.e., firm or various types of interruptible service). Utility service territories are typically distinguished by restricted geographic locations, although this can vary across different states. Classes of service, or sectors, for electricity customers typically include residential, commercial, industrial, and others and are used for setting rates and for long-run capacity planning (i.e., load growth and peak demand).

The main fuel sources used to generation electricity include natural gas, coal, nuclear, hydroelectric, solar, and wind. Since the late 1800s, coal has been one of the largest sources of electricity generation (EIA 2013 Jul 3). However, over the last two decades, there have been drastic declines in the use of coal due to ever increasing environmental regulations and greenhouse gas (GHG) emissions concerns. Natural gas and renewables are increasingly replacing the role that coal played in the US electricity generation fuel mix. Transmission, and some distribution infrastructure has grown to accommodate increasing renewables use at both the bulk power level and behind-the-meter. Many states offer rebates or tax breaks or other financial support mechanisms that incentivize renewable generation development.

12.2 Typical Facility Characteristics

An electric power system is a group of generation, transmission, and distribution, facilities that are physically connected and operated as a single unit under one control (Figure 200) (EIA 2019 Oct 11). Dispatch centers are responsible for matching the supply and demand of electricity and maintaining the electricity flow.

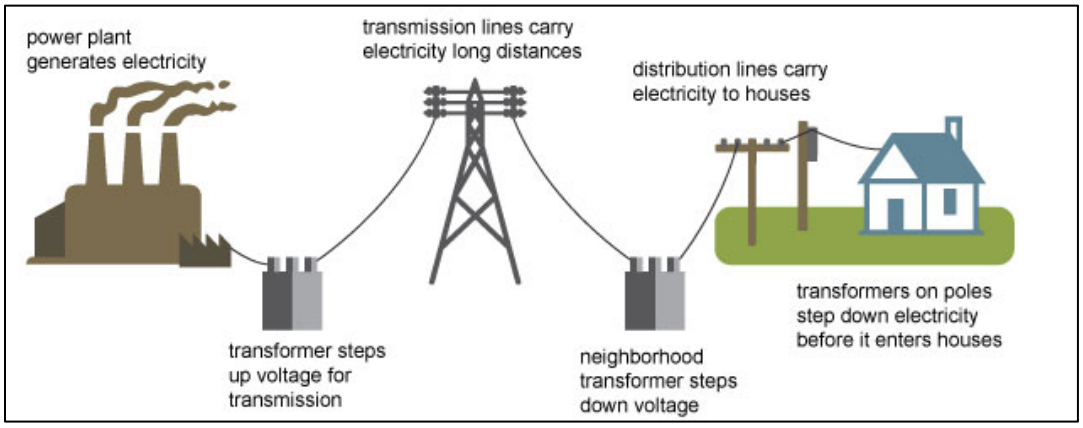

Figure 200. Electric power generation, transmission, and distribution.

Source: Energy Information Administration (EIA 2019 Oct 11).

Power plants use a number of different types of fuel to produce electricity: fossil fuels (coal, natural gas, or a refined oil product), nuclear energy, and renewable energy sources, such as water (hydroelectric power), biomass, waste-to-energy, geothermal, wind, solar energy, and alternative fuels. Figure 201 shows the relative share of electricity generation produced in 2018 by fuel type. As noted earlier, coal has diminished in importance relative to natural gas generation. As of 2018, natural gas generation comprised 35 percent of the overall US generation fuel mix; coal held a subordinate position at 27 percent. Nuclear is the other large fuel source for power generation in the US but is limited in its growth opportunities given the high capital cost and long construction duration requirements for reactor development.

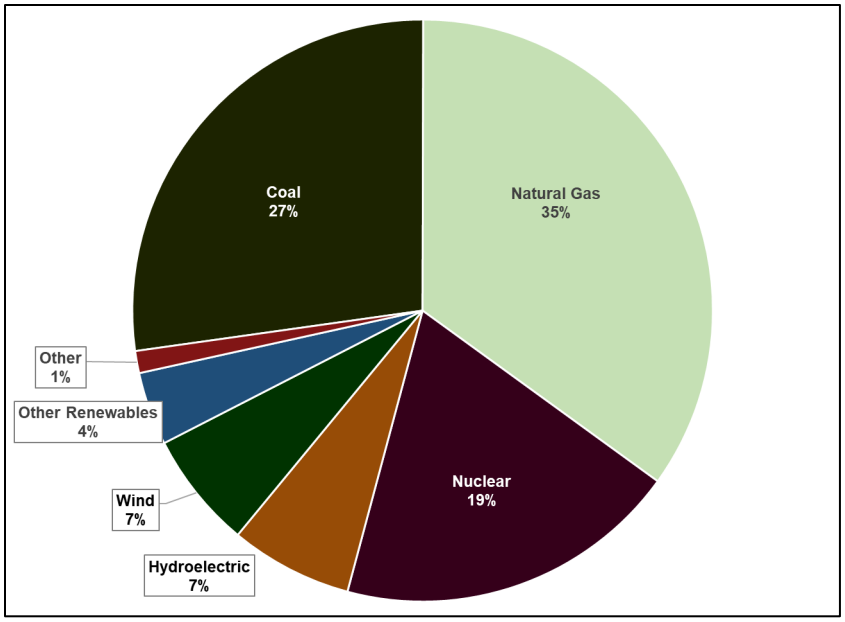

Figure 201. US electric power industry net generation by fuel source, 2018.

Source: Energy Information Administration (EIA c2019).

Electricity demand fluctuates hourly, daily, monthly and on seasonal basis. Electricity generation development is based on these various needs. Central power generation dispatchers accommodate fluctuating demand requirements in order to maintain a safe, economic and reliable system. For instance, electricity demand usually rises significantly around noon and early afternoon hours and then peaks at early evening (on-peak) hours. Seasonal demand reflects regional weather and climatic conditions; the highest demand occurs in the summer when air-conditioning use is greatest.

Electricity generation plants are "dispatched" to meet these changing load requirements. Base-load power plants, for instance, run at virtually constant levels throughout the day and are designed to meet the basic, core electricity requirements of a power system. These baseload generation facilities are typically comprised of large steam coal or nuclear facilities. While coal and nuclear plants have high capital costs, they also have relatively low operating costs (or marginal costs) and are dispatched at an almost continuous rate to spread their high capital costs across a large generation base. Peaking plants are used when demand increases above the normal base load or demand. These peaking or "cycling" units are ramped up and down to follow the daily, monthly and seasonal fluctuations in demand. These plants are also held in stand-by for reliability purposes.

Transmission lines are the large, high-voltage power lines that move electricity from generating plants, sometimes over long distances to substations located near population centers. The US electric transmission grid totals more than 240,000 miles (386,243 kilometers) of high-voltage transmission lines (EEI c2019).[10] The voltage from these transmission lines is reduced to move power onto smaller, lower voltage distribution lines.

[10] This includes lines that are 230 kV or greater.

Local utilities deliver electricity to customers through a network of existing transmission and distribution lines. These are the lines that are seen along streets, supported by wood poles (Figure 202).

Figure 202. Electric transmission: high voltage transmission and low voltage distribution.

Source: (US Fish and Wildlife Service 2018 May 2; Schmidt c2020).

Historically, vertically-integrated utilities charged customers regulated cost-based rates, made up of the cost to generate, transport, and distribute electricity. Though cost-of-service regulation is still pervasive throughout the US, there are places along the Atlantic coast and in New England that allow retail customers to choose their own electricity service providers. Electric utilities in the states that have retail electricity competition (or "choice") are functionally separated companies: their generation assets are split and run entirely separate from the lines (transmission and distribution) part of their business. Strict separation rules are placed between these two sets of operations and the utility part (rate regulated part) of the business is restricted to just the lines part of the operations.

Figure 203, shows the allocation of states between regulated and retail choice categories. The map clearly demonstrates that a good portion of the upper Atlantic region is functionally separated and allows for retail choice.

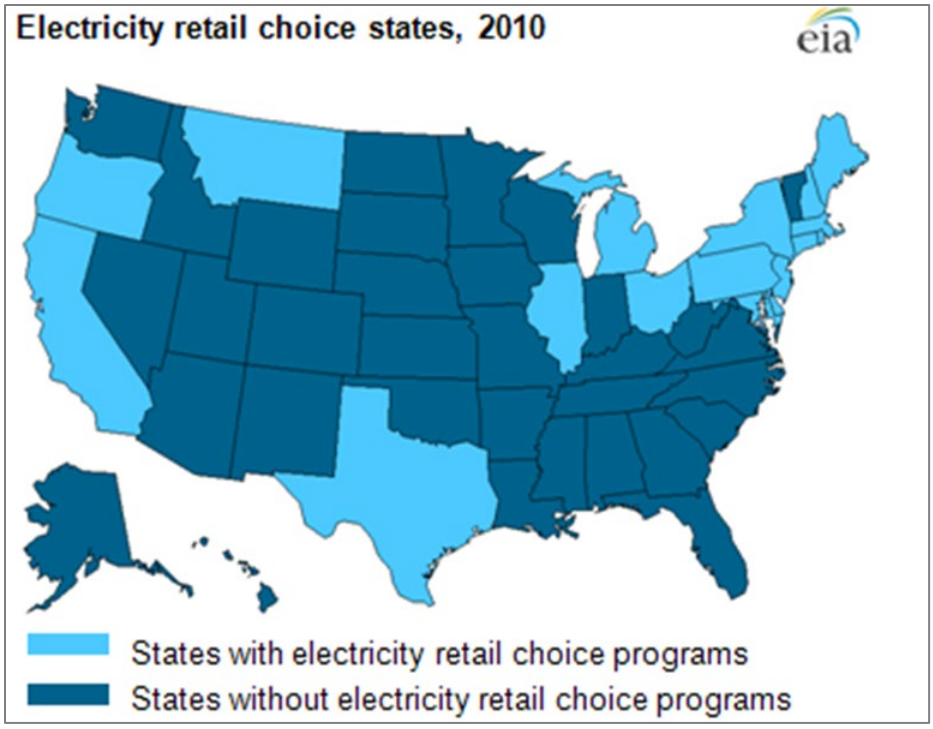

Figure 203. Electricity restructuring by state.

Source: Energy Information Administration (EIA 2012 May 14)

There are 2,930 electric utilities, of all types, currently operating in the US (EIA 2019 Aug 15). There are approximately 168 IOUs, 1,958 munis , and 812 rural coops in the US (EA 2019 Aug 15). Although IOUs make up only 168 of the total companies, they serve over 70 percent of all US retail customers (EA 2019 Aug 15).

12.3 Geographic Distribution

12.3.1 Generation

There are 6,897 individual electric power generators in the Atlantic region accounting for 361,618 MW of generating capacity (EIA 2019 Sep 3). Figure 204 shows the regional break-out of the capacity of these facilities. The most generation capacity is located in Florida, which totals 17 percent of the regional total. Pennsylvania is second with 14 percent followed by New York, Georgia, and North Carolina with 12 percent, 11 percent, and 10 percent, respectively. The smallest share is Delaware, with less than a one percent share.

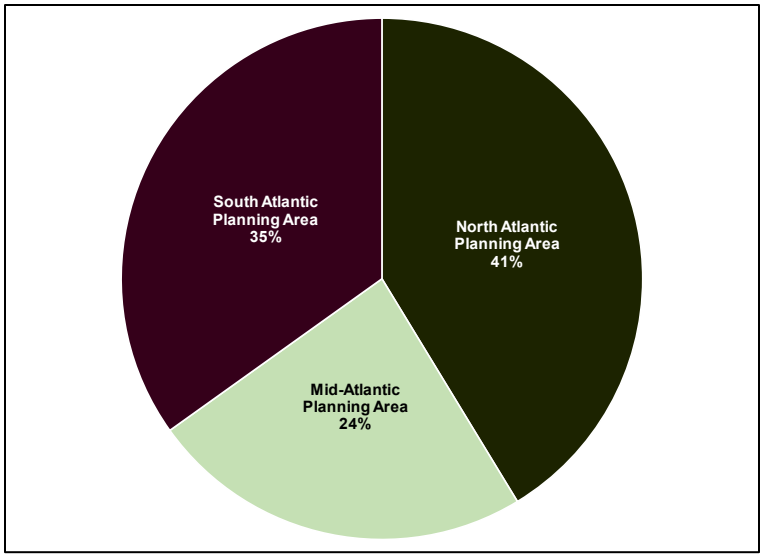

Figure 204. Atlantic region's share of electric generation capacity, 2018.

Source: Energy Information Administration (EIA c2019).

Figure 205 shows the North Atlantic planning area's percent generation capacity by fuel type. Over the last several years, coal has been replaced as the primary source of generation in the Atlantic region much like it has throughout the US Natural gas is now the most used fuel source, fueling over 50 percent of the regional total. Nuclear produces the next highest with 16 percent of capacity followed by coal at 11 percent.

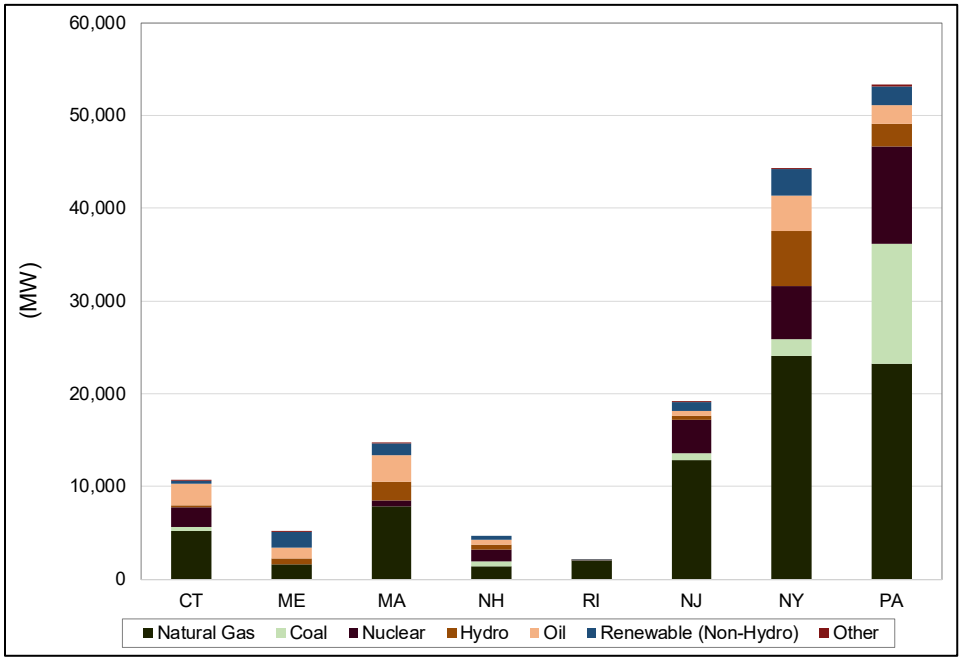

Figure 205. North Atlantic planning area capacity by state and fuel type, 2018.

Source: Energy Information Administration (EIA 2019 Sep 3).

Figure 206 breaks down the types of fuel used in the Mid and South Atlantic region by state. Florida accounts for 37 percent of all petroleum generation capacity in this region and this generating mix is heavily dominated by natural gas. This is not surprising given the initiatives taken in the state to reduce its previously heavy reliance on fuel oil for power generation during the energy crises of the late 1970s and early 1980s. There is also a significant amount of renewable capacity in Florida and North Carolina, however a good portion of this capacity is dedicated to solar power generation.

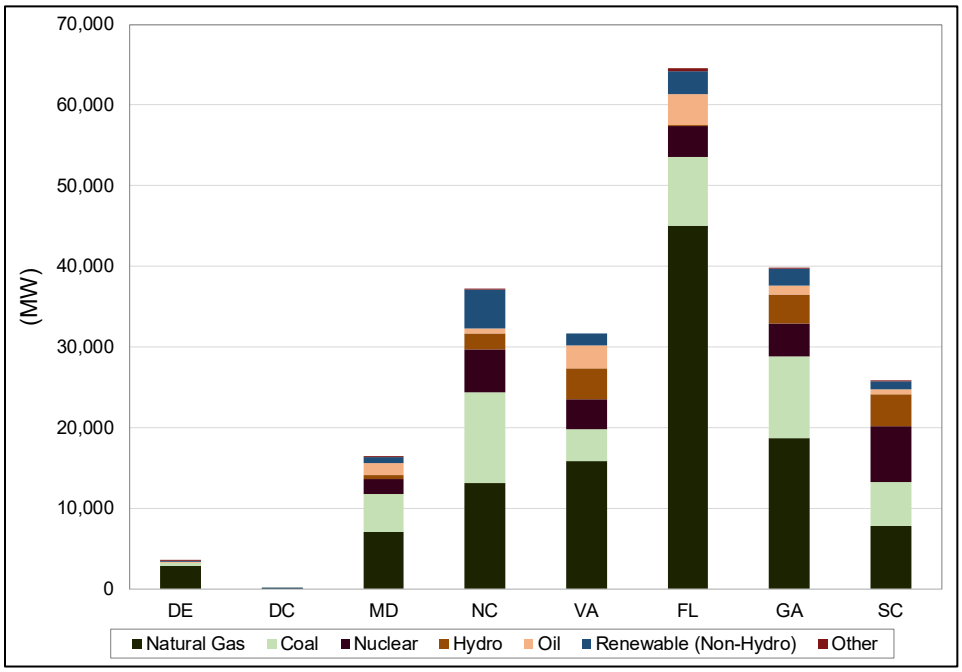

Figure 206. Mid and South Atlantic planning area capacity by state and fuel type, 2018.

Source: Energy Information Administration (EIA 2019 Sep 3).

12.3.2 Transmission

The US transmission system is the backbone of the US electric power industry, moving electric power over long distances from generation source to local distributor. Over the past several years, transmission operations and planning have moved away from traditional utilities, particularly IOUs, and to what is referred to as Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs). Ownership of transmission assets still remains with utilities, even to this day. However, the organization and planning for these systems has been delegated to an independent manager in order to remove potential conflicts of interest that generation-owning utilities may have in running their transmission systems. It is commonly believed that utilities that own both generation and transmission will use their transmission system to create difficulties for non-affiliate generations sources. RTOs and ISOs run the system, therefore, in an independent capacity to maximize the common carrier aspects of the business.

Interconnected transmission lines become high-voltage transmission networks. In the US, these networks are referred to as grids and there are three major grids in the US: the Eastern Interconnect, the Western Interconnect, and the Electric Reliability Council of Texas (ERCOT). As shown in Figure 207, these three regions are separated into six regional transmission reliability entities (that coordinate with but differ from the RTOs and ISOs discussed above).

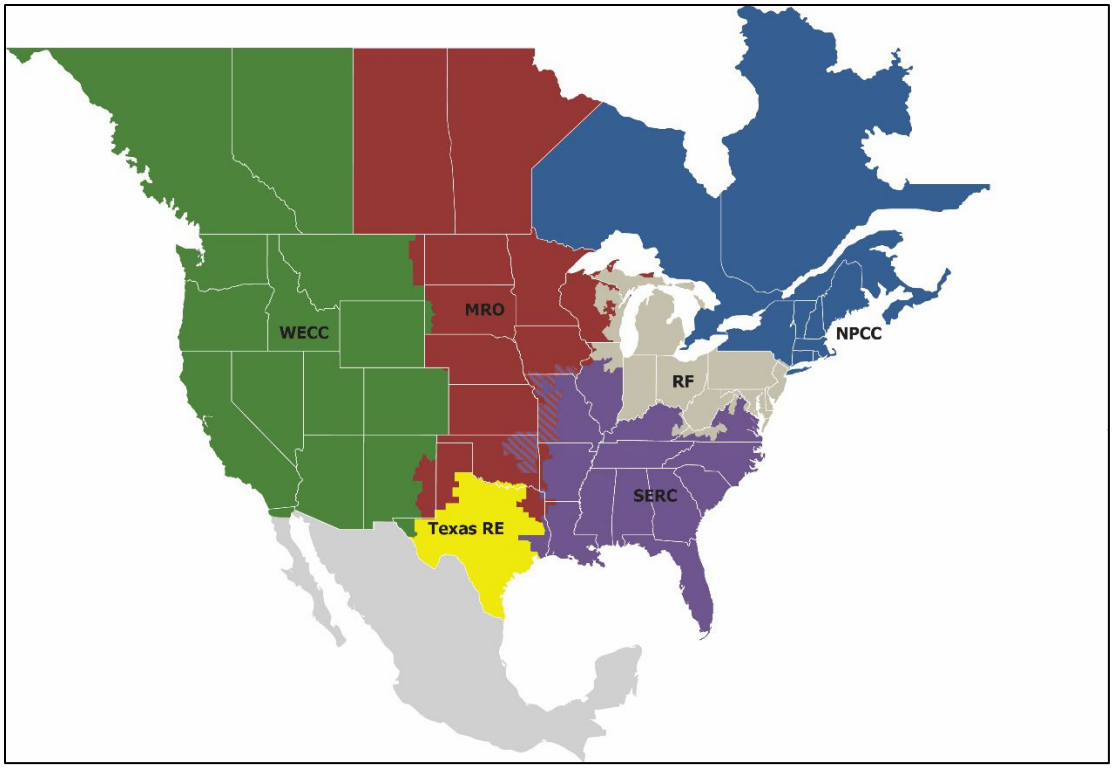

Figure 207. Current North American Reliability Corporation regions.

Source: North American Electric Reliability Corporation (NERC c2020).

System reliability across each interconnection, and each of the regional reliability entities, is coordinated by the North American Electric Reliability Corporation, or NERC. In 2007, FERC granted NERC the legal authority to enforce reliability standards with all US users, owners, and operators of the bulk power system and made compliance with those standards mandatory and enforceable (NERC 2014 May 19).

There were originally eight regional reliability entities within NERC. However, in 2018, the Southwest Power Pool (SPP) regional reliability entity was dissolved and transferred its registered entities to the Midwest Reliability Organization (MRO) and Southeastern Electric Reliability Council (SERC) (FERC 2018 May 4). The Florida Reliability Coordinating Council (FRCC) was also recently absorbed into SERC as of July 1, 2019 (FRCC 2018). The remaining current reliability regions that are show in the above may are defined as:

1) Northeast Power Coordinating Council (NPCC);
2) Reliability First Corporation (RFC);
3) Midwest Reliability Organization (MRO);
4) SERC Reliability Corporation (SERC);
5) Texas Regional Entity (TRE); and
6) Western Electricity Coordinating Council (WECC).

12.3.3 Distribution

There are over 56 million customers in the Atlantic region, with total retail sales of nearly 1.3 billion MWh. These retail customers are all interconnected to utilities, usually at the distribution level. The exception arises for large industrial customers that can tend to interconnect into electric utility sub-transmission or transmission level facilities.

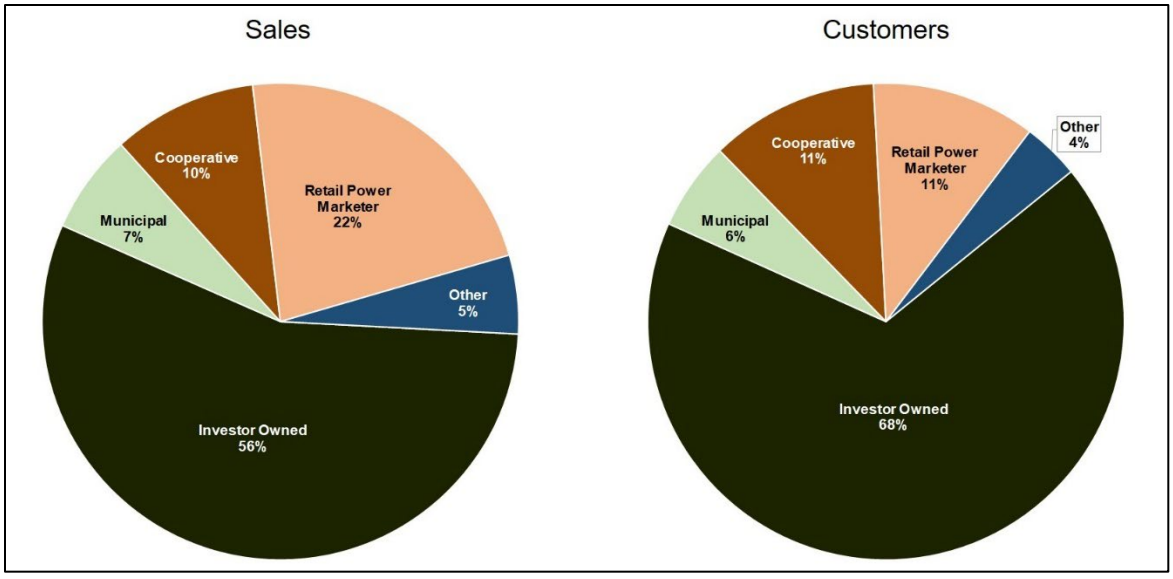

Figure 208. Atlantic region's energy sales and customers by utility type.

Source: Energy Information Administration (EIA 2019 Oct 1).

Figure 209 and Figure 210 show the North Atlantic region's customers and sales by state and type of utility. Pennsylvania and New York have the largest number of customers and utility sales, most of which are served by retail power marketers (50 percent). In general, investor-owned utilities have a larger role in electricity distribution in the northern part of the Atlantic region. Municipalities, however, serve only one to two percent of customers in most of this region.

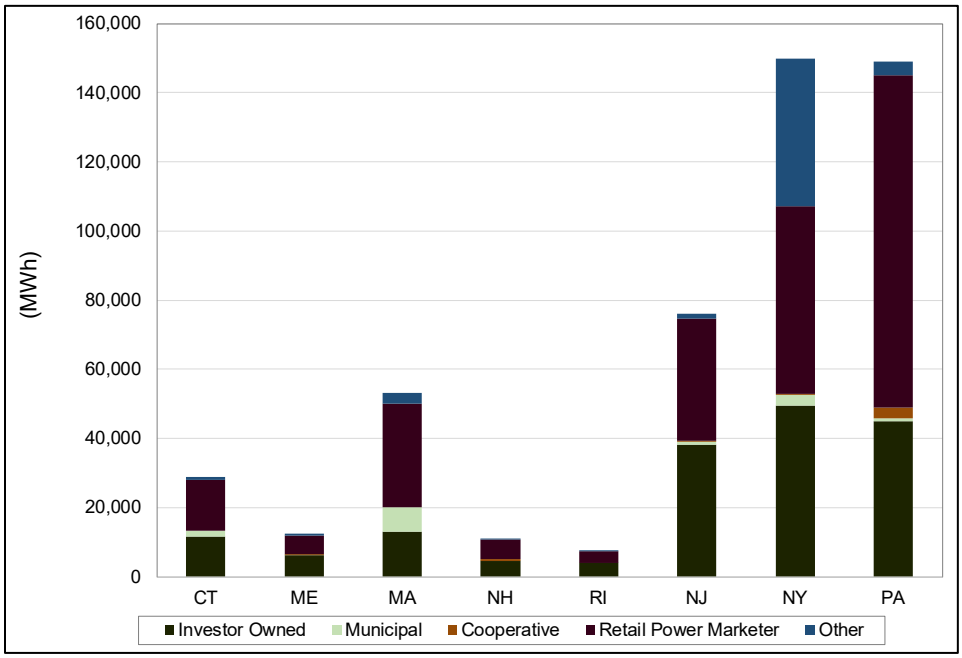

Figure 209. North Atlantic region energy sales by state and type of utility.

Source: Energy Information Administration (EIA 2019 Oct 1).

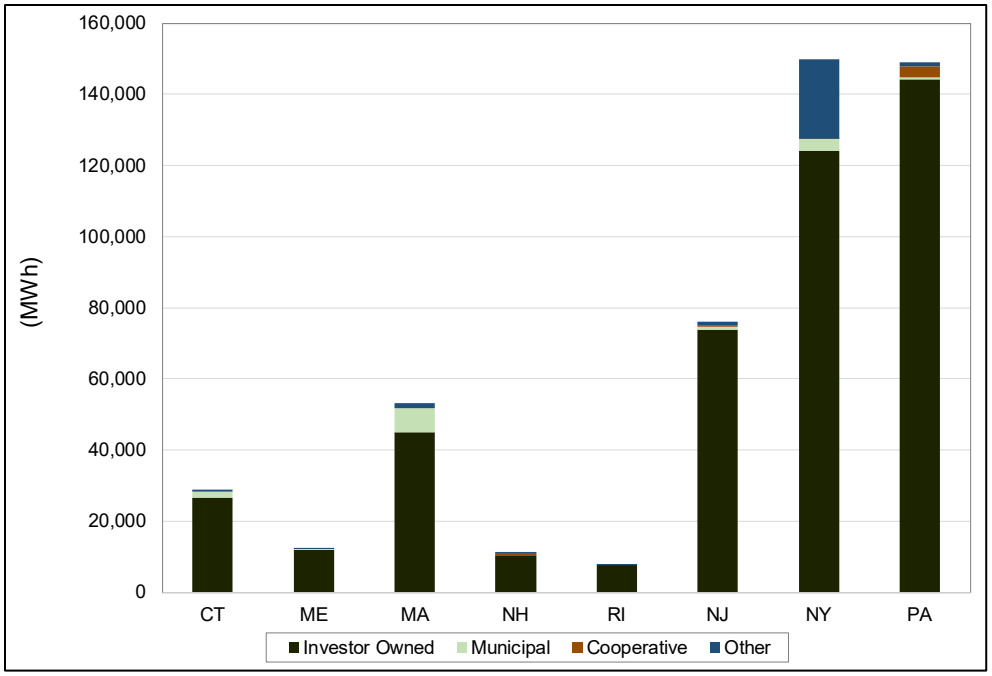

Figure 210. North Atlantic region energy delivery by state and type of utility.

Source: Energy Information Administration (EIA 2019 Oct 1).

Figure 211 and Figure 212 show the Mid and South Atlantic regions' customers and sales by state and type of utility. Investor-owned utilities dominate the electricity distribution market in this region. Florida has the largest number of customers and utility sales among these states, most of which are served by investor-owned utilities (75 percent).

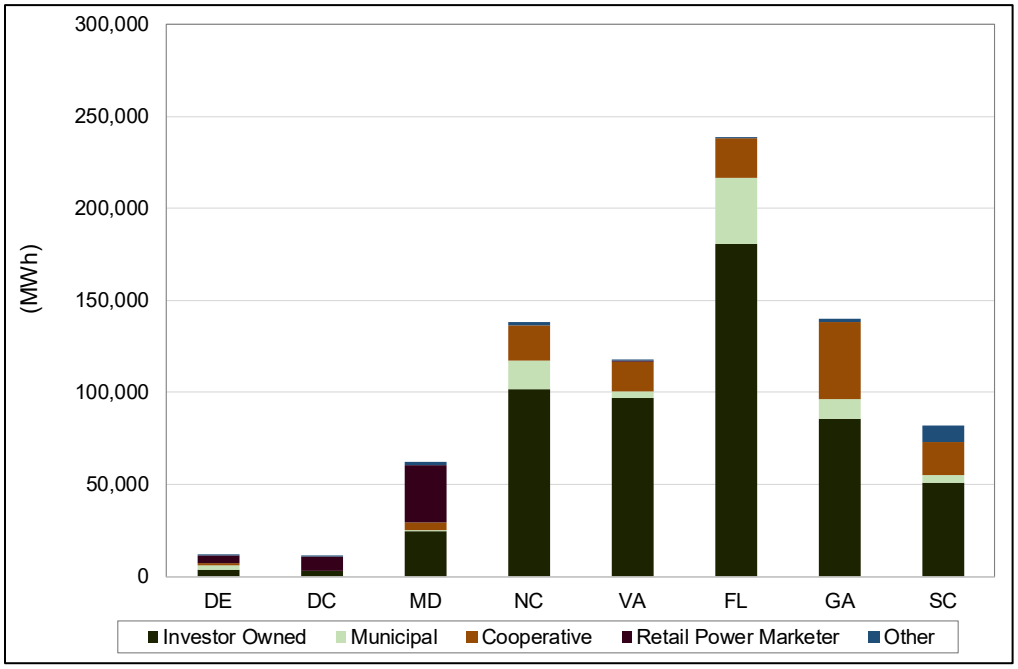

Figure 211. Mid- and South Atlantic region energy sales by state and type of utility.

Source: Energy Information Administration (EIA 2019 Oct 1).

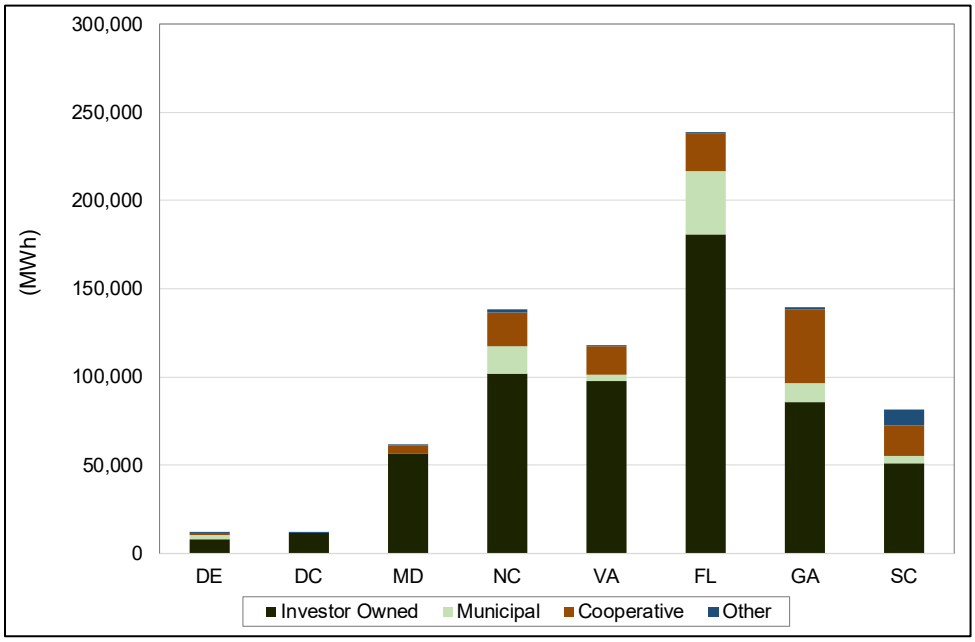

Figure 212. Mid- and South Atlantic region energy delivery by state and type of utility.

Source: Energy Information Administration (EIA 2019 Oct 1).

12.4 Scope of Economic Contribution to Regional Economy

As noted earlier, the electricity industry can be broken into two parts: the generation and the wires portion of the business. The generation component represents the bulk of the capital investment in the industry, with fewer proportional jobs than the wires portion of the business. The US Electric power generation employment contributions are relatively small in comparison to the total employment in each of the Atlantic region's states. None of the states in the Atlantic region have electric power employment totals that are over one percent of the overall statewide employment totals. On a regional basis, South Carolina has the highest share of total electric power employment (Table 54). Notice though, that these types of jobs make up a relatively small portion of total state employment, the electric power employment in these states makes up over 31 percent of total electric power generation and supply employment in the US.

Table 54. Regional and national employment contribution, electric power generation, 2018

State	Power Generation and Supply Jobs	Total State Jobs	Power Generation and Supply Percent of Total State Employment (%)	Power Generation and Supply Percent of Total US Employment (%)
CT	3,933	1,673,925	0.23	0.82
DC	636	771,750	0.08	0.13
DE	1,495	447,075	0.33	0.31
FL	22,138	8,700,654	0.25	4.61
GA	15,692	4,430,136	0.35	3.27
MA	7,777	3,586,034	0.22	1.62
MD	8,775	2,679,064	0.33	1.83
ME	1,420	615,271	0.23	0.30
NC	11,409	4,410,791	0.26	2.38
NH	1,637	658,836	0.25	0.34
NJ	7,494	4,043,517	0.19	1.56
NY	31,930	9,432,830	0.34	6.65
PA	16,209	5,867,783	0.28	3.38
RI	676	481,569	0.14	0.14
SC	12,318	2,091,683	0.59	2.57
VA	8,359	3,893,254	0.21	1.74
Total Region	**151,898**	**53,784,172**	**0.28**	**31.63**
US	**480,159**	**146,131,754**	**0.33**	**100.00**

Source: Bureau of Labor Statistics (BLS 2020).

Figure 213 shows the electric power generation and supply employment shares in the Atlantic Coast's regions. The Southern region contains the most employment related to power generation and supply, of which Georgia and Florida account for the majority at 15 percent and 10 percent, respectively. The Mid-North region closely follows, with Pennsylvania contributing 11 percent and New York contributing 21 percent of the employment shares.

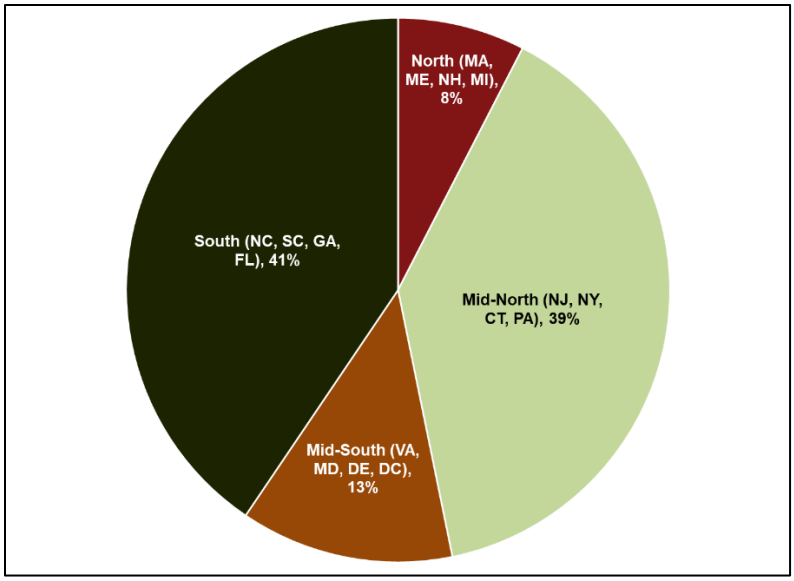

Figure 213. Atlantic region electric power generation employment shares, 2018.

Source: Bureau of Labor Statistics (BLS 2020).

Figure 214 breaks down employment data for the Atlantic Coast over the last 10 years. As we can see there was a decline in jobs from around the time of the financial crisis in 2008–2009. We see total jobs for this region dropping but leveling off over the last few years with some regions seeing slight increases.

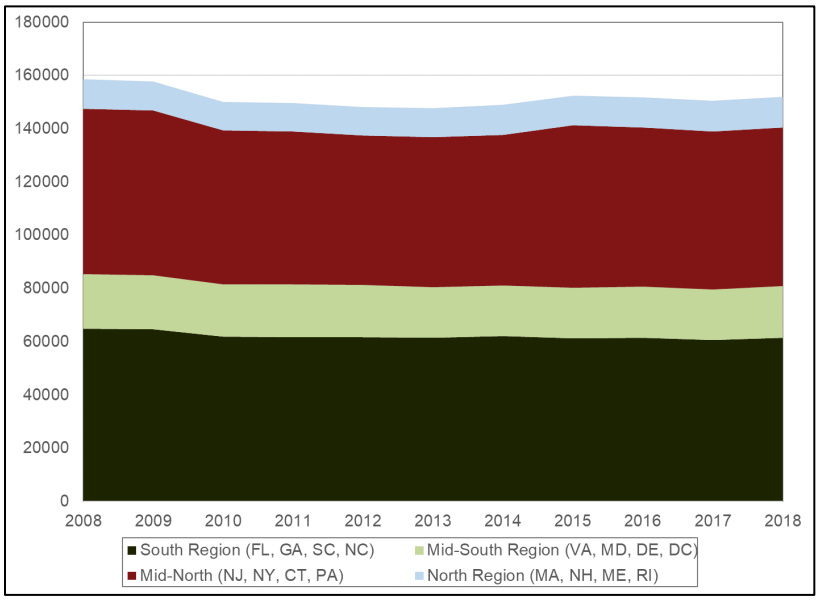

Figure 214. Trends in Atlantic region electric power generation employment, 2009–2018.

Note: D.C., New York, and South Carolina lack sufficient data for many or some of the years included in this analysis.

Source: Bureau of Labor Statistics (BLS 2020).

Table 55 corroborates the employment levels discussed above. Regional shares of total wages paid by Atlantic coast electric power have been provided in Figure 215. New York has the largest percent of wage shares for the region with 23 percent. Florida and Pennsylvania are all close behind with 13 and 12 percent, respectively.

Table 55. Regional and national wage contribution, electric power generation, 2018

State	Power Generation and Supply Jobs (Million $)	Total State Wages (Million $)	Power Generation and Supply Percent of Total State Wages	Power Generation and Supply Percent of Total US Wages
CT	554	113,395	0.49	1.03
DC	79	74,017	0.11	0.15
DE	185	25,400	0.73	0.34
FL	2,412	435,853	0.55	4.47
GA	1,646	236,992	0.69	3.05
MA	1,044	260369	0.40	1.93
MD	1,141	163,829	0.70	2.11
ME	129	27,915	0.46	0.24
NC	1,183	223,873	0.53	2.19
NH	203	37,410	0.54	0.38
NJ	1,039	265,770	0.39	1.93
NY	4,253	687,658	0.62	7.88
PA	2,106	326,411	0.65	3.90
RI	88	25,878	0.34	0.16
SC	1,149	93,559	1.23	2.13
VA	990	226,740	0.44	1.83
Total Region	**18,199**	**3,225,069**	**0.56**	**33.73**
US	**53,961**	**8,368,407**	**0.64**	**100.00**

Source: Bureau of Labor Statistics (BLS 2020).

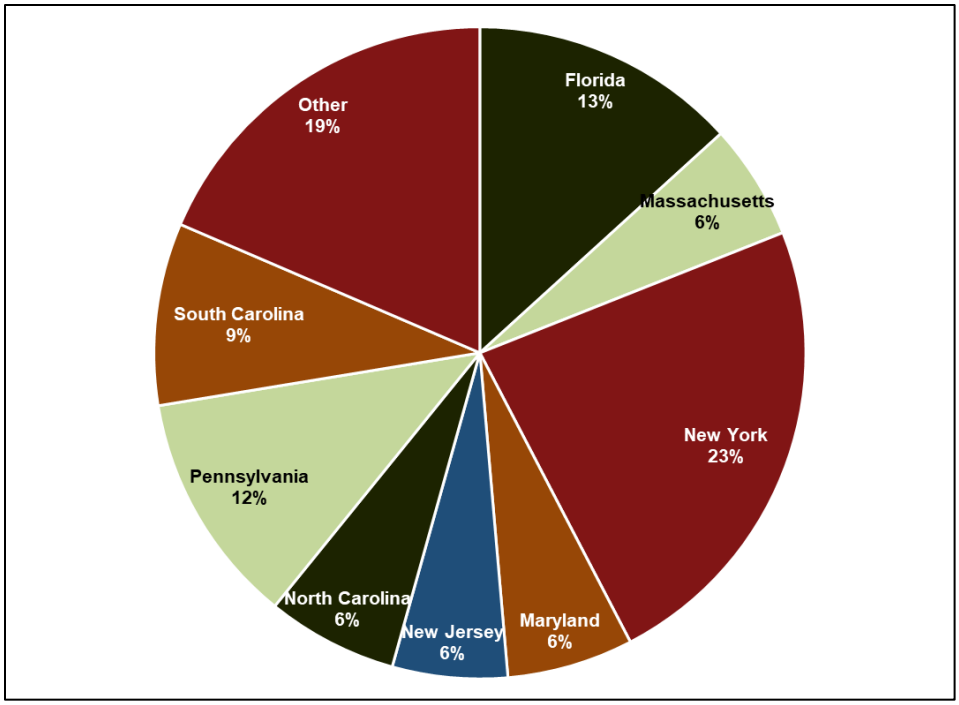

Figure 215. Atlantic region electric power generation wage shares, 2018.

Source: Bureau of Labor Statistics (BLS 2020).

Figure 216 shows the trend of electric power wages for the Atlantic Coast regions. The South and Mid-North regions by far have the highest regions along the Atlantic. Specifically, D.C. and New York provided the highest annual wages of any Atlantic state, making up 18 percent and 15 percent of the total regional wages, respectively.

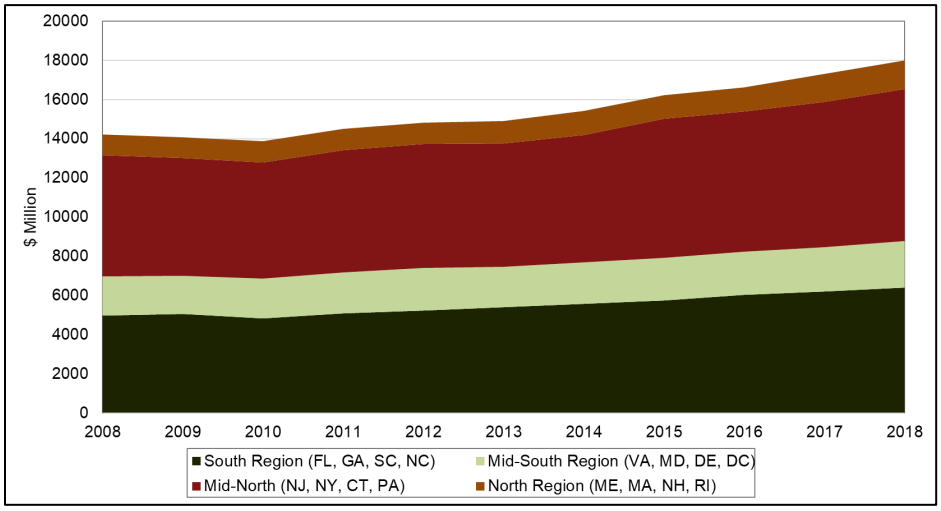

Figure 216. Trends in Atlantic region electric power generation wages, 2009–2018.

Note: D.C., New York, and South Carolina lack sufficient data for many or some of the years included in this analysis.

Source: Bureau of Labor Statistics (BLS 2020).

In each of the Atlantic region's states, average annual wages for electric power are nearly double the total state average annual wage (Table 56). In ten states, the average annual wage for electric power is greater than the US electric power average, which is $115,690. The highest average state annual wage (for private sector) is in Connecticut at $143,664, and the lowest is in Maine with $91,544.

Table 56. Regional and national average annual wage contribution, electric power generation, 2018

State	Power Generation and Supply Avg. Annual Pay (Private) ($)	Total State Jobs Avg. Annual Pay (Private) ($)	Power Generation and Supply Percent of Total State Avg. Annual Pay (%)	Power Generation and Supply Percent of Total US Avg. Annual Pay (%)
CT	143,664	67,742	212.08	124.18
DC	123,890	95,909	129.17	107.09
DE	123,878	56,814	218.04	107.08
FL	114,150	50,094	227.87	98.67
GA	104,874	53,496	196.04	90.65
MA	134,207	72,606	184.84	116.01
MD	130,001	61,151	212.59	112.37
ME	91,544	45,370	201.77	79.13
NC	103,695	50,756	204.30	89.63
NH	124,163	56,782	218.67	107.32
NJ	138,696	65,727	211.02	119.89
NY	127,045	72,900	174.27	109.82
PA	129,912	55,628	233.54	112.29
RI	129,437	53,736	240.88	111.88
SC	94,326	44,729	210.88	81.53
VA	118,434	58,239	203.36	102.37
Region Avg.	**120,745**	**60,105**	**200.89**	**210.85**
US	**115,690**	**57,266**	**202.02**	**100.00**

Source: Bureau of Labor Statistics (BLS 2020).

12.5 Current Trends

12.5.1 Regulatory Trends

Electric utilities are regulated by local, state, and federal authorities. As with natural gas pipelines, in general, interstate activities are subject to federal regulation, while intrastate activities are subject to state regulation. Plant and transmission line construction issues and retail rates are also state regulatory functions. Other issues, such as wholesale rates (sales and purchases between electric utilities), licensing of hydroelectric facilities, questions of nuclear safety and high-level nuclear waste disposal, and environmental regulation are federal issues.

Federal Regulation

For many years, the focus of national policy has been to encourage competition in wholesale power markets. FERC is charged with regulating the prices, terms, and conditions of wholesale power sales and transmission services. FERC states that its core responsibility is to "guard the consumer from exploitation by non-competitive electric power companies" (FERC 2019). To do this, FERC attempts to maintain a balance between regulation and competition. At the wholesale level, the FERC tightly regulates transmission service, while allowing markets and competition to dominate actual power generation and electricity commodity sales. Market oversight, however, is maintained by the FERC to assure no market manipulation or other anti-competitive outcomes. (FERC 2019).

The Energy Policy Act of 2005 (EPAct 2005)

EPAct 2005 has been an instrumental piece of federal legislation that propelled the electric industry into the use of more competition and competitive market outcomes and built off the original EPAct 1992 that first opened wholesale markets to competition. EPAct 2005 updated several federal laws that govern the electric power industry and made important changes to guarantee electric reliability for consumers. The Act strengthened the legal framework for encouraging wholesale competition (FERC 2019). In addition, EPAct 2005 gave the FERC authority to review merger and acquisition activity by IOUs. Some of the important changes made by EPAct 2005 are detailed below (EEI 2007):

- Repeal of the Public Utility Holding Company Act (PUHCA): PUHCA was part of the New Deal legislation of the 1930s (1935) and was designed to regulate the corporate structure and financial operations of utility holding companies that had contributed in part to the highly concentrated nature of the electric utility industry at that time. PUHCA was repealed by EPAct since it was argued, at the time, that the need for this legislation had passed.
- Reform of the Public Utility Regulatory Policies Act (PURPA): PURPA was originally passed in 1978 as one title to the National Energy Act. PURPA expanded the use of cogeneration and renewable energy sources. PURPA required utilities to purchase power from a qualified facility ("QF") at their avoided cost, not the generator's cost, regardless of whether the utility needed the power.[11,12] PURPA was reformed in order to recognize that barriers to entry for non-utility generation were considerably lower than in the 1970s primarily due to the creation of RTOs and ISOs across the country. PURPA reform included a provision that made markets for QFs greater than 20 MW "presumptively competitive" if that market was part of an RTO or ISO.
- Creation of the Electric Reliability Organization (ERO): EPAct also created an independent, self-regulating entity called ERO. ERO enforces reliability rules on the nation's transmission system. Unregulated utilities (cooperatives and government-owned utilities) are required to comply with reliability standards as well. FERC has oversight authority for ERO. In July 2006, FERC certified the North American Electric Reliability Corporation (NERC) as the ERO, which became operational in January 2007 (EEI 2007).

[11] A qualifying facility, or QF, is a class of generating facility that receives special rate and regulatory treatment. These facilities are either small power production facilities with a capacity of 80 MW or less, and a renewable primary energy source (hydro, wind, solar, biomass, waste, or geothermal resources); or a cogeneration facility that sequentially produces electricity and another form of useful thermal energy (heat or steam) in a way that is more efficient than the separate production of both forms of energy.

[12] Avoided cost is the cost the utility would have paid to build or generate power on its own.

FERC Orders 888, 890, and 1000

FERC Order 888, promulgated in 1996, requires transmission providers to offer open-access transmission service on a nondiscriminatory basis to wholesale transmission customers. In 2007, FERC issued Order 890, which requires public utility transmission providers to participate in open transmission planning processes at the local and regional level. Through this order, FERC encouraged greater coordination among neighboring transmission providers and interconnected systems, state authorities, and other stakeholders. This has the effect of creating broad areas of commerce through an open access, common carrier electric transmission system that works, in large part, like an electric highway system allowing users to freely move their electricity on an equal and non-discriminatory fee-basis.

In July 2011, FERC built upon Order 890 by issuing Order 1000 which further attempts to prevent undue discrimination and preferential treatment in transmission service. Through Order 1000, FERC allows each public utility transmission provider 18 months to comply with a series of planning, cost allocation, and non-incumbent developer reforms. Though Order 1000 provides a framework for cost allocation and requires certain considerations that need to be addressed, in terms of enhancing reliability, the potential benefit the order brings is in its inter-regional transmission planning reform. Specifically, Order 1000 requires public utility transmission providers to participate in regional transmission planning processes that consider, in part, the transmission needs of the region driven by public policy requirements of state and federal laws. Order 1000 also requires these same providers to participate in regional cost allocation discussions to determine cost allocation of new transmission facilities, while satisfying six regional cost allocation principles laid out by FERC (FERC 2019 Aug 22).

Environmental Regulations

Hundreds of environmental rules and regulations apply to the electric power industry. Two of the most significant are the Clean Air Act (CAA) and Clean Water Act. In addition, electric generators are subject to regulations that focus on air emissions from fossil fuel-based plants. In 1990, the Acid Rain Program made a series of amendments to the CAA and subsequent programs to address ozone transport. These changes have helped to significantly reduce emissions of sulfur dioxide (SO_2) and nitrogen oxides (NOX) from electricity generation. Other noteworthy federal regulations include the Toxic Substances Control Act, which controls chemicals, and the Resource Conservation and Recovery Act, which controls hazardous waste. Electric companies are also subject to state issued environmental regulations (EEI 2007).

In 2005, the US Environmental Protection Agency (EPA) issued three new major regulations to further reduce SO_2, NOX, and mercury emissions: the Clean Air Interstate Rule (CAIR), the Clean Air Mercury Rule (CAMR), and the Clean Air Visibility Rule (CAVR). In 2008, however, CAIR was vacated by the US Court of Appeals for the D.C. Circuit. The court decision kept the requirements of CAIR in place temporarily but directed the EPA to develop a new rule to implement CAA requirements. In 2011, the EPA finalized the replacement rule: the Cross-State Air Pollution Rule (CSAPR). CSAPR was implemented in 2015, replacing CAIR, and requires 27 states to improve air quality by reducing power plant emissions that cross state lines and contribute to ozone and fine particle pollution in other states (USEPA 2018 Sep 27).

In 2008 George W. Bush signed the Energy Improvement and Extension Act of 2008 (EIEA 2008), which was a tax credit given to companies for the production of renewable resources and refined coal facilities. Specific provisions included tax credits for solar and wind, geothermal heat pump systems, electric vehicle purchases, investments in new clean renewable energy bonds, advanced coal-based generation technology projects, CO2 sequestration, and many more (Rep. Rangel 2008). Recently, however, EIEA 2008's federal tax credits for the purchase of electric vehicles have started to run out for companies like GM and Tesla. In EIEA 2008, there was a phase-out provision that stated that once a specific quota of electronic cars were met, the federal tax credit would no longer apply (Redfern 2019 Dec 2). As of January 1, 2020, any cars delivered by Tesla will not qualify for the federal tax credit, although there are still other electric vehicles that have their tax credits in place including those from Chevrolet, Toyota, Volkswagen, and more (Redfern 2019 Dec 2; Johnson 2020 Feb 12).

In 2009, the Regional Greenhouse Gas Initiative (RGGI) was launched as a market-based program to cut carbon pollution from power plants by instituting a "cap and invest" program (Ho 2018 Jun 12). RGGI requires fossil fuel electric power generators with capacities of 25 MW or greater to buy allowances equal to their CO_2 emissions. The allowance represents a limited authorization to emit one short ton of CO_2 from a regulated source (RGGI, Inc. c2020). The RGGI is currently established in ten Northern and mid-Atlantic states: Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont. Soon, Virginia will be the eleventh state to join the RGGI. The state recently passed legislation in February 2020 that will allow Virginia to join the program (Chesapeake Bay Foundation 2020 Feb 28).

12.5.2 Generation and Consumption Trends

One of the primary generation trends in the Atlantic region, much like the rest of the US, has been the decreased reliance upon coal, in favor of natural gas and renewables. Figure 217 shows the dramatic shift in coal generation across the large Atlantic region states. For most of these states, coal generation in 2018 is about half of its level two decades earlier. A very pronounced drop in coal generation is evident during the recession years of 2008 and 2009 and carrying into the economic recovery of 2010.

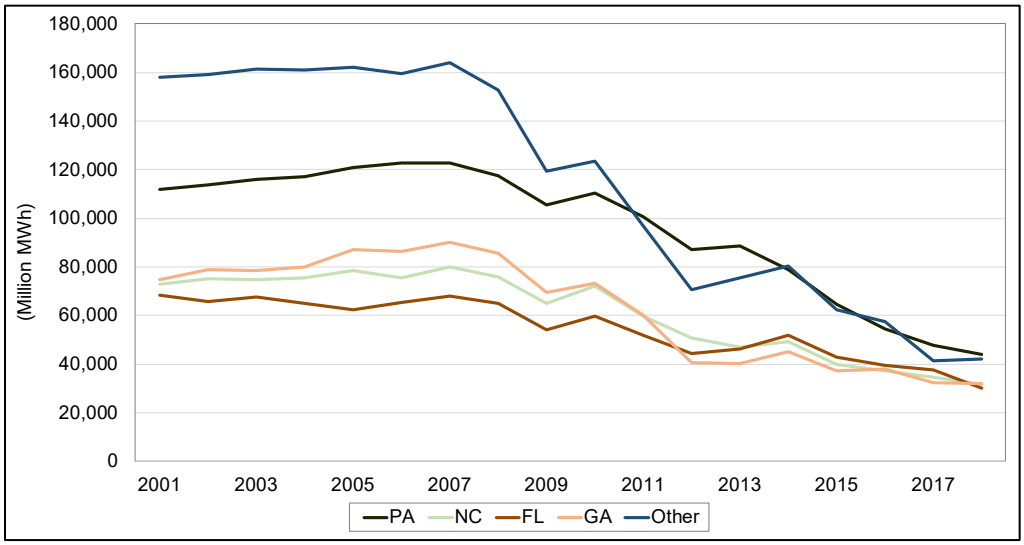

Figure 217. Atlantic region net generation, coal.

Source: Energy Information Administration (EIA c2019).

A number of factors have led to lower coal generation. First, as noted earlier, environmental regulations and concerns about GHG emissions have significantly impacted coal generation in a negative fashion. Second, low-priced and abundant natural gas supplies have made natural gas more competitive than coal. Third, many states have adopted renewable portfolio standards that set mandated renewable energy capacity development requirements. Over the past decade, Pennsylvania's coal generation fell a total of 58 percent . Similarly, Georgia, North Carolina, and Florida's coal generation decreased 54 percent, 51 percent, and 44 percent, respectively, over the same time period.

In Pennsylvania, FirstEnergy Solutions shut down one of the state's largest coal plants, the Bruce Mansfield power plant. It was slated to retire in June 2021, but due to financial troubles, the company was forced to shut it down in November 2019 (Litvak 2019 Aug 9).

In 2018, Florida Power and Light also retired the St. Johns River Power Park coal plant, which was the second of three coal plants they planned to shut down (Walton 2018 Jan 9). This capacity that was lost by retiring the coal plant was gained with the construction of new solar facilities as well as new natural gas infrastructure. The St. Johns coal plant was a 1,300 MW plant that the company said was "one of the highest-cost generating facilities to maintain and operate" (Walton 2018 Jan 9). This move was estimated to annually save customers $183 million. This follows the retirement of one of FPL's other coal plants, the Cedar Bay Generating Plant, in 2016 (Walton 2018 Jan 9).

Nuclear generation is also started to be impacted by increased emphasis on natural gas and renewable energy. For example, Exelon retired the last operating unit of its famous Three Mile Island nuclear power plant in September 2019 (Exelon c2019). Three Mile Island Unit 1 had operated in Pennsylvania since 1974 at a capacity of 837 MW (Exelon 2019 Sep 20).

Figure 218 shows that natural gas generation has increased 130 percent since 2001. Renewables have also seen a steady growth since 2001, increasing by over 250 percent during the last decade. Wind accounts for most of this growth, as it alone increased by 269 percent during this time.

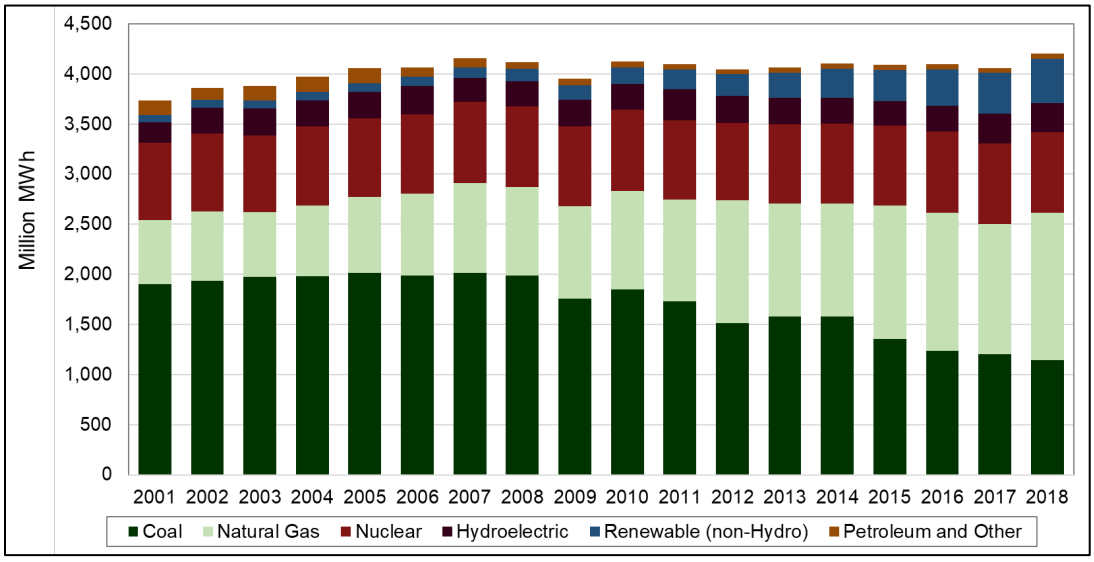

Figure 218. US electric power generation by fuel type.

Source: Energy Information Administration (EIA c2019).

Figure 219 shows the fuel disposition of electric generation by major Atlantic region state. Florida is by far the largest natural gas generator although on a relative percentage basis, Pennsylvania natural gas fired generation has increased by over 2,400 percent over the past decade.

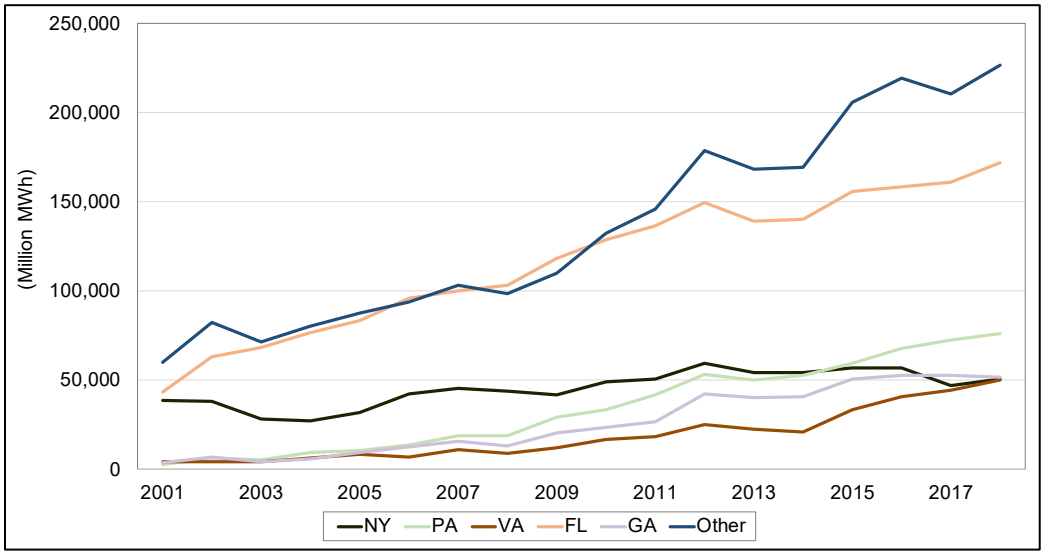

Figure 219. Atlantic region net generation, natural gas.

Source: Energy Information Administration (EIA c2019).

An interesting trend within the Atlantic region has been the increased interest of offshore wind (OSW) development. Many states along the eastern seaboard are exploring offshore renewable energy production development. A good portion of this interest is being motivated by state RPS requirements, while a general interest in offshore energy production and economic development is also motivating new initiatives.

Rhode Island was the first Atlantic region state to establish an OSW project with the Block Island Wind Farm (AWEA c2019). Other states such as New York, New Jersey, and Massachusetts have also begun planning to incorporate offshore wind projects off their own coasts. New York, for instance, has a goal of producing 9,000 MW of offshore wind energy by 2035 (NYSERDA c2019). Figure 220 shows the growth in wind capacity (onshore and offshore) in select Atlantic states. New York, Pennsylvania, and Maine are the significant leaders in wind energy, mainly due to onshore wind farms. Other states, such as Maryland and New Hampshire, have also shown a substantial increase in wind capacity since 2010.

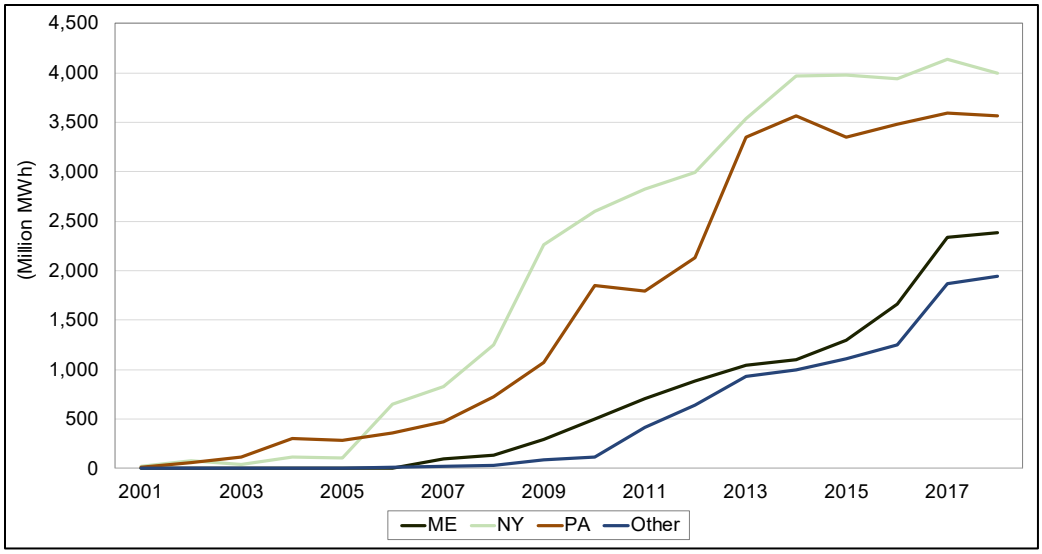

Figure 220. Atlantic region net generation, wind.

Source: Energy Information Administration (EIA c2019).

Several factors influence decisions to add capacity and the type of capacity (fuel choice). These factors include an increase in electricity demand; the need to replace older, inefficient plants; the cost and operating efficiencies of different generation options; fuel prices; state mandates for renewable resources; and the availability of tax incentives for certain technologies (EIA 2012 Jun) As noted in the EIA's Annual Energy Outlook (AEO) 2019, efficiency has played a large part in slowing demand growth rates. With more efficient appliances such as heating and cooling units, the demand for the amount of electricity has decreased from previous years (EIA 2019 Jan 24). Figure 221 presents the expectations for capacity additions by fuel.

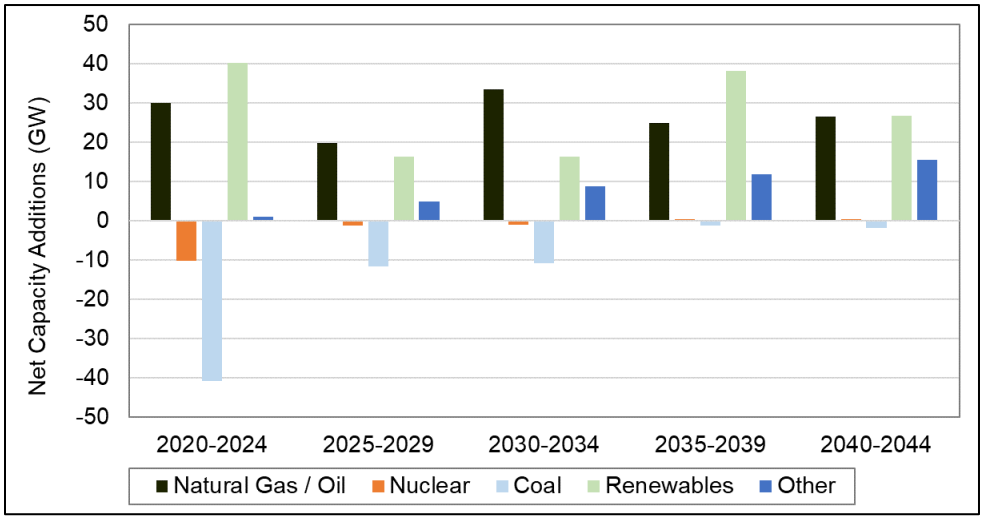

Figure 221. Annual energy outlook, capacity additions by fuel type.

Source: Annual Energy Outlook 2020 ((EIA 2020c).

Figure 222 shows the trends in electric power consumption. Since 2008, electric power consumption increased for residential (6 percent) and commercial customers (3 percent). Industrial power consumption has decreased 1 percent since 2008. Over the last 10 years, total consumption across all sectors has remained relatively flat.

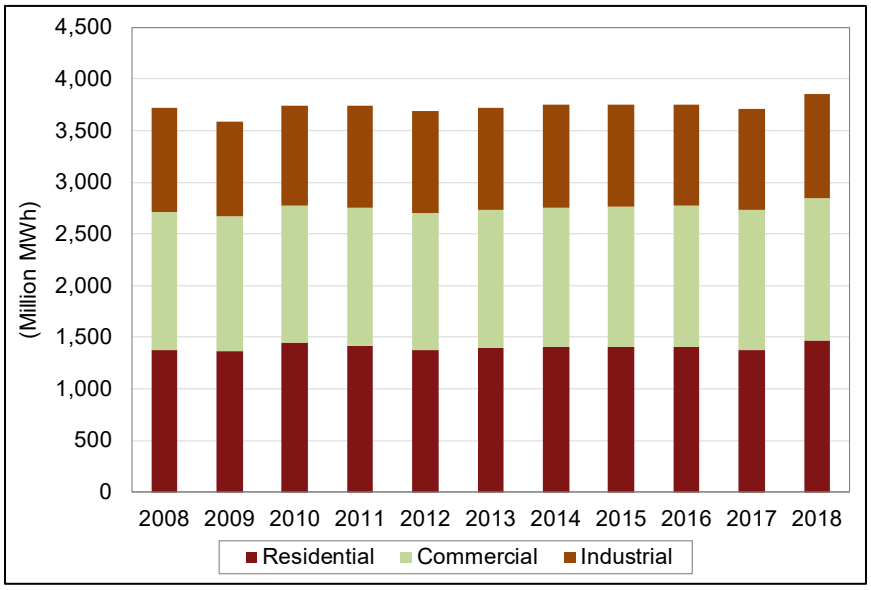

Figure 222. Electric power consumption by customer class.

Source: Energy Information Administration (EIA 2019 Oct 18).

12.5.3 Transmission and Distribution Trends

Over the past decade, the cost of transmitting electricity to customers has continuously risen. Transmission related costs, however, are the smallest category of costs behind generation (production) and distribution. The EIA has reports that transmission costs increased nearly every year over the past decade and comprises a larger share of total electricity costs (Figure 223) (EIA 2017 Sep 7).

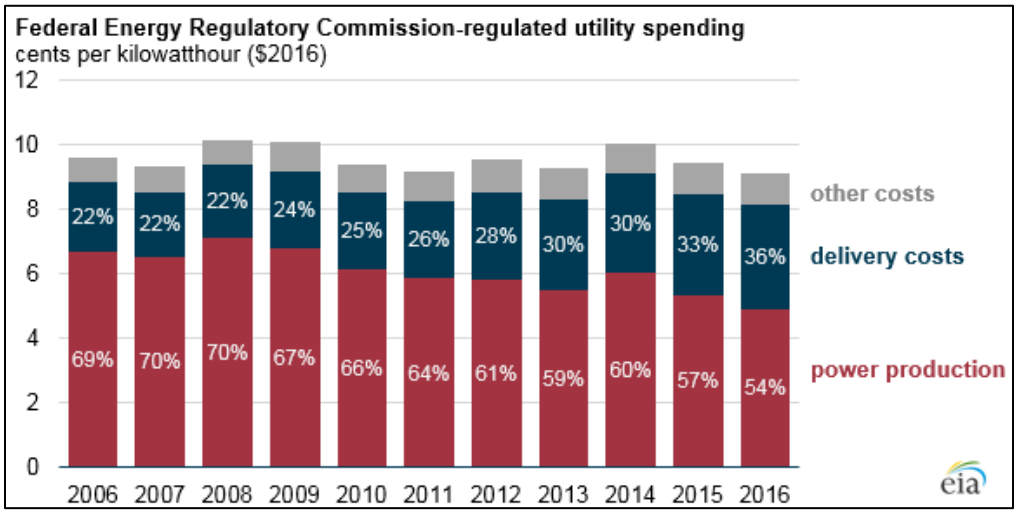

Figure 223. Utility spending on electricity.

Source: Energy Information Administration (EIA 2017 Sep 7).

This increase in transmission costs is due to several factors, including the replacement of aging infrastructure with new equipment that allows utilities to (EIA 2017 Sep 7):

- Remote fault repairs on transmission lines ;
- Remote substation meter reading and automation; and
- Finding and repairing, reliability related outages.

In 2016, total transmission expenditures by FERC-regulated utilities was approximately $35 billion, with investment in transmission infrastructure accounting for 61 percent of that total (EIA 2018 Feb 9). Spending on transmission infrastructure has been steadily increasing for decades as utilities build, upgrade, and replace station equipment, poles, fixtures, and overhead lines and devices. As seen in Figure 224, the EIA attributes most of the costs of transmission infrastructure to station equipment (EIA 2018 Feb 9).

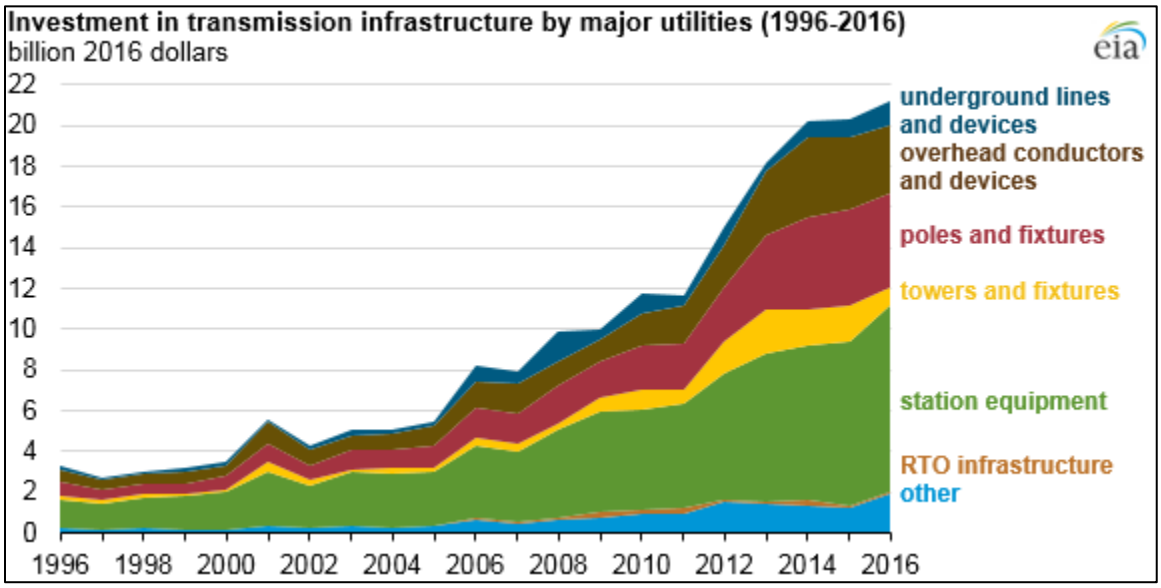

Figure 224. Investment in transmission infrastructure by electric utilities.

Source: Energy Information Administration (EIA 2018 Feb 9).

Other infrastructure has also been built in the Atlantic region, to connect to new renewable sources of electricity generation such as wind and solar, and to reduce transmission-line congestion in quickly growing areas (EIA 2017 Sep 7).

There is currently a major transmission program in place within the PJM Interconnection region called the "Energizing the Future" program that has been replacing aging equipment with advanced smart grid technologies designed to enhance system reliability since its inception in 2014.

12.6 Outlook

12.6.1 Generation and Consumption Outlook

Total electricity generation in the US is expected to increase over 30 percent by 2050. Figure 225, shows that this increase in generation will come from resources that are fueled by natural gas or renewables. Renewables alone are projected to increase by 167 percent during this time and are expected to become the major source of electricity by 2045 (EIA 2020d).

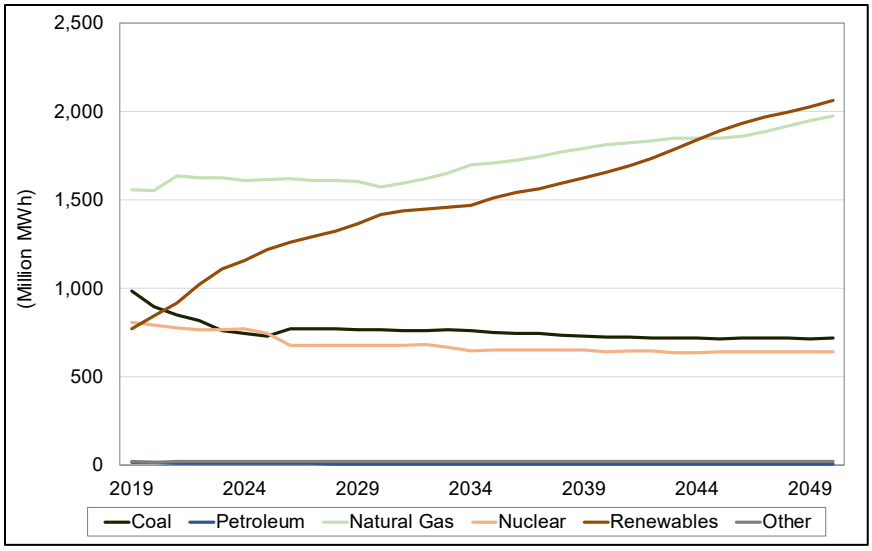

Figure 225. Projected electric generation capacity in the US, 2019–2050.

Source: Energy Information Administration (EIA 2020d).

Several Atlantic region states have proposed to develop a considerable degree of renewable energy over the next two decades. Even by 2023, over 10 GW of proposed renewable capacity for the Atlantic region is expected to be online, 84 percent of which will come from solar projects. Figure 226 shows that Florida will lead in regional renewable generation development, followed by other states such as South Carolina, Virginia, and Georgia. While wind energy has been the predominate renewable over the past decade, future renewable development will focus heavily on solar generation, with some facilities at capacity levels up to 240 MW. New York is anticipated to lead the North Atlantic region in renewable development, primarily dedicated to wind (primarily OSW) at 920 MW of proposed capacity (EIA 2019 Sep 3).

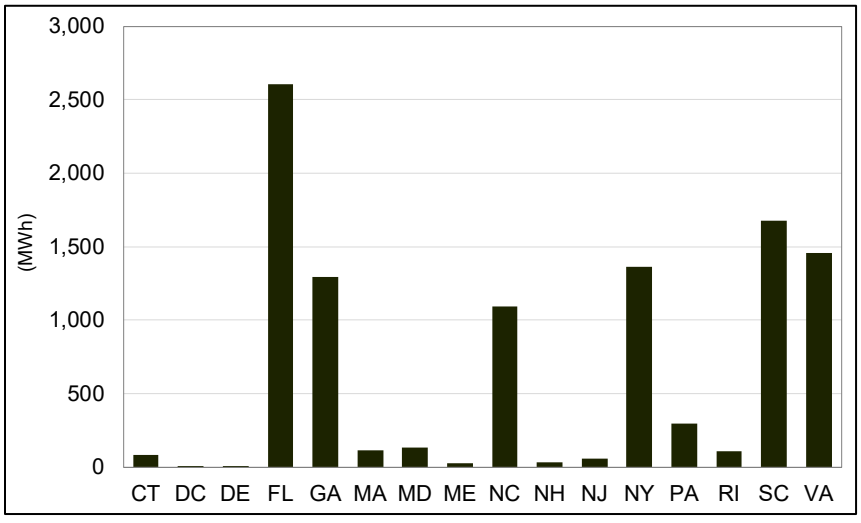

Figure 226. Proposed renewable capacity by state, 2019–2023.

Source: Energy Information Administration (EIA 2019a Oct 22).

The EIA anticipates that renewable costs will continue to fall, and those cost decreases will be passed only through lower rates to retail customers. EIA anticipates generation costs to decrease between 15 and 20 percent by 2050. This decrease is due to the retirement and replacement of older, less efficient generators with more efficient, low-cost units and renewables (EIA 2019 Jan 24). Already, over 53 GW of coal, natural gas, and nuclear capacity were retired between 2013 and 2018 (NERC 2018 Dec). As of 2018, fourteen nuclear powered units totaling 7.1 GW had announced retirement plans (NERC 2018 Dec).

12.6.2 Transmission and Distribution Outlook

Most electric transmission and distribution lines were constructed in the 1950s and 1960s, with a life expectancy of 50 years, and have now reached or exceeded their originally-designed lives (ASCE 2017a). Many lines may need to be replaced or upgraded, while new power lines are needed to maintain the electric system's reliability and to provide connections to new renewable generators, such as wind and solar units, which are often located far from customers. However, there are several factors that pose a challenge to the improvement of the electric grid's infrastructure (EIA 2019 Oct 11):

- Getting approval of new routes and obtaining rights to land needed for new transmission lines;
- Recovering construction costs of transmission lines that are built in one state but provide benefits to another;
- Uncertainty in federal regulations regarding who is responsible for the costs of new transmission lines;
- Expanding the network of long-distance transmission lines to renewable energy generators located far from where electricity demand is concentrated; and
- Protecting the grid from physical and cyber-attacks.

One of the largest transmission projects currently underway in the Atlantic region is Central Maine Power's New England Clean Energy Connect project (NECEC). Expected to be completed in 2022, the NECEC is a nearly $1 billion project that will transmit 1,200 MW of clean energy to the New England electrical grid in Lewiston, Maine by harnessing Canadian hydropower from Quebec (NECEC 2020 Feb 20). The project includes 145 miles (233 kilometers) of new HVDC transmission line that will connect to the existing transmission system and 50 miles (80 kilometers) of upgrades to old AC transmission lines. The NECEC will also construct a new converter station and substation and include multiple system upgrades (NECEC c2020). Once completed, it will be New England's largest source of renewable energy (NECEC 2020 Feb 20).

Overall, there are about 400 transmission projects expected to come online in the next several years, most of which are located in the North Atlantic region, as shown in Figure 227.

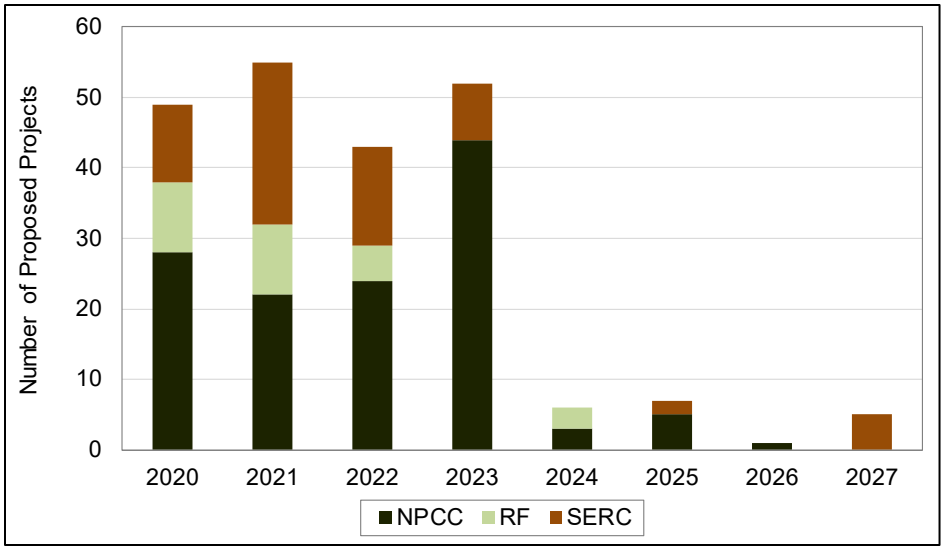

Figure 227. Proposed transmission projects on Atlantic Coast.

Source: North American Electric Reliability Corporation (NERC 2019).

If all of these proposed projects are completed as planned, nearly 6,000 miles of transmission line would be added to the Atlantic region, largely in the NPCC and SERC service areas (Figure 228).

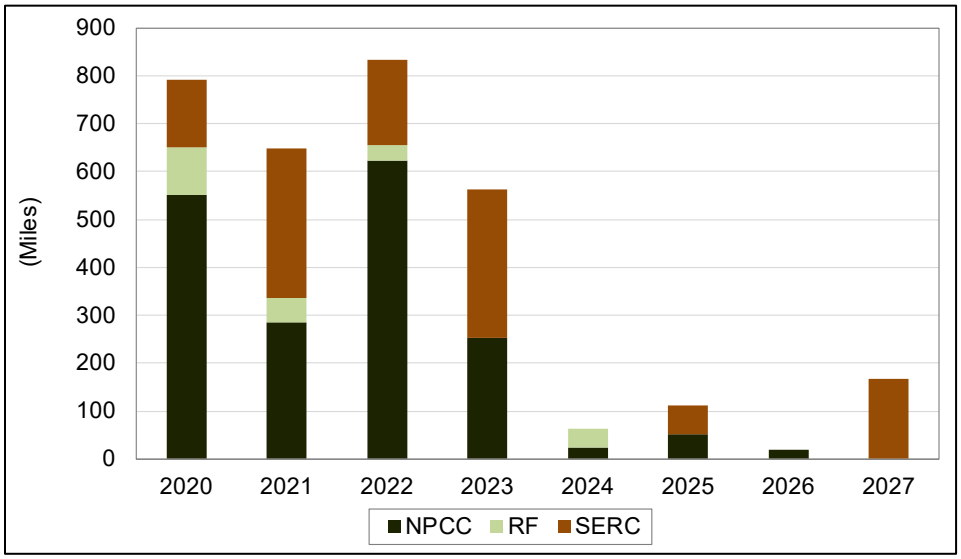

Figure 228. Length of lines of proposed transmission projects on Atlantic Coast.

Source: North American Electric Reliability Corporation (NERC 2019).

12.6.3 Factors Impacting East Coast Development

Electric power infrastructure in the Atlantic region is extensive with more than 2,905 power generation facilities located in Atlantic Coast states (EIA 2019 Sep 3). Many of these states are anticipating the development of considerable new offshore alternative energy assets that may have implications for offshore oil and gas production infrastructure.

The South Atlantic region (Florida, Georgia, South Carolina) has 430 power generation facilities that total over 45,500 MW of generating capacity. Most of this capacity (48 percent) is fueled by natural gas, while 38 percent is fueled by coal, 9 percent by nuclear, and 3 percent by renewables. The remainder is fueled mainly by oil (3 percent). The Atlantic region (Virginia, North Carolina, Maryland, Delaware, D.C.) has 931 generation facilities with 64,000 MW of generating capacity. 37 percent followed by coal at 27 percent and renewables at 13 percent. The North Atlantic region contains the largest amount of generation facilities (1,544) and the largest share of capacity in the Atlantic region (146,000 MW). As with the other Atlantic subregions, natural gas is the most-used fuel type, making up nearly 50 percent of the generation in this area. However, coal has been surpassed in this region by nuclear and renewables generation, which generates 17 percent and 15 percent, respectively, of electricity in the North Atlantic states (EIA 2019 Sep 3).

This trend toward natural gas and renewables generation and away from coal will continue into the foreseeable future. The low price and abundant supply of natural gas have been the driving forces behind its increased use and are expected to remain constant over the next 30 years, as seen in Figure 229. Thus, natural gas will continue to be an attractive option for energy generation so long as these trends persist.

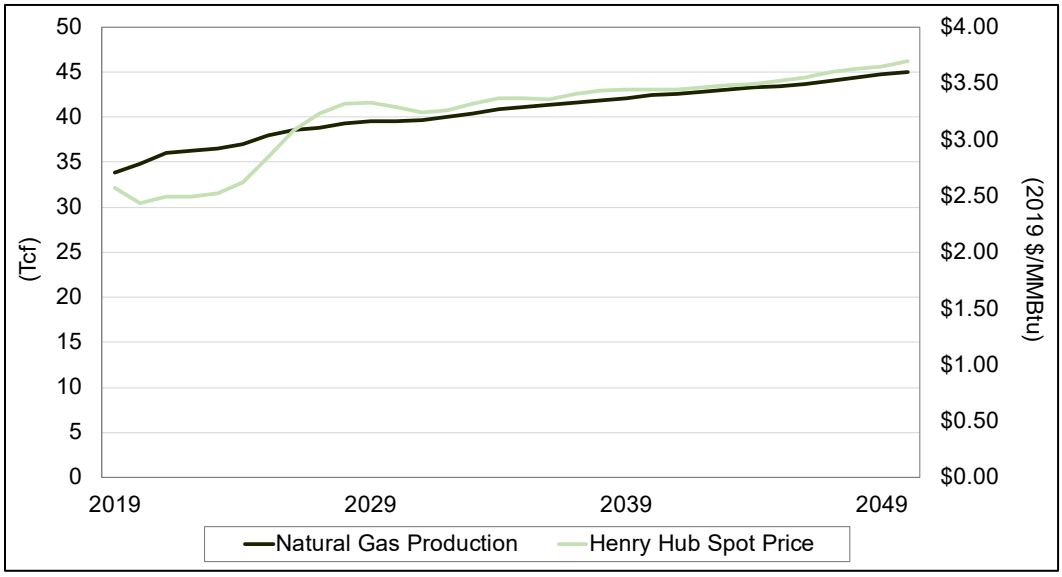

Figure 229. Projected natural gas supply and price, 2019–2050.

Source: Energy Information Administration (EIA 2020d).

Although natural gas is currently the easiest and cheapest fuel source, interest in renewable energy has increased exponentially as more and more consumers have begun demanding the use of cleaner energy. The increasing focus on renewables has led many states to sign renewable energy requirements into law in recent years. In 2019, New York's governor signed the Climate Leadership and Community Protection Act (CLPA). This bill requires that the state operate on a carbon-free electricity system by 2040 and reduce greenhouse gases 85 percent below 1990 levels by the year 2050 (Cuomo 2019 Jul 18). In 2018, the New Jersey's governor signed Executive Order 8, which set the goal of 3,500 MW of offshore wind by 2030 (Murphy 2019 Nov 19). North Carolina was one of the first states in the Southeast to pass a Renewable Energy Portfolio Standard, which required all investor-owned utilities in the state to supply 12.5 percent of 2020 retail electricity sales from renewable energy resources by 2021 (NC Clean Energy Technology Center 2018 Jul 9). In less than 10 years, North Carolina has gone from almost zero solar capacity to one of the largest in the nation. North Carolina currently has the second largest installed solar capacity with over 6,100 MW, trailing only California nationally (SEIA c2020). Figure 230 shows that 11 states on the Atlantic Coast and D.C. currently have renewable energy standards in place as of July 2019.

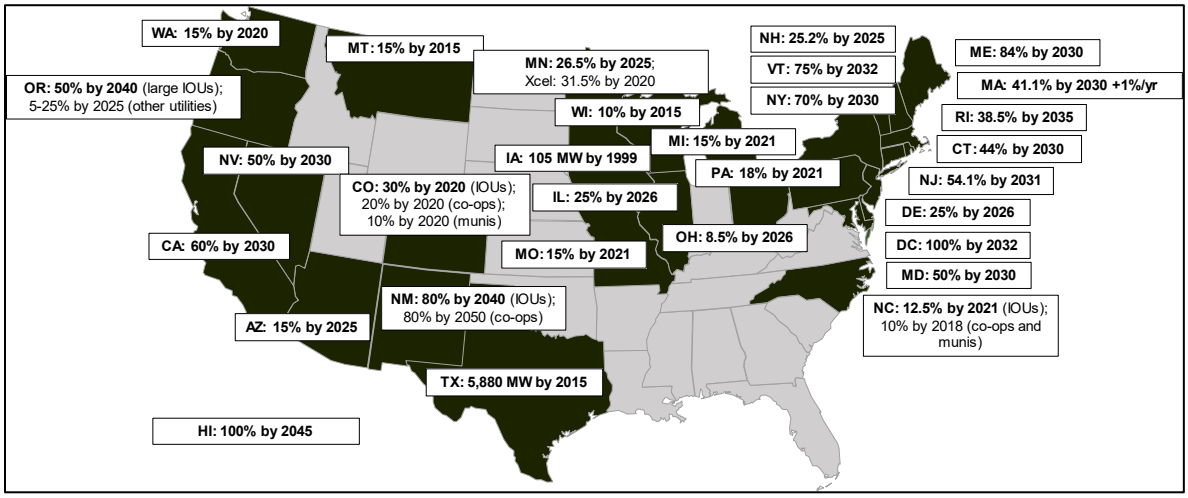

Figure 230. Existing state renewable energy standards, 2019.

Source: (Berkeley Lab 2019).

In the South Atlantic region, solar power will most likely be the renewable fuel of choice moving forward. States such as Florida, Georgia, and North Carolina have seen a major spike in solar capacity over the last decade (Figure 231).

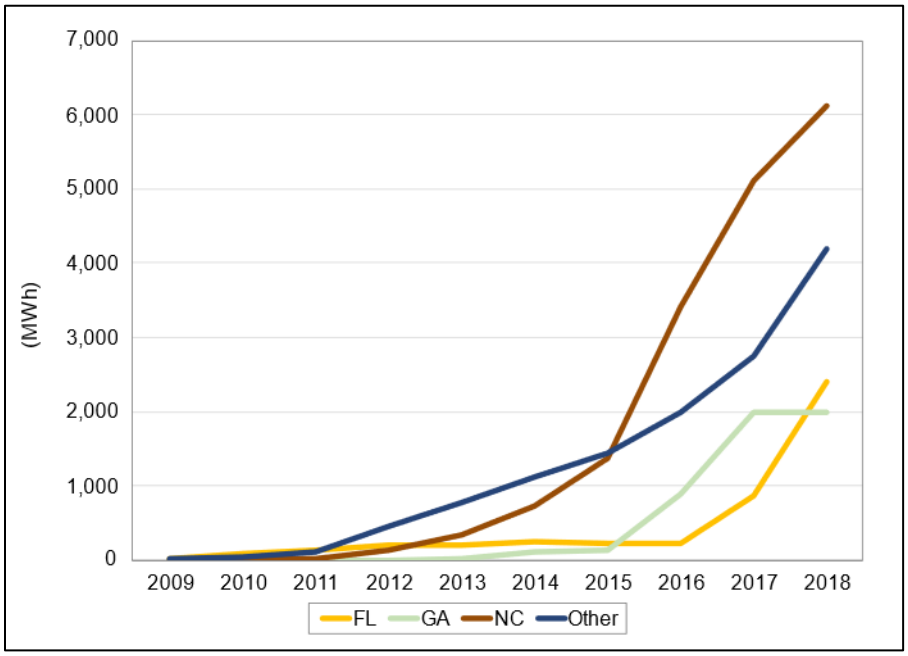

Figure 231. Atlantic region net generation, solar.

Source: Energy Information Administration (EIA c2019).

North Carolina leads the Atlantic region in solar power generation and is second only to California in the US Solar's rapid growth in the state can be attributed to several factors (Rocky Mountain Institute 2015 Apr 27):

- The early adoption of an RPS. In 2007, North Carolina was the first state in the southeastern US to pass a law requiring a certain percent of the state's electricity sales be fueled by renewable energy.
- A 35 percent state renewable energy tax credit, in addition to the 30 percent federal solar investment tax credit, reduces the after-tax installed cost of solar and provides incentives for companies to develop solar generation systems.
- North Carolina's QF practices provide certainty of long-term cash flows that QF developers can expect from their projects. Any QF under 5 MW can receive a 15-year fixed price contract at the utility's avoided cost, which enables QF developers to achieve low-cost financing for their solar projects.
- The costs for installed solar in North Carolina over the past decade have declined more than the US average due to the state's economies of scale regarding solar generation systems and its market structure related to QF regulations.
- The leadership in solar development by major tech companies, investor-owned utilities, and local businesses in the state. Apple, Facebook, and Google have data centers in North Carolina and have advocated for the option to purchase renewable energy directly from utilities. Additionally, Duke Energy installed the Green Source Rider program, which allows large commercial customers to purchase renewable electricity directly from Duke. The program incentivizes Duke to build, procure, and dedicate additional renewable capacity directly to the subscribing customer.

Similar policies have since been set by other states in the region, and many solar facilities are now expected to come online in the coming years, as seen in Figure 232.

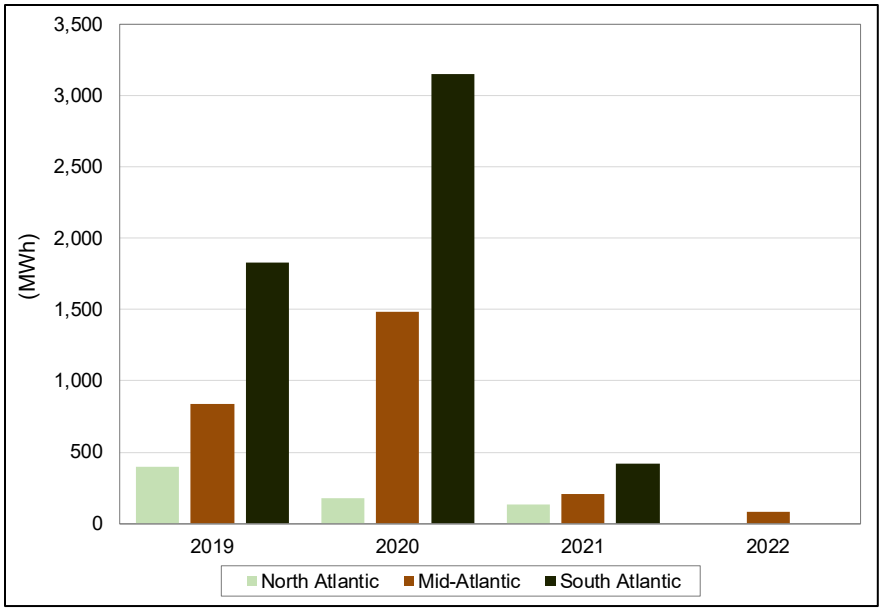

Figure 232. Planned solar capacity by Atlantic subregion.

Source: Energy Information Administration (EIA 2019a Oct 22).

Though the investment in solar power seems to mainly be concentrated in the southern states, offshore wind has become the desired renewable energy source in the North and Mid-Atlantic regions. Rhode Island is currently the only state with an operational offshore wind farm.

By early 2018, however, BOEM had approved area leases for the construction of thirteen OSW projects off the coast of Maine, Maryland, Massachusetts, New Jersey, New York, North Carolina, Rhode Island, and Virginia (Weissman et al. 2018 Mar). Offshore wind has the potential to generate nearly double the US's current electricity use, but a vast amount of new transportation and distribution infrastructure will be needed to transport this energy back onto shore for customers (Woods 2019 Dec 13). The Atlantic Wind Connection was designed as a major undersea transmission system meant to span the North and Mid-Atlantic regions, extending from northern New Jersey down to southern Virginia (Figure 233). The project would cost approximately $5 billion and support the development of up to 6,000 MW of OSW energy (Crompton 2019 Jun 26).

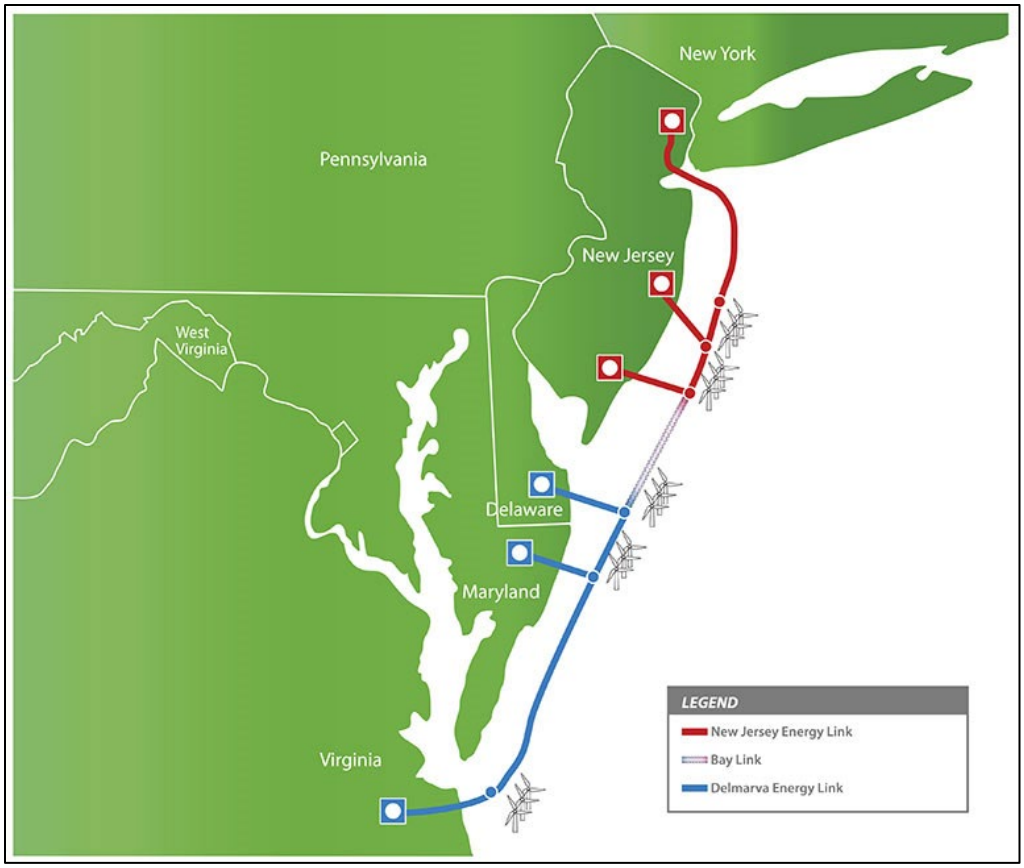

Figure 233. Atlantic Wind Connection planned route.

Source: (Atlantic Wind Connection c2017).

The question for states now is whether they see a greater advantage in working together to create a large, multistate offshore transmission backbone similar to the Atlantic Wind Connection or in constructing their own separate lines to connect their wind farms to their own coastlines and customers. Anbaric Development Partners, a large-scale transmission and storage solutions company, currently has applications open with BOEM for the development of two offshore transmission networks: (1) the New York and New Jersey Ocean Grid and (2) the Southern New England OceanGrid Project. The New York and New Jersey Ocean Grid includes the installation of approximately 213 miles (343 kilometers) of submarine transmission cables and up to nine offshore collector platforms that would collect and distribute OSW-generated power to up to six onshore landings from Long Island, NY to Cardiff, NJ. The project would be able to bring 2,400 MW of OSW energy into New York and 3,500 MW into New Jersey by 2030 (Behr 2018 Dec 12; BOEM 2020d). Similarly, the Southern New England OceanGrid Project includes approximately 388 miles (624 kilometers) of underwater transmission cables and up to eight offshore collector platforms that would collect and distribute OSW power to landings ranging from Massachusetts to Long Island Sound (BOEM 2020d). It is too early to tell if these projects will be approved, but if so, it could be the beginning of major transmission developments in the Atlantic OCS.

13. Intermodal Transportation

13.1 Description of the Industry and Services Provided

The transportation of oil and gas from platform to market is vital to any offshore project, and while pipelines are the most common mode of transport from established/GOM production sites, other modes—including inter-modal transport—can be much more important where there are not any established pipelines.

Transportation is considered "intermodal" if it facilitates more than one means to move products or goods from the shipper a consignee, or buyer. Crude oil, for instance, is commonly transported twice through the supply chain. First, upstream from wells to the refinery and then downstream from the refinery to the market. Special or standardized containers are used for intermodal transport of cargo on trucks, freight trains, and ships/barges. Intermodal transportation does not require the direct handling of the product and allows for faster transportation of the product to the end-user or buyer. In the oil and gas industry, the responsibility of transporting products can fall to the producer, refiner, one of several downstream distributors, or a common carrier whose only role in the distribution chain is providing the means for transportation.

Existing infrastructure within the Atlantic region would play an important role in the transportation of OCS oil and gas. The most used modes of transportation in the energy industry are pipelines, railways, tanker trucks, and barges, and all of these will play a vital role in the transmission of Atlantic OCS oil and gas. Natural gas market hubs, for instance, are the last stop before reaching an end user, and import/export terminals facilitate the transfer of oil and gas to and from other countries.

13.2 Pipelines

Pipelines are the most used method for transporting oil and gas in the US. The first pipelines in the US were constructed in the 1800s and were used to transport oil and natural gas across short distances. Today, nearly all the natural gas and over 90 percent of crude oil and refined petroleum products produced in the US are transported by pipeline at some point after production (Allison and Mandler 2018 Jun 1). With over 2.8 million miles of pipeline spanning across the US, they are considered one of the safest and cheapest forms of fuel transportation and are able to carry the largest amount of fuel at one time, albeit slowly (Allison and Mandler 2018 Jun 1).

On average, it costs about $5 per barrel to transport oil and gas by pipeline compared to $10-$15 a barrel for rail and $20 a barrel by truck (Frittelli et al. 2014). Likewise, pipelines are one of the safest methods of energy transportation, second only to ships in terms of human death and property destruction. Moreover, shipping oil via pipeline results in less oil spilled pilled per billion-ton-miles and reduced impacts on the environment in comparison to that of trucking and shipping (Frittelli et al. 2014; Conca 2018 Oct 11).

In addition to domestic transportation, pipeline systems in the US are also largely used to import and export oil and natural gas from neighboring countries and can be built underwater to transport oil and gas to and from offshore facilities.

13.1.2 Rail and/or Train

Shipment by train was one of the first means of oil transportation. Although its popularity dwindled with the advent of metal pipelines, it has once again become an attractive transportation alternative as new oil and gas reserves are identified across the world. After pipelines, it is the most common method of land transportation for these fuels. The relatively small capital costs and short construction period make rail transport an ideal alternative to pipelines for long distance shipping. Additionally, because not all oil wells are accessible by pipeline, transportation by rail is the most financially viable option for accessing land-locked oil wells that need to be transported to refineries. However, speed, carbon emissions, and accidents are some significant drawbacks to rail transport (Hansen and Dursteler 2017).

Transporting oil by rail also involves more parties than transporting by pipeline. Oil is taken from the production site by pipeline or truck to a rail loading terminal. The shippers can be the producers, refiners, or third-party marketing agents. At the terminal, operators are responsible for the proper loading and unloading of oil tanks on railcars, also known as tank cars, in accordance with hazardous material regulations. Once loaded, the railroads transport the oil to various terminals around the country, where it can be exported, stored, or taken for consumption (Birn and Osuna 2015 Mar).

Currently, LNG is not authorized to be shipped by rail in the US unless a special permit is received from the Federal Railroad Administration (FRA), which occurs on rare occasions. This is because natural gas with high methane content becomes highly flammable when exposed to oxygen and poses a significant risk if a tank car ruptures or is compromised (Cambridge Systematics, Inc. 2019; Nunno 2019 Dec 19). However, railways are a popular mode of hydrocarbon gas liquid ("HGL") transportation and haul it in much the same way as oil.

Rail is a popular method for transporting HGL because many regions in the United States (such as the West, New England, and Florida) are not served by HGL pipelines (EIA 2019 Oct 31). In these areas, railroads often transport large volumes of HGL to wholesale and bulk purchasers in pressurized railroad tank cars.

13.1.3 Trucking

Truck transportation is usually only used to move smaller quantities of oil and gas over shorter distances due to the high costs and capacity constraints associated with it. Road transportation is the most expensive and inefficient method for crude oil transportation.[13] It is also the most limited due to trucks' limited holding capacity (Hansen and Dursteler 2017). Therefore, this method is typically used only when wellhead locations are not accessible by pipeline or rail networks, or for short distances during final-mile segments of the product movement (Breakthrough 2019 Nov 1).

Trucks indirectly support the transportation of OCS oil and gas by carrying materials to construct infrastructure, such as pipelines, to refineries. They are also critical in the distribution of refined products to the marketplace.

[13] The geographic makeup of trucking along the Atlantic is discussed in Subsection 12.3.3.

Although the most expensive method of transport, trucks can move energy fuel the greatest distance over highways from production sites to pipelines, railways, and other long-distance transportation infrastructure, as well as across areas where pipeline or rail infrastructure does not exist. Trucks have the greatest flexibility in delivery destinations out of all the four modes of transportation, since they have access through a wide range of roads and highways to ports and terminals that pipelines, trains, and barges may not have. Despite this flexibility, the high costs associated with trucking means that trucks are often only used as the last step in the transport process, delivering oil and refined petroleum products to intended storage locations or final destinations such as gas stations (T M 2015).

Trucks are also used to transport and deliver propane to consumers. The propane is transported by truck in pressurized tanks to homes, farms, and businesses, where it can be used as engine fuel, for crop drying, for space heating and water heating, and for cooking, among other applications (EIA 2019 Oct 31).

Although natural gas can be transported via truck, it is a very small part of the overall distribution system in the US It is speculated that less than one percent of total natural gas used in the US is moved by truck, or "virtual pipeline" systems (Nobel 2019 May 21). In order for trucks to transport natural gas, the product must first be converted into compressed natural gas (CNG) or LNG so that more of the fuel can easily be stored and moved (NGV America c2020).

13.1.4 Marine Ships and/or Barges

Where transport over land is not suitable, oil and natural gas can be transported by ship. Tankers were first used by the oil industry to transfer refined fuel in bulk from refineries to locations closer to the customer. The fuel would then be stored in large tanks ashore and divided for delivery to customers. A typical 30,000-barrel tank barge can carry as much oil as 45 rail tank cars at about one-third the cost (T M 2015). Tank barges traditionally carry petrochemicals and natural gas feedstocks to chemical plants, but LNG carriers have started to become increasingly popular over the last few years for transcontinental transport. Compared to a pipeline, this method of transportation is about 20 to 35 percent cheaper, depending on the route, but has significant drawbacks including speed and environmental concerns (T M 2015).

The barges and tankers that transport energy fuels use the many navigable waterways and ports spread throughout the US to deliver these products. The greater Mississippi Basin and Intracoastal Waterways in the US have more miles of navigable internal waterways than the rest of the world combined, and the Atlantic Coast has more major ports than the rest of the Western Hemisphere. These coastal ports and inland waterways are part of a larger waterborne transportation network called the Martine Transportation System (MTS), which includes 25,000 miles of navigable channels and related infrastructure such as marine terminals, intermodal connections, shipyards, and related repair facilities. The MTS handles nearly 2.3 billion tons of commerce annually, making waterborne transportation a critical part of the US economy. In 2012, 55 percent of this cargo included crude oil, refined petroleum, and coal. Around 15 percent of all petroleum products consumed in the US are shipped on inland waterways, and 60 percent of the oil consumed arrives through a US port (US DOE 2015a). A detailed description of the typical facility characteristics and geographic distribution of marine ships and barges is continued in subsections 12.2.4 and 12.3.4.

13.1.5 Natural Gas Market Hubs

Before natural gas reaches an end-user, it is likely to pass through a hub when traveling by pipeline. A hub is a physical transfer point and market center where two or more pipelines are connected, and natural gas is bought and sold. Hubs increase the flexibility of gas flow by allowing operators to switch gas from one pipeline to another as needed. They also allow for quick and easy trading between a wide range of buyers and sellers, creating an effective and efficient natural gas market. Out of the dozens of natural gas hubs in the US, there are about 20 major hubs, of which the Henry Hub in Louisiana is the most well-known. The Henry Hub serves as the primary national hub due to its strategic location in the Gulf Coast producing area and its high level of interconnection with the country's pipeline systems. The Henry Hub has four major receipt points and at least twelve delivery points. It is seen as the national benchmark for natural gas pricing that is used to reflect the US natural gas market as a whole. However, it has been speculated that recent developments in the northeastern US could grow large enough to usurp Henry Hub as the primary price point by as soon as 2030 (FERC 2015; US DOE 2015b).

Most of the interstate natural gas transportation system along the East Coast has been developed to facilitate the movement of natural gas from its primary producing area (GOM) to market areas along the eastern seaboard. A number of the existing interstate natural gas lines, run along the Appalachian Mountain range and then progress northwards and eastward to New York. Future pipeline development along the Atlantic OCS is likely to be based on a series of line segment extensions from future coastal producing areas to the existing major trunk lines running along the Appalachian range. The overall investment level needed to link this production into the existing long-haul system will be a function of a variety of factors that include the volumes and economics of the gas production from the offshore Atlantic relative to production coming from the other five areas (i.e., GOM, Canada, Rockies, Marcellus, Great Lakes) in addition to imported sources by LNG regasification facilities.

New natural gas transportation systems developed to accommodate new Atlantic OCS natural gas production are likely to be made up of a major trunk-line type segment for a large diameter pipeline (at or greater than 24 inches [61 cm]) that will directly connect into an existing major trunk line; more than likely the existing Transco system. The beginning of this system (upstream, production side) is likely to be interconnected into a series of smaller diameter pipes that connect individual offshore wells and structures to the new system. The size of the individual gathering lines, or gathering systems, will be a function of anticipated production from the area. The number of major trunklines and individual gathering systems will be determined, generally, by the scope and scale of Atlantic OCS production. Larger volumes produced in a concentrated geographic region are likely to see a fewer number of large trunk or gathering system configurations. Larger volumes produced over a broad geographic region will have a tendency to be smaller in capacity (diameter) but more numerous in terms of trunk and gathering segments.

As noted earlier, the likely configuration for new natural gas transportation systems along the Atlantic OCS will include (1) a major trunkline, and (2) a series of smaller gathering lines connected to the trunkline. This new configuration, in turn, will likely be connected into an existing long-haul transportation system that delivers to major end use markets. A new production to consuming area pipeline from the Atlantic production area to either the northeast, or even southeastern US, while possible, is unlikely.

Future pipeline development decisions can be thought of as having two components. First, where and at what point along an existing natural gas pipeline, will a major trunkline connection be developed? Second, where, and at what point will a gathering system be developed to connect the producing wells arising from Atlantic OCS development. The exact size, location and nature of this development cannot be answered at this time, but each component of a future development has a number of factors that will have to be considered before any infrastructure development scenarios.

There are a number of factors that will influence one, or a series of major trunkline developments that connect coastal production to the existing interstate system. These factors include:

1. Production location: pipeline developments cannot ignore their primary purpose of moving gas from point A to point B. Major pipeline segments generally tend to move from production areas to transportation segments moving gas to consumption areas. These systems' connections to the major interstate system can vary and are often influenced by many of the other considerations discussed below.

2. Distance: is related to location but does differ and can be influenced by a number of factors such as geography, topology, bathometry, and available right of way. The geography along the eastern seaboard, and its population density, differs considerably from the GOM, which is likely to lead to different prioritization of factors and pipeline siting outcomes.

3. Deliverability: an important commercial consideration in developing pipeline projects is maximizing its ability to facilitate a wide range of transactions across a range of different shippers (which can be producers or consumers, or both). Generally, pipeline companies will attempt to maximize the number of shippers on its system. In addition to linking new production to the interstate system, some new trunk line developments may also attempt to link new Atlantic OCS production to large, intermediate purchasers like power generations, manufacturing and industrial plants, and municipal gas systems and local distribution companies.

4. Supporting infrastructure: new line segments will also have to consider the degree to which supporting infrastructure such as compression, processing, and storage will be needed. Compression requirements are likely to be a function of the size and scope of the configuration and deliverability factors impacting development. Processing and storage considerations will be discussed in a later section of his memo.

5. Potential competition from other supply resources: since 2008 there has been a dramatic paradigm-shifting development in gas production from shale-based geological formations. A significant amount of production from the Marcellus shale play has risen and will compete with Atlantic OCS production for incremental pipeline capacity and access to northeastern markets. In addition, pipeline developments linking western (Rockies) production to eastern markets have materialized. This new source of additional production will also create some new market opportunities for Atlantic OCS gas production. Further, new shale resources in the Great Lakes region are likely, at some point in the future, to see development and transportation into the Northeast. Last, there are a large number of LNG regasification facilities that have seen development or expansion over the past several years. These facilities will also be a source of competition with Atlantic natural offshore gas production.

13.1.6 Import and Export Terminals

Import and export terminals are facilities where oil and natural gas products stop on their way to or from other countries before reaching end-users. These terminals tend to be very streamlined in their duties. In most cases, terminals are only used for storage and for moving energy products from one mode of transportation to another. There is normally no processing or transformation on site, aside from LNG regasification and liquefaction. There are several types of terminals, including marine terminals, bulk terminals, and airport terminals, that transport energy products into and out of the US

Marine terminals are the most popular type of import/export terminals and usually cater to only one type of fuel (oil and petroleum products, natural gas, or LNG). They are generally located on coastlines around the US for the greatest access to tanker ships. Tankers transporting oil from other countries, for instance, dock at oil import marine terminals and offload the oil into storage tanks on site or to another mode of transportation such as pipelines, railcars, or tanker trucks. Conversely, pipelines, railcars, or tanker trucks bring oil or natural gas products from refineries and processing plants to export terminals, where the products are loaded onto ships to be delivered to consumers around the world.

Most natural gas imports and exports are transported by pipeline as a gas or by ship as LNG, and Chapter 8 of this fact book contains a more in-depth analysis of LNG terminals, which are abundant across the Atlantic region. As such, this chapter will focus more on the import and export of oil and petroleum products and the terminals required to service such products.

13.2 Typical Facility Characteristics

13.2.1 Pipelines

Generally, there are three types of pipelines: (1) gathering lines; (2) transmission (or trunk) lines; and (3) refined product distribution pipelines. As shown in Figure 234, natural gas is usually transported through low pressure, small diameter gathering lines from the wellhead (production location) to an intermediate processing facility. From there, the gas is either sent to transportation “hubs,” storage tanks, or onward through the pipeline system, where it is eventually delivered to the end-user. Oil is transported in much the same way with slight variations along the supply chain.

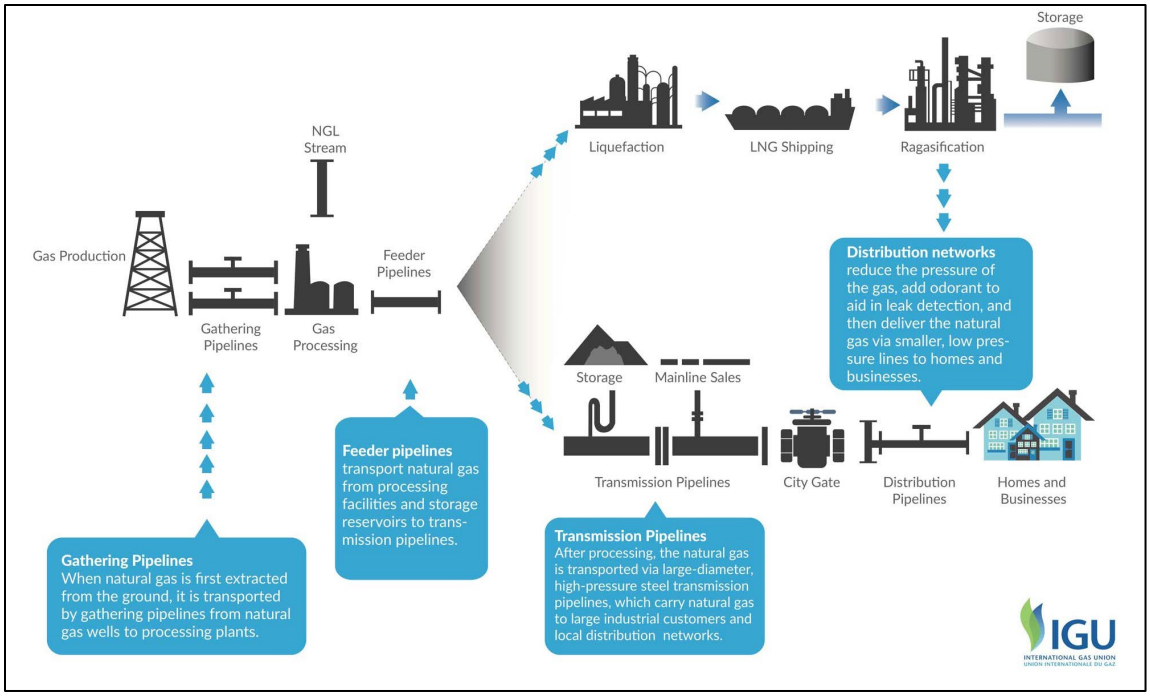

Figure 234. Movement of natural gas by pipelines.

Source: International Gas Union (IGU c2017).

Transmission pipelines are large in diameter and use high pressures to carry large volumes of energy over long distances to large industrial users or to transportation hubs like LNG terminals. The distribution system, on the other hand, includes smaller diameter pipelines that deliver oil or natural gas across shorter distances to the final, usually smaller, consumers such as residential homes and businesses (IGU c2017). A majority of the natural gas pipeline system (roughly 85 percent) is made up of millions of these smaller distribution lines. The other 15 percent is composed of gathering and transmission lines that transport the gas from the production site to several intermediate locations (Allison and Mandler 2018 Jun 1). About half of the natural gas transmission and distribution networks still in use today were installed in the 1950s and 1960s following the significant increase in consumer demand for natural gas after World War II (EIA 2019 Dec 5).

Pipelines can also be classified as interstate or intrastate. Interstate pipelines typically carry oil and natural gas across state boundaries, while intrastate pipelines transport energy products within a single state. Interstate pipelines are under federal jurisdiction and need approvals from FERC before they can be constructed, operated, or abandoned. No such federal jurisdiction applies to intrastate pipelines (FracTracker Alliance 2016 Jun 14). Additionally, federal agencies such as PHMSA are also responsible for inspecting and enforcing safety regulations regarding interstate lines. States can receive certification from PHMSA to take on these duties themselves for intrastate pipelines operating within their territory (PST 2015 Sep).

Over the years, pipelines have been constructed out of numerous materials, the most popular of which are cast/wrought iron, steel, and plastic. Cast and wrought iron pipelines are among the oldest pipelines used in the US and were built for energy transportation through the 1940s. Many of these pipelines are still operating today; however, the degrading nature of iron alloys and the age of these pipelines have significantly increased the risk in using them. Steel pipelines have been used extensively since the 1950s and can be categorized as coated (protected) or uncoated (bare). Similar to cast/wrought iron pipes, bare steel pipelines are more susceptible to corrosion due to the lack of protective coating, and many have been taken out of service, although there are some still currently in operation. Plastic pipelines became commonplace in the 1970s and are a popular material used today (PHMSA 2017 May 3).

13.2.2 Rail and/or Train

The US rail system can be divided into two categories: private freight railroads and passenger rail. Of the freight railroads, seven are large Class I railroads, 21 are regional/Class II railroads, and 547 are short line/Class III railroads (ASCE 2017b). When pipeline transport is not feasible, oil and gas are often hauled on these freight railroads by unit train—a type of train that carries only one type of cargo in a single type of car and serves one destination. Unit trains do not need to be switched to different tracks and return to their original location as soon as they are unloaded, which saves time and reduces costs.

Rail cars on these types of trains generally have an economic life of 30 to 40 years. A typical tank car used for transporting oil is about 60 feet (18 meters) long, 11 feet (3.3 meters) wide, and 16 feet (5 meters) high. It weighs about 80,000 lbs. (36,287 kg) when empty and can hold roughly 30,000 gallons or 715 barrels of oil, increasing the car's weight to 286,000 lbs. (129,727 kg) when full. A train consisting of 70 to 120 tank cars can carry anywhere between 50,000 and 90,000 barrels of oil, depending on the type of crude being delivered (Frittelli et al. 2014). Figure 235 shows a diagram of a basic railcar used in oil transportation.

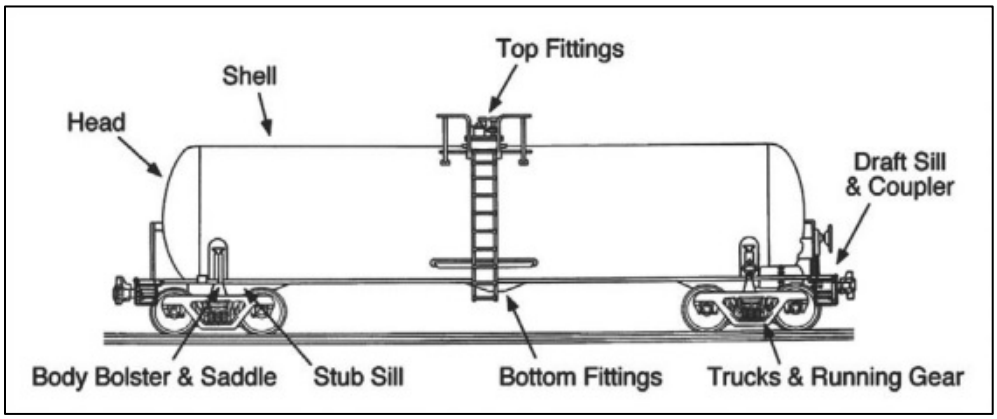

Figure 235. Non-jacketed, non-pressure tank car for rail oil transport.

Source: (Frittelli et al. 2014).

The tank car is made of steel plate, 7/16 of an inch (11 mm) thick, and is commonly loaded from a valve on top of the car and unloaded from a valve on the bottom. Loading and unloading a car can take several hours, but multiple cars in a train can be done simultaneously. Recently, efforts to improve the safety of these oil tank cars has led to an increased focus on reinforcing the shells of the cars with a "jacket" of steel, adding protective shields to both ends, eliminating or modifying bottom valves so that they do not break open during derailment, and increasing insulation for fire protection such as that found on pressurized tank cars used for carrying explosive liquids. The tank in the figure above does not include these extra safety features (Frittelli et al. 2014).

Generally speaking, trains carrying carloads of crude oil can travel between 40 and 50 mph (64.3 and 80.5 kph), making it much faster than pipeline at transporting energy over long distances (Frittelli et al. 2014; AAR 2014 Jul). For instance, oil transported by railway can be delivered from the remote Bakken field region in North Dakota to the Gulf Coast in five to seven days, whereas oil transported by pipeline would take about 40 days to travel the same distance (Hansen and Dursteler 2017). However, because of their limited capacity, trains are only used to transport oil when pipelines are not a viable option.

13.3.3 Trucking

Tanker trucks are vehicles with large tanks used for transporting liquids. They are built in various sizes for specific cargos and are usually equipped with a pumping system for loading and offloading liquids. Tanks transporting oil and other hazardous liquids are usually made of steel or aluminum and can be insulated or non-insulated (Cordock 2018 Aug 9).

Many tanker trucks can carry different liquids simultaneously (including industrial chemicals, concrete, diesel, gasoline, and water) using several compartments separated by bulkheads on the truck. Each type of liquid has a different density, which alters the truck's maximum capacity. Despite varying in size, all tanker trucks have the same cylindrical shape (see Figure 236) that provides maximal storage capacity. Within these tanks are several baffles that minimize liquid movement and aid in stabilizing the truck, increasing transport efficiency (Transcourt 2018 Nov 19).

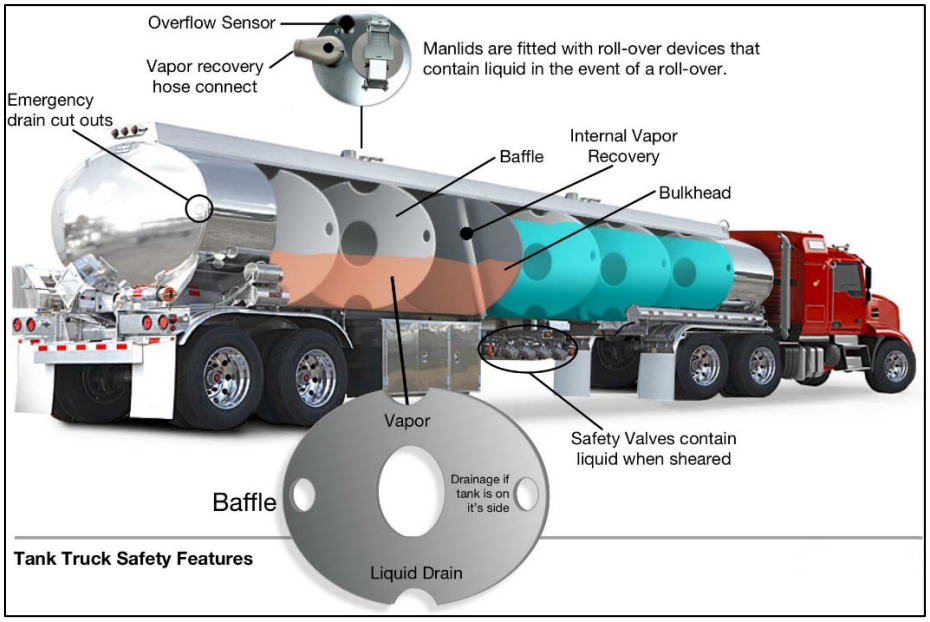

Figure 236. Features of a standard tanker truck.

Source: (SafeRack 2019 Jun 5).

To meet US DOT regulations, tanker trucks transporting oil must also include a separate manhole for each compartment, emergency shutoff on the driver's side front, and rollover protection to prevent the manholes from opening if the tanker tips or rolls over. If a tank does roll over, the manholes are outfitted with pressure release technology that allows a small amount of spillage to prevent pressure from building up in the tank and causing an explosion. Additionally, vapor recovery equipment such as valves and vents are installed to channel vapors to the correct location so that there is no build-up in the tanker and harmful chemicals are not released into the atmosphere (SafeRack 2019 Jun 5).

The maximum capacity of a tanker truck depends on the size of the truck and the density of the liquid being transported, varying anywhere between 3,000 gallons for a small truck to 11,600 gallons for large trucks (Transcourt 2018 Nov 19). On average, tanker trucks can hold about 200-250 barrels of oil, or about one-third of the capacity of the average railcar, making them an expensive and inefficient option compared to other transportation methods (Hansen and Dursteler 2017; Breakthrough 2019 Nov 1).

13.3.4 Marine Ships and/or Barges

A marine ship that is designed to transport or store liquids and gases is most commonly referred to as a tanker or tank ship. Oil tankers, chemical tankers, and gas carriers are some of the most common types of tank ships that have been developed to handle oil and oil-derived products, dangerous chemicals, and liquefied natural gas, respectively. Ocean and sea tankers can range in size and capacity from several hundred tons, which includes vessels for servicing small harbors and coastal settlements, to several hundred thousand tons for long-range hauls. There are also specialized inland-waterway tankers, which operate on rivers and canals, that have an average cargo capacity up to some thousand tons. Some popular types of oil transport vessels are described below.

Barges are flat-bottomed vessels that must be tugged or towed by other ships to transport cargo. They mainly operate on inland waterways, but there are types that are designed for coastal use on the ocean such as articulated tug barges (ATBs). Barges typically range in size from 180 feet (52.7 meters) to 300 feet (91.4 meters) long, although 300-foot barges are the most popular because they can transport larger volumes of cargo (Jha 2019 Oct 2). Just one river barge can hold 10,000 to 30,000 barrels of oil and travel up to 5 mph. If two or three are tied together in a single tow, one shipment can transport as much as 90,000 barrels. Coastal barges, like the ATB shown in Figure 237, can extend beyond 650 feet (198 meters) long and carry as much as 340,000 barrels of oil in one trip. Seafaring barges like these can reach speeds of up to 12 mph (10 knots) (Frittelli 2014; Valentine 2015 Aug 26).

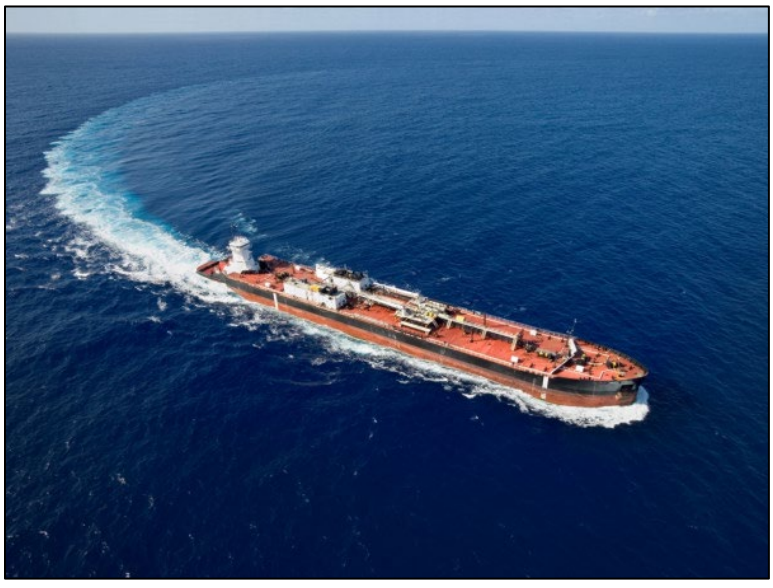

Figure 237. Articulated tug barge.

Source: (Crowley c2020).

Coastal tankers are the smallest type of tanker built for ocean transportation, aside from specialized barges like ATBs. As seen in Figure 238, coastal tankers (also called small range or product tankers) average about 670 feet in length and are designed to carry various fuels such as petroleum products, hydrocarbon products, kerosene, gasoline, liquefied petroleum gas (LPG), and LNG. These tankers are made to transport products from processing plants over short distances to distribution units and can hold 300,000 to 650,000 barrels of oil (Frittelli 2014; Rodrigue 2017 Dec 19; Chakraborty 2019 Dec 4).

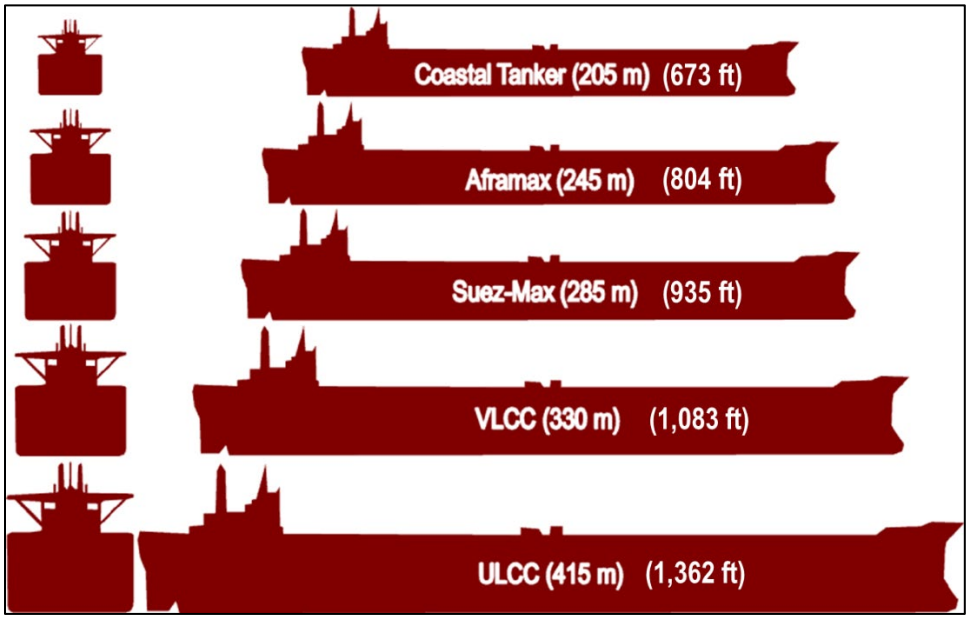

Figure 238. Tanker sizes and classes.

Source: (Rodrigue 2017 Dec 19).

Panamax, Aframax, and **Suezmax tankers** are larger tankers that cater to specific parts of the world. Their sizes generally range from 700 feet to over 1,000 feet long, with Panamax ships typically being the smallest and Suezmax ships being the largest (BTS 2018; Marine Insight 2019 Oct 20).

- *Panamax tankers* operate in North and South America and were designed specifically to transport cargo through the Panama Canal, hence their name. They can carry an average of 500,000 barrels of oil. The Panama Canal's original lock chambers that are used to load and unload cargo from ships are 1,050 ft long, 110 ft wide, and 41.2 ft deep, and the Panamax ships were developed to fit these parameters. However, in 2016, a third channel opened with larger locks at 1,400 ft long, 180 ft wide, and 60 ft deep in order to accommodate larger vessels called New Panamax ships. New Panamax ships are much larger than their predecessors with dimensions of 1,200 ft long, 160 ft wide, and 50 ft deep and a cargo capacity of 13,000 TEU (Maritime Connector c2020; BTS 2018).
- *Aframax tankers* mainly operate in areas where there is lower crude oil production such as non-OPEC countries that lack large harbors and canals able to accommodate larger classes of tankers. They can generally be found carrying oil exports in the Caribbean Sea, Mediterranean Sea, Black Sea, and the China Sea. Aframax tankers measure about 804 ft long, have a DWT between 80,000 and 120,000, and have an average carrying capacity of 750,000 barrels (BTS 2018; Maritime Connector c2020).

- *Suezmax tankers* derive their name from being the largest tanker capable of going through the Suez Canal, much like Panamax tankers. A typical Suezmax tanker is around 900 ft long, has a DWT between 120,000 and 200,000, and can transport one million barrels of oil, on average (BTS 2018; Raunek 2019 Dec 4).

Very Large Crude Carriers (VLCCs), also known as "supertankers," are one of the largest types of tanker used in energy transportation. Standard VLCCs range from 984 feet (300 meters) to 1,083 feet (330 meters) long and can have a DWT between 200,000 and 320,000. They are commonly used for long-haul crude transportation from the Persian Gulf to European, Asian, and North American countries and are large enough to transport two million barrels of oil (BTS 2018; Maritime Connector c2020). This type of supertanker was created as global oil trade grew, and it became more efficient to use larger vessels for crude shipments. Now, VLCCs are responsible for most crude oil shipments around the world (EIA 2014 Sep 16).

Ultra Large Crude Carriers (ULCCs) are the largest shipping vessels in the world. With a size of over 1,300 feet (396 meters) long and between 320,000 and 500,000 DWT, ULCCs require custom built terminals for loading and unloading. Consequently, they can serve only a limited number of ports who have adequate facilities able to accommodate them. The *Knock Nevis* was a ULCC that measured over 1,500 feet (457 meters) long and had a DWT of 564,760 (Figure 239). Constructed in 1979, it was the largest ship ever built but was ultimately decommissioned and scrapped in 2009 after 30 years of operation (Maritime Connector c2020).

Figure 239. *Knock Nevis* ULCC tanker.

Source: (Elliot 2017 Sep 6).

Vessels specifically designed to carry gas in bulk are called gas tankers and can vary depending on what form of gas they are transporting. As such, gas tankers can be classified into five categories (Mohit 2019 Nov 22):

1) *Fully pressurized ships* – usually smaller in size, these tankers transport cargo in ambient temperature inside of heavy, carbon steel tanks with no thermal insulation and a design pressure of 18 bars.
2) *Semi-pressurized ships* – ships that are designed to carry gas at a maximum pressure of 5 to 7 bars in tanks very similar to fully pressurized ships. They usually operate in busy coastal areas and are one of the most popular types of gas tankers among plant owners and operators.

3) *Ethylene ships* – gas tankers built for transporting a number of gases, including liquefied petroleum gases (LPGs) and chemical gases. They contain Type C pressurized tanks, like the pressurized ships described above, and have thermal insulation and liquefaction capabilities.
4) *Fully refrigerated LPG ships* – tankers that transport liquefied petroleum gases at low temperature and atmospheric pressure. Their cargo tanks are prismatic-shaped and are constructed with up to 3.5 percent of nickel steel, which enables them to carry cargo at temperatures as low as -54ºF (-48ºC).
5) *LNG ships* – vessels that are specifically designed to transport large quantities of LNG at its boiling point of -260ºF (-162ºC). These tankers can carry as much as 5.8 Bcf, although an average-sized carrier usually transports as much as 3.8 Bcf at one time (Daiss 2019 Oct 10). With average life spans between 20 to 25 years, there are currently over 500 LNG carriers worldwide (GIIGNL 2019; Mohit 2019 Nov 22).

13.3.5 Natural Gas Market Hubs

Generally, all natural gas hubs[14] have the same key elements (Xunpeng and Variam 2018):

1) A trading point for buyers and sellers to meet and agree to a transaction, usually at a sufficient interconnection point of pipelines that allows gas to be transferred to the final customer.
2) A hub operator and/or transmission system operator (TSO) that provides administrative services such as the registration of trades, title transfer and matching services, the operation of the balancing market, market surveillance, and reporting. In addition to these duties, the TSO also operates the transfer of gas.
3) A trading platform or exchange that provides a place where the price of gas is revealed. An exchange is a specialized trading platform that trades the hub's products and allows parties to anonymously buy or sell gas.
4) The specification and standardization of products/contracts by their place and time of delivery, which helps concentrate liquidity that attracts volume and thus, traders.
5) A mix of market participants such as producers, wholesalers, retailers, and consumers.

Although all gas market hubs share the same core elements and purpose, the infrastructure of the hubs themselves can be configured in several different ways. Some hubs are associated with and use all, or a large portion, of an entire pipeline system to carry out their operations and provide transportation services between all pipeline interconnect points that are part of their system. This type of hub is called a "full pipeline system" and its infrastructure may encompass all or part of the operations and facilities included in Figure 240 (EIA 2009).

[14] There are 32 natural gas hubs in the US, and eight are located in the Atlantic states. These are discussed in Subsection 12.3.5.

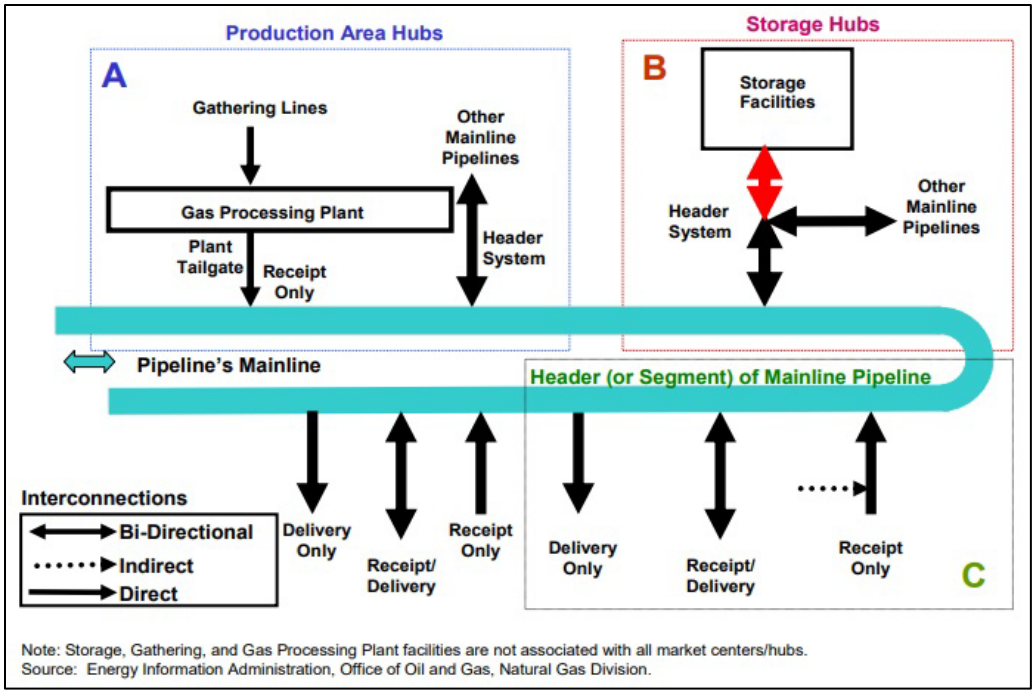

Figure 240. Generalized market hub operational schematic.

Source: Energy Information Administration (EIA 2009).

If a hub is not a full pipeline system, it is a type of header system. A "non-storage header system" is a market hub that operates using only a short portion of a mainline pipeline, or a stand-alone lateral, where two or more pipeline interconnections are concentrated within a short distance of each other, as can be seen in Box C of Figure 240. In "production area header systems," market hub operations dispatch production volumes onto the mainline transmission grid from interconnections on the header system with other mainline intrastate pipelines or from the tailgate of a natural gas processing plant, as shown in Box A. These types of systems confine their activities mostly to providing hub services to natural gas producer clients. Lastly, Box B shows bi-directional lateral "storage header systems" that connect underground storage facilities to the mainline pipelines and are used to transport a shipper's natural gas between these interconnects. Depending on what services are needed by the customer, the transported natural gas may or may not move through the associated storage facilities located at these hubs (EIA 2009).

13.3.6 Import and Export Terminals

Marine terminals used for exports or imports have one or more berths consisting of a loading (or unloading) platform and several berthing and mooring dolphins where the tanker ship is docked and held in place while the cargo is loaded or unloaded. The loading/unloading platform is usually large enough to accommodate piping and other mechanical equipment, safety equipment, personnel access, and sometimes supplies for the vessels (Agerschou et al. 2004). Some terminals also have a foreshore that allows land facilities to extend out over the water. In Figure 241, the foreshore contains a control building, electrical substation, and firefighting equipment in addition to a vapor recovery system that is used to capture emissions from vessel loading operations. There are pipelines onshore and running the length of the dock that transfer oil from the storage tanks on site to the loading/unloading platform and vice versa in the case of imports (Trans Mountain c2020). These storage tanks can be found above or below ground and hold the oil or gas products at the appropriate temperature until they are transferred again. In the case of imported oil, once it leaves the storage tank, it may be delivered to a nearby refinery so it can be processed and sent on its way by pipeline, rail, or truck to the end-user. Pumps help push the oil or gas through hoses or some other flexible device into or out of the ships' storage containers (Agerschou et al. 2004; Matrix PDM c2017).

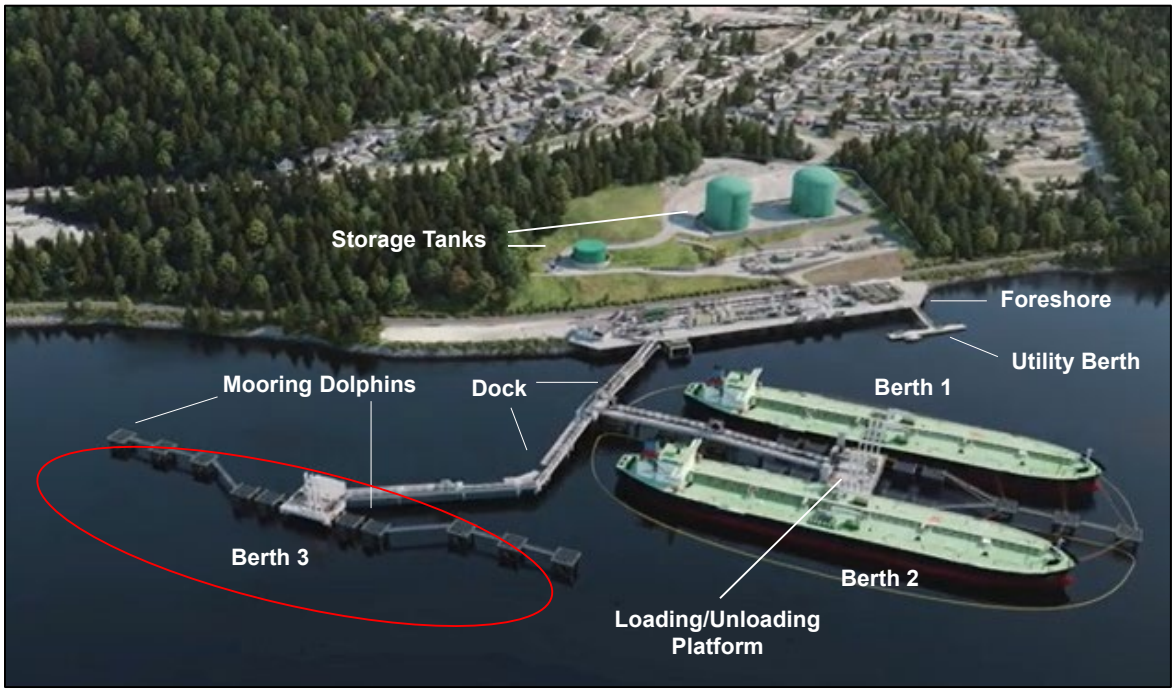

Figure 241. Marine export and import terminal.

Source: (Trans Mountain c2020).

13.3 Geographic Distribution

13.3.1 Pipelines

The US has more miles of pipeline than any other country in the world with over 200,000 miles (321,869 km) of hazardous liquid lines, 300,000 miles (482,803 km) of natural gas transmission and gathering lines, and 2.2 million miles (3.5 million km) of smaller natural gas distribution pipeline spanning across the country (PHMSA 2020 May 1). While some are built above ground, a majority of these pipelines are buried underground, and some are even constructed underwater, primarily in the GOM. As shown in Figure 242, many of these systems overlap in the middle and southern regions of the US, where major shale plays and export facilities are located.

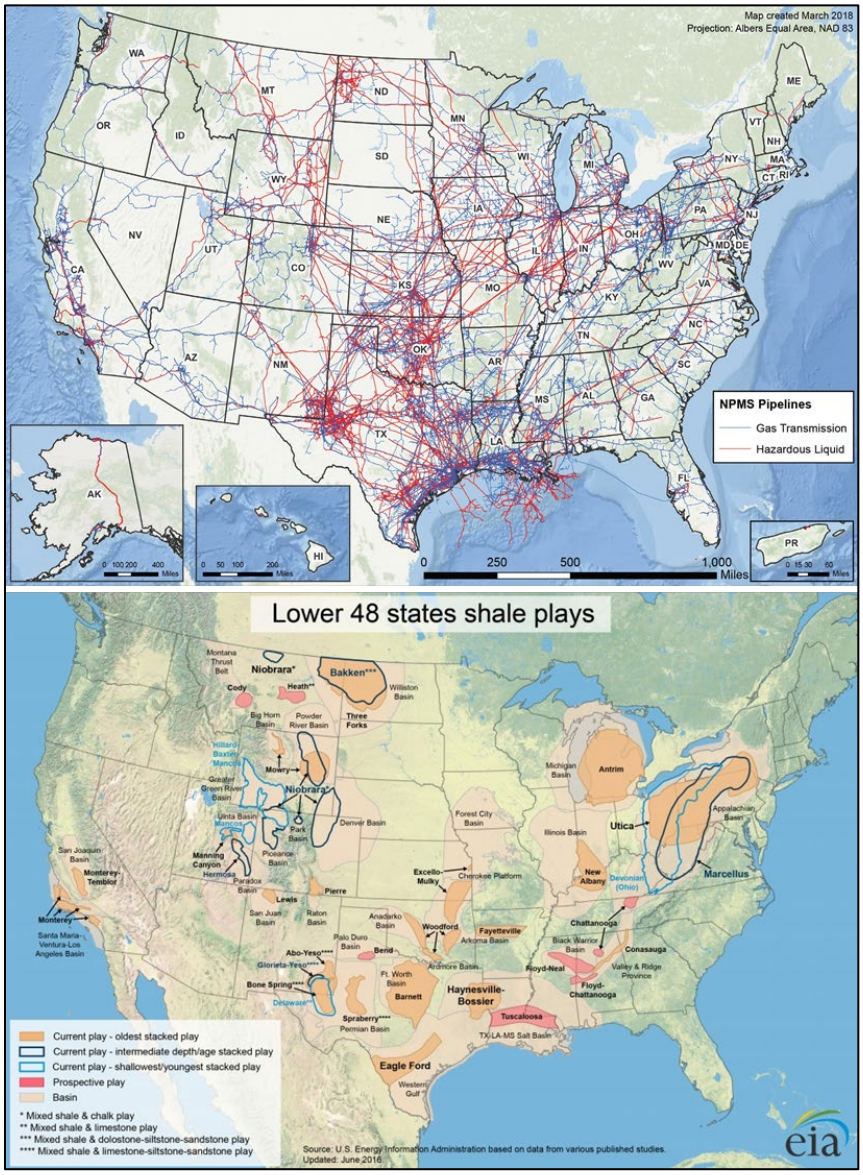

Figure 242. US pipeline network and shale plays.

Source: (EIA 2016a; Allison and Mandler 2018 Jun 1).

Dozens of pipelines in the northern US extend into Canada, allowing seamless trading between the two countries. Figure 243 is a map of the major pipelines that carry oil and other liquid fuel between the US and Canada. As the largest energy trading partner of the US, Canada accounted for 48 percent of total US crude oil imports and 97 percent of all US natural gas imports in 2018 (EIA 2019 May 28). A few pipelines also extend into Mexico through Texas for the same purpose but to a much lesser extent.

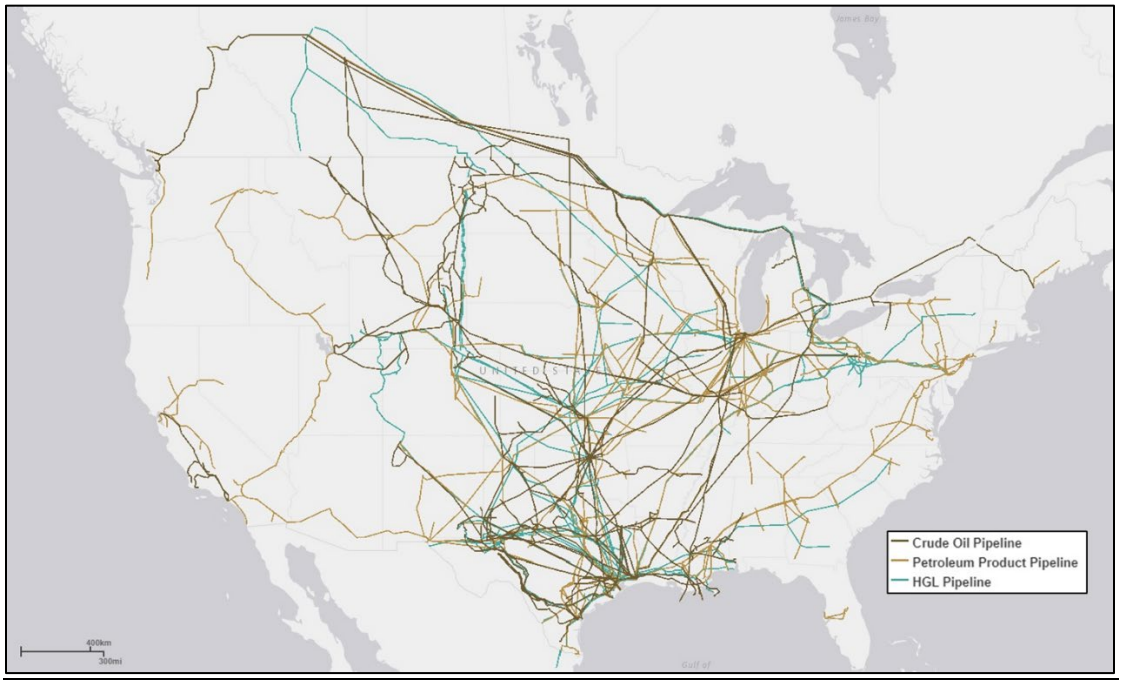

Figure 243. Major liquid pipelines between the US and Canada.

Source: Energy Information Administration (EIA c2020).

Major pipelines on the Atlantic Coast consist mainly of interstate pipelines, as seen in Figure 244. Before the discovery of the Marcellus and Utica shale plays in the Northeast, many of these pipelines were used to carry natural gas and petroleum products from the highly productive GOM to populated areas along the East Coast.

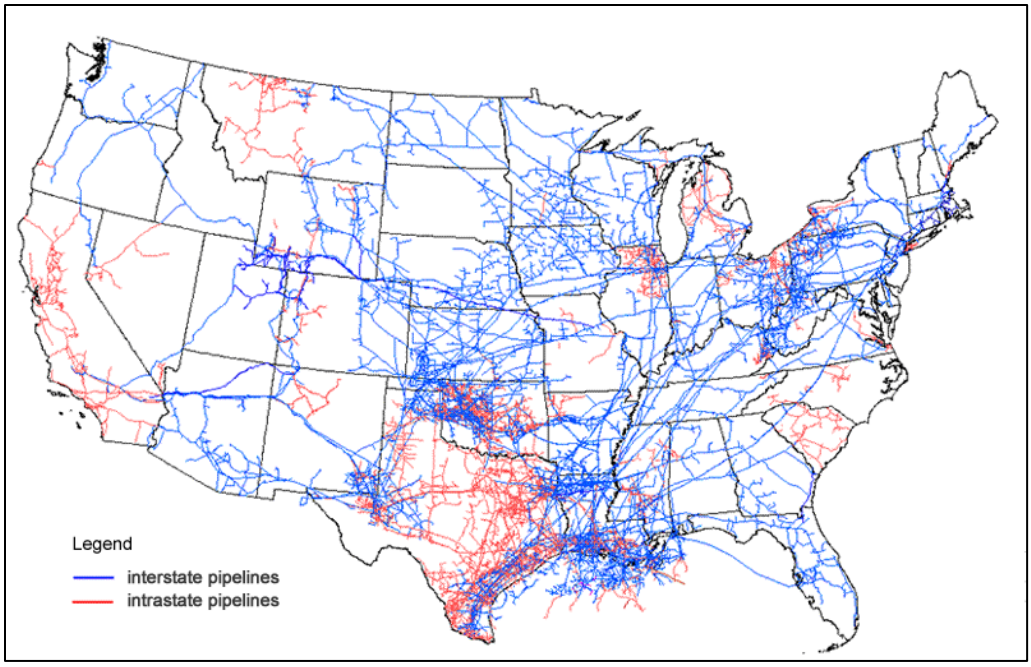

Figure 244. Interstate and intrastate natural gas pipelines in the US.

Source: Energy Information Administration (EIA 2019 Dec 5).

The Atlantic Coast's limited refinery capacity is only able to meet one-fifth of its regional demand for petroleum products like gasoline, diesel, and jet fuel. With over half of the US's total refining capacity, the Gulf Coast is the main supplier of these products to the region, primarily through pipelines or by marine shipments (Figure 245) (EIA 2016b).

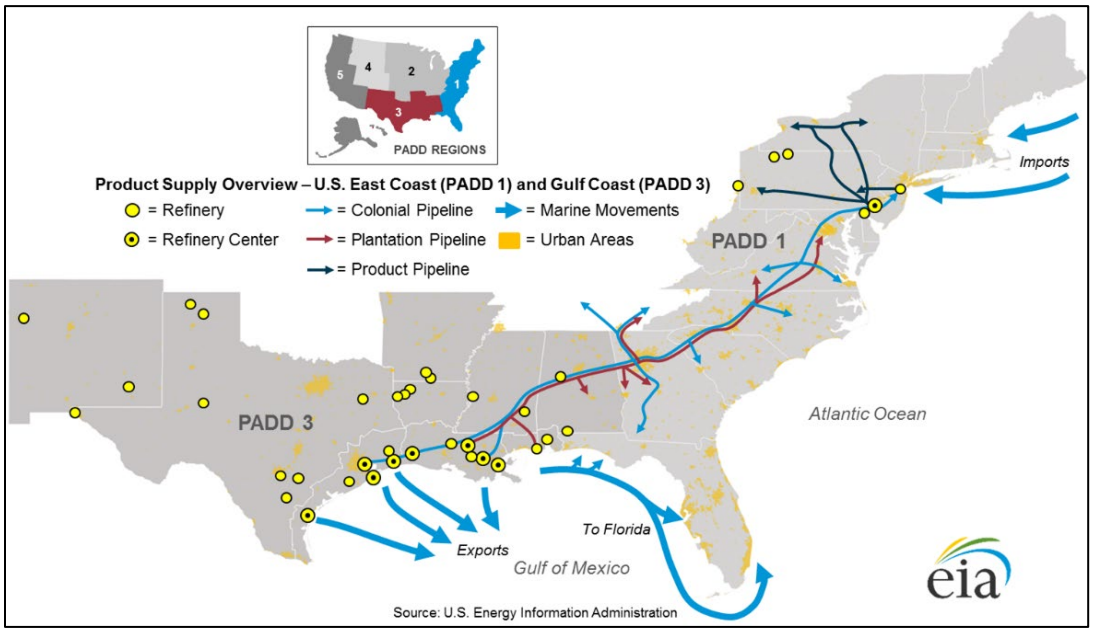

Figure 245. Petroleum product flows from Gulf Coast to East Coast.

Source: Energy Information Administration (EIA 2016b).

The Colonial Pipeline and Plantation Pipeline are the two major pipeline systems used to supply transportation fuels to the East Coast. These two pipelines carry over 2.3 million barrels of refined products a day, accounting for nearly 47 percent of the East Coast's consumption (EIA 2016b).

13.3.2 Rail and/or Train

Across the US spans nearly 140,000 miles (225,308 km) of railroad track, almost 30,000 miles (48,280 km) of which are in the Atlantic Coast region. Pennsylvania alone has the greatest number of railroads, or rail lines, in the nation and is ranked fourth in total rail miles. With approximately 60 railroads spanning over 5,130 miles (8,256 km), Pennsylvania contains 17 percent of the total rail miles located in the Atlantic region (AAR 2017).

Figure 246 shows the routes of the seven largest freight railways in the US, also known as Class I carriers. A large amount of oil transported by freight train travels along this 95,000-mile (152,888-km) network of railroads. Of these seven Class I railroads, two operate heavily in the Atlantic region: the CSX and the Norfolk Southern railways. Approximately 700 miles of the Pennsylvania's rail system are used by these two railroads (PennFuture c2019). Among various other products, these railways transport large amounts of crude oil and LPG each year.

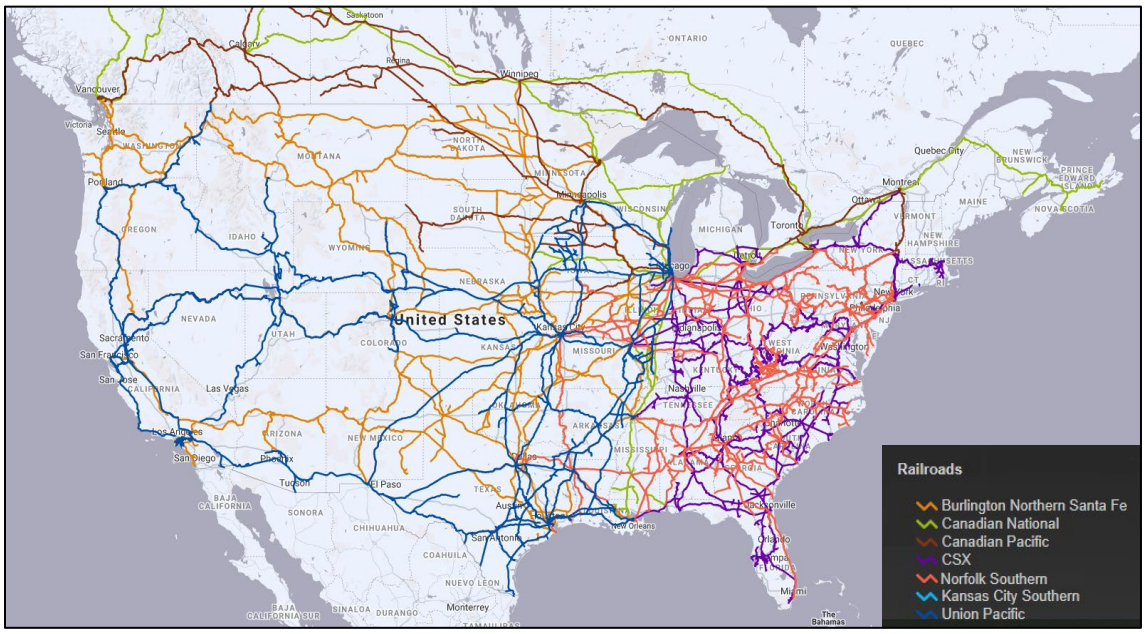

Figure 246. Class I railroads in the US.

Source: Oil Change International (OCI c2019).

The CSX railroad has the most crude oil destinations on the East Coast. Oil travels from basins found in the western and southern US, such as the Bakken and Eagle Ford basins, to the CSX's interchange locations in Chicago, St. Louis, Memphis, and New Orleans. From there, the CSX's 21,000 miles (33,796 km) of track transports the oil to refineries and terminals throughout the Eastern US, as shown in Figure 247 (CSX c2016).

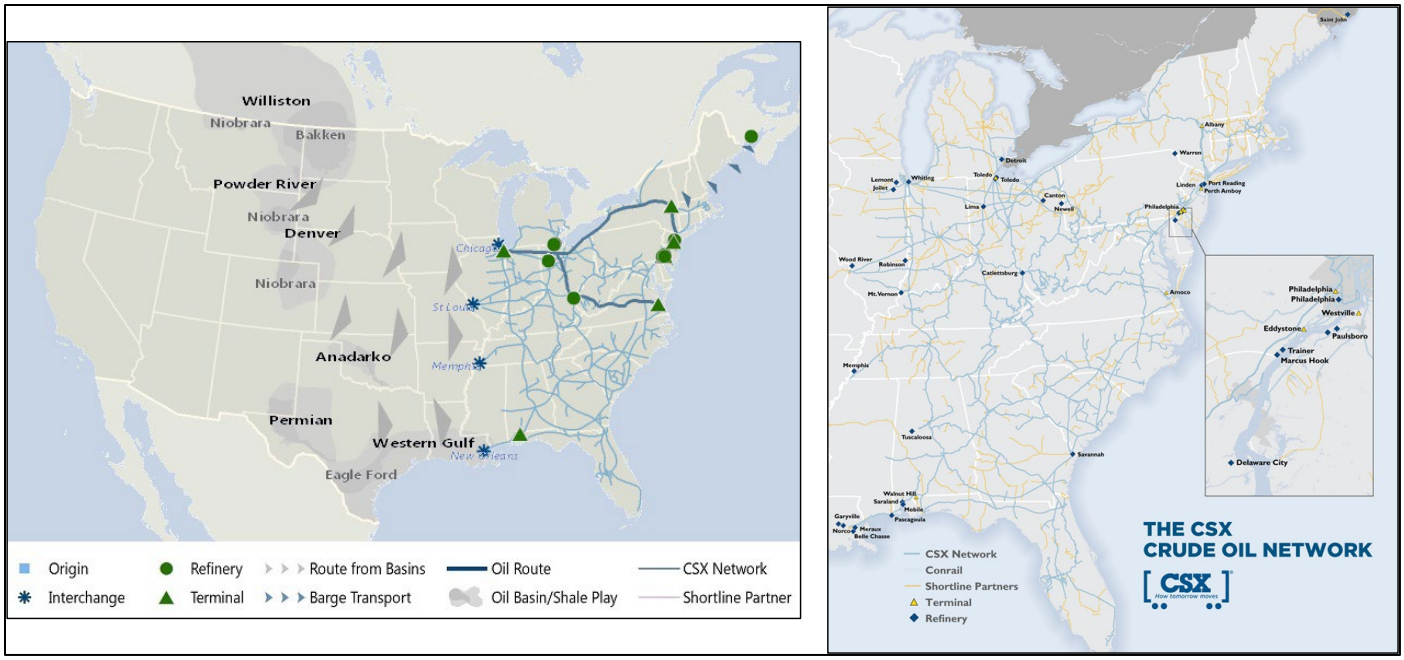

Figure 247. CSX crude oil network.

Source: (CSX c2016).

Similarly, the Norfolk Southern railway operates around 20,000 miles (32,187 km) of track and has access to a number of primary crude oil refiners along the Atlantic Coast. It is capable of transporting over 102,000 carloads of oil in addition to other energy products like coal (Norfolk Southern c2015).

Rail terminals are facilities used for the transfer of cargo to other modes of transportation, either to or from the railcar. They are usually centered near port terminals or other locations that provide accessibility to markets or resources. As shown in Figure 248, rail terminals in the Atlantic states are almost exclusively positioned along the coast in the Northeast between the Marcellus and Utica shale plays and the large amount of ports and marine terminals used for overseas trade.

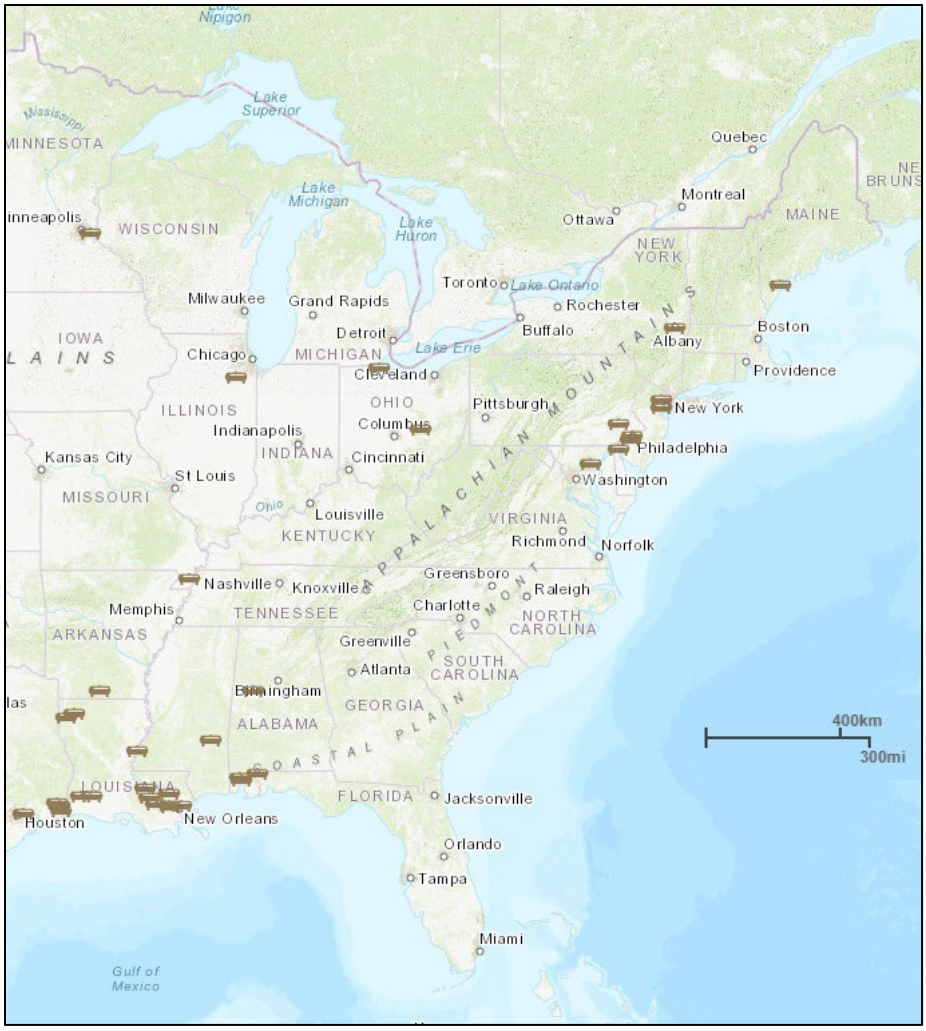

Figure 248. Crude oil rail terminals in the eastern US.

Source: Energy Information Administration (EIA c2020).

13.3.3 Trucking

There are over 220,000 miles (354,056 km) of interstates and other major roads that carry most of the highway freight and traffic in the US (ARTBA c2020). Like pipelines and railroads, these highways are busiest in the southern and northeastern parts of the US, where high levels of oil and natural gas are produced (Figure 249).

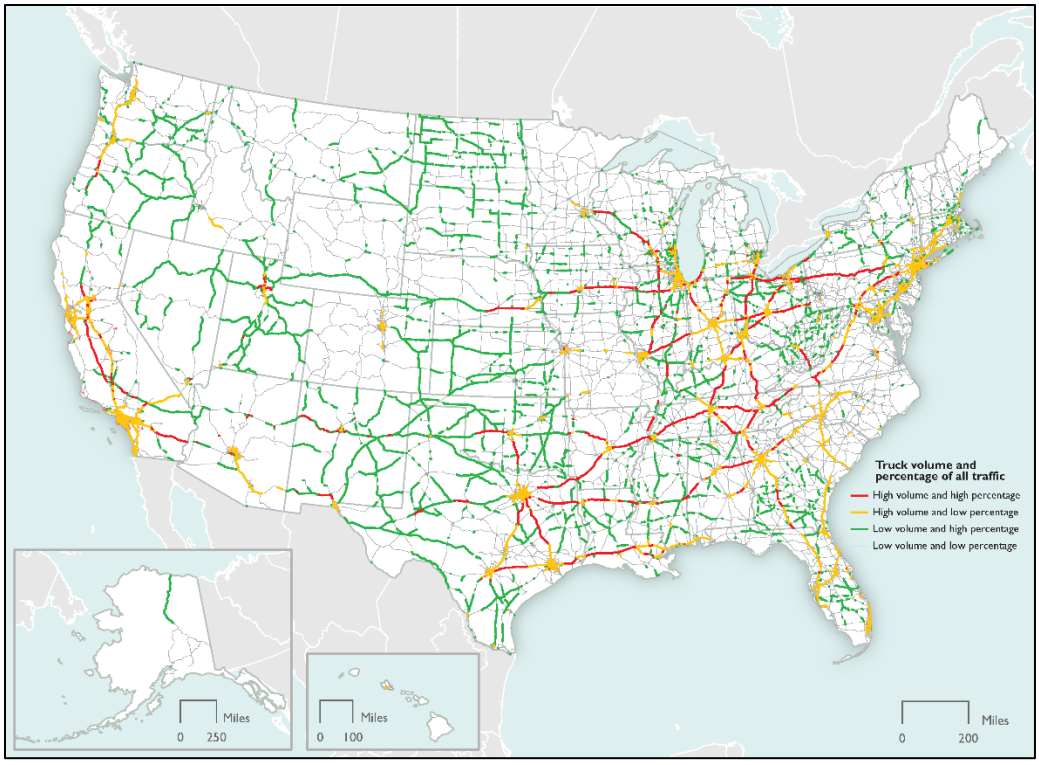

Figure 249. Major trucking routes by volume and traffic.

Source: Bureau of Transportation Statistics (BTS 2015).

Highways transport over 1.22 billion tons of petroleum products a year, including gasoline, diesel, and aviation fuel, which accounts for nearly half of all tank truck tonnage in the US (Bulk Transporter 2015 Apr 7).

The Atlantic Coast region is home to the longest north-south highways in the US Interstate 95, for example, runs over 1,900 miles from the Canadian border in northern Maine down to Miami, Florida (Figure 250). It's the country's most-used highway in terms of vehicle miles traveled and serves about 40 percent of the US population while only serving about 10 percent of its land area (Meyer 2018 Jan 20). Once in Miami, it connects with US Highway 1, the longest north-south road in the US that extends over 2,593 miles long and stretches from Fort Kent, Maine to Key West, Florida (US DOT 2017 Jun 27).

Figure 250. Route of Interstate 95.

Source: (i95Highway.com).

Approximately 126 bulk transload facilities are located within the Atlantic region, where cargo is transferred between tank trucks and rail or water transportation modes. Nearly 17 percent of these locations are found in Pennsylvania alone, and many are operated by major transport companies such as TRANSFLO and Norfolk Southern TBT (Bulk Transporter 2019a Dec 31). Additionally, there are around 20 bulk container storage facilities in the Atlantic region, concentrated mainly in New Jersey, North Carolina, Pennsylvania, and South Carolina. New Jersey has the most, however, with a total of around eight tank container depots (Bulk Transporter 2019b Dec 31).

13.3.4 Marine Ships and/or Barges

Over 3,350 inland tank barges move crude oil, refined products, and petrochemicals along inland waterways in the US Excluding traffic routes in the Great Lakes and deep ocean off the coast, there are approximately 25,000 miles (40,237 km) of navigable waterways in the US that are used by tank barges. About 12,000 miles (19,312 km) of these waterways are inland and intracoastal shallow-draft waterways with a depth of 9 to 14 feet (2.7 to 4.3 meters), and 13,000 miles (20,921 km) consist of channels greater than 14 feet (4.3 meters) deep (Fielden 2014 Mar 10; USACE c2020).

Figure 251 shows the major waterways designated by the Secretary of Transportation to carry goods throughout the US There are currently 25 of these “marine highway routes” that expand the country’s transportation system and offer relief for traffic congestion on land (MARAD 2020 Apr). M-95, for example, runs along the entire Atlantic Coast parallel to Interstate 95, transporting cargo to various destinations between Florida and Maine.

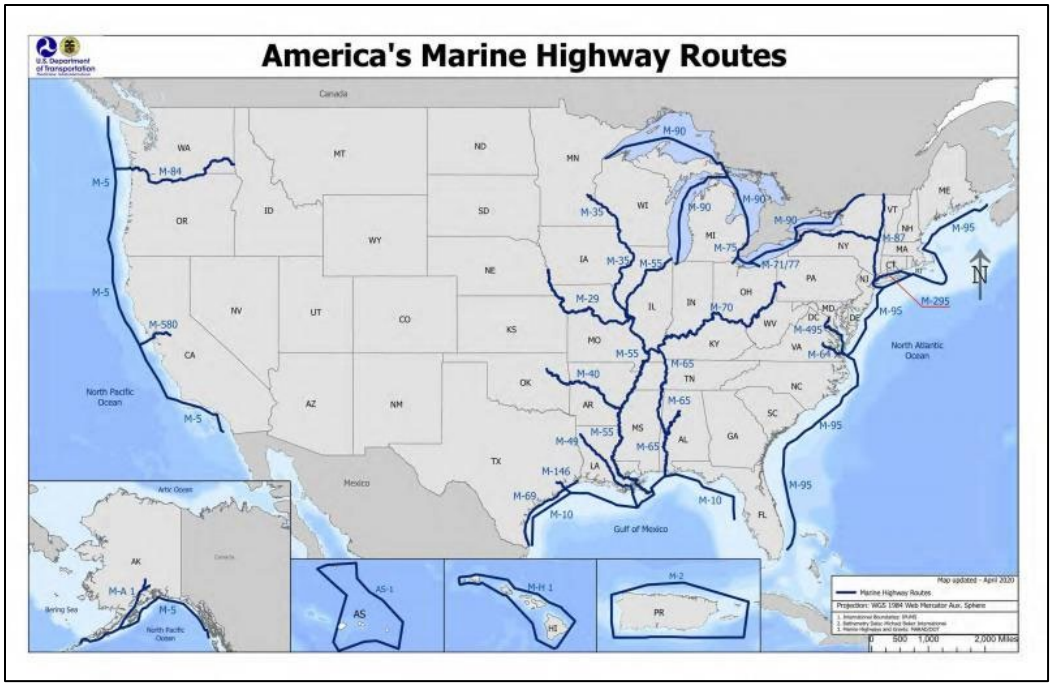

Figure 251. Navigable waterways in the US.

Source: US DOT, Maritime Administration (MARAD 2020 Apr).

As mentioned in Section 1.3.2 of this chapter, much of the oil produced in the Bakken shale play is transported to refineries by rail. However, there are several well-established intermodal routes from this region that also involve navigable waterways (Frittelli 2014):

1) Rail to barge at St. Louis and Hayti, Missouri, and Osceola, Arkansas on the Mississippi River to Gulf Coast refineries;
2) Rail to barge at Hennepin, Illinois on the Illinois Waterway to Gulf Coast refineries;
3) Rail to vessel at Albany, New York on the Hudson River to East Coast refineries;
4) Rail to Yorktown, Virginia for coastal transport to East Coast refineries;
5) Rail to vessel at Anacortes and Vancouver, Washington for coastal transport to West Coast refineries; and
6) Pipeline to barge in Cushing, Oklahoma for transport down the Arkansas and Mississippi Rivers to Gulf Coast refineries.

These and other major crude oil shipping routes in the US are shown below in Figure 252.

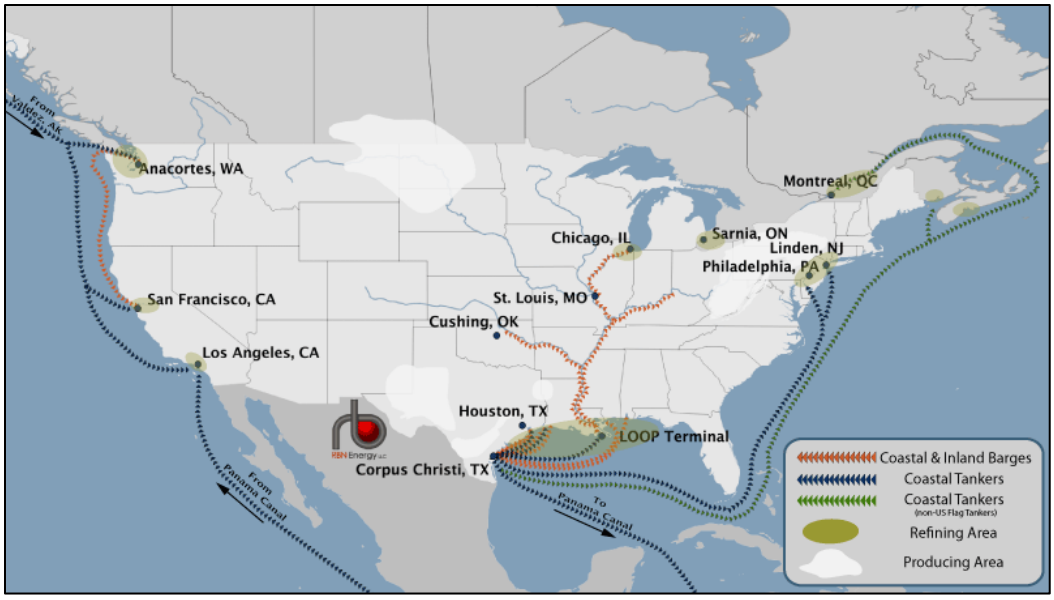

Figure 252. Marine transportation of crude oil in the US.

Source: RBN Energy, LLC (Carr 2014 Mar 16).

13.3.5 Natural Gas Market Hubs

The US contains 32 natural gas market hubs and three HGL market hubs. Hubs act as the central marketplace for natural gas and are, therefore, located where large amounts of natural gas are concentrated. A majority of natural gas pipelines are located near shale plays in order to transport the produced gas to refineries and consumers. As a result, most gas hubs in the US are located near shale plays because that is where they have access to the most pipelines and natural gas flow. As shown in Figure 20, eight of the 32 natural gas hubs in the US are located in the Atlantic states and are all found within the northeastern part of the region near the Marcellus and Utica shale plays.

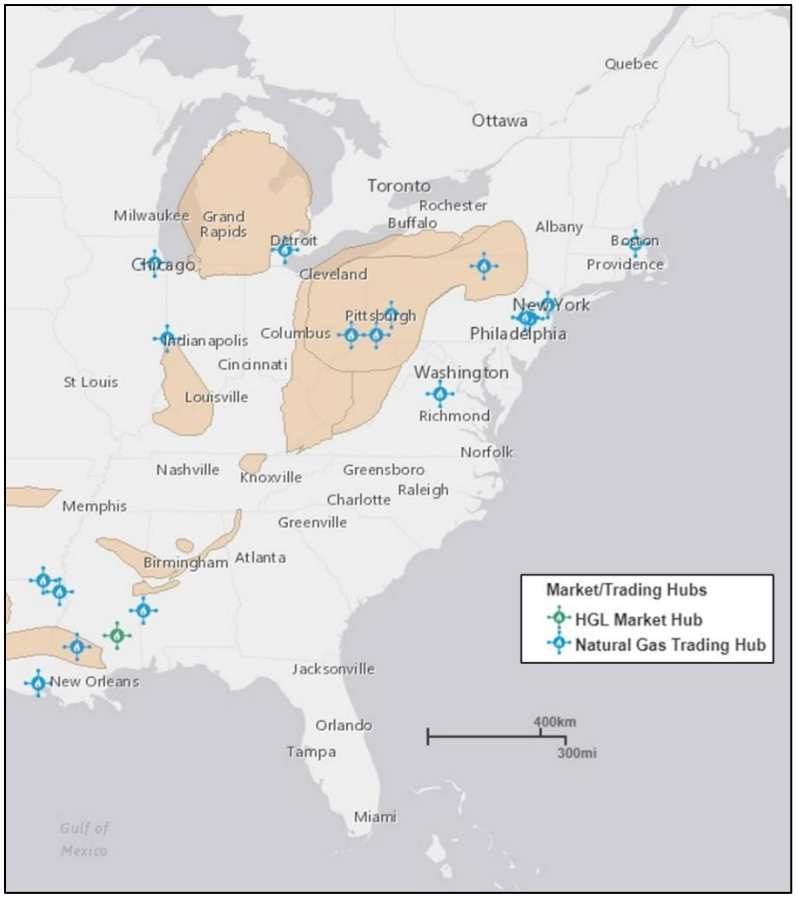

Figure 253. Natural gas and HGL hubs in the Atlantic region.

Source: Energy Information Administration (EIA c2020).

Natural gas hubs tend to be owned and operated by companies that control major pipelines and other gas facilities in the region. For example, the Henry Hub is owned by Sabine Pipe Line LLC, a wholly owned subsidiary of EnLink Midstream Operating, LP ("EnLink") that owns and operates 131 miles of bi-directional natural gas pipeline (EnLink Midstream c2020). EnLink provides integrated midstream services and operates gathering and transportation pipelines, processing plants, fractionators, barge and rail terminals, storage facilities, and a crude oil trucking fleet (EnLink Midstream c2020). The Transco Zone 6 market hubs in New Jersey are part of the Transcontinental Gas Pipeline Company, or Transco, a 10,000-mile interstate natural gas pipeline system that is owned by The Williams Companies, which is an energy company that focuses on natural gas processing and transportation infrastructure (The Williams Companies c2020).

13.3.6 Import and Export Terminals

A majority of US natural gas imports are carried by pipeline from Canada through entry points along the Midwest and Northeast border, while exports are transported to Canada and Mexico through pipelines in the Northeast and Southwest, as shown in Figure 254. Natural gas coming from or going to countries abroad is liquefied and passes through the LNG terminals located along the Atlantic and Gulf Coasts.

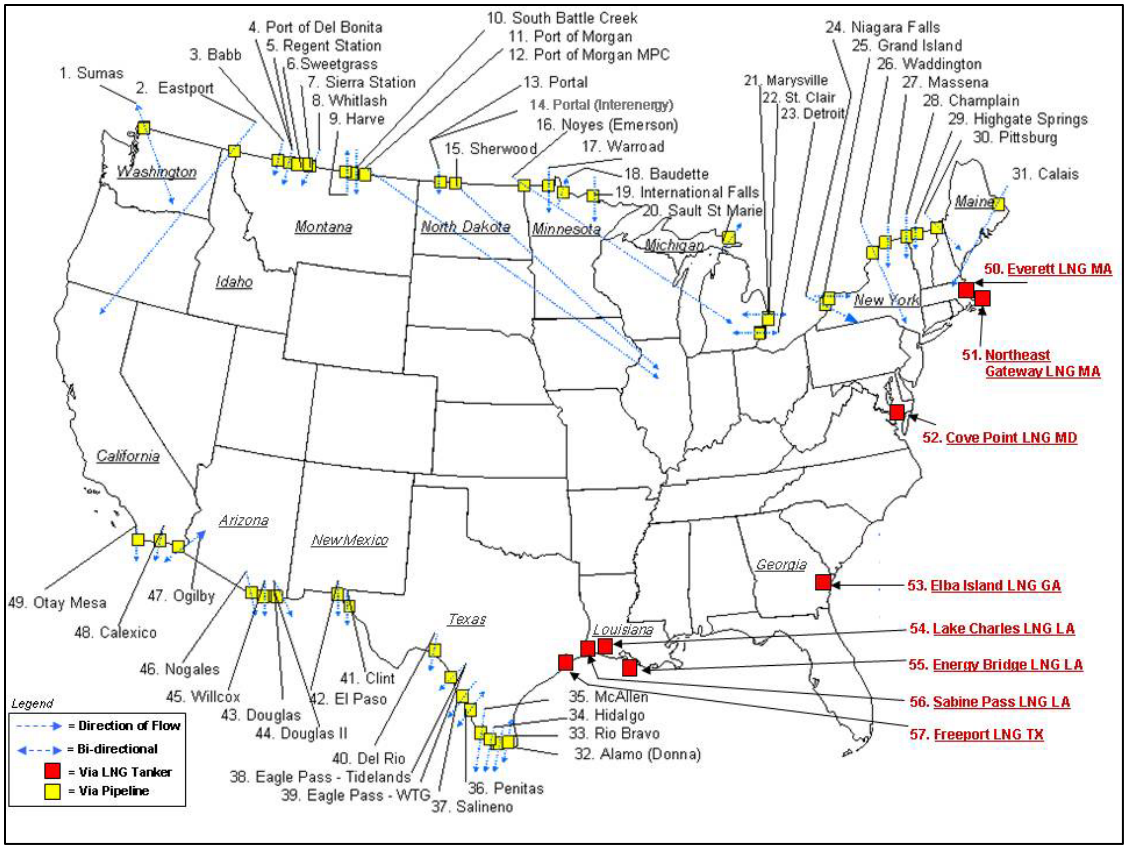

Figure 254. Points of entry and exit of natural gas by pipeline and ship.

Source: (Anderson 2013 Oct 10).

Similarly, aside from trades with Canada and Mexico via pipeline, the US almost exclusively imports and exports petroleum products by ship at marine terminals. These terminals are mostly positioned along the coast for the easiest access to large tankers but can also be found inland on major waterways. As seen in Figure 255, the Atlantic states contain approximately 33 petroleum ports, which can each handle a total volume of 200,000 or more short tons per year of petroleum products (EIA c2020).

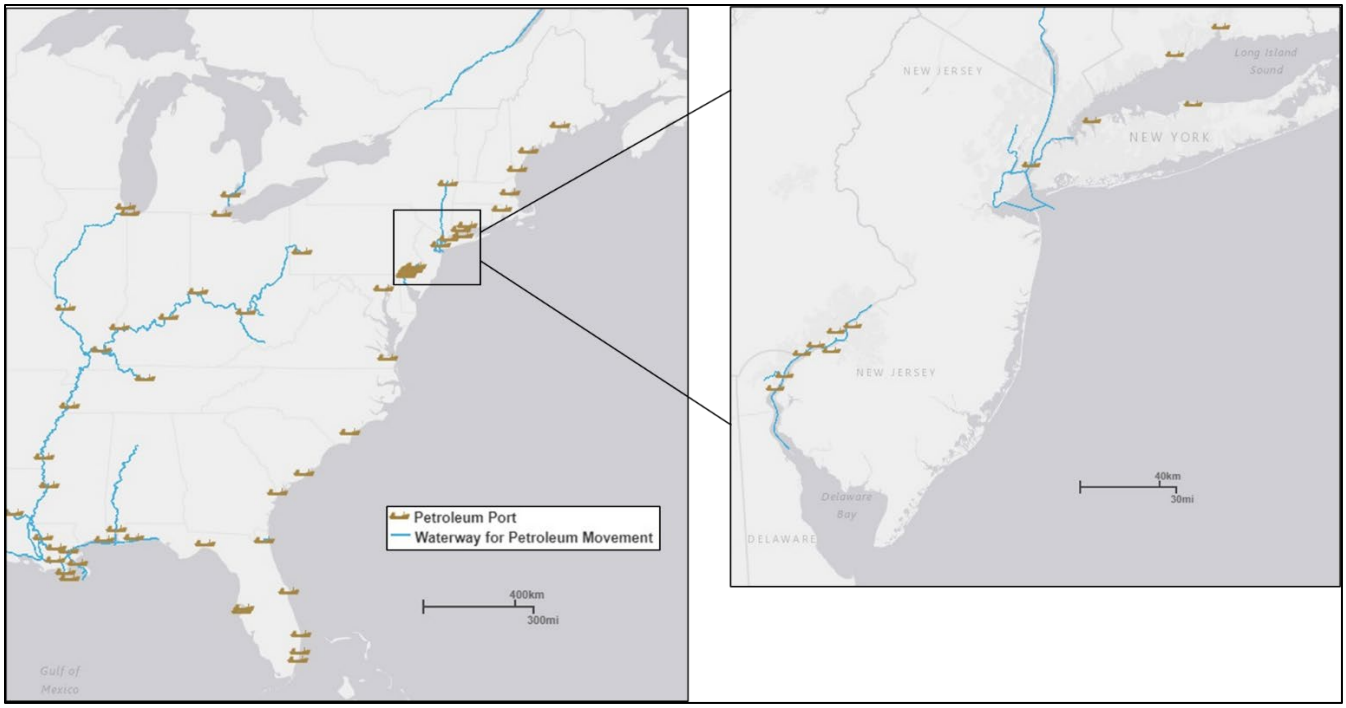

Figure 255. Petroleum ports in the Atlantic region.

Source: Energy Information Administration (EIA c2020).

Although mostly located on land along coastlines, marine terminals can also be found offshore. There are two LNG terminals located off the coast of Massachusetts, although they have rarely been used since their construction. In the case of oil and petroleum products, the Louisiana Offshore Oil Port ("LOOP") is currently the only existing deepwater port in the US and has an offshore marine terminal specifically designed for the import and export of crude oil.

13.4 Scope of Economic Contribution to Regional Economy

There is not enough sufficient data provided by the Bureau of Labor Statistics (BLS) or the Bureau of Economic Analysis (BEA) for the specific transportation of oil and gas by railroad and truck to analyze these modes' contributions to the Atlantic region's economy. While economic data is available for marine transportation, a more in-depth analysis can be found in the Ports chapter (Chapter 2) of this fact book. Likewise, there is not enough employment data available regarding all oil and gas terminals in the US, but a brief economic analysis of LNG terminals can be found in the Liquefied Natural Gas chapter (Chapter 8) of this fact book. As such, this section will focus primarily on economic activity related to pipelines and petroleum bulk terminals.

13.4.1 Pipelines

Multiple NAICS codes encompass oil and gas pipeline transportation as well as services related to the construction of these pipelines:

- 237120: Oil and gas pipeline and related structures construction;
- 486110: Pipeline transportation of crude oil;
- 486210 Pipeline transportation of natural gas;
- 486910: Pipeline transportation of refined petroleum products; and

- 424710: Petroleum bulk stations and terminals.

For purposes of this section, the data provided by BLS under these sub-level NAICS codes have been combined to present analyses based on all oil and gas pipeline related activity. Additionally, the labor data provided for the total US in these analyses includes both private and publicly owned businesses. The BEA collects state GDP information based on pipeline transportation but does not provide data for the sub-levels like that provided in the labor data from the BLS.

Table 57 compares each Atlantic state's pipeline transportation GDP to its own state-level GDP to determine the importance of pipeline transportation activities to each state's economy and the entire region. The Atlantic region accounts for over 15 percent of all US pipeline transportation economic activity in terms of GDP. Within the Atlantic region, Pennsylvania's pipeline transportation activities are by far the largest, accounting for 75 percent of total regional economic activity. The next states with the largest pipeline transportation activity, as measured by GDP in 2017, are Georgia, Connecticut, and New York, which each comprise less than 6 percent of the regional pipeline transportation GDP.

Table 57. Regional and national GDP contributions, pipeline transportation sector, 2017

State	Pipeline Transportation GDP (Millions in Current $)	Total GDP (Millions in Current $)	Pipeline Transportation GDP as a Percent of Total State GDP (%)	Pipeline Transportation GDP as a Percent of Total US Pipeline Transportation GDP (%)
CT	327	268,311	0.12	0.8
DC	3	134,043	0.00	0.0
DE	3	70,775	0.00	0.0
FL	103	985,665	0.01	0.3
GA	350	566,474	0.06	0.9
MA	56	540,786	0.01	0.1
MD	33	394,259	0.01	0.1
ME	28	62,040	0.04	0.1
NC	87	538,402	0.02	0.2
NH	2	80,900	0.00	0.0
NJ	171	595,325	0.03	0.4
NY	224	1,604,134	0.01	0.5
PA	4,737	744,290	0.64	11.6
RI	6	58,506	0.01	0.0
SC	22	223,111	0.01	0.1
VA	154	509,373	0.03	0.4
Total Region	**6,304**	**7,376,392**	**0.09**	**15.4**
Total US	**40,976**	**19,519,424**	**0.21**	**100.0**

Source: US Bureau of Economic Analysis (BEA c2020).

Figure 256 compares the trends in pipeline transportation GDP since 1997 for the Atlantic region and the US The figure shows a dramatic increase in pipeline transportation-related economic activity in the Atlantic region after the 2008-2009 recession. Most of this rapid increase is driven by pipeline transportation activities in Pennsylvania that are attributable to the Marcellus and Utica shale plays located around Pennsylvania .

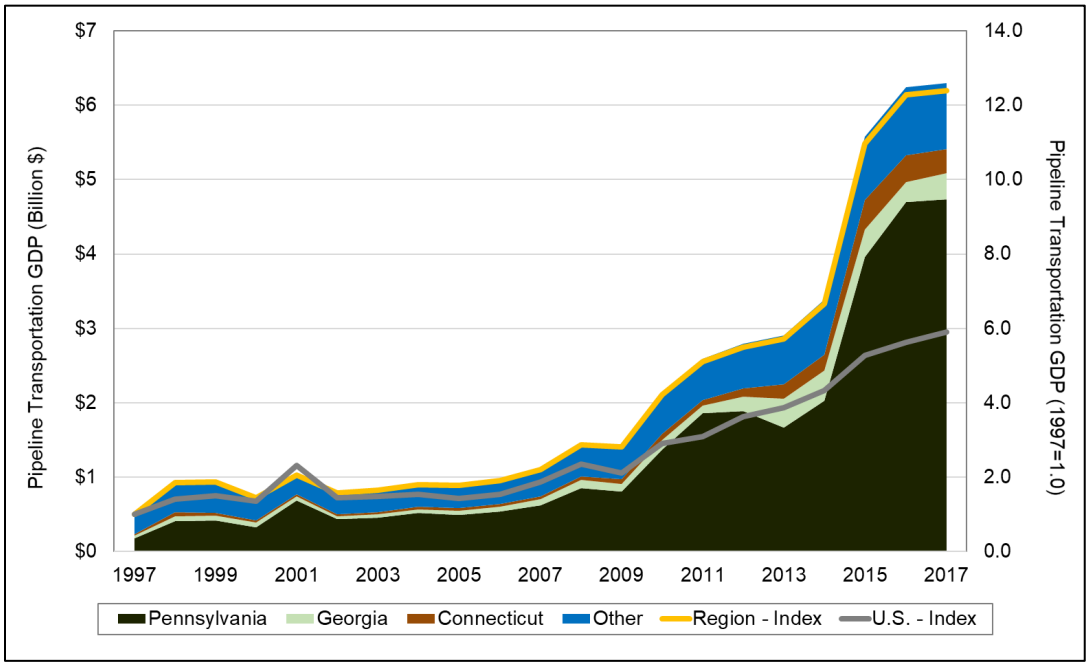

Figure 256. Trends in Atlantic region pipeline transportation GDP, 1997–2017.

Source: US Bureau of Economic Analysis (BEA c2020).

Regional pipeline transportation and construction-related employment trends are similar to the GDP trends discussed above. As shown in Table 58, Pennsylvania has the largest share of pipeline employment in the region and accounts for nearly 6 percent of all pipeline-related employment in the US The entire Atlantic region accounts for almost 15 percent of all pipeline sector employment in the U.S (BEA c2020).

Table 58. Regional and national employment contribution, pipeline sector, 2018

State	Number of Pipeline Jobs (2018)	Total State Jobs (2018)	Pipeline Employment as a Percent of Total State Employment (%)	Pipeline Employment as a Percent of Total US Pipeline Employment (%)
CT	576	1,449,072	0.04	0.23
DC	0	534,661	0.00	0.00
DE	0	384,332	0.00	0.00
FL	2,428	7,635,037	0.03	0.98
GA	1,896	3,777,824	0.05	0.77
MA	835	3,156,298	0.03	0.34
MD	1,048	2,188,298	0.05	0.42
ME	314	518,990	0.06	0.13
NC	3,319	3,710,090	0.09	1.34
NH	287	574,083	0.05	0.12
NJ	2,440	3,472,611	0.07	0.98
NY	4,107	8,017,398	0.05	1.66
PA	13,990	5,193,979	0.27	5.65
RI	191	421,767	0.05	0.08
SC	1,093	1,743,243	0.06	0.44
VA	4,533	3,188,362	0.14	1.83
Total Region	**37,057**	**45,966,045**	**0.08**	**14.96**
Total US	**247,718**	**124,551,838**	**0.20**	**100.00**

Source: US Bureau of Economic Analysis (BEA c2020).

At the aggregate level, pipeline employment in the US has consistently increased over the past ten years. Figure 257 illustrates these trends in regional and national sector employment. Since 2009, national sector employment has increased by 44 percent, while regional sector employment has increased by over 57 percent. Pennsylvania alone experienced a 197 percent increase in pipeline employment over the same period (BEA c2020).

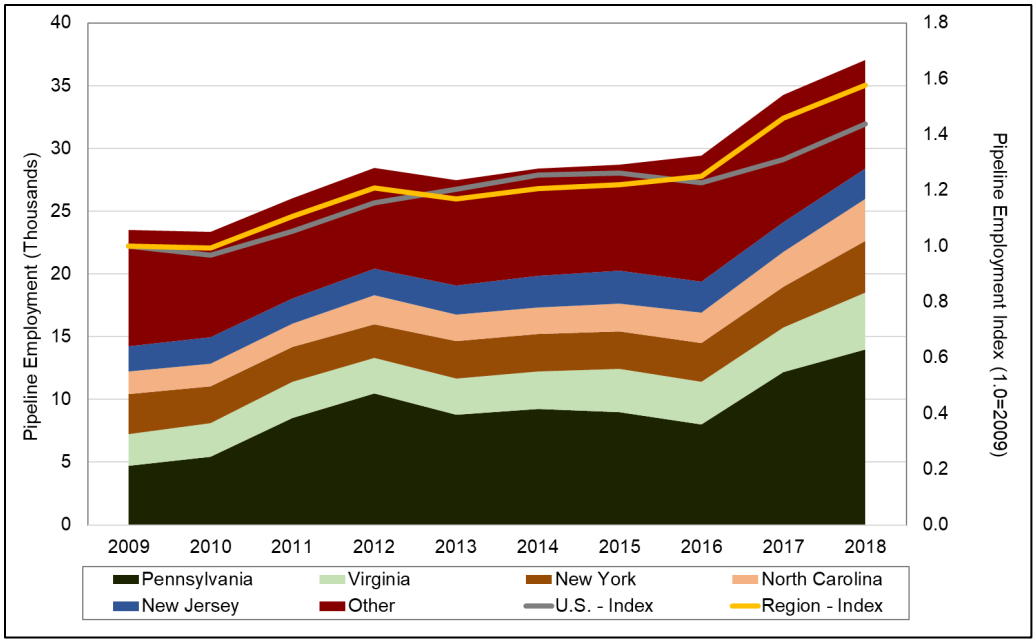

Figure 257. Trends in Atlantic region pipeline employment, 2009–2018.

Source: US Bureau of Labor Statistics (BLS 2020).

The growth in pipeline wages follows the same pattern as employment. As seen in Table 59, the Atlantic region accounts for 14.5 percent of pipeline industry wages in the US Within the region, Pennsylvania, New York, and Virginia comprise the three highest shares of total wages (BLS 2020).

Table 59. Regional and national wage contribution, pipeline sector, 2018

State	Pipeline Wages (Millions in 2018 $)	Total State Wages (Millions in 2018 $)	Pipeline Wages as a Percent of Total State Wages (%)	Pipeline Wages as a Percent of Total US Pipeline Wages (%)
CT	51,208	98,976,443	0.05	0.22
DC	0	47,148,826	0.00	0.00
DE	0	21,785,214	0.00	0.00
FL	199,754	377,741,168	0.05	0.86
GA	135,577	204,738,291	0.07	0.58
MA	64,999	231,687,162	0.03	0.28
MD	96,973	128,523,234	0.08	0.42
ME	20,286	23,322,212	0.09	0.09
NC	215,653	188,651,372	0.11	0.92
NH	21,408	33,028,901	0.06	0.09
NJ	247,760	226,946,160	0.11	1.06
NY	455,991	589,087,033	0.08	1.96
PA	1,427,749	287,198,234	0.50	6.12
RI	16,982	21,809,170	0.08	0.07
SC	67,147	76,779,000	0.09	0.29
VA	370,450	184,434,708	0.20	1.59
Total Region	**3,391,937**	**2,741,857,128**	**0.12**	**14.55**
Total US	**23,315,894**	**7,124,159,437**	**0.33**	**100.00**

Source: US Bureau of Economic Analysis (BEA c2020).

Over the past decade, pipeline wages doubled across the Atlantic region and increased by 80 percent across the US These sector wage gains in the Atlantic region are mainly driven by Pennsylvania, whose 2018 wage levels were over 4 times greater (349 percent more) than the state's 2009 wages. These trends can be seen in Figure 257 (BLS 2020).

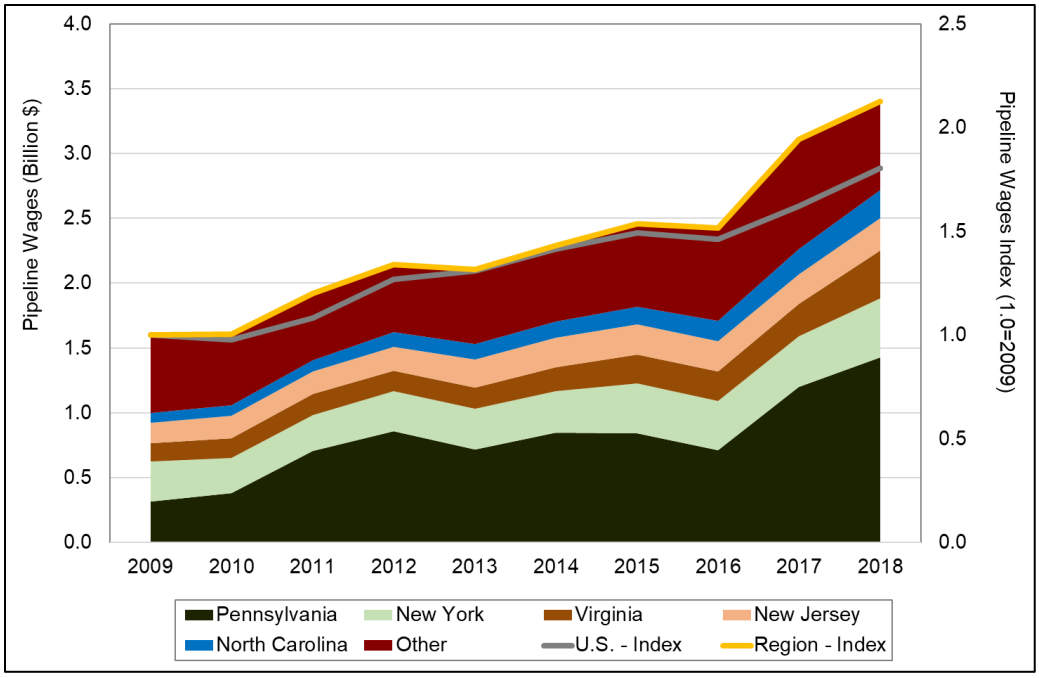

Figure 258. Trends in Atlantic region pipeline wages, 2009–2018.

Source: US Bureau of Labor Statistics (BLS 2020).

Average annual pay within the regional sector is below that of the US pipeline industry yet above the US economy as a whole (Table 60). In all Atlantic states, the average annual industry wage is lower than the US industry average, which is $123,486. The highest average state annual wage (for private sector) is in New York at $108,350, and the lowest is in South Carolina with $59,822.

Table 60. Regional and national average annual wage contribution, pipeline sector, 2018

State	Average Annual Pay (Pipeline Transportation) ($)	Average Annual Pay (All Sectors) ($)	Pipeline Transportation Avg. Annual Pay as a Percent of Total State Avg. Annual Pay (%)	Pipeline Transportation Avg. Annual Pay as a Percent of Total US Pipeline Avg. Annual Pay (%)
CT	96,293	68,303	140.98	77.98
DC	0	88,184	0.00	0.00
DE	0	56,683	0.00	0.00
FL	94,226	49,475	190.45	76.30
GA	71,835	54,195	132.55	58.17
MA	77,775	73,405	105.95	62.98
MD	97,336	58,732	165.73	78.82
ME	62,917	44,938	140.01	50.95
NC	67,873	50,848	133.48	54.96
NH	72,365	57,533	125.78	58.60
NJ	97,430	65,353	149.08	78.90
NY	108,350	73,476	147.46	87.74
PA	105,946	55,294	191.60	85.80
RI	88,795	51,709	171.72	71.91
SC	59,822	44,044	135.82	48.44
VA	89,950	57,846	155.50	72.84
Total Region	**74,432**	**59,376**	**125.36**	**60.28**
Total US	**123,486**	**57,198**	**215.89**	**100.00**

Source: US Bureau of Economic Analysis (BEA c2020).

Although no states in the Atlantic region report average wages higher than the US pipeline industry baseline, most of them have seen an overall increase in average wages since 2009, especially Florida. Figure 259 shows the trends in average annual pay over the last ten years for the US and the Atlantic states with the largest wage shares. During this time, the pipeline sector has experienced moderate gains both regionally and nationally. Since 2009, average annual pay in the pipeline sector increased by 13 percent in the US and by 17 percent in the Atlantic region (BLS 2020).

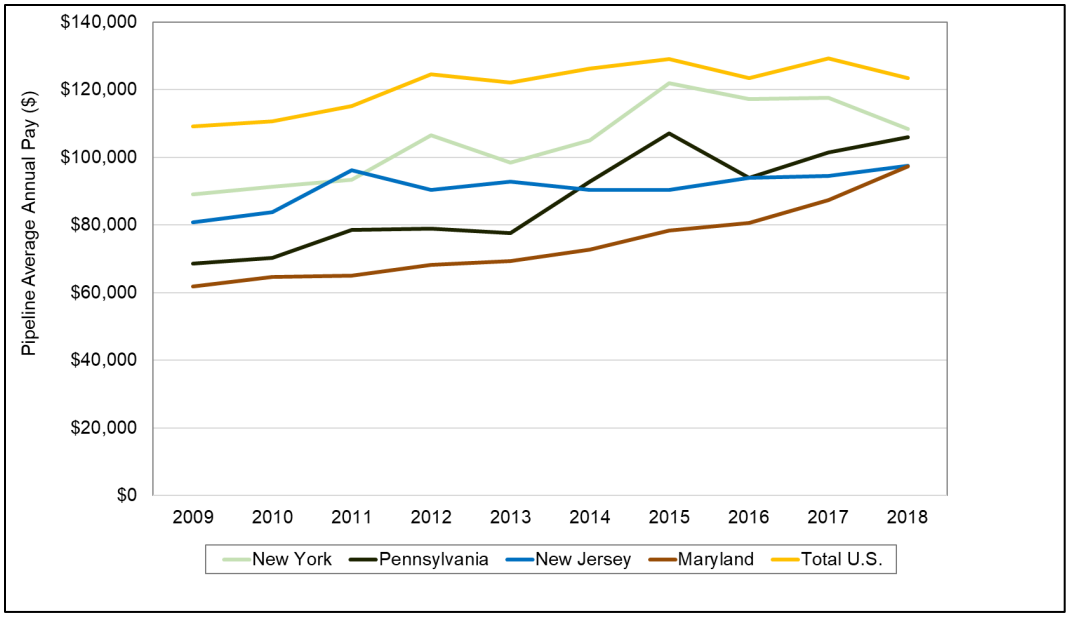

Figure 259. Trends in Atlantic region pipeline average annual wages, 2009–2018.

Note: Pennsylvania's steep increase after 2013 is caused by a lack of reported data for NAICS code "486910 – Pipeline transportation of refined petroleum products" before 2014.

Source: US Bureau of Labor Statistics (BLS 2020).

13.4.2 Rail and/or Train

There are no specific NAICS codes related to the transportation of oil and gas by railroad. NAICS code 482111 covers line-haul railroads, which is usually the type of rail used to transport oil over long distances in addition to passengers and other cargos. Additionally, NAICS code 488210 comprises support activities for rail transportation such as servicing, repairing, maintaining, loading, and unloading rail cars as well as operating independent terminals. However, there is not enough data provided for the Atlantic states to include in this analysis.

Although there is a scarce amount of Atlantic-specific economic data for railroads available, the Association of American Railroads (AAR) releases similar data regarding the US as a whole. According to the AAR, the 614 freight railroads in the US employed 167,257 workers in 2017, and the average wage and benefit amount per freight rail employee was $121,620 for that year. Additionally, major US railroads supported approximately 1.1 million jobs nationwide in 2017, or around eight jobs for every one railroad job. The private spending by these major railroads contributed nearly $219.5 billion in annual economic activity, $71 billion in wages, and around $26 billion in tax revenues for that year (AAR 2019 Jul).

13.5 Current Trends

13.5.1 Regulatory Changes

The transportation of oil and gas products is a delicate process that can become dangerous and harmful if not done carefully. Various accidents caused by pipeline breaks, rail and truck crashes, and vessel spills have cost hundreds of lives, millions of dollars, and unquantifiable negative impacts on the environment. In response to such accidents, a multitude of new laws have been instated in recent years in an attempt to mitigate future disasters.

One such instance was the implementation of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 ("2011 Pipeline Safety Act") by Congress in response to the San Bruno, California natural gas pipeline explosion in 2010. The pipeline's operator reportedly had an inadequate integrity management program that failed to detect a defective pipeline segment, which resulted in a natural gas leak that exploded and caused a fire, killing eight people and destroying nearly 40 homes (LA Times 2016 Aug 9). As a result, the 2011 Pipeline Safety Act requires gas pipelines to perform periodic integrity management reassessments every seven years, consider seismicity in evaluating potential threats, and report to PHMSA instances where a pipeline's maximum allowable operating pressure (MAOP) is exceeded (Weiler 2019 Oct 4).

More recently, in 2019, following a few other major pipeline accidents, PHMSA issued three new rules to promote pipeline safety (Weiler 2019 Oct 4):

1) The *MAOP Reconfirmation Rule* requires operators of natural gas pipelines to reconfirm the MAOP of their pipeline segments, collect records to substantiate the MAOP, perform integrity assessments on certain pipelines outside of high consequence areas (HCAs), and use in-line inspection facilities only when pressure is safely relieved in a barrel to prevent operator injury.
2) The *Hazardous Liquid Pipeline Safety Rule* sets forth several new regulations for pipelines transporting crude oil, petroleum products, and other fuels:
    a. Extends reporting requirements to certain hazardous liquid gravity and rural gathering lines;
    b. Requires inspection of all pipelines, onshore and offshore, affected by extreme weather and natural disasters;
    c. Requires integrity assessments at least once every ten years of "piggable" [15] onshore pipelines outside HCAs;
    d. Extends the use of leak detection systems beyond HCAs to all regulated, non-gathering pipelines; and
    e. Requires all pipelines in or affecting HCAs to be piggable within 20 years.
3) The *Enhanced Emergency Order Procedures Rule* increases PHMSA's existing authority under the PIPES Act of 2016 to protect life, property, and the environment. The PIPES Act allows PHMSA to issue a corrective action order to the owner or operator of a hazardous pipeline facility and a notice of proposed safety order after finding that a pipeline poses an integrity risk. The Enhanced Emergency Order Procedures Rule now also allows PHMSA to address an imminent hazard by issuing an emergency order across a group of gas or hazardous liquid pipeline owners or operators without a notice or hearing.

Several high-profile rail incidents involving crude oil spills within the last few years have also prompted increased regulatory oversight on railroad transportation. One such incident was a 2013 derailment that killed 47 people in Quebec, Canada and released 1.6 million gallons of crude oil into the area (Shepardson 2019 Feb 14). To mitigate the effects of disasters such as this in the US, PHMSA and the FRA issued a rule in 2019 that requires railroads to have Comprehensive Oil Spill Response Plans in place for route segments traveled by High Flammable Trains (HHFTs) that are transporting petroleum oil in a block of 20 or more loaded tank cars or those that have a total of 35 loaded petroleum oil tank cars spread throughout the train. The rule also requires railroads to establish geographic response zones along various rail routes and ensure that personnel and equipment are prepared to respond within 12 hours in the event of an accident (PHMSA 2019 Feb 14).

[15] "Piggable" pipelines are those that are able to accommodate a maintenance tool, known as a "pig," that is inserted into the pipeline and pushes out debris build-up so that oil or natural gas can flow freely through (Rigzone c2020).

While regulation on oil transportation by rail are tightening, restrictions on rail LNG transport may significantly loosen in the near future. PHMSA proposed a rule in late 2019 that would allow railroads to transport LNG in bulk without receiving special permits. In addition to lifting the transport restrictions, PHMSA is considering several methods for reducing the risk associated with transporting LNG by rail but has not yet proposed any definitive rule changes addressing these operational issues (PHMSA 2019e). It is too early to tell if the proposed rule will be approved and finalized, but if so, it could greatly affect the rail, natural gas, and overall intermodal transportation industries in the US

One of the most significant regulatory changes to affect the US energy sector in the last ten years was Congress' decision to lift a 40-year ban on exporting domestically produced oil. Before the final order in December 2015 to lift the ban, US crude oil exports almost exclusively went to Canada, which had been exempt from the ban. Since then, the US oil export industry has grown to as many as 31 destinations per month (EIA 2019b Oct 22). Congress' ruling was a direct result of the 2000s oil boom, which had increased US crude oil production by 82 percent between 2008 and 2015 (EIA 2020a Jun 30). The glut of oil being supplied was more than enough to meet domestic demand and created the opportunity for companies to export excess oil for the first time since 1975. This, in turn, has led to major overhauls of US terminal infrastructure in recent years.

13.5.2 Trends

Pipelines

During World War II, the fifty US states were divided into five districts to organize the rationing of gasoline and other petroleum products. Although no longer needed for rationing purposes today, these five regions, known as Petroleum Administration for Defense Districts (PADDs), are now used to analyze patterns of crude oil and petroleum product movements throughout the US (EIA 2012 Feb 7). As seen in Figure 260, the Atlantic Coast states are included in PADD 1.

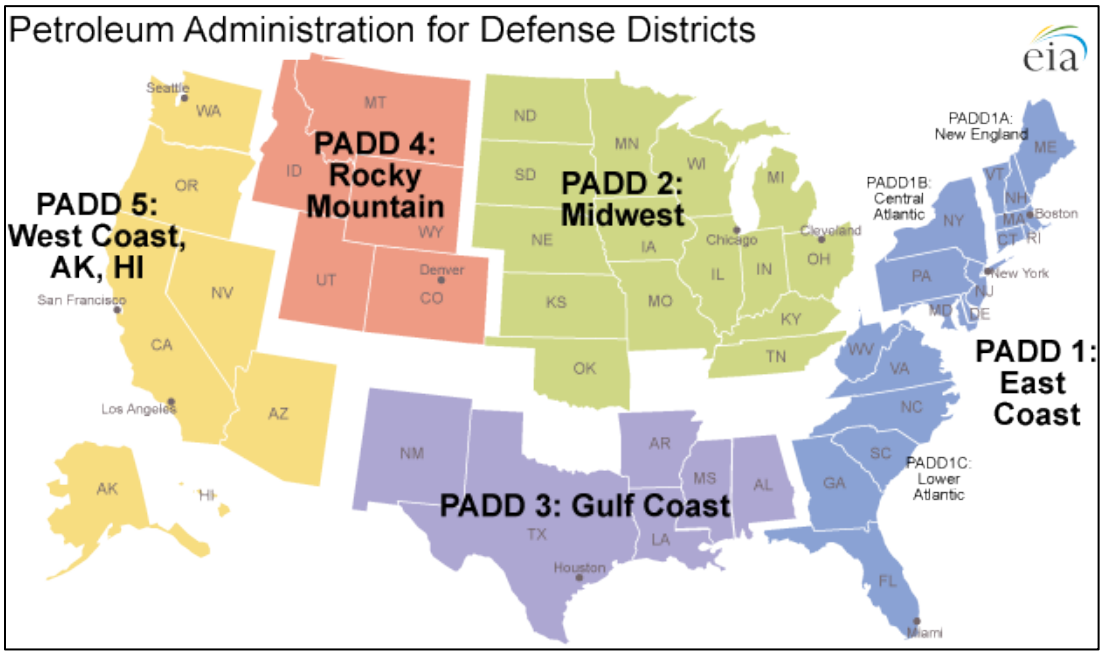

Figure 260. Petroleum Administration for Defense Districts regions in the US.

Source: Energy Information Administration (EIA 2012 Feb 7).

Table 61 shows the amount of crude oil moved via pipeline between PADD regions in 2019. Compared to the other PADD regions, PADD 1 has very little inter-region pipeline activity, whereas PADD 5's is non-existent. Although a small amount, all the crude oil pipeline imports received by PADD 1 from other PADD regions, about 4.4 million barrels, came from the Midwest and Gulf Coast. The even smaller amount of crude oil transported via pipeline from PADD 1 likewise went to those two regions of the country.

Table 61. Crude oil inter-PADD pipeline movements, thousands of barrels, 2019

PADD	From PADD 1	From PADD 2	From PADD 3	From PADD 4	From PADD 5	Total Receipts
To PADD 1	-	2,799	1,600	0	0	4,399
To PADD 2	2,365	-	338,428	303,307	0	644,100
To PADD 3	522	750,908	-	3,798	0	755,228
To PADD 4	0	80,405	0	-	0	80,405
To PADD 5	0	0	0	0	-	0
Total Shipments	**2,887**	**834,112**	**340,028**	**307,105**	**0**	**1,484,132**

Source: Energy Information Administration (EIA 2020a May 29).

The same travel patterns can be seen with petroleum products, though on a larger scale (Table 62). In 2019, PADD 1 led the US in petroleum product receipts by pipeline, receiving over 1 billion barrels of petroleum products from the Midwest and Gulf Coast. These receipts alone made up almost half of the total amount of inter-PADD petroleum receipts in the US via pipeline. However, the amount of petroleum products transported *from* PADD 1 were the lowest in the country, excluding PADD 5 (EIA 2020a May 29).

Table 62. Petroleum products inter-PADD pipeline movements, thousands of barrels, 2019

PADD	From PADD 1	From PADD 2	From PADD 3	From PADD 4	From PADD 5	Total Receipts
To PADD 1	-	49,400	991,272	0	0	1,040,672
To PADD 2	194,637	-	214,960	150,574	0	560,171
To PADD 3	0	343,018	-	41,432	0	384,450
To PADD 4	0	93,423	0	-	0	93,423
To PADD 5	0	0	52,807	22,424	-	75,231
Total Shipments	**194,637**	**485,841**	**1,259,039**	**214,430**	**0**	**2,153,947**

Source: Energy Information Administration (EIA 2020a May 29).

Since 2010, the Atlantic states in PADD 1 have shipped than 39 million and received nearly 59 million barrels of crude oil from the Midwest and Gulf Coast, respectively. However, shipments of these products by pipeline have greatly decreased since the early 2010s. As shown in Figure 261, PADD 1 received 4.4 million barrels of crude oil from these regions in 2019, which is almost half of its total amount received in 2010 (EIA 2020a May 29).

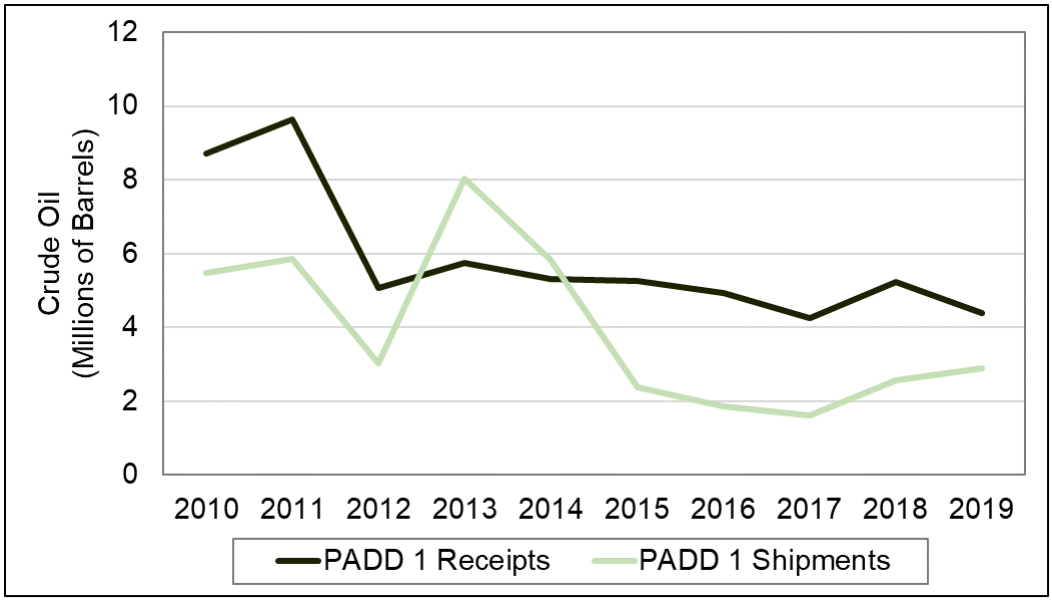

Figure 261. Total crude oil receipts and shipments to and from PADD 1, 2010–2019.

Source: Energy Information Administration (EIA 2020a May 29).

While movement of crude oil to and from the Atlantic region by pipeline has decreased since 2010, the transport of petroleum products has increased. Figure 262 shows that the Atlantic states received over 1 billion barrels of petroleum products from PADD 2 and PADD 3 in 2019, a 15 percent increase from 2010. Additionally, total petroleum product shipments from PADD 1 have skyrocketed from its low of 108 million barrels in 2012 to over 194 million barrels in 2019, an increase of 80 percent (EIA 2020a May 29).

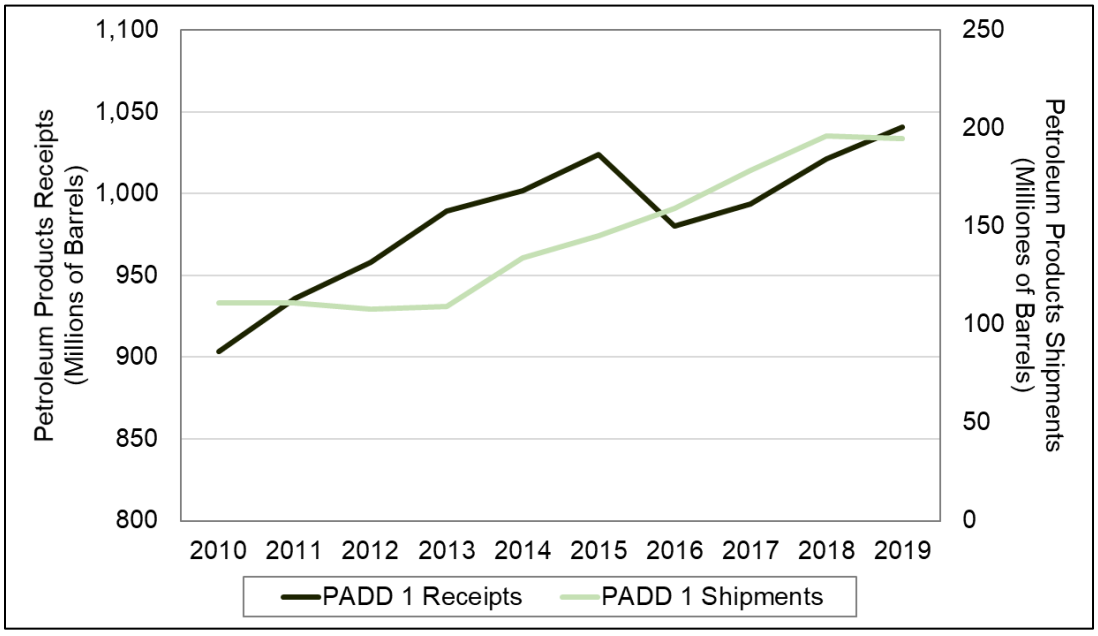

Figure 262. Total petroleum product receipts and shipments to and from PADD 1, 2010–2019.

Source: Energy Information Administration (EIA 2020a May 29).

The Atlantic region has had a few pipeline projects completed either partially or entirely within its borders since 2010 including two new pipelines, two expansion projects, two conversion projects, and a reversal project. All the pipelines were constructed to transport HGLs, such as ethane and propane, aside from the two projects completed in 2019 and 2020 that were made to transport petroleum products. The 2020 project, for example, was an expansion project that increased Kinder Morgan's Plantation Pipeline capacity by 21 Mbbls/d from origin points in Baton Rouge, Louisiana and Collins, Mississippi to its destination in the Roanoke, Virginia area (EIA 2020 Jun 4).

When determining the flow of natural gas between regions, the EIA splits the US into areas slightly different than the PADDs used for crude oil and petroleum. As shown in Figure 263, the Atlantic states are split into two regions, Northeast and Southeast, with the Northeast region also containing Ohio and West Virginia. Additionally, the figure shows the amount of natural gas inflow and outflow of each region in 2019.

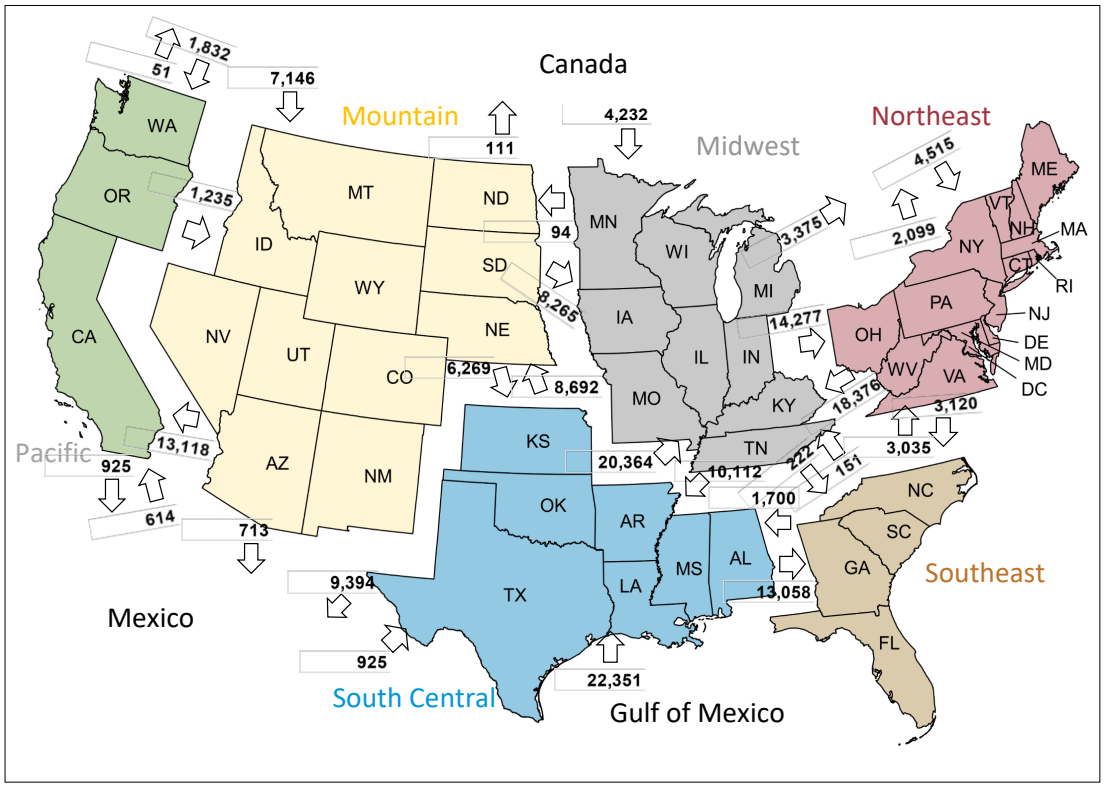

Figure 263. Natural gas flow (MMcf/d) via pipeline between US regions, 2019.

Source: Energy Information Administration (EIA 2020 Jan 22).

The southeast Atlantic states receive a majority of their natural gas pipeline supply (80 percent) from the Gulf Coast, although a large portion (19 percent) also comes from the northern Atlantic states. Conversely, the northeastern Atlantic region's natural gas receipts are less lop-sided. Over 65 percent of the natural gas inflow into the area comes from the Midwest, and 21 percent is imported from Canada. Nearly 14 percent of the Northeast's natural gas comes from the southeastern US, although the gas is originally produced along the Gulf Coast and can only reach the Northeast through southeastern pipeline systems.

Figure 264 and Figure 265 show the trends of natural gas flows into and out of the Atlantic subregions via pipeline. The gas inflows have steadily and discreetly increased over the last decade as the Atlantic states' demand growth has remained relatively constant. The regions' natural gas outflow, however, saw a major increase in 2015 to the Midwest region, likely due to increased production at the Marcellus and Utica shale plays located around Pennsylvania. By 2019, the annual gas outflow from the Atlantic states had doubled the amount shipped in 2014.

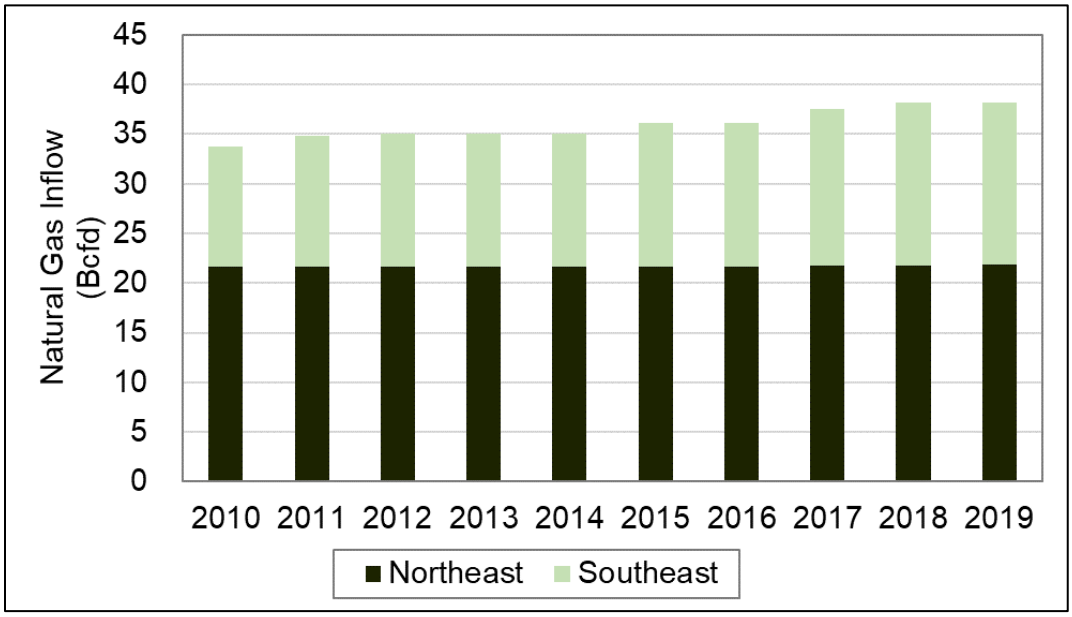

Figure 264. Atlantic region's natural gas inflow by pipeline, 2010–2019.

Source: Energy Information Administration (EIA 2020 Jan 22).

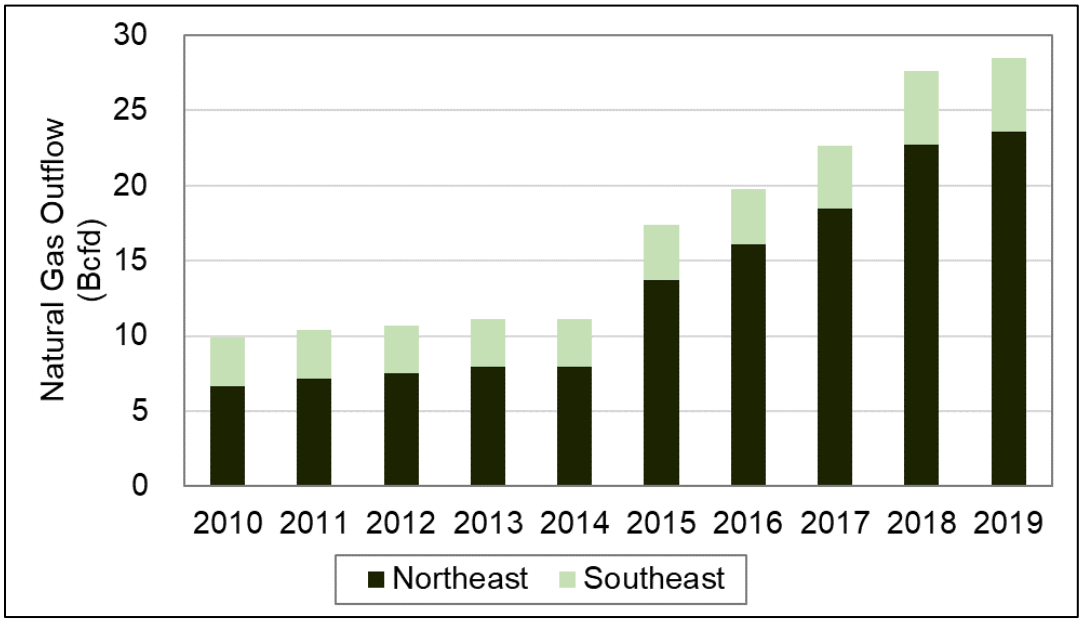

Figure 265. Atlantic region's natural gas outflow by pipeline, 2010–2019.

Source: Energy Information Administration (EIA 2020 Jan 22).

Since the shale boom in the early 2000s, there have been hundreds of major natural gas pipeline projects completed that have added billions of cubic feet to the US pipeline system's transport capacity. Figure 266 presents the amount of capacity added by natural gas projects completed partially or entirely within the Atlantic region since 1996.

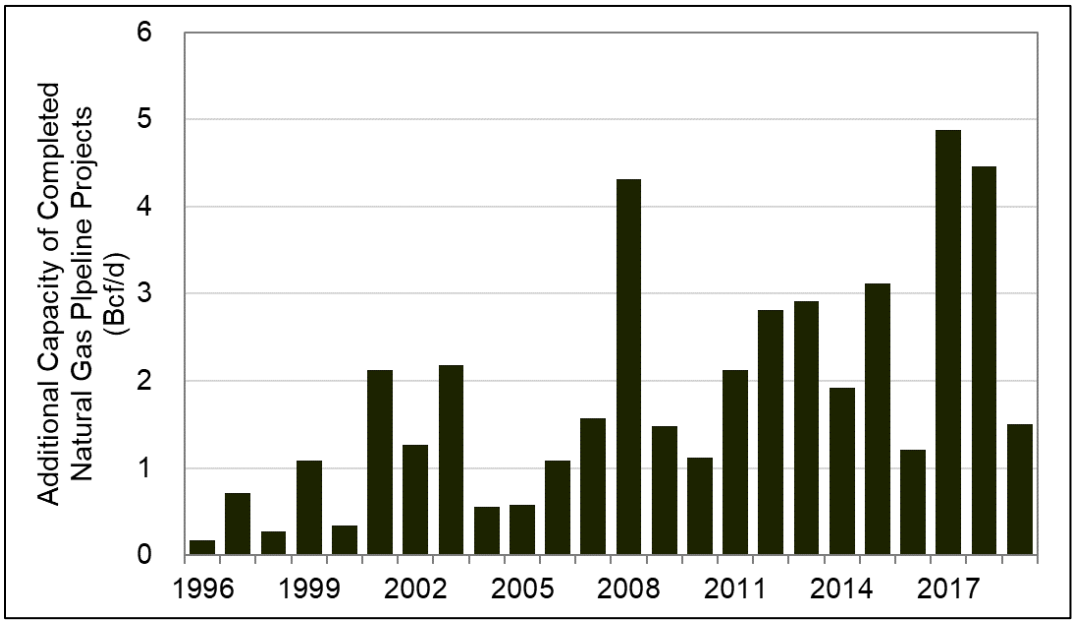

Figure 266. Added capacity of completed natural gas pipeline projects in the Atlantic region, 1996–2019.

Source: Energy Information Administration (EIA 2020 Mar 5).

The largest single year capacity increase occurred recently in 2017, when nearly 5 Bcf/d of capacity was added to the natural gas pipeline system. Over half of this capacity came from the Rover Pipeline Project that partially operates in Pennsylvania.

The Rover Pipeline spans 713 miles from Pennsylvania to Michigan and parts of Canada and is capable of transporting up to 3.25 Bcf/d, of which 1.75 Bcf/d came online in 2017 and 1.55 Bcf/d came online with the completion of the project's second phase in 2018. It was built to take advantage of the rapidly expanding production areas in the Marcellus and Utica shale basins by delivering natural gas from processing plants in Western Pennsylvania, West Virginia, and Ohio to markets across the US and into Canada via interconnecting pipeline systems (Energy Transfer c2020).

Rail and/or Train

Since 2010, crude oil transport by rail has grown into a large enough industry to be discussed alongside pipelines and barges as a means of energy intermodal transportation. The EIA did not even start recording crude oil movements by rail until 2010. Since then, railroads have become a primary alternative for oil and gas companies to move their products.

As seen in Figure 267, total US crude oil movements by rail spiked and reached an all-time high in 2014, increasing by roughly 29 percent from 2013 values (EIA 2020c Apr 30). This was due in large part to the domestic oil boom that resulted in a surplus of oil in the US market during that time period (EIA 2014 Aug 28). This excess of domestic oil created bottlenecks on pipelines due to insufficient pipeline capacity, and, as a result, rail transport increased significantly since it was considered the next best alternative to move oil. After peaking in 2014, the movement of crude oil by rail decreased from a high of 382 million barrels to about 140 million barrels in 2017. However, the amount of oil transported by rail has begun to increase again over the last few years and reached over 250 million barrels in 2019 (EIA 2020c Apr 30). This increase in transportation by rail is similar to that which occurred from 2010 to 2014, as it is again due to the limited availability of capacity on pipelines (EIA 2018 Apr 18).

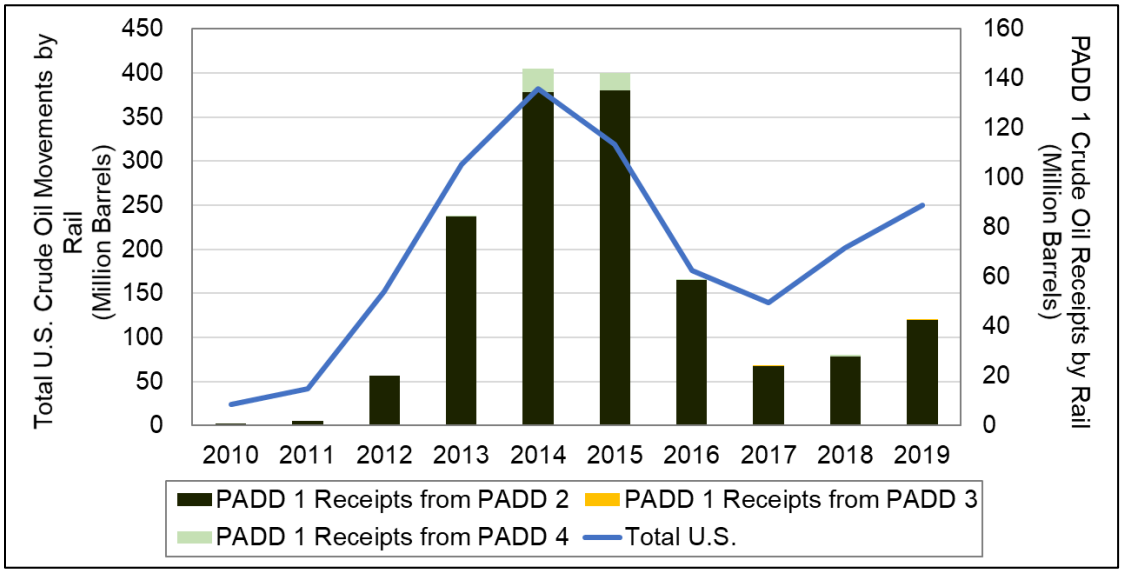

Figure 267. Total US crude oil movements by rail and PADD 1 crude oil receipts by rail, 2010–2019.

Note: Total US crude oil movements include intra-US movements, US exports to Canada, and US imports from Canada.

Source: Energy Information Administration (EIA 2020b May 29).

Although the Gulf Coast is responsible for a large amount of petroleum product shipments to the Atlantic region, it has a significantly smaller presence in the crude oil trade, especially via rail. The extensive pipeline and marine infrastructure already in place between the Gulf Coast and Atlantic states means that there is hardly ever a need for crude oil or natural gas to be shipped by rail between these two regions.

Instead, crude oil is mainly transported from the center of the US (PADD regions 2, 3, and 4) eastward and westward by rail. As seen in Figure 267, almost all crude oil rail shipments to the Atlantic states come from producing areas in the Midwest, although some traveled from as far as the Rockies when US rail shipments were at their peak and pipelines alone were insufficient to transport the large amounts of oil being produced. Most of the crude oil from the Midwest is shipped from the extremely productive Bakken shale play. The lack of major pipelines connecting the Atlantic and Midwest regions, along with the expansion of crude-by-rail infrastructure, has significantly boosted railroads' importance in energy transport to the Atlantic region (EIA 2014 Jun 10).

As such, rail is by far the most popular method by which crude oil is received on the East Coast. Figure 268 shows that of the 52.5 million barrels of crude oil shipped to PADD 1 in 2019, nearly 85 percent was transported by rail, while pipelines and marine modes comprised 8 and 7 percent, respectively.

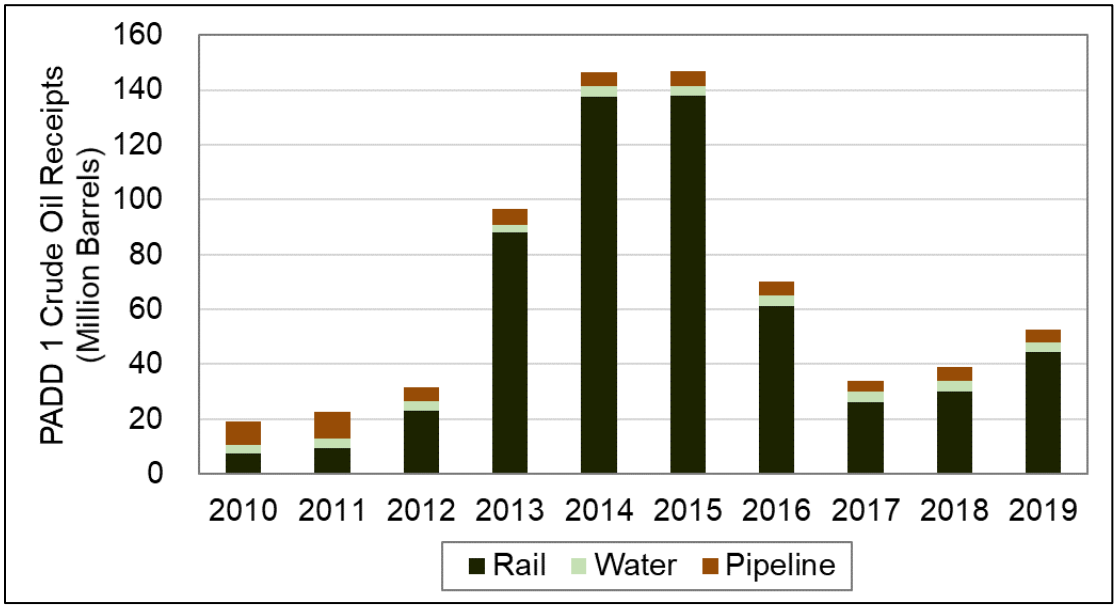

Figure 268. PADD 1 crude oil receipts by transportation mode, 2010–2019.

Source: Energy Information Administration (EIA 2020b Jun 30).

When dealing with crude oil, the Atlantic region strictly uses its railways for international trade and to import oil from other areas in the US There is no recorded rail movement of crude oil from PADD 1 to any other US region by the EIA (EIA 2020b May 29).

Even though rail is a popular alternative for oil and petroleum product transportation, coal is the most transported energy product by railroads in the US In fact, as seen in Figure 269, coal is the most transported commodity by rail overall, followed by intermodal shipping containers carrying various consumer products and nonmetallic minerals such as sand and gravel.

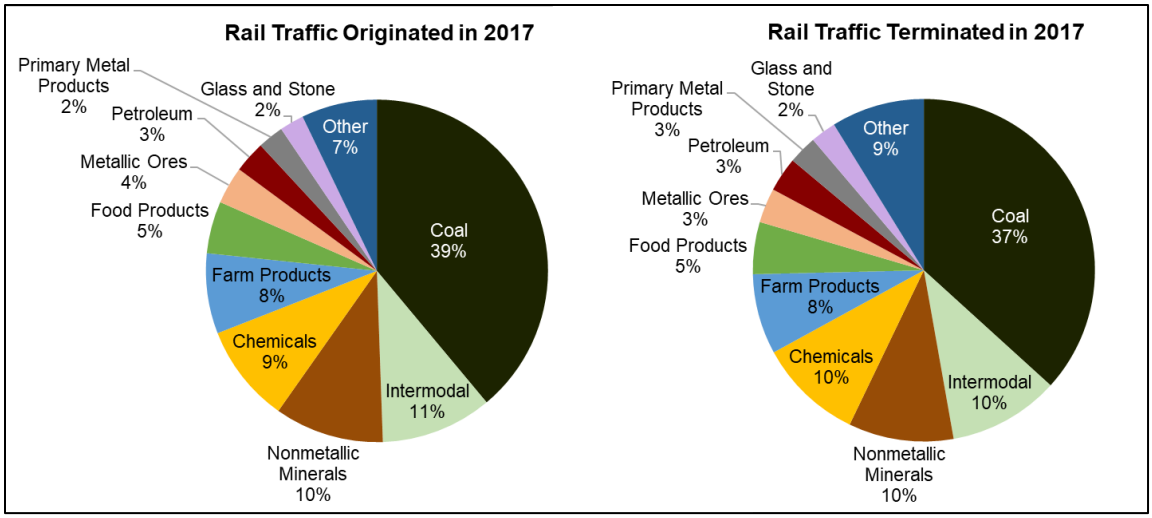

Figure 269. Rail traffic by commodity tonnage, 2017.

Source: Association of American Railroads (AAR 2019 Jul).

Figure 270 compares the average annual costs of transporting coal to Atlantic states and to other US states by rail since 2008. The data includes real average annual transportation costs for eight Atlantic states (Florida, Georgia, Maryland, New York, North Carolina, South Carolina, Virginia) that receive coal shipments by rail. As seen in the figure, the average cost to transport coal via railroad to such Atlantic states has been much higher than the average cost to move coal elsewhere in the U.S over the last decade. Florida and Georgia are two of the most expensive coal transport destinations by rail, having consistently ranked first or second in highest average costs compared to every other US state nearly every year since 2008. Most recently, in 2018, Georgia was the destination with the highest recorded average annual rail transportation cost at $31.39 per ton of coal (EIA 2020 Apr).

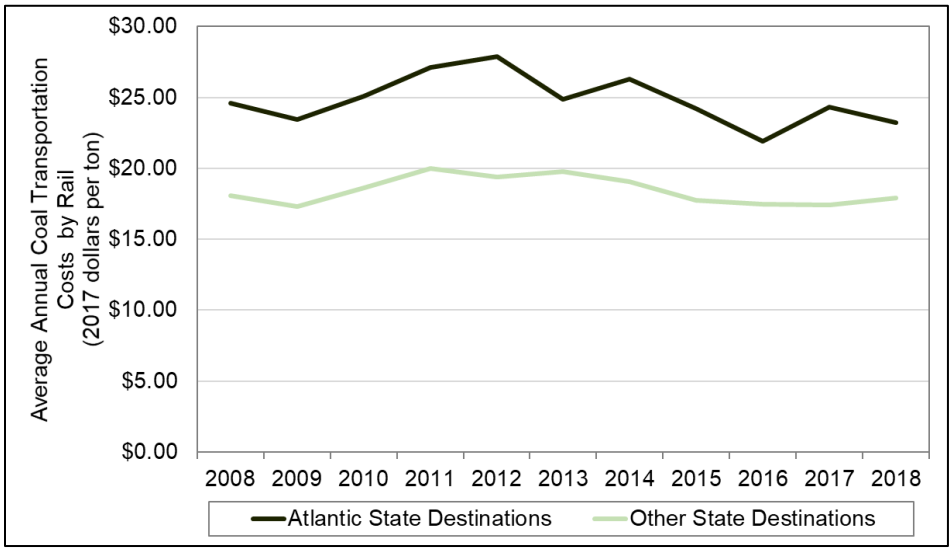

Figure 270. Real average annual coal transportation costs from state to state by railroad, 2008–2018.

Source: Energy Information Administration (EIA 2020 Apr).

Trucking

Although trucks are the least used mode of energy transportation among the main four, their use in the US has still increased, mainly due to higher levels of production and the increased need to deliver these energy products to consumers. As seen in Figure 271, the amount of crude petroleum moved by truck and water modes experienced the largest increase since 2012, transporting 89 percent and 104 percent more in 2018, respectively.

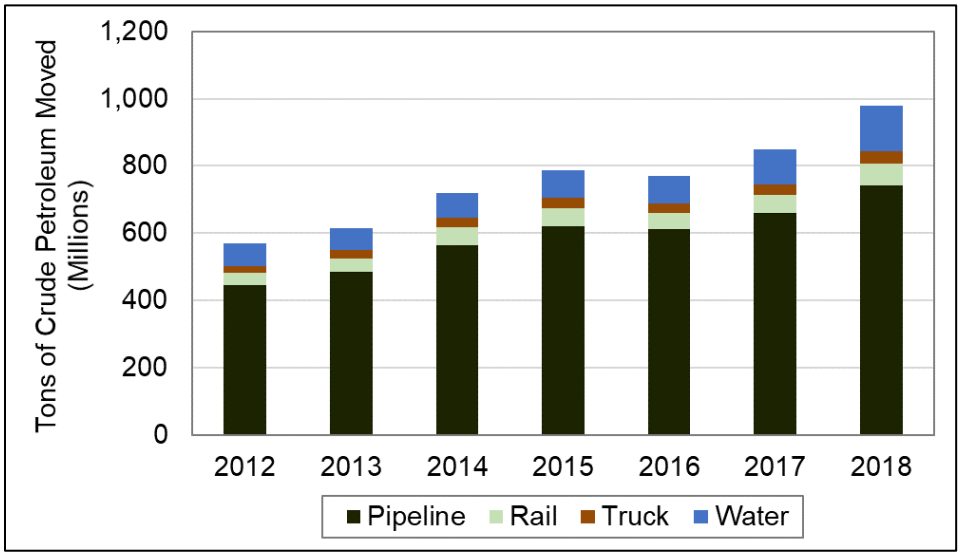

Figure 271. Tons of crude petroleum moved by mode in the US, 2012–2018.

Source: US Department of Transportation (US DOT 2019).

Despite this growth in truck transportation nationwide, the amount of crude oil transported by trucks to PADD 1 refineries has seen a steady decline in the past ten years (Figure 272). This is most likely due to several major refinery closures experienced along the East Coast since the early 2010s. For example, two refineries around Philadelphia that had accounted for roughly a quarter of the East Coast's refining capacity closed in 2011. Before that, a Virginian and a New Jersey refinery with capacities equaling approximately 211 Mbbls/d had shut down in 2010 (EIA 2012 May 11). More recently, in June 2019, the East Coast's largest producing refinery of gasoline, diesel, and other refined products shuttered in Philadelphia (Hurdle 2019 Dec 24). The steep decrease in total US receipts seen in the figure mirrors the drop in crude oil prices around 2015.

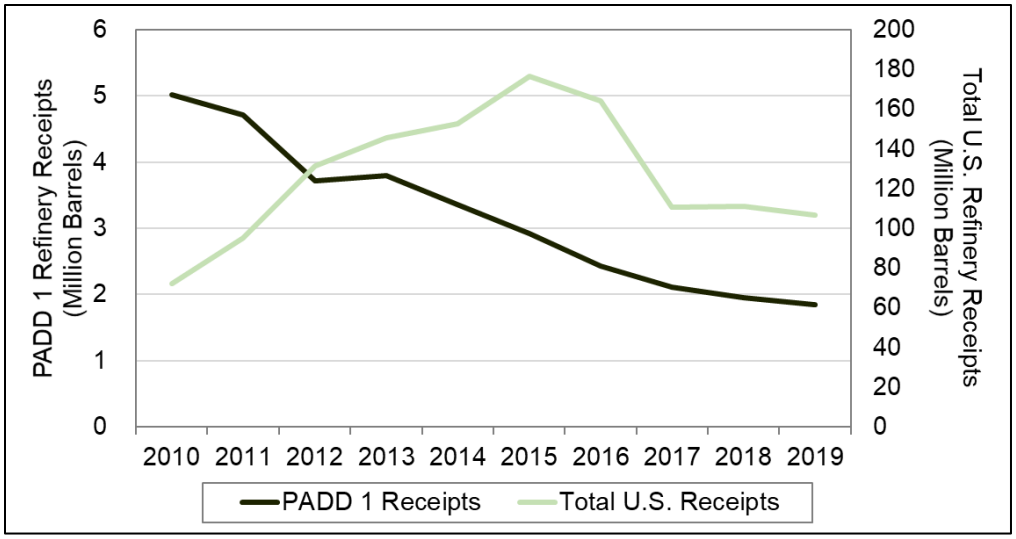

Figure 272. PADD 1 and total US crude oil refinery receipts by truck, 2010–2019.

Source: Energy Information Administration (EIA 2020a Jun 22).

Marine Ships and/or Barges

Little crude oil is moved between the Atlantic region and other US states by tankers or barges, as seen in Figure 268 earlier. However, after pipelines, marine modes are companies' most preferred method of transporting petroleum products to the East Coast. In 2019, the East Coast received over 287 million barrels of petroleum products from other parts of the US Figure 273 shows that most of these shipments come from the Gulf Coast and enter PADD 1 through the lower Atlantic states.

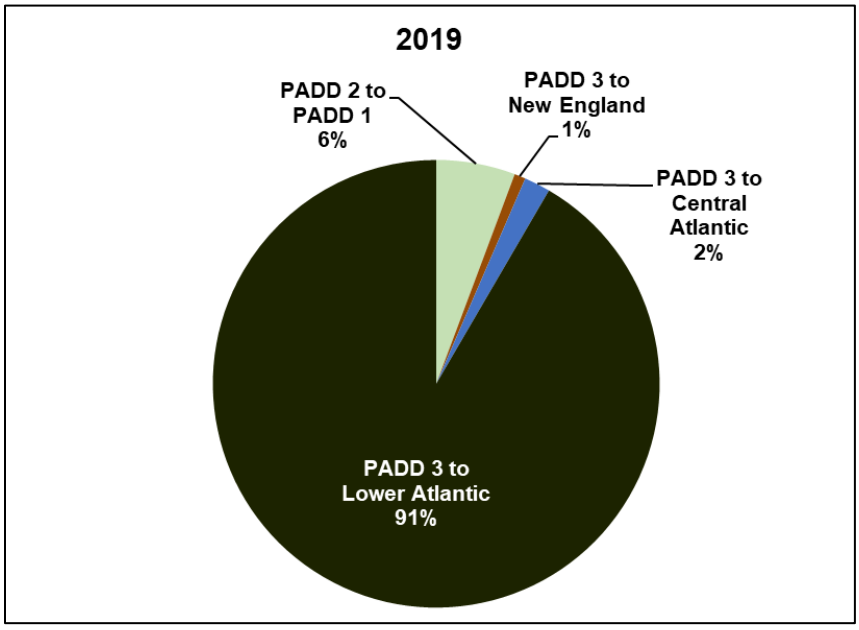

Figure 273. PADD 1 petroleum products received via ship from PADD 2 and PADD 3, 2019.

Source: Energy Information Administration (EIA 2020b Jun 30).

The Atlantic Coast's limited refinery capacity is only able to meet one-fifth of its regional demand for petroleum products like gasoline, diesel, and jet fuel (also known as transportation fuels). With over half of the US's total refining capacity, the Gulf Coast is the main supplier of these products to the region, primarily through pipelines or by marine shipments (Figure 274) (EIA 2016b).

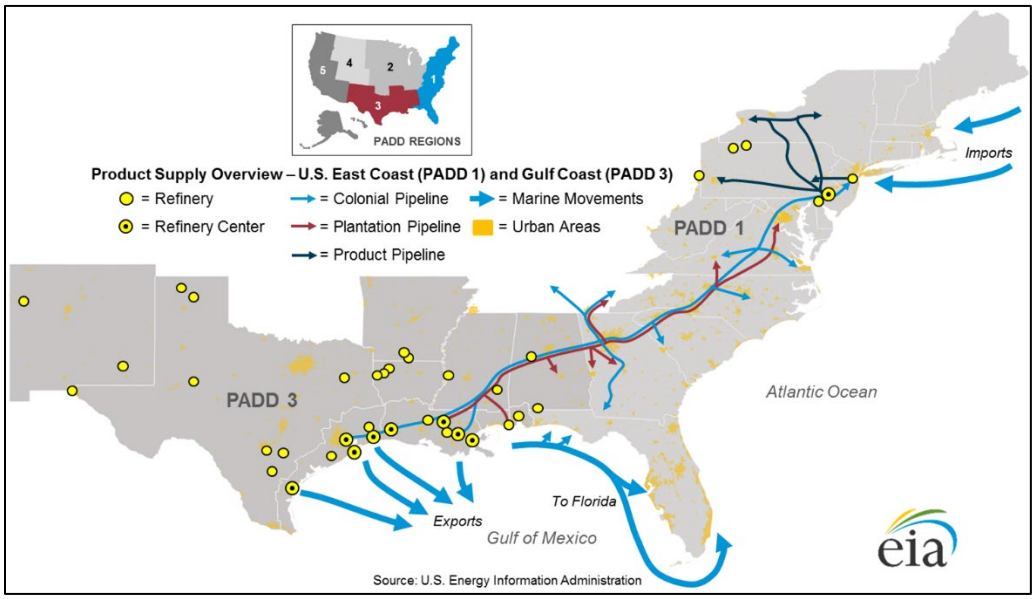

Figure 274. Transportation fuel flows from Gulf Coast to East Coast.

Source: Energy Information Administration (EIA 2016b).

The Colonial Pipeline and Plantation Pipeline are the two major pipeline systems used to supply transportation fuels to the East Coast. These two pipelines carry over 2.3 million barrels of refined products a day, accounting for nearly 47 percent of the East Coast's consumption (EIA 2016b). Additionally, 500 Mbbls/d of transportation fuels are shipped to PADD 1 via coastal tankers and barges to East Coast ports located primarily in Florida. In 2016, these pipeline and marine shipments from the Gulf Coast covered approximately 58 percent of the Atlantic region's consumption of transportation fuels (EIA 2016b).

When natural gas is transported by ships, it is usually converted to LNG. However, despite the exponential increase in US natural gas production over the last decade, the amount of LNG shipped to and from the East Coast within the US is very limited since the large ships used to carry LNG are foreign based. The Jones Act requires shipping between US ports to be conducted by US-flag ships, and as such, LNG cannot legally be transported to the Atlantic region from US export terminals using foreign vessels. Therefore, the East Coast's demand for natural gas is mainly met by domestic supply through pipelines or, when those pipelines develop bottlenecks, by imports from other countries.

Import and Export Terminals

Since 2009, refineries within the Atlantic region have received more crude oil from foreign countries than from domestic sources. As shown in Figure 275, almost all the crude oil received by other countries was transported by tankers and barges. A large portion of the crude oil received from domestic sources was also transported over water, although, this is most likely the result of movement between Atlantic locations rather than shipments from other PADDs.

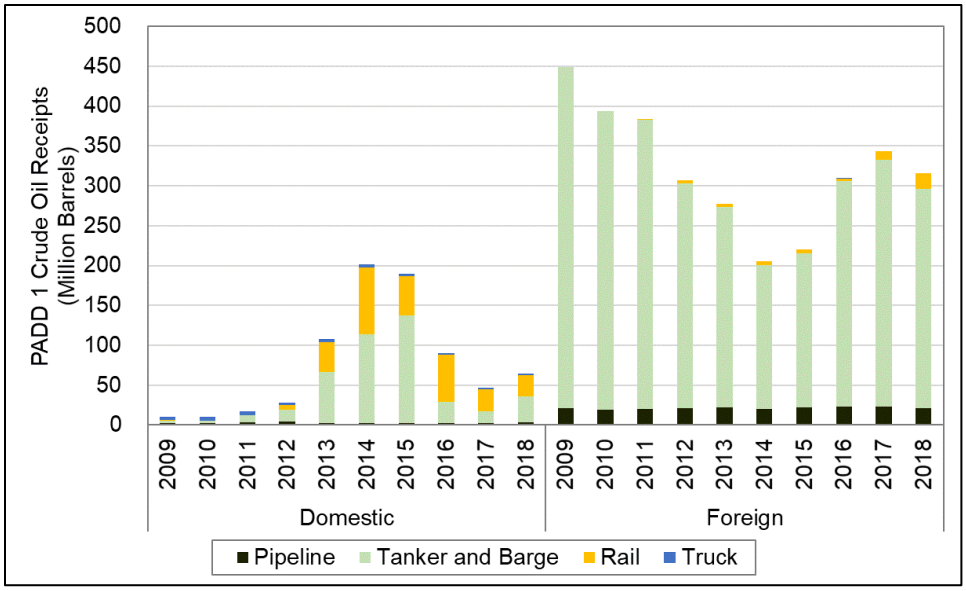

Figure 275. PADD 1 refinery crude oil receipts by source and transportation method, 2009–2018.

Source: Energy Information Administration (EIA 2020b Jun 22).

The amount of crude oil imported from foreign countries has declined since 2009, with 2018 levels 29 percent lower than they were in 2009. The significant growth in domestic crude oil production has been the cause of this decrease in imports. However, much of the new production is from unconventional sources, which often are not located where it can be easily transported by the current pipeline network and also is of quality that is not efficiently processed by refineries (i.e. oil sands, tight oil, etc.). Although some pipelines have been constructed or expanded to accommodate this production growth, and rail and marine modes are being used to move the increased load, it is still easier for some areas on the East Coast to meet their demand from imports (API 2014). Thus, despite their decline, imports still provided over four times more of Atlantic refineries' crude oil than domestic sources in 2018.

Over a quarter of all the Atlantic region's imported crude oil and petroleum, nearly 600 Mbbls/d, come from Canada, mostly by pipeline. Following Canada, countries and areas such as Nigeria, the United Kingdom, Russia, and Saudi Arabia have averaged the most crude oil and petroleum imports to PADD 1 over since 2010, utilizing tanker ships to transport the products overseas (EIA 2020c Jun 30).

Similarly, about 30 percent of the crude oil and petroleum products exported from the Atlantic Coast are sent to Canada, although the region's exports are substantially less than its imports. In 2019, for example, PADD 1 imported nearly 650 million barrels of crude oil and petroleum but exported only 130 million barrels (EIA 2020d Jun 30). US exports of oil and petroleum, however, have been on the rise, and the Atlantic region saw a 130 percent increase in exports from 2010 to 2019, as shown in Figure 276.

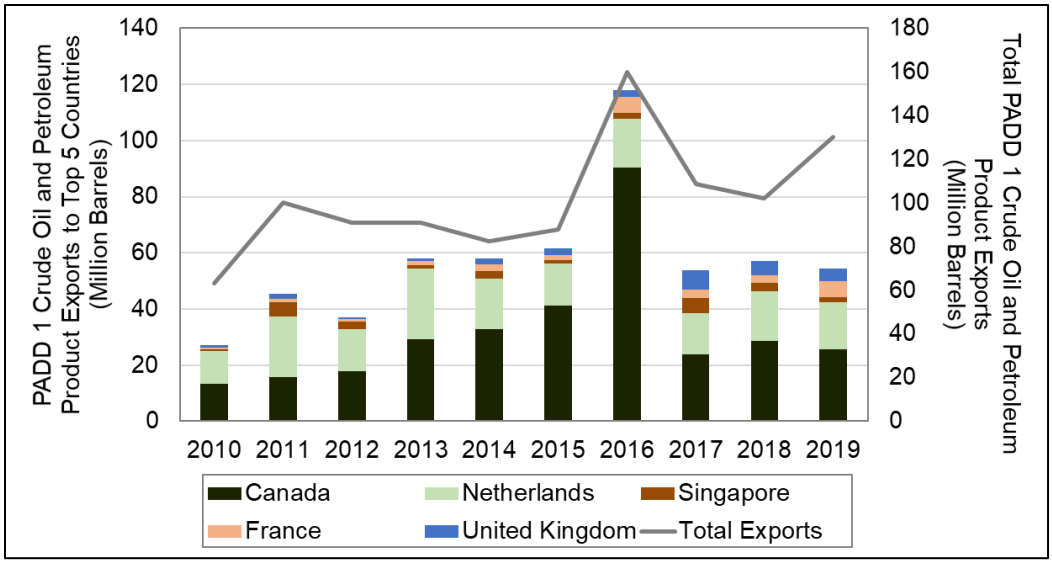

Figure 276. PADD 1 crude oil and petroleum product exports by destination, 2010–2019.

Source: Energy Information Administration (EIA 2020d Jun 30).

When the US lifted its restrictions on exporting domestically produced crude oil in late 2015, the amount of Atlantic region exports spiked considerably. Since then, however, the region's exports have returned to levels seen before 2016, though the US as a whole has experienced a significant increase in crude oil and petroleum exports since 2015. In 2019, for example, the number of US crude oil export destinations surpassed the number of its import origins for the first time. In 2009, the US had received crude oil from as many as 37 locations per month, but by 2019, that number had dwindled down to 27 (EIA 2019b Oct 22). Most of the crude oil being exported, however, is exiting by way of new and expanded terminals in the Gulf Coast, where production and pipeline infrastructure is far greater than that on the East Coast.

Like the oil industry, the Atlantic region's natural gas imports have decreased dramatically since 2009. As seen in Figure 277, imports from the Atlantic region were 66 percent less in 2018 than in 2009. The region's exports, however, have slowly grown over the last decade to levels that are now almost equal to its imports. As mentioned in the LNG chapter of this fact book, the abundant natural gas production in the Marcellus and Utica shale basins, as well as the development of LNG terminals along the East Coast, are major contributors to these import and export trends.

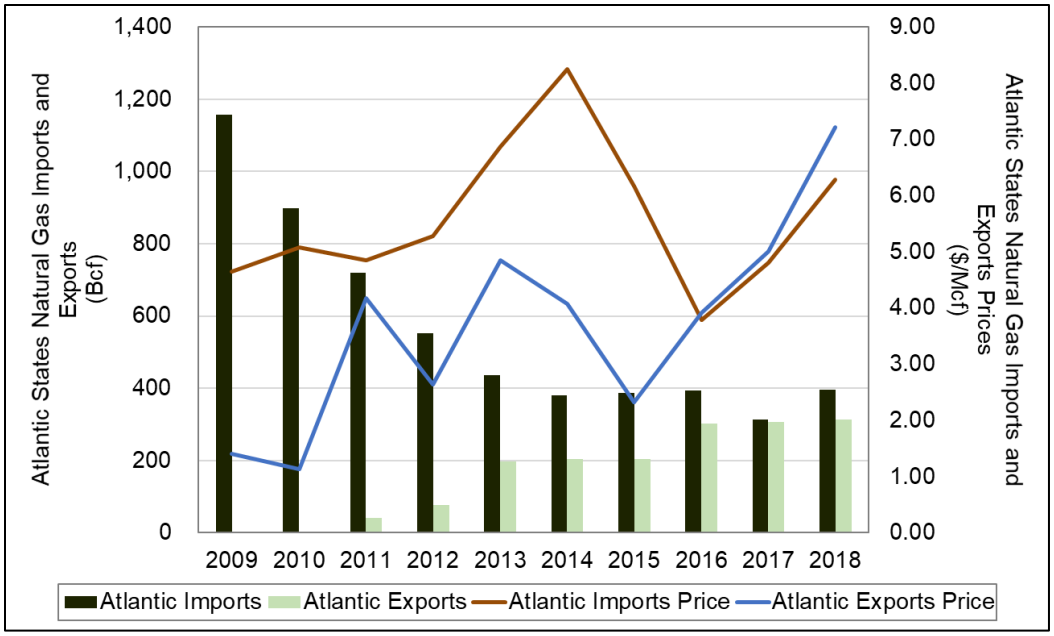

Figure 277. Atlantic region exports, imports, and prices, 2009–2018.

Source: Energy Information Administration (EIA 2020e Jun 30).

Most of the region's natural gas exports and imports are traded with Canada through extensive pipeline systems. However, the LNG exiting Atlantic Coast marine terminals can be sent as far away as Japan, India, Europe, and South America, among other destinations, while imports are normally received from countries like France and Trinidad (US DOE 2019; Rector 2019 Mar 20). The amount of the Atlantic region's LNG imports received by ship is very low compared to the natural gas imports received by pipeline from Canada. In 2018, for example, US LNG imports totaled only 11.4 Bcf of natural gas, all of which arrived through terminals in the Atlantic region, namely the Everett terminal and Northeast Gateway offshore terminal in Massachusetts (US DOE 2019).

13.6 Current Outlook

Transportation modes such as railways and trucks are being used now more than ever to help transport the surplus of domestically produced oil and natural gas that has begun to overwhelm the existing pipeline systems as a result of the shale and oil booms of the 2000s. If these products continue to be produced at this heightened rate, transportation infrastructures will need to be updated and expanded to continue moving these energy fuels smoothly from producer to consumer.

As of mid-2020, eighteen liquid pipeline projects had been announced and 23 had already begun construction in the US, five of which are wholly or partially located within the Atlantic states, specifically Pennsylvania. Figure 278 shows how much capacity will be added to the pipeline system if these projects reach fruition.

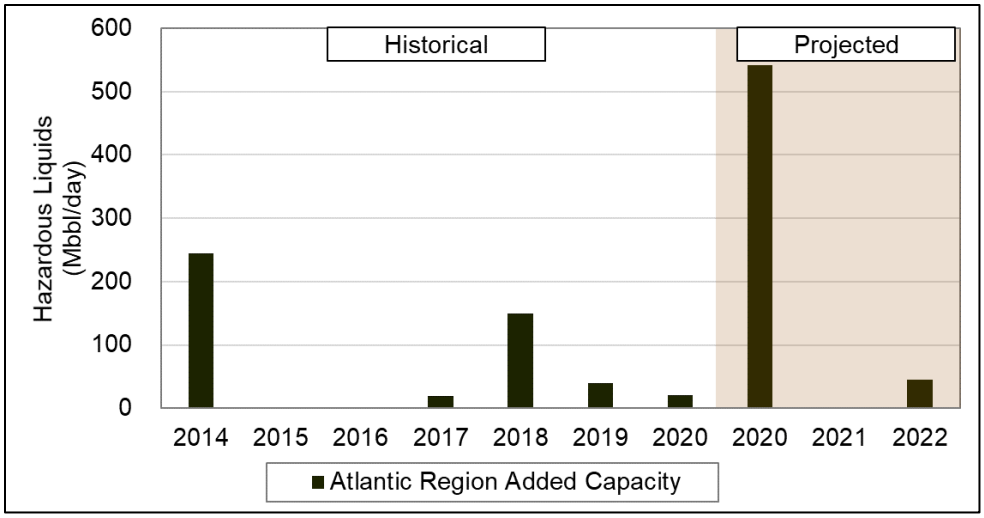

Figure 278. Added capacity of historical and projected Atlantic region liquid pipeline projects, 2014–2022.

Source: Energy Information Administration (EIA 2020 Jun 4).

Four of these five planned Atlantic projects are brand new pipelines that are already under construction as of June 2020. They will be used to transport about 292 thousand barrels of hazardous gas liquids per day and 250 thousand barrels of petroleum products per day. The fifth planned project is a 45 Mbbl/d hazardous gas liquid project that has been announced and is expected to begin construction in 2022.

Additionally, there are 34 planned natural gas projects located partially or entirely within the Atlantic region as of June 2020. Figure 279 shows that most of the added capacity from these planned projects are expected to come online in 2021, the largest of which will be a new pipeline called the Mountain Valley Pipeline. The approximately $5 billion pipeline will span over 300 miles from Wetzel County, West Virginia to Pittsylvania County, Virginia and provide up to two Bcf/d of capacity to the Mid- and South Atlantic regions (EIA 2020 Mar 5; Mountain Valley Pipeline c2020).

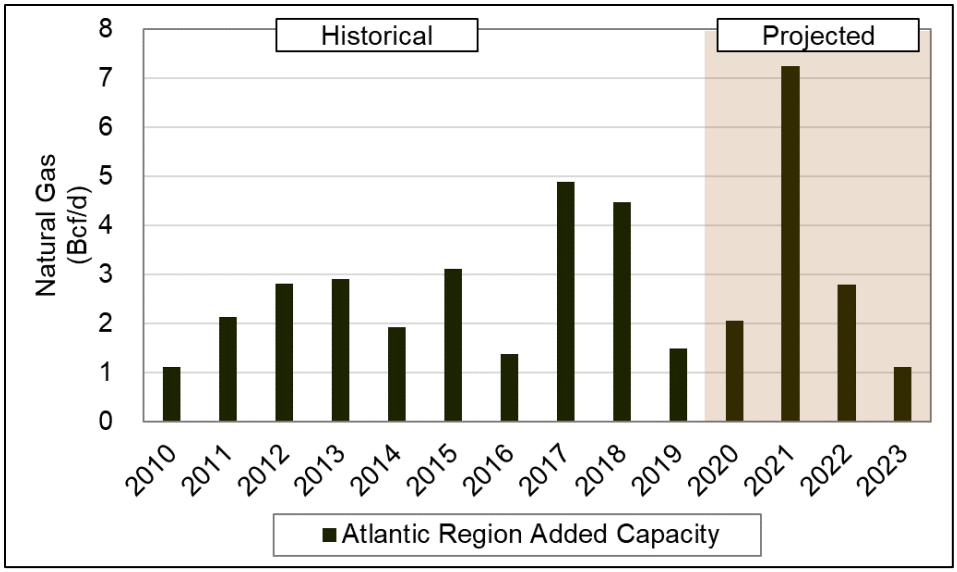

Figure 279. Added capacity of historical and projected Atlantic region natural gas pipeline projects, 2010–2023.

Source: Energy Information Administration (EIA 2020 Mar 5).

These planned Atlantic pipeline projects comprise approximately 27 percent of the total number of planned pipelines expected to come online in the US from 2020-2023. Many of these projects are in response to the growth of natural gas production in the Marcellus and Utica basins and will be used to carry the produced gas from Pennsylvania, Ohio, and West Virginia to awaiting markets along the East Coast.

Although there are increasing efforts to expand the pipeline network in the Atlantic region, many proposed projects have encountered siting challenges, motivating producers, especially of natural gas, to pursue other ways to supply markets where pipeline capacity is constrained (CRS 2020). For decades, producers have used large marine vessels to import and export LNG overseas and tanker trucks to transport LNG domestically. However, these modes are not enough to ship the large amounts of natural gas being produced in the Bakken, Marcellus, and Utica basins to the ever-growing demand markets in the Atlantic region. These limited shipment options prompted the Trump Administration to issue an executive order on April 10, 2019, directing the Secretary of Transportation to allow LNG to be shipped by rail tank cars throughout the US In response, PHMSA proposed a rule that would permit LNG to be carried by insulated rail tank cars that are designed to carry liquefied ethylene. The proposed rule was sent to the Office of Management and Budget (OMB) for review in April 2020, and was approved in June 2020 (CRS 2020; Marsh 2020 Jun 19). This approval was expected, as demand for natural gas is projected to increase significantly in the US and remain relatively constant in the Atlantic region over the next 30 years (Figure 280).

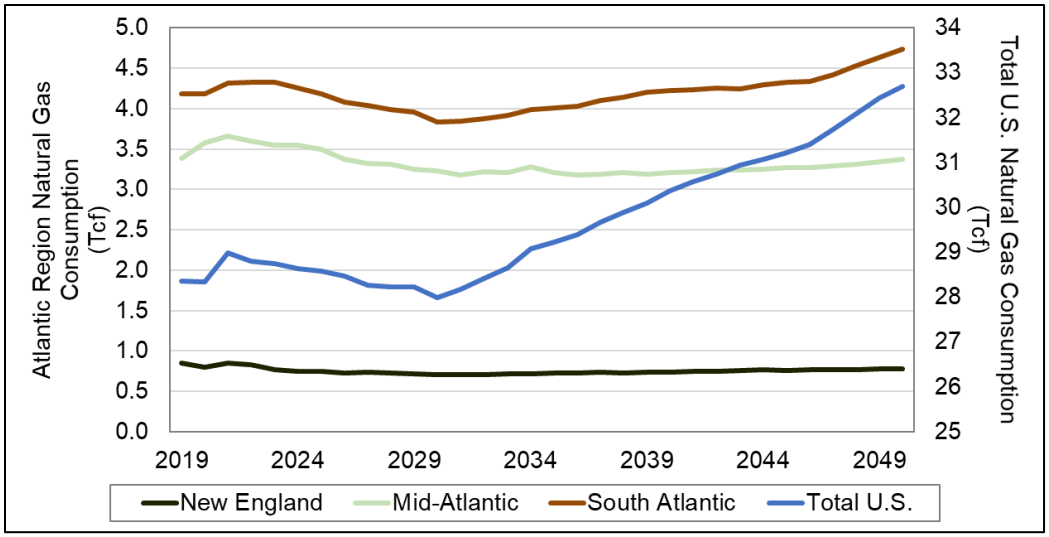

Figure 280. Projected natural gas consumption in the Atlantic region and US, 2019–2050.

Source: Energy Information Administration (EIA 2020a Jan 29).

In addition to the possible emergence of LNG transportation by rail car to the Atlantic region, efforts are underway to provide coastal and inland waterway transportation of LNG via smaller marine vessels. In August 2019, NorthStar Midstream and Fincantieri Bay Shipbuilding entered into an agreement to build a 5,400 cubic meter articulated barge to transport LNG and provide bunkering services along the East Coast. The LNG will be sourced from a new LNG production facility in Jacksonville, Florida and will be used as fuel for other marine vessels (The Maritime Executive 2019 Aug 22). Although this project is solely focused on moving and distributing LNG as a marine transportation fuel source, it could open the door for other consumer demands in the Atlantic region to be met by coastal and inland waterway vessels.

As mentioned in the Liquefied Natural Gas chapter of this fact book (Chapter 8), there has been a major push to have LNG export terminals approved and built along the East Coast in order to take advantage of the large amounts of natural gas being produced in the Appalachian region. Likewise, the lifting of the oil export ban and the increase in oil production in West Texas' Permian Basin has triggered a race among companies to build deepwater oil export terminals, though mainly in the GOM. These deepwater export terminals are in response to the limited ability of even the largest onshore ports to handle the large flow of oil produced and to load the biggest supertankers for export (Blum 2019 Aug 16). As of now, the LOOP off the coast of Louisiana is the only operational deepwater oil port in the US, and there have been no efforts to construct these types of terminals along the Atlantic Coast.

13.6.1 Factors Impacting East Coast Development

Despite the expected growth in oil and natural gas production, states' surging interest in renewable energy could have a significant impact on the development of transportation infrastructure in the Atlantic region. For example, in March 2020, New York's Public Service Commission (NYPSC) ordered a review of companies' natural gas planning and policies aimed at reducing or eliminating the need for investment in gas infrastructure. Soon after the order was released, two of the state's largest gas utilities, New York State Electric & Gas Company and Rochester Gas and Electric Corporation, entered into an agreement with the NYPSC to limit the growth of natural gas use in their service territories by offsetting growing gas demand with renewables, refraining from promoting the fuel, and avoiding pipeline construction and expansion where possible. The companies established the groundwork for a process to evaluate whether non-pipeline alternatives are suitable in place of the construction, expansion, or replacement of gas pipelines (DiChristopher 2020 Jul 1). This trend is likely to spread as more East Coast states adopt and begin implementing decarbonization policies.

Figure 281 shows that the East Coast's oil and natural gas production is expected to grow at an average rate of about 2 percent each year over the next 30 years. With the region's growing interest in renewable energy, its consumption of natural gas is not expected to increase by much going forward. However, other parts of the US, especially the Gulf Coast, are projected to demand more and more of the fuel for power generation and exporting in the next few decades (Barth et al. 2020 Jan 6). With these shifts in demand, it is likely that gas flows and transportation infrastructure will also shift and be constructed to provide more natural gas from the productive upper East Coast to the South Atlantic and GOM regions as well as to global markets.

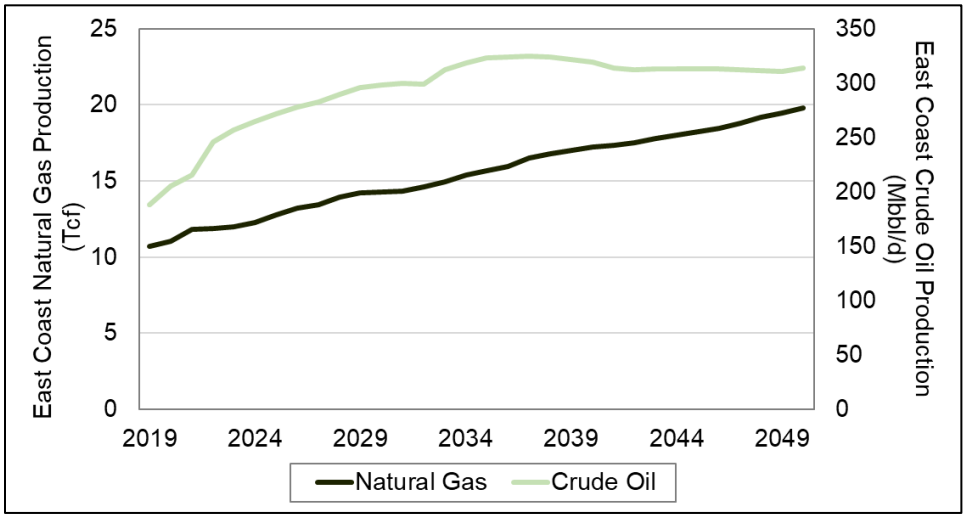

Figure 281. Projected East Coast natural gas and crude oil production, 2019–2050.

Source: Energy Information Administration (EIA 2020b Jan 29; EIA 2020c Jan 29).

The Atlantic region's focus on offshore wind as a new energy source may also change the landscape of intermodal transportation within the region. As shown in Figure 282, trains and marine vessels will be needed to carry the wind turbines to their final destinations off the coast. Additionally, various types of ships will also be needed to construct and maintain the offshore wind farms once the turbines are offloaded and operational. This could require investments in infrastructure to better equip rail and ships for transporting such large pieces of machinery. With many states along the coast seeking approval for their own offshore wind projects, these modes of transportation will be harnessed to move a new kind of energy in addition to the traditional oil and LNG fuels.

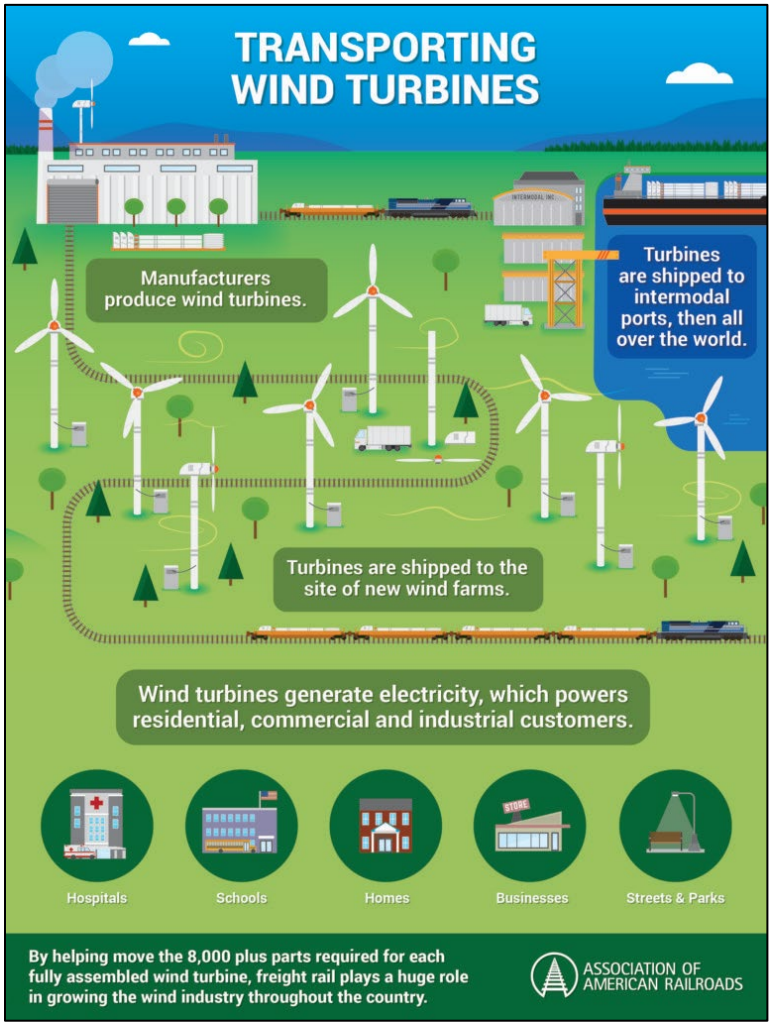

Figure 282. Wind turbine transportation.

Source: Association of American Railroads (AAR c2020).

14. Conclusion

14.1 Fabrication Yards

Five fabrication facilities have been identified that have been or could be used in the development of offshore platforms or other offshore structures. All of these fabrication yards are owned by one company, Cianbro. The development of any additional facilities in the region will likely depend on the degree to which offshore energy production progresses. Under a limited or moderate development scenario, it is likely that platforms and associated structures would originate in the Gulf of Mexico (GOM) region or at international sites.

14.2 Shipyards and Shipbuilding

There are twenty-one shipyards in the Atlantic region, ranging from those that construct small vessels for coastal or inland use to those that focus on large oceangoing military and commercial ships. Six facilities in the Atlantic region construct new vessels, while another fifteen facilities are identified as offering repair services. The medium-sized shipyards located in Virginia, Maryland, and Pennsylvania appear to be likely candidates for offering support capabilities to the Atlantic for oil and gas offshore activities. Collectively, these facilities are more concentrated and have more extensive experience over the past several decades than their smaller counterparts.

Shipyards dedicated to medium-sized vessels would be likely candidates for offering support capabilities in this region given their previous experience and likely high interest in growing market share to serve new and emerging offshore oil and gas activities. It is unlikely that any new facilities would be constructed in support of anticipated offshore oil and gas lease activities, considering the high degree of excess capacity and underutilization at all shipyards at the current time.

The shipbuilding industry is highly competitive and Atlantic facilities could face competition from existing facilities along the GOM, particularly if offshore oil and gas development were limited. Existing GOM yards have decades of experience and are also underutilized relative to their existing capacity. GOM yards have a number of important advantages over both Atlantic greenfield developments and/or yards that expand and/or diversify to meet new Atlantic offshore activity. These benefits include facility capacity; a sizable skilled workforce; engineering and design experience; decades of construction experience across a range of offshore service vessels and crafts; relationships with input vendors; and relationships with service and production companies.

A dependence on military contracts and a dearth of commercial shipbuilding have made oil and gas-related shipbuilding a dubious prospect for Atlantic region shipyards, particularly under very limited offshore development scenarios. Thus, the development of new Atlantic shipyards may be a challenge without an expansive regulatory development scenario with tight oil and gas market conditions over an extended period of time.

14.3 Port Facilities

The Atlantic region has good port coverage, and it is unlikely that any new ports would be constructed to support offshore energy production alone. Port development would be influenced by: (1) the specific location where offshore oil and gas activity is expected to occur; and (2) the degree to which offshore support activities compete, or are in conflict with, bulk container and cargo trade that is currently the focus of larger regional ports. A number of moderately-sized ports located in the Chesapeake Bay region could likely serve as support bases for offshore oil and gas activities.

Many ports along the eastern seaboard, particularly the upper Mid-Atlantic region such as the Port of New York and New Jersey, are already highly developed and in locations that have expensive or limited expansion possibilities. Development at these ports will likely compete with alternative uses for waterfront and port surface space. Because of the cost and physical restrictions, smaller to medium sized ports may have a competitive edge to in the pursuit of oil and gas support activities particularly if offshore development is limited and/or arises slowly over decades rather than in a "burst" of a few years.

Recent port expansions resulting from the growth of offshore wind projects have led to capital upgrades that could also make ports more useful in serving other offshore energy production activities like oil and gas E&P. Channel depth will also be an issue at many ports because of increases in the size of ships. Multiple channel dredging projects are planned for Atlantic ports in the coming years.

Lastly, there are a number of moderately-sized ports located in the Chesapeake Bay region that could serve as likely support bases for offshore oil and gas activities. These central Atlantic region ports are the closest to possible offshore development.

14.4 Support and Heliport Facilities

No dedicated support and transport facilities have been identified on the Atlantic coast. General offshore support and transportation is tied directly to ports; any service-oriented basis that arise from offshore oil and gas activities will likely originate at these ports. Like ports, development in response to offshore activity will be influenced by the specific location of offshore activity.

The capital cost of developing such types of facilities may be too expensive for an individual offshore operator alone, necessitating multi-company facilities, which are becoming more common even along the GOM. Factors that may challenge private support base facility development include:

- Potential conflicts with recreation and residential development.
- Permitting challenges.
- Facility development costs.
- Offshore development scenario uncertainties.
- Lower cost commercial port opportunities.

Few heliports in the Atlantic region would be suitable for offshore oil and gas activity. As is the case with much of the GOM oil and gas helicopter industry, initial offshore helicopter activities would likely be based in airports near the coast.

14.5 Oil Spill Response

A number of oil spill response companies are located in the Atlantic region, including companies that respond to marine situations. The Atlantic region has a number of refineries and petroleum terminals that receive cargo from water-borne suppliers, and spills from these cargoes and other industrial activities are likely to be greater than those associated with OCS development.

Though oil spill response uses capital-related equipment, this is mostly a knowledge-based industry that is highly mobile and assets from other producing areas could be used if a catastrophic accident were to occur. It is unlikely that new oil spill response investments will be needed in the region.

14.6 Waste Management Facilities

A small number of oil field waste disposal facilities are located in the Atlantic region; and most have been developed to support Appalachian drilling activities, with heavy concentration in Pennsylvania. Development in the Atlantic region will likely require expanded oilfield waste disposal capacity. The amount of capacity will be a direct function of the level of drilling and production activity anticipated in the Atlantic OCS because more drilling or production will result in expanded capacity requirements.

14.7 Pipe-coating Yards

The pipe coating business is highly dependent on the cyclical nature of oil and natural gas markets. Currently, existing pipe coating facilities in the Atlantic states are located in Pennsylvania and Florida, with smaller facilities in New York, Massachusetts, and Florida also offering pipe coating services as part of a range of coating services. The degree to which these existing facilities would be used to support offshore OCS activities is undetermined. Under a limited or moderate development scenario, it is likely that coated pipe would come from existing facilities in the Appalachian region or the GOM region. However, additional pipe coating facilities may be developed as a result of increased production in the Marcellus shale.

14.8 Natural Gas Processing Facilities

There are eight natural gas processing plants in the Mid-Atlantic region, however they are all in western Pennsylvania and used to support Appalachian production. The need for gas processing in the Atlantic OCS will be a function of the degree to which wet or sour gas volumes, or both, are anticipated to be produced from offshore areas. Assuming gas processing is needed, many of the same factors influencing gas transportation will be important, including location, volumes and commercial factors (the ability to store, transport and market natural gas liquids processed from the gas stream will be important in determining facility configuration).

14.9 Natural Gas Storage Facilities

A number of natural gas storage facilities have been identified in the Atlantic region. However, these facilities are associated with Appalachian production or intermediate storage requirements for New England LDCs, with all such storage facilities being located in Pennsylvania, Maryland, Virginia, and New York. Thus, some regional gas storage may be needed along the Atlantic OCS to accommodate new offshore natural gas production volumes.

Four important factors to consider in the development of natural gas storage are (1) gas storage will likely be located near new areas of production; (2) the size will be a function of location and geological capabilities; (3) developers will need to determine the availability and cost effectiveness of reservoir, aquifer, or salt cavern storage; and (4) the type of cavern and size of the injection well will be driven by deliverability goals, location, and the number of proximate pipelines and potential storage customers.

14.10 Liquified Natural Gas Facilities

Large marine-based onshore LNG terminals have been proposed across different areas of the coastal US and have received increased media and public attention in recent years. In 2019, there were three LNG import facilities located in the Atlantic region, located in Massachusetts, Maryland, and Georgia.

There have also been a considerable number of announcements and applications for new regasification and export facilities throughout the coastal US As of December 2019, twenty-three facilities had requested authorization to export LNG. Two of the Atlantic facilities, in Jacksonville, FL and Elba Island, GA, have requested this authorization.

14.11 Refineries

There are six active refineries in the Atlantic region, located in Delaware, New Jersey, and Pennsylvania. Four of these refineries have capacities in excess of 160,000 barrels per day. The refineries handle varying weights of crude and produce a range of products. One refinery, for instance, maintains an onsite propylene plant.

Existing refinery capacity would likely be used to process Atlantic OCS crude oil. Export opportunities arising since the lifting of the United States' ban on crude exports in 2014 have eroded domestic refineries' cost advantage, making additional refinery development less likely.

14.12 Petrochemical Facilities

While the data are not granular enough to focus specifically on the petrochemical chemical industry, the chemical industry as a whole has declined as a share of national GDP over the past decade. Further, economic output in the chemical manufacturing industry is projected to grow more slowly over the next decade than total economic output across all industries, and industry employment is forecast to decrease. However, gas reserves in the Marcellus shale and oil reserves in the Utica and Pleasant Point formations in nearby Ohio and western Pennsylvania could spur additional development in the region's petrochemical industry.

14.13 Electric Power Infrastructure

Electric power systems are based on a collection of generation, transmission, distribution and communication facilities that are physically connected and operated as a single unit under one control. Power plants (generation) can be grouped into the types of fuel or energy source they use to produce electricity. These include fossil fuels (coal, natural gas, or a refined oil product), nuclear energy, and renewable energy sources such as water (hydroelectric power), biomass, waste-to-energy, geothermal, wind, and solar energy. Power generation in the Atlantic is heavily dependent on natural gas as a fuel source. Thus, the price and availability of natural gas can have important implications for power generation supply and price.

According to the EIA, total electricity generation capacity is projected to increase significantly from 2020 to 2050 (USEIA 2020a Jun 30). Most of this new capacity will be powered by natural gas and renewable sources.

14.14 Intermodal Transportation

Before the discovery of the Marcellus and Utica shale plays in the Northeast, many of the existing pipelines in the Atlantic region were used to carry natural gas and petroleum products from the highly productive GOM to populated areas along the East coast. The Colonial Pipeline and Plantation Pipeline are the two major pipeline systems used to supply transportation fuels to the East coast. These two pipelines carry over 2.3 million barrels of refined products a day, accounting for nearly 47 percent of the Atlantic region's consumption.

Of the seven largest railroads in the US, two operate heavily in the Atlantic region: the CSX and the Norfolk Southern railways. Two major highways, Interstate 95 and US Highway 1, run the length of the Atlantic region, from Maine to Florida. Finally, the entire coast of the Atlantic region is spanned by the Intracoastal Waterway. The Atlantic region includes approximately 126 bulk transload facilities for transferring cargo between modes of transportation.

Natural gas is concentrated in market hubs throughout the US. Two of these are located in the Atlantic region, from Virginia in the south to Massachusetts in the north. Natural gas is transferred internationally through multiple pipelines located along the Atlantic region's border with Canada, as well as terminals along the east coast. Petroleum imports and exports in the Atlantic region take place exclusively through marine terminals.

Prospects for future pipeline development could be positively impacted by expected growth in oil and natural gas production, but this may be offset by states' interests in switching to energy from renewable energy. However, the infrastructure needed to transport equipment for renewable energy products, especially offshore wind, could lead to further development of the region's rail, road, and marine transportation infrastructure.

References

§ 62.1-195.1. Chesapeake Bay; drilling for oil or gas prohibited. [accessed 2020 Mar 27].

109th Congress. 2006 Jan 6. National Defense Authorization Act of 2006. Washington (DC): Govinfo.com. [accessed 2020 Feb 19].

116th Congress. 2019 Jul 18. H.R. 3829 - Energizing American Shipbuilding Act of 2019. Washington (DC): Congress.gov. [accessed 2020 Mar 31].

116th Congress. 2019 Dec 20. H.R. 1865 - Further Consolidated Appropriations Act, 2020. Washington (DC): Congress.gov. [accessed 2020 Feb 19].

40 CFR 43544. Oil and Gas Extraction Point Source Category. [accessed 2020 Nov 13].

49 CFR § 192.455 - External corrosion control: Buried or submerged pipelines installed after July 31, 1971. 2019 Oct. 1. 10-1-19 Ed. Washington (DC): Government Printing Office. [accessed 2019 Nov 20].

AAR [Association of American Railroads]. 2014 Jul. Moving Crude Oil by Rail. Washington (DC): Association of American Railroads. [accessed 2020 May 14].

AAR [Association of American Railroads]. 2017. Freight Rail in Your State - State Rankings 2017. Washington (DC): Association of American Railroads. [accessed 2020 May 21]. https://www.aar.org/data-center/railroads-states/.

AAR [Association of American Railroads]. 2019 Jul. Freigh Railroads in the United States - Fact Sheet 2017. Washington (DC): Association of American Railroads. [accessed 2020 Jun 24].

AAR [Association of American Railroads]. c2020. Infographics - Transporting Wind Turbines. Washington (DC): Association of American Railroads. [accessed 2020 Jul 24]. https://www.aar.org/infographics/.

Abbott P. 2020 Mar 9. Port of Virginia welcoming business with enhanced facilities, efficiencies. Plymouth (MA): American Journal of Transportation. [accessed 2020 Apr 1].

About McCutcheon Enterprises. 2017. Apollo, PA: McCutcheon Enterprises. [accessed 2020 Mar 26]. http://completewastemgmt.com/about-us/.

ABS [American Bureau of Shipping]. 2017. LNG Bunkering: Technical and Operational Advisory. Houston (TX): American Bureau of Shipping: American Bureau of Shipping. [accessed 2020 May 5]. https://ww2.eagle.org/content/dam/eagle/advisories-and-debriefs/ABS_LNG_Bunkering_Advisory.pdf.

Adams R. 2021 Jan 13. Sunset Park to house massive offshore wind turbine assembly plant. [accessed 2021 Apr 8]. https://www.brooklynpaper.com/sunset-park-offshore-wind-assembly-plant/.

Adriatic LNG. c2020. The Plant. Milan (Italy): Adriatic LNG. [accessed 2020a Apr 22]. https://www.adriaticlng.it/en/the-terminal/the-plant.

Adriatic LNG. c2020. The Terminal. Milan (Italy): Adriatic LNG. [accessed 2020b Apr 22]. https://www.adriaticlng.it/en/the-terminal.

Adriatic LNG. c2020. Construction. Milan (Italy): Adriatic LNG. [accessed 2020c Apr 22]. https://www.adriaticlng.it/en/the-terminal/the-plant/construction.

Advansix. 2019 Jun 24. Advansix Issues Statement Regarding Philadelphia Refinery Fire. Washington (DC): SEC. [accessed 2020 Aug 4].

Advansix. c2020. Phenol Caprolactam Acetone Meko | AdvanSix Chemical Intermediates. Parsippany (NJ): AdvanSix. [accessed 2020 Aug 3]. https://www.advansix.com/chemicalintermediates/products/#acetone.

Affiliated Marine. c2009. Affiliated Marine. Houma (LA): Affiliated Marine. [accessed 2020 Feb 28]. http://www.affiliatedmarine.com/.

Agerschou H, Dand I, Ernst T, Ghoos H, Jensen OJ, Korsgaard J, Land JM, McKay T, Oumeraci H, Petersen JB, et al. 2004. Planning and Design of Ports and Marine Terminals. Second Edition. London (UK): Thomas Telford Publishing. [accessed 2020 May 19].

AIP. 2017 Sep 1. Refining of Petroleum. Australian Institute of Petroleum. [accessed 2019 Dec 14]. https://aip.com.au/resources/refining-petroleum.

AJOT [American Journal of Transportation]. 2019 May 1. Brieda Cabins launches ground control station for remote crane operations. Plymouth (MA): American Journal of Transportation. [accessed 2020 Apr 14].

Alaska Oil Spill Commission. 1990 Feb 1. Details about the Accident. Exxon Valdez Oil Spill Trustee Council. [accessed 2020 Apr 21]. http://www.evostc.state.ak.us/index.cfm?FA=facts.details.

Alexander RJ. 2016 Jun. FAA's heliport location database may be rife with errors. Rotor & Wing. [accessed 2020 Apr 4]. https://digitaledition.rotorandwing.com/june-2016/deadly-data/.

Ali U. 2019 Apr 2. Five of the newest helping the industry. New York (NY): Offshore-Technology. [accessed 2020 Feb 19].

Allison E, Mandler B. 2018 Jun 1. Transportation of Oil, Gas, and Refined Products - The methods, volumes, risks, and regulation of oil and gas transportation. Alexandria (VA): American Geosciences Institute. [accessed 2020 May 13].

American Chemistry Council. 2017. Cumene | Uses, Benefits, and Chemical Safety Facts. Washington (DC): American Chemistry Council. [accessed 2020 Aug 3]. https://www.chemicalsafetyfacts.org/cumene/.

American Chemistry Council, ACC. 2018. US Chemical Industry Investment Linked to Shale Gas Reaches $200 Billion. [accessed 2020 Jun 18].

American Fuel & Petrochemical Manufacturers. 2017. Petrochemical Manufacturing Basics. [accessed 2020 Apr 14]. https://www.afpm.org/newsroom/infographic/petrochemical-manufacturing-basics.

American Fuel & Petrochemical Manufacturers. 2018. Midstream-Report-Supply-Chain.png. [accessed 2020 Aug 3]. https://www.afpm.org/newsroom/infographic/americas-fuel-and-petrochemical-supply-chain.

American Refining Group. 2017 Mar 4. American Refining Group Inc. marks 20 years in Bradford today. [accessed 2020 Mar 11]. http://www.bradfordera.com/opinion/american-refining-group-inc-marks-years-in-bradford-today/article_3587016e-007c-11e7-a641-b7af79fbb0ae.html.

American Refining Group. c2019. Refinery History. American Refining Group. [accessed 2019 Dec 13]. https://www.amref.com/Refinery/Refinery-History.aspx.

Anderson J. 2013 Oct 10. US LNG Export Facility Map and Information. [accessed 2020 May 28]. https://breakingenergy.com/?s=export+map&submit=Search.

API [American Petroleum Institute]. 2001. Guidelines for Commercial Exploration and Production Waste Management Facilities. https://www.api.org/~/media/Files/EHS/Environmental_Performance/E_P_Waste_Guidelines.pdf.

API [American Petroleum Institute]. 2014. Understanding Crude Oil and Product Markets. Washington (DC): American Petroleum Institute. [accessed 2020 Jul 7]. https://www.api.org/~/media/Files/Oil-and-Natural-Gas/Crude-Oil-Product-Markets/Crude-Oil-Primer/Understanding-Crude-Oil-and-Product-Markets-Primer-High.pdf.

API [American Petroleum Institute]. c2020. Offshore Production Facilities. Washington (DC): American Petroleum Institute. [accessed 2020 Feb 14].

Argonne National Laboratory. 2001. Offshore Waste Management – Discharge, Inject, or Haul to Shore. :16.

ARTBA [American Road & Transportation Builders Association]. c2020. Frequently Asked Questions. Washington (DC): American Road & Transportation Builders Association. [accessed 2020 May 21]. https://www.artba.org/about/faq/.

ASCE [American Society of Civil Engineers]. 2017a. 2017 Infrastructure Report Card. Reston (VA): ASCE. [accessed 2020 Mar 27]. https://www.infrastructurereportcard.org/wp-content/uploads/2017/01/Energy-Final.pdf.

ASCE [American Society of Civil Engineers]. 2017b. 2017 Infrastructure Report Card. Reston (VA): American Society of Civil Engineers. [accessed 2020 May 21]. https://www.infrastructurereportcard.org/cat-item/rail/.

Ashar A, Swigart S. 2017. A Comparative Analysis of Intermodal Ship-to-Rail Connections at Louisiana Deep Water Ports. [accessed 2020 Apr 3].

Ashe A. 2019 Dec 23. Charleston awarded final portion of federal dredging funds Ari Ashe, Senior Editor. New York (NY): Journal of Commerce. [accessed 2020 Apr 3].

Aspinwall C, Hacker HK, Emily J. 2018 Mar 25. Did Atmos heed ’warning signs’ before deadly gas explosion? The Dallas Morning News. [accessed 2020 Feb 3].

Atlanta Gas Light. n.a. The PRP Construction Process.

Atlantic Communications. 2011. Gulf coast oil directory, 2011 edition. 59(1).

Atlantic Wind Connection. c2017. Atlantic Wind Connection Projects. Silver Spring (MD): Atlantic Wind Connection. [accessed 2020 Mar 31]. http://atlanticwindconnection.com/projects/.

Atmos Energy. 2018 Jul 25. Atmos Energy Announces Plans to Further Accelerate Pipe Replacement in its Mid-Tex Division. Atmos Energy. [accessed 2020 Feb 3]. https://www.atmosenergy.com/sites/default/files/atmos_energy_2018_accelerated_plan.pdf.

Austin D, Priest T, Penney L, Pratt J, Pulsipher AG, Abel J, Taylor J. 2008. History of the offshore oil and gas industry in southern Louisiana. New Orleans (LA): US Department of Interior, Mineral Management Service, Gulf of Mexico OCS Region Report No.: MMS 2008-042. [accessed 2020 Feb 21].

AWEA [American Wind Energy Association]. US Offshore Wind Fact Sheet September 2018. https://www.awea.org/Awea/media/About-AWEA/U-S-Offshore-Wind-Fact-Sheet-September-2018_2.pdf.

AWEA [American Wind Energy Association]. c2019. America's new ocean energy resource. Washington (DC): AWEA. [accessed 2019 Dec 16]. https://www.awea.org/policy-and-issues/u-s-offshore-wind.

Ayala C. 2009 Sep 27. History of Offshore Drilling. Oceana USA. [accessed 2020 Apr 2]. https://usa.oceana.org/history-offshore-drilling.

Bai Y, Bai Q. c2018. Subsea Engineering Handbook. 2nd ed. Houston (TX): Gulf Professional Publishing. [accessed 2020 Mar 2].

Baker K. 2019 Jul 12. DNREC settles dozens of Delaware City refinery violations for nearly $1 million. Delaware Online. [accessed 2020 Feb 10].

Barnea N. c2020. Health and Safety Aspects of In-situ Burning of Oil. Washington (DC): NOAA. [accessed 2020 Apr 22]. https://response.restoration.noaa.gov/sites/default/files/health-safety-ISB.pdf.

Barnes S. 2017 May 15. The jackets supporting wind turbines off the coast of Rhode Island were engineered in New Orleans and built in Houma. Baton Rouge (LA): Business Report. [accessed 2020 Mar 17].

Barrett D. 2008 Feb. The offshore supply boat sector. Marine & Commerce. https://www.marineandcommerce.com/files/mc0208supply.pdf.

Barth A, Brick J, Dediu D, Tai H. 2020 Jan 6. The future of natural gas in North America. New York (NY): McKinsey & Company. [accessed 2020 Jul 24]. https://www.mckinsey.com/industries/electric-power-and-natural-gas/our-insights/the-future-of-natural-gas-in-north-america.

Bayou Companies. 2019a. Three Layer Coating - Pipeline Protection. Bayou Companies. [accessed 2019 Nov 20]. https://www.bayoucompanies.com/services/three-layer-coating/.

Bayou Companies. 2019b. ID Flow Efficiency Coating - Pipe Coating. Bayou Companies. [accessed 2019 Nov 20]. https://www.bayoucompanies.com/services/id-flow-efficiency-coating/.

Bayou Companies. 2019c. Concrete Weight Coating. Bayou Companies. [accessed 2019 Nov 20]. https://www.bayoucompanies.com/concrete/.

BEA [Bureau of Economic Analysis]. 2019 Sep 24. Table SAEMP25N: Total Full-Time and Part-Time Employment by NAICS Industry [dataset]. Washington (DC): BEA. [accessed 2020 Aug 3]. https://apps.bea.gov/itable/index.cfm.

BEA [Bureau of Economic Analysis]. 2020 Apr 7. Table SAGDP9N: Real GDP by State [dataset]. Washington (DC): BEA. [accessed 2020 Aug 3]. https://apps.bea.gov/itable/index.cfm.

BEA [Bureau of Economic Analysis]. c2020. GDP by State. Washington DC: BEA. [accessed 2020a Feb 20]. https://www.bea.gov/data/gdp/gdp-state.

BEA [Bureau of Economic Analysis]. c2020. GDP by State. US Bureau of Economic Analysis (BEA). [accessed 2020b Feb 20]. https://www.bea.gov/data/gdp/gdp-state.

BEA [Bureau of Economic Analysis]. c2020. GDP by State. US Bureau of Economic Analysis (BEA). [accessed 2020c Jun 2]. https://www.bea.gov/data/gdp/gdp-state.

BEA [Bureau of Economic Analysis]. c2020. GDP by State | US Bureau of Economic Analysis (BEA). Washington DC: BEA. [accessed 2020 Jul 8]. https://www.bea.gov/data/gdp/gdp-state.

Bearden D, Ramseur J. 2017 Aug 29. Oil and Chemical Spills: Federal Emergency Response Framework. Washington (DC): CRS. [accessed 2020 Apr 22].

Behr P. 2018 Dec 12. Offshore transmission seeks second wind. Washington (DC): E&E News. [accessed 2020 Mar 31]. https://www.eenews.net/stories/1060109405.

Berg Pipe. 2019. Coating and Other Services. Berg Pipe. [accessed 2019 Nov 20]. https://www.bergpipe.com/coating.

Berg Pipe. Berg Pipe — Selected Projects. Berg Pipe. [accessed 2020 Feb 3]. https://www.bergpipe.com/selected-projects.

Berkeley Lab. 2019. Renewables Portfolio Standards Resources. Berkeley (CA): Electricity Markets and Policy Group. [accessed 2020 Mar 31]. https://emp.lbl.gov/projects/renewables-portfolio.

Birn K, Osuna J. 2015 Mar. Crude By Rail. Derby (KS): The American Oil & Gas Reporter. [accessed 2020 May 22]. https://www.aogr.com/web-exclusives/exclusive-story/railroad-oil-shipping-is-here-to-stay.

Bloomberg. 2019 Nov 15. Dominion Energy Cove Point LNG Terminal Loads 100th Commercial Ship. New York (NY): Bloomberg. [accessed 2020 Apr 23]. https://www.bloomberg.com/press-releases/2019-11-15/dominion-energy-cove-point-lng-terminal-loads-100th-commercial-ship.

BLS [Bureau of Labor Statistics]. 2019 May. Occupational Employment Statistics National and State Datasets [Dataset]. Washington (DC): Bureau of Labor Statistics. [accessed 2020 Aug 4]. https://www.bls.gov/oes/#data.

BLS [Bureau of Labor Statistics]. 2019 Nov 8. Employment and output by industry [dataset]. Washington (DC): Bureau of Labor Statistics. [accessed 2020 Aug 4]. https://www.bls.gov/emp/tables/industry-employment-and-output.htm.

BLS [Bureau of Labor Statistics]. 2020. Quarterly Census of Employment and Wages [dataset]. Washington (DC): Bureau of Labor Statistics. [accessed 2020 Feb 18]. https://data.bls.gov/PDQWeb/en.

BLS [Bureau of Labor Statistics]. c2020. Quarterly Census of Employment and Wages.Bureau of Labor Statistics. [accessed 2020a Feb 20]. https://data.bls.gov/PDQWeb/en.

BLS [Bureau of Labor Statistics]. c2020. Quarterly Census of Employment and Wages. Washington DC: US Bureau of Labor Statistics. [accessed 2020b Feb 20]. https://data.bls.gov/PDQWeb/en.

BLS [Bureau of Labor Statistics]. c2020. Quarterly Census of Employment and Wages. Bureau of Labor Statistics. [accessed 2020c Feb 20]. https://data.bls.gov/PDQWeb/en.

BLS [Bureau of Labor Statistics]. c2020. c2020. Quarterly Census of Employment and Wages. Washington DC: Bureau of Labor Statistics. [accessed 2020 Feb 20]. https://data.bls.gov/PDQWeb/en.

Blum J. 2019 Aug 16. Race Is on to Build Offshore Oil Export Terminals. Houston (TX): Houston Chronicle. [accessed 2020 Jul 24].

BOEM [Bureau of Ocean Energy Management]. 2019 Mar. Outer Continental Shelf Renewable Energy Leases Map Book. Washington (DC): Bureau of Ocean Energy Management. [accessed 2020 Mar 16]. https://www.boem.gov/sites/default/files/renewable-energy-program/Mapping-and-Data/Renewable_Energy_Leases_Map_Book_March_2019.pdf.

BOEM [Bureau of Ocean Energy Management]. 2020a. Atlantic OCS Lease Status Information. Washington (DC): Bureau of Ocean Energy Management. [accessed 2020 Apr 30]. https://www.boem.gov/oil-gas-energy/atlantic-ocs-lease-status-information.

BOEM [Bureau of Ocean Energy Management]. 2020b. Questions, Answers, And Related Resources | Bureau of Ocean Energy Management. [accessed 2020 Mar 12]. https://www.boem.gov/environment/environmental-assessment/questions-answers-and-related-resources.

BOEM [Bureau of Ocean Energy Management]. 2020c. Atlantic Oil And Gas Information | Bureau of Ocean Energy Management. [accessed 2020 Apr 2]. https://www.boem.gov/oil-gas-energy/atlantic-oil-and-gas-information.

BOEM [Bureau of Ocean Energy Management]. 2020d. Regional Proposals. Washington (DC): Bureau of Ocean Energy Management. [accessed 2020 Mar 31]. https://www.boem.gov/renewable-energy/state-activities/regional-proposals.

BOEM [Bureau of Ocean Energy Management]. 2020 Feb 9. Offshore Statistics by Water Depth [dataset]. Washington (DC): Bureau of Ocean Energy Management. [accessed 2020 Feb 11]. https://www.data.boem.gov/Leasing/OffshoreStatsbyWD/Default.aspx.

BOEM [Bureau of Ocean Energy Management], Post PJ, Klazynski RJ, Klocek ES, Riches, Jr TJ, Li K. 2016. Inventory of technically and economically recoverable hydrocarbon resources of the Atlantic Outer Continental Shelf as of Jaunary 1, 2014. Washington (DC): Office of Resource Evaluation Report No.: BOEM 2016-071.

Borr Drilling. c2020. Heimdal Specifications. Hamilton (Bermuda): Borr Drilling Ltd. [accessed 2020 Feb 13]. https://borrdrilling.com/wp-content/uploads/2020/01/Borr-Drilling-Heimdal-06-Jan-2020.pdf.

BP. 2020a. Cooper River Chemicals | Where we operate | Home. Houston (TX): BP. [accessed 2020 Aug 3]. https://www.bp.com/en_us/united-states/home/where-we-operate/south-carolina/cooper-river-chemicals.html.

BP. 2020b. Amoco | Who we are | Home. Houston (TX): BP. [accessed 2020 Aug 4]. https://www.bp.com/en/global/corporate/who-we-are/our-brands/amoco.html.

Brayton Point Commerce Center. 2020. Brayton Point Commerce Center | About the Project. The Largest Fossil-Fueled Power Plant In New England, Now Repurposed to Support Renewable Energy. [accessed 2021 Apr 8]. http://www.braytonpointcommercecenter.com/about/.

Breakthrough. 2019 Nov 1. Oil in Motion: Visibility into Crude Oil Transportation. Green Bay (WI): Breakthrough. [accessed 2020 May 13]. https://www.breakthroughfuel.com/blog/oil-in-motion-visibility-into-crude-oil-transportation/.

Bristow Group. c2020. Bristow Helicopter Fleet. Houston (TX): Bristow Group. [accessed 2020a Feb 27]. http://bristowgroup.com/about-bristow/helicopter-fleet/.

Bristow Group. c2020. Oil and Gas Helicopter Transport of Personnel. Houston (TX): Bristow Group. [accessed 2020b Feb 27]. http://bristowgroup.com/helicopter-services/oil-and-gas-transportation/.

Broadmoor, LLC. c2018. Shell Appomattox Living Quarters. Metairie (LA): Broadmoor LLC. [accessed 2020 Feb 12]. http://www.broadmoorllc.com/project/shell-appomattox-living-quarters/.

Broehl J. 2019 Oct 10. The US Near-Term Offshore Wind Pipeline. Chicago (IL): Navigant Research. [accessed 2020 Mar 13]. https://www.navigantresearch.com/news-and-views/the-us-near-term-offshore-wind-pipeline.

Brown RH, Garten JE. 1994. US Industrial Outlook 1994. Darby (PA): DIANE Publishing (An Almanac of Industry, Technology and Services). [accessed 2020 Feb 14].

BSEE [Bureau of Safety and Environmental Enforcement]. c2020. What is decommissioning of offshore platforms? Washington (DC): USDOI. [accessed 2020 Apr 2]. https://www.bsee.gov/faqs/what-is-decommissioning-of-offshore-platforms.

BTS [Bureau of Transportation Statistics]. 2015. Major Truck Routes on the National Highway System: 2015. Washington (DC): US DOT, Bureau of Transportation Statistics. [accessed 2020 May 21]. https://www.bts.gov/major-truck-routes-national-highway-system-2015

BTS [Bureau of Transportation Statistics]. 2018. Port Performance Freight Statistics Program: Annual Report to Congress 2018 (Appendix C). Washington (DC): US Department of Transportation, Buruea of Transportation Statistics. [accessed 2020 May 15].

BTS [Bureau of Transportation Statistics]. 2017 May 20. 3 Measures of Throughput and Capacity. Washington DC: BTS. [accessed 2020 Feb 19].

BTS [Bureau of Transportation Statistics]. 2017 May 21. Table 4-54: Petroleum Oil Spills Impacting Navigable US Waterways. Washington DC: BTS. [accessed 2020 Apr 22].

Bulk Transporter. 2015 Apr 7. New NTTC economic study redefines scope of US tank truck industry. Nashville (TN): Bulk Transporter. [accessed 2020 May 22].

Bulk Transporter. 2019a Dec 31. Bulk Transload Facilities Directory. Nashville (TN): Bulk Transporter. [accessed 2020 May 22]. https://www.bulktransporter.com/page/transload-directory/bulk-transload-facilities-directory.

Bulk Transporter. 2019b Dec 31. Tank Container Depots, New Jersey to South Carolina. Nashville (TN): Bulk Transporter. [accessed 2020 May 22]. https://www.bulktransporter.com/resources/depot-directory/article/21655930/tank-container-depots-new-jersey-to-south-carolina.

Bull AS, Love MS. 2019. Worldwide oil and gas platform decommissioning: A review of practices and reefing options. Ocean & Coastal Management. Volume 168:274–306. doi.

BUTF [Beneficial Use Task Force of the ASTSWMO Materials Management Subcommittee]. 2015. Oil and Gas Exploration and Production Waste Management - Survey Report. Washington (DC): Association of State and Territorial Solid Waste Management Officials

Caldwell E. 2019 Jun 10. Report: The United States Will Be the World's Top LNG Exporter in the Next Five Years. Washington (DC): Energy In Depth. [accessed 2020 May 4].

Cambridge Systematics, Inc. 2019. Risk Assessment of Surface Transport of Liquid Natural Gas. Bethesda (MD): Cambridge Systematics, Inc.: US DOT Pipeline and Hazardous Materials Safety Administration. [accessed 2020 May 14].

Canaport LNG. c2020. LNG Process. Saint John (Canada): Canaport LNG. [accessed 2020 Apr 22]. https://www.canaportlng.com/lng-process.

Carr H. 2014 Mar 16. Rock the Boat, Don't Rock the Boat -- Crude-By-Water and the Jones Act. Houston (TX): RBN Energy. [accessed 2020 May 27]. https://rbnenergy.com/rock-the-boat-don-t-rock-the-boat-crude-by-water-and-the-jones-act.

CBS Baltimore. 2021. Ørsted Completes First Phase Of Building Offshore Wind Staging Center At Tradepoint Atlantic In Sparrows Point. [accessed 2021 Apr 8].

CBS Boston. 2019 Oct 20. Massachusetts Selects 2nd Planned Offshore Wind Project. Boston (MA): CBS Boston. [accessed 2020 Mar 13].

Chakraborty S. 2019 Dec 4. Understanding Design of Oil Tanker Ships. Bangalore (India): Marine Insight. [accessed 2020 May 15]. https://www.marineinsight.com/naval-architecture/oil-tanker-ships/.

Chapa S. 2019 Sep 16. Slideshow: Five LNG export terminals now operating in United States. Houston (TX): Houston Chronicle. [accessed 2020 Apr 30].

Chapa S. 2019 Sep 20. Annova LNG offers new guidance on final investment decision. Houston (TX): Houston Chronicle. [accessed 2020 May 11].

Chapa S. 2019 Dec 16. Kinder Morgan sends out first export cargo from Elba Island LNG. Houston (TX): Houston Chronicle. [accessed 2020 Apr 24].

Chesapeake Shipbuilding. 2015 Dec 22. 5th Hull Fabrication Building Completed at Chesapeake Shipbuilding. Salisbury (MD): Chesapeake Shipbuilding. [accessed 2020 Feb 18]. https://www.chesapeakeshipbuilding.com/news/2016/11/1/5th-hull-fabrication-building-completed-at-chesapeake-shipbuilding.

Chesapeake Shipbuilding. c2020. About Chesapeake Shipbuilding. Salisbury (MD): Chesapeake Shipbuilding. [accessed 2020 Feb 18]. https://www.chesapeakeshipbuilding.com/what-we-do.

Chetan. 2005. Anodes-on-jacket.jpg. [accessed 2020 Apr 2]. https://commons.wikimedia.org/wiki/File:Anodes-on-jacket.jpg.

Chopra K. 2019 Sep 18. Who is a Ship Chandler? Bangalore (India): Marine Insight. [accessed 2020 Apr 3]. https://www.marineinsight.com/careers-2/who-is-a-ship-chandler/.

Christopher B. 2015 Oct 7. Corrosion in Oil Platforms. COMSOL Multiphysics. [accessed 2020 Apr 2]. https://www.comsol.com/blogs/corrosion-in-oil-platforms/.

Chu F, Gailus S, Liu L, Ni L. 2018 Dec 1. The future of automated ports. New York (NY): McKinsey. [accessed 2020 Apr 1].

CIA [Central Intelligence Agency]. 2017. Country Comparison: Natural Gas - Exports - The World Factbook. Washington (DC): Central Intelligence Agency. [accessed 2020 Apr 30].

Cianbro. 2010 Jun 28. Drilling Vessel Stena Forth Departs Maine Ahead of Schedule. Pittsfield (ME): Cianbro. [accessed 2020 Feb 17]. https://www.cianbro.com/News-Videos/ArticleID/676.

Cianbro. 2013 Dec 23. Cianbro Slated to Build Electrical Service Platform for Cape Wind Project. Pittsfield (ME): Cianbro. [accessed 2020 Feb 17]. https://www.cianbro.com/News-Videos/ArticleID/816.

Cianbro. 2017 Jun 12. Offshore Marine Services EBrochure. Pittsfield (ME): Cianbro. [accessed 2020 Feb 17]. https://www.cianbro.com/Portals/1/pdfs/OffshoreMarineServices_EBrochure.pdf.

Cianbro. c2020. VolturnUS 1:8 Floating Offshore Wind Turbine. Pittsfield (ME): Cianbro. [accessed 2020a Feb 17]. https://www.cianbro.com/Projects-Markets/ProjectDetails/pid/494.

Cianbro. c2020. Fabrication & Coating. Pittsfield (ME): Cianbro. [accessed 2020b Feb 17]. https://www.cianbro.com/Fabrication-Coating.

Clarke K, Hemphill J. 2002. The Santa Barbara Oil Spill: A Retrospective. University of Hawaii Press.(64):157–162.

Clean Harbors. 2020. Leading Provider of Environmental, Energy & Industrial Services | Clean Harbors. [accessed 2020 Mar 26]. https://www.cleanharbors.com/about-us.

Clemente J. 2009 Mar 21. Pennsylvania As The New Natural Gas Giant. Forbes. [accessed 2020 Mar 24].

Clemente J. 2020 Mar 22. The US Is Becoming the World's Largest Oil and Natural Gas Exporter. Jersey City (NJ): Forbes. [accessed 2020 Apr 30]..

CNG Services. 2019. Onshore Gas Storage. [accessed 2020 Jul 9]. https://www.cngservices.co.uk/index.php/services/onshore-gas/gas-storage.

Cocklin J. 2020 Mar 19. Business as Usual at US LNG Export Terminals Amid Outbreak, but Overseas Markets Reeling. Sterling (VA): Natural Gas Intelligence. [accessed 2020 Apr 30].

Colson J. 2012 Feb 22. Encana shifting focus to natural gas liquids. PostIndependent. [accessed 2020 May 11]. https://www.postindependent.com/news/encana-shifting-focus-to-natural-gas-liquids/.

Colton T. 2019 Oct 20. Newport News Shipbuilding, Newport News VA. Delray Beach (FL): ShipbuildingHistory. [accessed 2020 Feb 17]. http://shipbuildinghistory.com/shipyards/large/newportnews.htm.

Colton T. c2019. US Builders of Small Ships, Boats and Barges. Delray Beach (FL): ShipbuildingHistory. [accessed 2020a Feb 21]. http://shipbuildinghistory.com/shipyards/small.htm.

Colton T. c2019. US Builders of Large Ships. Delray Beach (FL): ShipbuildingHistory. [accessed 2020b Feb 17]. http://shipbuildinghistory.com/shipyards/large.htm.

Commonwealth of Virginia. 2020 Jan 28. Governor Northam Applauds Deal to Jumpstart Offshore Wind Industry. Richmond (VA): governor.virginia.gov. [accessed 2020 Apr 1].

Conca J. 2018 Oct 11. Which Is Safer For Transporting Crude Oil: Rail, Truck, Pipeline Or Boat? Jersey City (NJ): Forbes. [accessed 2020 May 14].

Connolly A. 2019 Nov 20. Everything you need to know about FLNG. Warrington (UK): Fircroft. [accessed 2020 May 11]. https://www.fircroft.com/blogs/everything-you-need-to-know-about-flng-82911813351.

Cooper S. 2013. Recovering Drilling Muds and Drill Cuttings for Reuse -- Environmental Protection. Environmental Protection. [accessed 2020 Mar 3]. https://eponline.com/Articles/2013/10/04/Recovering-Drilling-Muds-and-Drill-Cuttings-for-Reuse.aspx?Page=1.

Cordock J. 2018 Aug 9. Understanding Bulk Liquid Transport Equipment. Mystic (CT): Bulk Connection. [accessed 2020 May 14]. https://www.bulkconnection.com/blog/understanding-bulk-liquid-transport-equipment.

Cowan G. 2019. FAA working to improve heliport database accuracy. Vertical Magazine. [accessed 2020 Feb 27].

COWI North America I. 2019. 2018 Ports Assessment: Port of Albany-Rensselaer Pre-front End Engineering Design Report. [accessed 2020 Apr 1]. https://www.nyserda.ny.gov/All-Programs/Programs/Offshore-Wind/Economic-Opportunities/Ports-and-Infrastructure.

Crompton J. 2019 Jun 26. 10 major Transmission & Distribution projects in 2019 and beyond. Houston (TX): Fircroft. [accessed 2020 Mar 31]. https://www.fircroft.com/blogs/10-major-transmission-and-distribution-projects-in-2019-and-beyond-91772616236.

Crowley. c2020. Articulated Tug Barges (ATBs). Jacksonville (FL): Crowley Maritime Corporation. [accessed 2020 May 15]. http://www.crowley.com/what-we-do/petroleum-and-chemical-transportation/articulated-tug-barges-atbs/.

CRS [Congressional Resesarch Service]. 2019a. LNG as a Maritime Fuel: Prospects and Policy. Washington (DC): Congressional Research Service: Congressional Research Service Report No.: R45488. https://fas.org/sgp/crs/misc/R45488.pdf.

CRS [Congressional Research Service]. 2019b. The Renewable Fuel Standard (RFS): An Overview. [accessed 2019 Dec 17]. https://fas.org/sgp/crs/misc/R43325.pdf.

CRS [Congressional Research Service]. 2020. Rail Transportation of Liquefied Natural Gas: Safety and Regulation. Washington (DC): Congressional Research Service Report No.: R46414. [accessed 2020 Jul 22].

CSX. c2016. Crude Oil Network:Maps/Locations. Jacksonville (FL): CSX [accessed 2020 May 21]. https://www.csx.com/index.cfm/customers/commodities/oil-gas-and-drilling-materials/crude-oil/maps-locations/.

Cuomo AM. 2019 Jul 18. Governor Cuomo Executes the Nation's Largest Offshore Wind Agreeement and Signs Historic Climate Leadership and Community Protection Act. Albany (NY): NY.gov. [accessed 2020 Mar 30].

Daiss T. 2019 Oct 10. LNG Carrier Market Struggles to Keep Up with Liquefaction Capacity Buildout. Sterling (VA): Natural Gas Intelligence. [accessed 2020 Apr 21].

Damen. c2020. See our barges. Gorinchem (Netherlands): Damen. [accessed 2020 Apr 2]. https://products.damen.com/en/clusters/barges.

DanaEnergy C. 2019. Underground Gas Storage. DanaEnergy. [accessed 2020 Jul 9]. https://www.danaenergy.ir/en/media-menu/dana-magazine/conversations/item/340-underground-gas-storage.

Daron. Daron-Shipchandler. Pointe Noire (Congo): Daron. [accessed 2020 Apr 3]. https://www.daron-shipchandler.com/en/.

Davidson P, Hansen B. 2012. Across USA, pace of jobs recovery is all over the map. Precision Staffing Services: The Talent You Need NOW. [accessed 2019 Nov 21]. https://www.precisionstaffingusa.com/2012/08/31/jobs_recovery/.

Davis C. 2016 Feb 6. Anadark Shutters Final NatGas Well at Independence Hub in GOM. Sterling (VA): Natural Gas Intelligence. [accessed 2020 Feb 19]. https://www.naturalgasintel.com/articles/105259-anadarko-shutters-final-natgas-well-at-independence-hub-in-gom.

Davis DW. 2002. Louisiana's Oil Spill Research and Development Program: 110 Research Awards in Support of 72 Projects and Still Counting. Louisiana State University. [accessed 2020 Feb 11]. http://www.osradp.lsu.edu/.

Davis Ship Service. c2010. Ship spares. Baltimore (MD): Davis Ship Service. [accessed 2020 Apr 3]. http://davisshipservice.com/ship-services/ship-spares/.

Deepwater Development Systems in the Gulf of Mexico Basic Options. c2020. Washington (DC): Bureau of Safety and Environmental Enforcement. [accessed 2020 Feb 14].

Devold H. 2016. Oil and Gas Production Handbook. 3.1. Oslo (Norway): ABB Oil and Gas. [accessed 2020 Aug 4]. https://new.abb.com/oil-and-gas/production-book/petrochemical.

Dhillon H. 2019 Jul 5. Philadelphia Refinery Woe Boosts US East Coast Margins - Bloomberg. Bloomberg. [accessed 2020 Feb 10]. https://www.bloomberg.com/news/articles/2019-07-05/philadelphia-refinery-woe-boosts-u-s-east-coast-fuel-margins.

Diamond Offshore. c2019. Offshore Rig Basics. Houston (TX): Diamond Offshore. [accessed 2020 Feb 13]. http://www.diamondoffshore.com/offshore-drilling-basics/offshore-rig-basics.

DiChristopher T. 2020 Jul 1. Avangrid's NY utilities commit to measures to prevent growth in natural gas. New York (NY): S&P Global. [accessed 2020 Jul 23].

Dismukes D. 2010. Fact book: Offshore oil and gas industry support sectors. New Orleans (LA): US Department of the Interior, Bureau of Ocean Energy Management, Regulation and Enforcement, Gulf of MexicoUS [accessed 2021 Feb 8].

Dismukes DE (Louisiana State University, Baton Rouge, LA). 2008. Examination of the development of liquefied natural gas on the Gulf of Mexico. New Orleans (LA): US Department of the Interior, Minerals Management Service. Report No.: MMS 2008-017. [accessed 2020 Apr 21].

Dismukes DE. 2004 Apr 14. Economic Opportunities for LNG Development in Louisiana. Baton Rouge (LA): Louisiana State University. [accessed 2020 May 7].

Divers Institute of Technology. c2020. Commercial diving on an oil rig: The thrills and dangers of working with offshore equipment. Seattle (WA): Divers Institute of Technology. [accessed 2020 Apr 2]. https://www.diversinstitute.edu/commercial-diving-oil-rig-thrills-dangers-working-offshore-equipment/.

DOE [US Department of Energy]. 2020. The Appalachian Energy and Petrochemical Renaissance: An Examination of Economic Progress and Opportunities. Washington (DC): US Department of Energy [accessed 2020 Aug 4].

DOE [US Department of Energy]. c2019. US Plug-in Electric Vehicle Sales by Model. US Department of Energy, Alternative Fuels Data Center. [accessed 2019 Dec 16]. https://afdc.energy.gov/data/10567.

Dominion Energy. 2020 Aug 1. Dominion Adds Gas Pipeline Links, Storage Capacity with Acquisition of Mid-Atlantic LNG Facility. Richmond (VA): Dominion Energy. [accessed 2020 Apr 23].

Dominion Energy. 2020 Dec 16. Dominion Energy Continues Development of First Jones Act Compliant Offshore Wind Turbine Installation Vessel. Dominion Energy. [accessed 2021 Apr 2].

Dominion Energy. c2020. Cove Point Terminal. Richmond (VA): Dominion Energy. [accessed 2020 Apr 23].

DredgingToday. 2020 Feb 25. Baltimore Dredging Kicks Off. [accessed 2020 Apr 3]. https://www.dredgingtoday.com/2020/02/25/baltimore-dredging-kicks-off/.

Dromgool M. 2015 Jul 8. Effective Maintenance Painting Practices for Offshore Structures. Pittsburgh (PA): KTA-Tator. [accessed 2020 Apr 2]. https://kta.com/kta-university/maintenance-painting-practices-part-2/.

Duchneskie J. 2019 Jul 23. Proposed LNG terminal plan needs more public voices. Philadelphia (PA): The Philadelphia Inquirer. [accessed 2020 May 7].

Dura-Bond. 2016. Corrosion Protection. Dura-Bond Industries. [accessed 2019 Nov 20]. https://www.dura-bond.com/corrosion-protection/.

DWMIS [Drilling Waste Management Information System]. 2012. Drilling Waste Management Technology Descriptions.

Edison Chouest Offshore. c2018. Highly Specialized Vessels Designed for Job-Specific Tasks. Cut Off (LA): Edison Chouest Offshore. [accessed 2020 Feb 14]. http://www.chouest.com/vessels.html.

EEI [Edison Electric Institute]. 2007. Key Facts about the Electric Power Industry. Washington (DC): Edison Electric Institute. [accessed 2020 Jan 1].

EEI [Edison Electric Institute]. c2019. Transmission. Washington (DC): EEI. [accessed 2019 Dec 19]. https://www.eei.org/issuesandpolicy/transmission/Pages/default.aspx.

EIA [US Energy Information Administration]. 2009. Natural Gas Market Centers: A 2008 Update. Washington (DC): Energy Information Administration. [accessed 2020 May 20].

EIA [US Energy Information Administration]. 2016a. Shale gas and oil plays, Lower 48 States. [accessed 2020 May 18].

EIA [US Energy Information Administration]. 2016b. East Coast and Gulf Coast Transportation Fuels Market. Washington (DC): Energy Information Administration A report prepared by ICF International for EIA. [accessed 2020 May 21].

EIA [US Energy Information Administration]. 2019. Form EIA-860: Annual Electric Generator Report. [accessed 2020 Jan 28].

EIA [US Energy Information Administration]. 2020a. US Liquefaction Capacity. [accessed 2020 Feb 3].

EIA [US Energy Information Administration]. 2020b. Annual Energy Outlook 2020. Washington, DC: EIA Office of Energy Analysis, US Department of Energy Annual Energy Outlook Report No.: #AEO2020. [accessed 2020 Feb 10].

EIA [US Energy Information Administration]. 2007 May. International Energy Outlook 2007, Chapter 4 - Natural Gas. Washington (DC): Energy Information Administration. [accessed 2020 Apr 21].

EIA [US Energy Information Administration]. 2012 Feb 7. PADD regions enable regional analysis of petroleum product supply and movements. Washington (DC): Energy Information Administration. [accessed 2020 Jun 17].

EIA [US Energy Information Administration]. 2012 May 11. Potential Impacts of Reductions in Refinery Activity on Northeast Petroleum Product Markets. Washington (DC): Energy Information Administration. [accessed 2020 Jun 30].

EIA [US Energy Information Administration]. 2012 May 14. State electric retail choice programs are popular with commercial and industrial customers - Today in Energy - US Energy Information Administration (EIA). Retail Choice EIA. [accessed 2020 May 5].

EIA [US Energy Information Administration]. 2012 Jun. Annual Energy Outlook 2012 with Projections to 2035. Washington (DC): US Energy Information Administration. [accessed 2020 Mar 18].

EIA [US Energy Information Administration]. 2013 Jul 3. Energy sources have changed throughout the history of the United States. Washington (DC): US Energy Information Administration. [accessed 2020 Mar 18].

EIA [US Energy Information Administration]. 2014 Jun 10. Crude-by-rail transportation provides Bakken Shale production access to major markets. Washington (DC): US Energy Information Administration. [accessed 2020 Jun 30].

EIA [US Energy Information Administration]. 2014 Aug 28. Rail deliveries of US oil continue to increase in 2014. Washington (DC): Energy Information Administration. [accessed 2020 May 13].

EIA [US Energy Information Administration]. 2014 Sep 16. Oil tanker sizes range from general purpose to ultra-large crude carriers on AFRA scale. Washington (DC): US Energy Information Administration. [accessed 2020 May 18].

EIA [US Energy Information Administration]. 2017 Sep 7. Electricity prices reflect rising delivery costs, declining power production costs. Washington (DC): US Energy Information Administration. [accessed 2020 Mar 25].

EIA [US Energy Information Administration]. 2017 Sep 21. Changing quality mix is affecting crude oil price differentials and refining decisions. [accessed 2020 Feb 25].

EIA [US Energy Information Administration]. 2017 Dec 4. Appalachia region drives growth in US natural gas production since 2012. Washington (DC): US Energy Information Administration. [accessed 2020 May 7].

EIA [US Energy Information Administration]. 2018 Feb 9. Utilities continue to increase spending on transmission infrastructure. Washington (DC): US Energy Information Administration. [accessed 2020 Mar 25].

EIA [US Energy Information Administration]. 2018 Mar 8. In the News: Dominion Energy's Cove Point LNG export facility begins commercial operations. Washington (DC): US Energy Information Administration. [accessed 2020 Apr 23].

EIA [US Energy Information Administration]. 2018 Apr 18. This Week in Petroleum: US imports of Canadian crude oil by rail increase. Washington (DC): US Energy Information Administration. [accessed 2020 May 13].

EIA [US Energy Information Administration]. 2018 Apr 19. In the News: Exelon to purchase Everett LNG terminal to ensure supply to Mystic Generating Station. Washington (DC): Energy Information Administration. [accessed 2020 Apr 23].

EIA [US Energy Information Administration]. 2019 Jan. International Energy Outlook 2019 - World total energy consumption by region and fuel [dataset]. Washington (DC): US Energy Information Administration. [accessed 2020 May 4].

EIA [US Energy Information Administration]. 2019 Jan 1. US Fuel Ethanol Plant Production Capacity. US Energy Information Administration (EIA). [accessed 2019 Dec 16]. https://www.eia.gov/petroleum/ethanolcapacity/.

EIA [US Energy Information Administration]. 2019 Jan 24. Annual Energy Outlook 2019 with projections to 2050. Washington (DC): US Energy Information Administration. [accessed 2020 Mar 18]. https://www.eia.gov/outlooks/aeo/pdf/aeo2019.pdf.

EIA [US Energy Information Administration]. 2019 May 28. Canada is a key energy trade partner to the United States. Washington (DC): US Energy Information Administration. [accessed 2020 May 18]. https://www.eia.gov/todayinenergy/detail.php?id=39632.

EIA [US Energy Information Administration]. 2019 Jun 21. US Number and Capacity of Petroleum Refineries. [accessed 2019 Dec 15].

EIA [US Energy Information Administration]. 2019 Aug 15. Investor-owned utilities served 72% of US electricity customers in 2017. Washington (DC): US Energy Information Administration. [accessed 2019 Dec 19].

EIA [US Energy Information Administration]. 2019 Sep 3. EIA Form 860 - Electricity [dataset]. Washington (DC): EIA. [accessed 2020 Mar 19].

EIA [US Energy Information Administration]. 2019 Sep 24. International Energy Outlook 2019 - World natural gas consumption by region [dataset]. Washington (DC): US Energy Information Administration. [accessed 2020 Apr 27].

EIA [US Energy Information Administration]. 2019 Oct 1. EIA Form 861 - Electricity [dataset]. Washington (DC): US Energy Information Administration. [accessed 2020 Feb 16].

EIA [US Energy Information Administration]. 2019 Oct 11. Electricity explained - How electricity is delivered to consumers. Washington (DC): US Energy Information Administration. [accessed 2020 Mar 27]. https://www.eia.gov/energyexplained/electricity/delivery-to-consumers.php.

EIA [US Energy Information Administration]. 2019 Oct 17. In the News: Elba Island, the sixth US LNG export terminal, begins commercial operations. Washington (DC): US Energy Information Administration. [accessed 2020 Apr 24].

EIA [US Energy Information Administration]. 2019 Oct 18. Table 2.2. Sales and Direct Use of Electricity to Ultimate Customers by Sector, by Provider, 2008 through 2018 (Megawatthours). Washington (DC): US Energy Information Administration. [accessed 2020 May 4].

EIA [US Energy Information Administration]. 2019a Oct 22. Electricity Detailed State Data. Washington (DC): US Energy Information Administration. [accessed 2020 May 4].

EIA [US Energy Information Administration]. 2019b Oct 22. The United States now exports crude oil to more destinations than it imports from. Washington (DC): US Energy Information Administration. [accessed 2020 Jul 8].

EIA [US Energy Information Administration]. 2019 Oct 31. Hydrocarbon gas liquids explained: Transporting and storing hydrocarbon gas liquids. Washington (DC): US Energy Information Administration. [accessed 2020 May 13].

EIA [US Energy Information Administration]. 2019 Dec 5. Natural gas explained: Natural gas pipelines. Washington (DC): US Energy Information Administration. [accessed 2020 May 13].

EIA [US Energy Information Administration]. 2019 Dec 12. US Dry Natural Gas Expected Future Production (Reserves) [dataset]. Washington (DC): US Energy Information Administration. [accessed 2020 Apr 30].

EIA [US Energy Information Administration]. 2019a Dec 14. US Refinery Yield. US Energy Information Administration . [accessed 2019 Dec 14].

EIA [US Energy Information Administration]. 2019b Dec 14. Crude Imports. US Energy Information Administration . [accessed 2019 Dec 14].

EIA [US Energy Information Administration]. 2020c. US Energy Information Administration - EIA - Independent Statistics and Analysis. Annual Energy Outlook 2020. [accessed 2020 May 5].

EIA [US Energy Information Administration]. 2020d. US Energy Information Administration - EIA - Independent Statistics and Analysis. Annual Energy Outlook 2020. Table: Table 8. Electricity Supply, Disposition, Prices, and Emissions [dataset]. Washington (DC): US Energy Information Administration. [accessed 2020 Mar 26].

EIA [US Energy Information Administration]. 2020 Jan 1. Crude Oil and Natural Gas Drilling Activity [dataset]. Washington (DC): US Energy Information Administration. [accessed 2020 Feb 20]. https://www.eia.gov/dnav/pet/pet_crd_drill_s1_m.htm.

EIA [US Energy Information Administration]. 2020 Jan 22. US State-to-State capacity [dataset]. Washington (DC): US Energy Information Administration. [accessed 2020 Jun 18].

EIA [US Energy Information Administration]. 2020 Jan 27. EIA forecasts US crude oil production will keep growing through 2021, but more slowly. Washington (DC): US Energy Information Administration. [accessed 2020 Feb 20].

EIA. 2020a Jan 29. Table 62. Natural Gas Consumption by End-Use Sector and Census Division [dataset]. Washington (DC): US Energy Information Administration. [accessed 2020 Jul 22].

EIA [US Energy Information Administration]. 2020b Jan 29. Table 60. Lower 48 Natural Gas Production and Supply Prices by Supply Region [dataset]. Washington (DC): US Energy Information Administration. [accessed 2020 Jul 23]. https://www.eia.gov/outlooks/aeo/data/browser/#/?id=72-AEO2020&cases=ref2020&sourcekey=0.

EIA [US Energy Information Administration]. 2020c Jan 29. Table 59. Lower 48 Crude Oil Production and Wellhead Prices by Supply Region [dataset]. Washington (DC): US Energy Information Administration. [accessed 2020 Jul 23].

EIA [US Energy Information Administration]. 2020a Jan 31. US Exports of Crude Oil (Thousand Barrels per Day). US Exports of Crude Oil (Thousand Barrels per Day). [accessed 2020 Mar 11].

EIA [US Energy Information Administration]. 2020b Jan 31. US Imports of Crude Oil (Thousand Barrels per Day). US Imports of Crude Oil (Thousand Barrels per Day). [accessed 2020 Mar 11].

EIA [US Energy Information Administration]. 2020 Feb 4. Frequently Asked Questions - How much natural gas does the United States have, and how long will it last? Washington (DC): US Energy Information Administration. [accessed 2020 Apr 21].

EIA [US Energy Information Administration]. 2020 Mar 2. US Refiner Petroleum Product Prices. US Energy Information Administration (EIA). [accessed 2020 Mar 10].

EIA [US Energy Information Administration]. 2020 Mar 5. Natural Gas Pipeline Projects [dataset]. Washington (DC): Energy Information Administration. [accessed 2020 Jun 24].

EIA [US Energy Information Administration]. 2020 Mar 11. Spot Prices for Crude Oil and Petroleum Products. US Energy Information Administration (EIA). [accessed 2020 Mar 12].

EIA [US Energy Information Administration]. 2020 Mar 16. Table 3.5 Petroleum Products Supplied by Type. US Energy Information Administration (EIA). [accessed 2020 Mar 16].

EIA [US Energy Information Administration]. 2020a Mar 31. US Natural Gas Imports [dataset]. Washington (DC): US Energy Information Administration. [accessed 2020 Apr 27].

EIA [US Energy Information Administration]. 2020b Mar 31. US Natural Gas Marketed Production [dataset]. Washington (DC): US Energy Information Administration. [accessed 2020 Apr 28]. https://www.eia.gov/dnav/ng/hist/n9050us2a.htm.

EIA [US Energy Information Administration]. 2020 Apr. Table 4c. Average Annual Coal Transportation Costs from State to State by Railroad [dataset]. Washington (DC): US Energy Information Administration. [accessed 2020 Jun 25]. https://www.eia.gov/coal/transportationrates/.

EIA [US Energy Information Administration]. 2020 Apr 7. Short-Term Energy Outlook Data Browser - Natural Gas Consumption [dataset]. Washington (DC): US Energy Information Administration. [accessed 2020 Apr 23].

EIA [US Energy Information Administration]. 2020 Apr 16. Dry shale gas production estimates by play. Washington (DC): US Energy Information Administration. [accessed 2020 May 7]. https://www.eia.gov/naturalgas/weekly/img/202003_monthly_dry_shale.png.

EIA [US Energy Information Administration]. 2020 Apr 17. Frequently Asked Questions - What is the volume of world natural gas reserves? Washington (DC): US Energy Information Administration. [accessed 2020 Apr 21]. https://www.eia.gov/tools/faqs/faq.php?id=52&t=8.

EIA [US Energy Information Administration]. 2020 Apr 22. Henry Hub Natural Gas Spot Price [dataset]. Washington (DC): Energy Information Administration. [accessed 2020 Apr 28].

EIA [US Energy Information Administration]. 2020a Apr 30. US Natural Gas Exports [dataset]. Washington (DC): US Energy Information Administration. [accessed 2020 Apr 30].

EIA [US Energy Information Administration]. 2020b Apr 30. US Natural Gas Exports and Re-Exports by Point of Exit - LNG volumes [dataset]. Washington (DC): US Energy Information Administration.

EIA [US Energy Information Administration]. 2020c Apr 30. Total Crude Oil by Rail [dataset]. Washington (DC): US Energy Information Administration. [accessed 2020 May 13].

EIA [US Energy Information Administration]. 2020a May 29. Movements by Pipeline between PAD Districts [dataset]. Washington (DC): Energy Information Administration. [accessed 2020 Jun 17].

EIA [US Energy Information Administration]. 2020b May 29. Movements of Crude Oil and Selected Products by Rail [dataset]. Washington (DC): Energy Information Administration. [accessed 2020 Jun 24].

EIA [US Energy Information Administration]. 2020 Jun 4. Liquids Pipeline Projects [dataset]. Washington (DC): Energy Information Administration. [accessed 2020 Jun 25].

EIA [US Energy Information Administration]. 2020a Jun 22. Refinery Receipts of Crude Oil by Method of Transportation - Total Crude by Trucks [dataset]. Washington (DC): US Energy Information Administration. [accessed 2020 Jun 30].

EIA [US Energy Information Administration]. 2020b Jun 22. Refinery Receipts of Crude Oil by Method of Transportation - East Coast (PADD 1) [dataset]. Washington (DC): US Energy Information Administration. [accessed 2020 Jul 6].

EIA [US Energy Information Administration]. 2020a Jun 30. US Field Production of Crude Oil [dataset]. Washington (DC): Energy Information Administration. [accessed 2020 Jul 8].

EIA [US Energy Information Administration]. 2020b Jun 30. Movements by Tanker and Barge between PAD Districts [dataset]. Washington (DC): US Energy Information Administration. [accessed 2020 Jul 1].

EIA [US Energy Information Administration]. 2020c Jun 30. PAD District Imports by Country of Origin [dataset]. Washington (DC): US Energy Information Administration. [accessed 2020 Jul 7]. https://www.eia.gov/dnav/pet/pet_move_impcp_a2_r10_ep00_IP0_mbblpd_a.htm.

EIA [US Energy Information Administration]. 2020d Jun 30. PAD District Exports by Destination [dataset]. Washington (DC): US Energy Information Administration. [accessed 2020 Jul 8].

EIA [US Energy Information Administration]. 2020e Jun 30. US Natural Gas Imports & Exports by State [dataset]. Washington (DC): US Energy Information Administration. [accessed 2020 Jul 9].

EIA [US Energy Information Administration]. c2020. FERC's Hackberry Decision (2002). Washington (DC): US Energy Information Administration. [accessed 2020a Apr 21].

EIA [US Energy Information Administration]. c2019. Refinery Capacity Report. [accessed 2019a Dec 15].

EIA [US Energy Information Administration]. c2006. Refinery Capacity Report. [accessed 2019 Dec 15].

EIA [US Energy Information Administration]. c2019. Movements by Pipeline, Tanker, Barge and Rail between PAD Districts. US Energy Information Administration. [accessed 2019b Dec 19].

EIA [US Energy Information Administration]. c2020. Table 38. Light-Duty Vehicle Sales by Technology Type. EIA. [accessed 2020b Mar 14].

EIA [US Energy Information Administration]. c2010. Table 57. Light-Duty Vehicle Sales by Technology Type. US Energy Information Administration. [accessed 2020 Mar 14].

EIA [US Energy Information Administration]. c2019. Electricity Data Browser - Net Generation [dataset]. Washington (DC): EIA. [accessed 2019c Dec 27].

EIA [US Energy Information Administration]. c2020. US Energy Mapping System. [accessed 2020c

Elengy. c2020. What is an LNG Terminal? Bois-Colombes (France): Elengy. [accessed 2020 Apr 22]. https://www.elengy.com/en/lng/what-is-an-lng-terminal.html.

Ellfeldt A. 2021 Mar 9. America's Biggest Banks Promise to Fight Climate Change. Scientific American. [accessed 2021 Oct 12].

Elliot AF. 2017 Sep 6. History of the Seawise Giant world's largest ship revealed. London (UK): Daily Mail. [accessed 2020 May 18]. https://www.dailymail.co.uk/travel/travel_news/article-4779070/History-Seawise-Giant-world-s-largest-ship.html.

Emission Standards: USA: Cars and Light-Duty Trucks—Tier 2. 2019. DieselNet. [accessed 2019 Dec 16]. https://www.dieselnet.com/standards/us/ld_t2.php.

Energy Transfer. c2020. Rover Pipeline Project. Dallas (TX): Rover Pipeline. [accessed 2020 Jun 24]. https://www.roverpipelinefacts.com/.

Engie. c2020. Natural Gas & LNG. Houston (TX): ENGIE. [accessed 2020 Apr 23]. http://www.engie-na.com/business/natural-gas-lng/.

EnLink Midstream. c2020. About Sabine Pipe Line LLC. Dallas (TX): EnLink Midstream. [accessed 2020a May 28]. https://sabinepipeline.enlink.com/about-sabine-pipe-line-llc/.

EnLink Midstream. c2020. Operations. Dallas (TX): EnLink Midstream. [accessed 2020b May 28]. https://www.enlink.com/operations/.

Enomoto CB, Trippi MH, Higley DK, Drake II RM, Gaswirth SB, Mercier TJ, Brownfield ME, Leathers-Miller HM, Le PA, Marra KR, et al. 2019. Assessment of undiscovered continuous oil and gas resources in the Upper Ordovician Point Pleasant Formation and Utica Shale of the Appalachian Basin Province, 2019. Reston (VA) Fact Sheet Report No.: 2019–3044..

EPA [US Environmental Protection Agency]. 1997. Profile of the Shipbuilding and Repair Industry. [accessed 2020 Feb 27].

EPA [US Environmental Protection Agency]. 1999. The History of Reducing Tailpipe Emissions. [accessed 2019 Dec 16].

EPA [US Environmental Protection Agency]. 2019a. Data Downloads ECHO. https://web.archive.org/web/20190917210220/https://echo.epa.gov/tools/data-downloads.

EPA [US Environmental Protection Agency]. 2020. Nontechnical Summary of the Risk Evaluation for Methylene Chloride (Dichloromethane, DCM). Washington (DC) Report No.: EPA-740-R1-8010. [accessed 2020 Aug 4].

EPA [US Environmental Protection Agency]. 2002. Exemption of Oil and Gas Exploration and Production Wastes from Federal Hazardous Waste Regulations. Washington (DC): US Environmental Protection Agency. [accessed 2020 Aug 4].

EPA [US Environmental Protection Agency]. 2014 Mar 1. EPA Sets Tier 3 Motor Vehicle Emission and Fuel Standards. US Environmental Protection Agency. [accessed 2019 Dec 16].

EPA [US Environmental Protection Agency]. 2014 Apr 1. Review of State Oil and Natural Gas Exploration, Development, and Production (E&P) Washington (DC): US Environmental Protection Agency. [accessed 2020 Aug 4]. Solid Waste Management Regulations.

EPA [US Environmental Protection Agency]. 2016 Jun 9. The Frank R. Lautenberg Chemical Safety for the 21st Century Act. Washington (DC): US Environmental Protection Agency. [accessed 2020 Aug 4].

EPA [US Environmental Protection Agency]. 2018 Sep 20. RIN Trades and Price Information. US Environmental Protection Agency (EPA). Washington (DC): US Environmental Protection Agency [accessed 2019 Dec 16].

EPA [US Environmental Protection Agency]. 2019b. Management of Oil and Gas Exploration and Production Waste | Hazardous Waste | US EPA. Washington (DC): US Environmental Protection Agency [accessed 2020 Feb 21].

EPA [US Environmental Protection Agency]. 2020 Apr 1. Chemicals Undergoing Risk Evaluation under TSCA. Washington (DC): US Environmental Protection Agency. [accessed 2020 Aug 4].

Equinor. 2019 Jul 18. Equinor offshore wind bid wins in New York State. Stavanger (Norway): Equinor. [accessed 2020 Mar 13]. https://www.equinor.com/en/news/2019-new-york-offshore-wind-bid.html.

Era Helicopters. 2020. AgustaWestland AW139. Houston (TX): Era Helicopters. [accessed 2020 May 4]. https://www.erahelicopters.com/fleet/detail/472/agustawestland-aw139#.

Era Helicopters. c2020. Locations. Houston (TX): Era Helicopters. [accessed 2020 Apr 4]. https://www.erahelicopters.com/locations.

Eureka. 2020. Eureka Resources. Eureka Resources. [accessed 2020 Mar 25]. https://www.eureka-resources.com.

Excelerate Energy. 2011 Apr 13. Excelerate Energy to Retire Its Gulf Gateway Deepwater Port. The Woodlands (TX): Excelerate Energy LP. [accessed 2020 Apr 23]. https://excelerateenergy.com/excelerate-energy-retire-gulf-gateway-deepwater-port/.

Excelerate Energy. c2020. Northeast Gateway Deepwater Port. The Woodlands (TX): Excelerate Energy LP. [accessed 2020a Apr 22]. https://excelerateenergy.com/project/northeast-gateway-deepwater-port/.

Excelerate Energy. c2020. Gulf Gateway Deepwart Port. The Woodlands (TX): Excelerate Energy LP. [accessed 2020b Apr 23]. https://excelerateenergy.com/project/gulf-gateway-deepwater-port-2/.

Exelon. 2019 Sep 20. Three Mile Island Generating Station Unit 1 Retires from Service After 45 Years. Chicago (IL): Exelon Corp. [accessed 2020 Mar 26]. https://www.exeloncorp.com/newsroom/three-mile-island-generating-station-unit-1-retires.

Exelon. c2020. Everett LNG Facility. Chicago (IL): Exelon Corp. [accessed 2020 Apr 23]. https://www.exeloncorp.com/locations/power-plants/everett-lng-facility.

Exelon. c2019. Three Mile Island Decommissioning - Exelon. Chicago (IL): Exelon Corp. [accessed 2019 Dec 20]. https://www.exeloncorp.com/locations/three-mile-island-decommissioning.

Fahim M, Al-Sahhaf T, Lababidi H, Elkilani A. 2009. Fundamentals of Petroleum Refining.

FAS, OTA [Federation of American Scientists, Office of Technology Assessment]. 1995 Sep. Assessing the Potential for Civil-Military Integration: Selected Case Studies. Washington (DC): Office of Technology Assessment. [accessed 2020 Feb 14].

Federici C, Mintz J. 2014 May 1. Oil Properties and Their Impact on Spill Response Options. Washington (DC): BSEE. [accessed 2020 Apr 22].

FERC [Federal Energy Regulatory Commission]. 2014. Order Granting Section 3 and Section 7 Authorizations - Docket No. CP13-113-000. Washington (DC): Federal Energy Regulatory Commission. [accessed 2020 Apr 23].

FERC [Federal Energy Regulatory Commission]. 2015. Energy Primer: A Handbook of Energy Market Basics. Washington (DC): Federal Energy Regulatory Commission. [accessed 2020 May 19].

FERC [Federal Energy Regulatory Commission]. 2020a. North American LNG Import Terminals (Existing). [accessed 2020 Apr 22].

FERC [Federal Energy Regulatory Commission]. 2020b. North American LNG Export Terminals (Approved, Not Yet Built). [accessed 2020 Apr 28].

FERC [Federal Energy Regulatory Commission]. 2018 May 4. Order Granting Approvals in Connection with the Dissolution of the Southwest Power Pool Regional Entity - Docket No. RR18-3-000. Washington (DC): FERC. [accessed 2020 Mar 19].

FERC [Federal Energy Regulatory Commission]. 2019 Aug 22. FERC: Industries - Order No. 1000 - Transmission Planning and Cost Allocation. Washington (DC): FERC. [accessed 2020 Jan 1]. https://www.ferc.gov/industries/electric/indus-act/trans-plan.asp.

FERC [Federal Energy Regulatory Commission]: Industries - Electric Competition. 2019. [accessed 2020 Jan 1]. https://www.ferc.gov/industries/electric/indus-act/competition.asp.

Fielden S. 2014 Mar 10. Rock the Boat Don’t Rock the Boat - The Inland Crude Tank Barge Fleet. Houston (TX): RBN Energy. [accessed 2020 May 27]. https://rbnenergy.com/rock-the-boat-don-t-rock-the-boat-the-inland-crude-tank-barge-fleet.

Fluor. 2019 Dec 14. Garyville Oil Refinery Major Expansion Project. Fluor. [accessed 2019 Dec 14]. https://www.fluor.com/projects/marathon-refinery-engineering-construction.

Folga SM. 2007. Natural Gas Pipeline Technology Overview.

de Fommervault OP, Rodríguez-Rubio E, Rincón-Martínez D. 2020 Mar 1. Autonomous underwater gliders conduct seep surveys off Colombia. Offshore. [accessed 2020 Apr 6].

Foss MM. 2012. Introduction to LNG: An overview on liquefied natural gas (LNG), its properties, the LNG industry, and safety considerations. Houston (TX): The University of Texas at Austin: Bureau of Economic Geology, Jackson School of Geosciences. [accessed 2020 Apr 22].

FracTracker Alliance. 2016 Jun 14. An Introduction to Oil and Gas Pipelines. Camp Hill (PA): FracTracker Alliance. [accessed 2020 May 18]. https://www.fractracker.org/2016/06/introduction-oil-gas-pipelines/.

Frangoul A. 2019 Nov 21. New Jersey ramps up targets ast it looks to go big on offshore wind energy. Englewood Cliffs (NJ): CNBC. [accessed 2020 Mar 13]. https://www.cnbc.com/2019/11/21/new-jersey-ramps-up-targets-looks-to-go-big-on-offshore-wind-energy.html.

FRCC Board Votes to Dissolve Regional Entity. 2018. https://www.frcc.com/Documents/BOD%20Vote%20-%20Release%20(10.30.18).pdf.

Freeman S. 2017 Oct 13. A giant comes home to Ingleside. Corpus Christi (TX): Corpus Christi Business News. [accessed 2020 Feb 12]. https://www.ccbiznews.com/appomatox-ingleside-shell-oil.

Frittelli J. 2014. Shipping US Crude Oil by Water: Vessel Flag Requirements and Safety Issues. Washington (DC): Congressional Research Service: Congressional Research Service Report No.: R43653. [accessed 2020 May 26].

Frittelli J. 2017 May 2. Revitalizing Coastal Shipping for Domestic Commerce. Washington DC: Congressional Research Service. [accessed 2020 Feb 20].

Frittelli J. 2019 Nov 21. Shipping Under the Jones Act: Legislative and Regulatory Background. Washington (DC): Congressional Research Service. [accessed 2020 Feb 19].

Frittelli J, Andrews A, Parfomak PW, Pirog R, Ramseur JL, Ratner M. 2014. US Rail Transportation of Crude Oil: Background and Issues for Congress. Washington (DC): Congressional Research Service: Congressional Research Service Report No.: R43390. [accessed 2020 May 14].

FURGO Consultants. 2015 Mar 26. Virginia Offshore Oil and Gas Readiness Study | BidNet. [accessed 2021 Oct 13]. https://www.bidnet.com/closed-government-contracts/virginia-offshore-oil-and-gas-readiness-study?itemId=354139331.

Gallagher P. 2018 Aug 24. A guide to FLNG (floating liquefied natural gas). London (UK): Oil & Gas IQ. [accessed 2020 May 11]. https://www.oilandgasiq.com/fpso-flng/articles/guide-to-flng.

Gardner T, Volcovici V. 2020 Mar 9. Where Biden and Sanders diverge on climate change. Reuters. [accessed 2020 Mar 15].

GCCOC [Gloucester Chamber of Commerce]. c2018. Paulsboro Refinery. Gloucester County Chamber of Commerce. [accessed 2019 Dec 15]. https://www.gc-chamber.com/wp-content/uploads/2019/04/Refinery-1.pdf.

General Dynamics. c2020. Electric Boat. Reston (VA): General Dynamics. [accessed 2020 Feb 17]. https://www.gd.com/our-businesses/marine-systems/electric-boat.

GIIGNL [International Group of Liquefied Natural Gas Importers]. 2019. GIIGNL Information Paper No. 3 - LNG Ships. Paris (France): International Group of Liquefied Natural Gas Importers. [accessed 2020 Apr 21].

Global Security. c2019. Shipyards. Alexandria (VA): Global Security. [accessed 2020 Feb 21]. https://www.globalsecurity.org/military/facility/intro-shipyard.htm.

Good news for UMaine and Maine: New England Aqua Ventus. 2020 Aug 5. University of Maine. [accessed 2020 Aug 5]. https://umaine.edu/president/2020/08/05/good-news-for-umaine-and-maine-new-england-aqua-ventus/.

Google Maps. c2020. DelDOT Helistop-0N5. [accessed 2020 Apr 4]. https://www.google.com/maps/place/DelDOT+Helistop-0N5/@39.1483947,-75.5036893,171m/data=!3m1!1e3!4m5!3m4!1s0x0:0x2ee704f2c090ae48!8m2!3d39.1482611!4d-75.5033874.

GPRID [Global Petroleum Research Institute Designs]. 2012. Conversion of Oil Field Produced Brine to Fresh Water.

Grabow C. 2019 Apr 25. The Jones Act is protecting US Shipyards to death - Opinion. Philadelphia (PA): The Philadelphia Inquirer. [accessed 2020 Mar 12].

Graham L, Hale C, Maung-Douglass E, Sempier S, Swann L, Wilson E. c2020. Chemical Dispersants and their role in Oil Spill Response. Ocean Springs (MS): Mississippi-Alabama Sea Grant Consortium. [accessed 2020 Apr 22].

Greenberg J. 2012 Jul. Deepwater needs spur most advances in offshore rig designs. Houston (TX): World Oil. [accessed 2020 Feb 13]. https://www.worldoil.com/magazine/2012/july-2012/special-focus/deepwater-needs-spur-most-advances-in-offshore-rig-designs.

Grijpink et al. 2020 Nov 6. How tapping connectivity in oil and gas can fuel higher performance. McKinsey & Company. [accessed 2021 October 21].

Guan SW. 2010. Layer of Protection, New Challenges and Developments in Pipeline Coatings.

Guan SW, Gritis N, Jackson A, Singh P. 2005. Advanced Onshore and Offshore Pipeline Coating Technologies. Shanghai, China: Bredero Shaw. p. 6.

Guillen P, Wetzler N, Abstoss N. 2011. Analysis of Maryland Port Facilities for Offshore Wind Energy Services. Kinetik Partners (Prepared for Maryland Energy Administration). [accessed 2020 Apr 1].

Gulf Island Fabrication. 2012. Gulf Island Fabrication, Inc. 10-K. Washington (DC): US Securities and Exchange Commission. [accessed 2020 Feb 11].

Gulf Island Fabrication. 2016. Gulf Island Fabrication, Inc. 10-K. Washington (DC): US Securities and Exchange Commission. [accessed 2020 Feb 17].

Gulf Island Fabrication. 2019. Gulf Island Fabrication, Inc. 10-K. Washington (DC): US Securities and Exchange Commission. [accessed 2020 Feb 13].

Gulf Island Fabrication. 2014 Jul 24. Gulf Island Fabrication, Inc. Announces Cooperative Agreement. Houston (TX): Gulf Island Fabrication, Inc. [accessed 2020 Feb 19]. https://www.gulfisland.com/news-media/press-releases/detail/117/gulf-island-fabrication-inc-announces-cooperative.

Gulf Island Fabrication. 2018 Apr 3. Bay State Wind Brings New Steel Facility and Manufacturing Capabilities to Massachusetts. Houston (TX): Gulf Island Fabrication, Inc. [accessed 2020 Mar 17].

Gulf Island Fabrication. c2020. Louisiana Facility. Houston (TX): Gulf Island Fabrication, Inc. [accessed 2020 Feb 20]. https://www.gulfisland.com/operations/fabrication/louisiana-facility.

Gulf Spill Restoration. c2020. Incident Overview. Washington (DC): NOAA. [accessed 2020 Apr 21].

Guo Q, Geehan T. 2004. An Overview of Drill Cuttings Re-Injection - Lessons Learned and Recommendations.

GustoMSC. c2020. ENSIS. Houston (TX): GustoMSC US, Inc. [accessed 2020 May 5]. https://www.gustomsc.com/design/wind-installation/ensis.

Halliburton. 2020c. Thermal Treatment - Halliburton. [accessed 2020 May 13]. https://www.halliburton.com/en-US/ps/baroid/fluid-services/waste-management-solutions/waste-treatment-and-disposal/thermal-processing-systems/default.html.

Hand M. 2018 Mar 23. Study predicts major expansion of offshore wind along Atlantic coast. Washington (DC): Think Progress. [accessed 2020 Mar 13]. https://thinkprogress.org/offshore-atlantic-wind-grows-as-costs-decline-585bed01c992/.

Hansen ME, Dursteler E. 2017. Pipelines, Rail, & Trucks. Logan (UT): Strata. [accessed 2020 May 13]. https://www.strata.org/pipelines-rails-trucks/.

Harris Beach PLLC. 2018. Proceeding on Motion of the Commission of the Commission as to the Rates, Charges, Rules and Regulations of St. Lawrence Gas Company, Inc. Regarding Franklin and St. Lawrence Counties Expansion Project. Testimony and Exhibits of: Construction Panel, Book 2. [accessed 2020 Feb 4].

Heineke K, Kloss B, Scurtu D, Weig F. 2019 Jan 1. Micromobility's 15,000-mile checkup. McKinsey and Company. [accessed 2020 Mar 15].

Herbert-Burns R, Bateman S, Lehr P. 2009. Lloyd's MIU Handbook of Maritime Security. Boca Raton (FL): CRC Press. [accessed 2020 Apr 21].

Hi-Tech Electric, Inc. c2020. Shell Appomattox. Houston (TX): High-Tech Electric. [accessed 2020 Feb 20]. https://hitechelectric.com/projects/shell-appomattox/.

Ho B. 2018 Jun 12. The Regional Greenhouse Gas Initiative Is a Model for the Nation. New York (NY): NRDC. [accessed 2020 Mar 25]. https://www.nrdc.org/resources/regional-greenhouse-gas-initiative-model-nation.

Hornbeck Offshore Services. 2012. Hornbeck Offshore Services, Inc. 10-K. Washington (DC): US Securities and Exchange Commission. [accessed 2020 Feb 14].

Hornbeck Offshore Services. 2019. Hornbeck Offshore Services, Inc. 10-K. Washington (DC): US Securities and Exchange Commission. [accessed 2020 Feb 20].

Huntington Ingalls. 2016 Jul 21. Defense Security Service (DSS) Rates NNS "Commendable." Newport News (VA): Huntington Ingalls Industries. [accessed 2020 Feb 20]. https://nns.huntingtoningalls.com/articles/defense-security-service-dss-rates-nns-commendable/.

Huntington Ingalls. 2020 Feb 13. Fact Sheet. Newport News (VA): Huntington Ingalls Industries. [accessed 2020 Feb 17]. https://www.huntingtoningalls.com/wp-content/uploads/2020/02/hii_facts13feb20.pdf.

Hurdle J. 2018 Feb 2. Are we next? Delaware refinery workers worry after Philadelphia plant files for bankruptcy. Delaware First Media. [accessed 2019 Dec 13]. h

Hurdle J. 2019 Dec 24. Shuttered Philadelphia Refinery May Get New Life After Fire. New York Times. [accessed 2020 Jun 30].

Hurdle J. 2020 Mar 4. Hearing on LNG Terminal Plan for South Jersey Will Give Critics Another Chance to Object. Montclair (NJ): NJ Spotlight. [accessed 2020 May 7].

Hurdle J. 2020 Apr 27. Complaint: New Jersey LNG terminal didn't get full assessment before permit granted. Montclair (NJ): NJ Spotlight. [accessed 2020 May 7].

Hydro International. 2007 Nov 20. Online Monitoring of Ageing North Sea Jackets. Lemmer (The Netherlands): Hydro International. [accessed 2020 Feb 19].

i95Highway.com. The I-95...Interstate 95 Highway. i95Highway.com. [accessed 2020 May 22]. http://www.i95highway.com/.

ICF. 2018 Jun 18. North America Midstream Infrastructure through 2035: Significant Development Continues. Washington DC: Interstate Natural Gas Association of America. [accessed 2020 Jul 10].

IEA [International Energy Agency]. 2019 Jun. Gas 2019. Paris (France): International Energy Agency. [accessed 2020 Apr 30]. https://www.iea.org/reports/market-report-series-gas-2019.

IER [Institute for Energy Research]. 2019 Jul 12. Atlantic Coast States Plan Expensive Offshore Wind Farms. Washington (DC): Institute for Energy Research. [accessed 2020 Mar 13].

IGU [International Gas Union]. c2017. Natural Gas Facts & Figures. Barcelona (Spain): International Gas Union. [accessed 2020 May 13]. https://www.igu.org/resources-data.

Ijaz M. 2018 Mar 1. Comparing Powder and Liquid Coatings for Pipeline Applications. [accessed 2019 Nov 19].

IMO [International Maritime Organization]. c2020. Sulphur 2020 - cutting sulphur oxide emissions. London (UK): International Maritime Organization. [accessed 2020a May 4]. http://www.imo.org/en/MediaCentre/HotTopics/Pages/Sulphur-2020.aspx.

IMO [International Maritime Organization]. c2020. Sulphur oxides (SOx) and Particulate Matter (PM) - Regulation 14. London (UK): International Maritime Organization. [accessed 2020b May 5].

Industrial College of Armed Forces. 2008. Spring 2008 Industry Study - Shipbuilding Industry Final Report. Washington (DC): National Defense University. [accessed 2020 Feb 20].

Industrial College of Armed Forces. 2009. Final Report: Shipbuilding Industry. Washington (DC): National Defense University. [accessed 2020 Feb 14].

Industrial College of Armed Forces. 2017. Spring 2017 Industry Study: Shipbuilding. Washington (DC): National Defense University. [accessed 2020 Feb 20].

INGAA [Interstate Natural Gas Association of America]. 2019. Interstate Natural Gas Association of America - Pipe Coating. [accessed 2019 Nov 19]. https://www.ingaa.org/Pipelines101/Operations/25952.aspx.

International Association of Oil & Gas Producers. c2020. Metocean. London (UK): International Association of Oil & Gas Producers. [accessed 2020 Apr 3]. https://www.iogp.org/metocean/.

International Marine Contractors Association. Our Industry - Marine. London (UK): International Marine Contractors Association. [accessed 2020 Feb 27]. https://www.imca-int.com/divisions/marine/industry/.

International Maritime Organization. 2006. Resolution MSC.235(82): Adoption of the guidelines for the design and construction of offshore supply vessels, 2006. [accessed 2020 Apr 30].

Intership. c2020. Camelot Brochure. [accessed 2020 Feb 28]. http://www.barges.com/pdf/camelot/brochures/2020-Camelot-Draft-V5-Online.pdf.

Intership. c2019. Intership Fleet. Houston (TX): Intership. [accessed 2020 Feb 28]. http://www.barges.com/fleet/.

Interstate Natural Gas Association of America, INGAA. 2014 Mar 18. North American Midstream Infrastructure through 2035: Capitalizing on Our Energy Abundance. Washington DC: INGAA. [accessed 2020 Jul 10].

ITOPF. 2020 Jan 1. Oil Tanker Spill Statistics 2019. London (UK): ITOPF. [accessed 2020 Apr 22]. https://www.itopf.org/fileadmin/data/Documents/Company_Lit/Oil_Spill_Stats_brochure_2020_for_web.pdf.

Jha B. 2019 Oct 2. Different Types of Barges Used in the Shipping World. Bangalore (India): Marine Insight. [accessed 2020 May 15]. https://www.marineinsight.com/types-of-ships/different-types-of-barges-used-in-the-shipping-world/.

Johnson C. 2020 Feb 12. Electric Vehicle Tax Credit: What to Know for 2020. Jacksonville (FL): Action News Jax. [accessed 2020 Apr 7]. https://www.actionnewsjax.com/news/consumer/clark-howard/electric-vehicle-tax/KKXSZQSGI5XNYIXEQECJQ7RJPU/.

Johnson K. 2020 Mar 3. Democrats Threaten Energy Rollback. Foreign Policy. [accessed 2020 Mar 15].

Johnson T. 2019 Apr 24. Which N.J. ports could be offshore-wind industry hubs? Edge for Paulsboro? Philadelphia (PA): WHYY. [accessed 2020 Apr 3].

Johnson T. 2019 Jul 2. Orsted’s Plan for Wind in NJ Promises to Aid Economic Development. Montclair (NJ): NJ Spotlight. [accessed 2020 Mar 17].

Kaminski-Morrow D. 2008 Apr 11. Bristow starts operations with first TCAS II-equipped helicopter. Hamburg (Germany): Flight Global. [accessed 2020 Apr 30].

Kammerzell J. 2005 Mar. Eastern GoM hub frees independent deepwater fields. New York (NY): LexisNexis.

Kaplan T. 2014 Dec 17. Citing Health Risks, Cuomo Bans Fracking in New York State. The New York Times. [accessed 2020 Mar 26].

Kelkar M. 2008. Natural Gas Production Engineering. Tulsa (OK): PenWell Books. [accessed 2020 Apr 27].

Keller P. 2019 Feb 2. 2019 Will be the Year of Acceleration for LNG as Marine Fuel. Fort Lauderdale (FL): The Maritime Executive. [accessed 2020 May 5].

Kemp J. 2019 Feb 12. Column: Venezuela sanctions leave oil market short of heavy crude - Kemp. Reuters. [accessed 2020 Feb 25]. https://www.reuters.com/article/us-venezuela-politics-oil-kemp/column-venezuela-sanctions-leave-oil-market-short-of-heavy-crude-kemp-idUSKCN1Q11TQ.

Kennedy JL. 1993. Oil and Gas Pipeline Fundamentals. 2nd ed. PenWell Books.

Keppel Offshore & Marine. 2019 Mar. Seizing Opportunities in Offshore Wind. Singapore: Keppel Offshore & Marine. [accessed 2020 Feb 21]. http://www.keppelom.com/en/content.aspx?sid=9450.

Khanna AS. 2008. High-performance organiz coatings. Woodhead Publishing Limited.

Kinder Morgan. 2018 Mar. The Role of Natural Gas Liquids (NGLs) in the American Petrochemical Boom. [accessed 2020 Jul 10].

Kinder Morgan. c2015. Companies involved in the Project. Houston (TX): Kinder Morgan. [accessed 2020 Apr 24]. https://www.kindermorgan.com/business/gas_pipelines/projects/elbaLNG/companies_involved.aspx.

KLAW LNG. c2020. LNG Vessel Bunkering. Westbury (UK): KLAW LNG. [accessed 2020 May 5]. https://www.klawlng.com/lng-applications/lng-vessel-bunkering/.

Kondash AJ, Lauer NE, Vengosh A. 2018. The intensification of the water footprint of hydraulic fracturing. Sci Adv. 4(8):eaar5982. doi:10.1126/sciadv.aar5982.

LA Times. 2016 Aug 9. PG&E is found guilty of obstructing investigators after deadly 2010 pipeline blast. Los Angeles (CA): Los Angeles Times. [accessed 2020 Jun 12].

Landers M. 2019 Jul 18. Startup delayed at Elba Island natural gas facility. Savannah (GA): Savannah Morning News. [accessed 2020 Apr 24].

Lane FC, Coll BD, Fischer GJ, Tyler DB. 2001. Ships for Victory: A History of Shipbuilding under the US Maritime Commission in World War II. Baltimore (MD): The Johns Hopkins University Press. [accessed 2020 Feb 21].

Larsen KR. 2017 Mar 1. Protecting a Pipeline When Its Coating Has Aged. [accessed 2019 Nov 19]. http://www.materialsperformance.com/articles/coating-linings/2017/03/protecting-a-pipeline-when-its-coating-has-aged.

Lauria M. 2020 Jan 27. Delaware City refinery agrees to pay $70,000 to settle air pollution problems. Delaware Online. [accessed 2020 Feb 10].

Lefevre-Marton N, Saharia R, Sellschop R, Tai H. 2019 Apr. Scaling the US East Coast offshore wind industry to 20 gigawatts and beyond. New York (NY): McKinsey & Company. [accessed 2020 Mar 16].

Leonardo. 2020. AW139 energy services brochure. [accessed 2020 May 4].

Lessig H. 2015 Dec 4. Newport News shipyard layoffs: 738 jobs to be cut. Newport News (VA): Daily Press. [accessed 2020 Mar 10].

Lessig H. 2016 Mar 18. BAE cuts 265 jobs at Norfolk shipyard, but avoids a larger layoff. Newport News (VA): Daily Press. [accessed 2020 Mar 10].

Levin K, Lebling K. 2019 Dec 3. CO2 Emissions Climb to an All-Time High (Again) in 2019: 6 Takeaways from the Latest Climate Data. Washington (DC): World Resources Institute. [accessed 2020 May 4].

Lewis I. c2019. Small-scale LNG applications make progress. Houston (TX): Gas Processing News. [accessed 2020 Apr 24].

Liberty Coating. 2019. Pritec. Liberty Coating Group Homepage. Liberty Coating Group. [accessed 2019 Oct 7]. http://www.libertycoating.com/.

Litvak A. 2019 Aug 9. Bruce Mansfield coal-fired plant to close in November, owner says. Pittsburgh (PA): Pittsburgh Post-Gazette. [accessed 2019 Dec 20].

Lloyd Minister. 2019 Dec 14. What is Heavy Oil? Lloyd Minister. [accessed 2019 Dec 14]. http://www.lloydminsterheavyoil.com/whatislaunch.htm.

Löffler, Thomas. 2018. “Shielding” - Coatings or “Non-Shielding”- Coatings? [accessed 2020 Feb 3]. http://www.iploca.com/platform/content/element/30191/Presentation5TKTLPrsentation_Shieldingvs.Non-shielding_iploca.pdf.

Lorco. 2016. About Us. Lorco Petroleum Services. [accessed 2020 Mar 26]. http://lorcopetroleum.com/about/.

Madueke U. c2013. Measuring and Benchmarking Efficiency and Productivity Levels of Liquid Bulk Terminal Operations Using a DEA AND OEE Approach. [accessed 2021 Apr 1]. https://www.panynj.gov/port/en/our-port.html.

Maersk Drilling. 2020 Jan 13. Maersk Drilling selected by Total to drill at world record water depth in Angola-Namibia campaign. Kongens Lyngby (Denmark): Maersk Drilling. [accessed 2020 Feb 13].

Maersk Drilling. c2020. Maersk Voyager Rig Brochure. Kongens Lyngby (Denmark): Maersk Drilling. [accessed 2020 Feb 13]. https://www.maerskdrilling.com/what-we-do/rigs/drillships/maersk-voyager.

Magill J. 2019 Oct 4. Kinder Morgan starts commercial service at Elba Island LNG terminal. New York (NY): S&P Global. [accessed 2020 Apr 24].

Mangia C, Carlesimo A. 2013 Apr. The Adriatic LNG Terminal: Industrial Firsts Into a Fully Operation Reality. Des Plaines (IL): GTI. [accessed 2020 May 8].

MARAD [United States Maritime Administration]. 2020 Apr. America’s Marine Highway. Washington (DC): US Department of Transportation, Maritime Administration. [accessed 2020 May 26]. https://maritime.dot.gov/grants/marine-highways/marine-highway.

Marcellus Shale Coalition. c2019. Marcellus and Utica Shale Formation Map. Pittsburgh (PA): Marcellus Shale Coalition. [accessed 2020 May 7]. https://marcelluscoalition.org/pa-map/.

Marine Insight. 2019 Oct 20. Panamax and Aframax Tankers: Oil Tankers with a Difference. Bangalore (India): Marine Insight. [accessed 2020 May 15].

Marine Transportation System. 1999. An Assessment of the US Marine Transportation System. [accessed 2020 Apr 3].

Maritime Connector. 2020. Platforms. Kastav (Croatia): Maritime-Connector.com. [accessed 2020 Feb 14]. http://maritime-connector.com/wiki/platforms/.

Maritime Connector. c2020. Platform supply vessel. Kastav (Croatia): Maritime-Connector.com. [accessed 2020a Feb 14]. http://maritime-connector.com/platform-supply-vessel/.

Maritime Connector. c2020. Aframax. Kastav (Croatia): Maritime Connector. [accessed 2020b May 15]. http://maritime-connector.com/wiki/aframax/.

Maritime Connector. c2020. VLCC and ULCC. Kastav (Croatia): Maritime Connector. [accessed 2020c May 18]. https://maritime-connector.com/wiki/vlcc/.

Marsh J. 2020 Jun 19. Feds issue final rule allowing liquefied natural gas by rail. Freight Waves. [accessed 2020 Jul 8]. https://www.freightwaves.com/news/feds-issue-final-rule-allowing-liquefied-natural-gas-by-rail.

Matrix PDM. c2017. What is a Bulk Terminal? Tulsa (OK): Matrix PDM Engineering. [accessed 2020 May 19]. https://www.matrixpdm.com/what-is-a-bulk-terminal.

Maykuth ndrew. 2020 Jan 23. Hilco's $240 million bid for South Philly refinery wasn't the highest offer, aggrieved creditors say. The Philadelphia Inquirer. [accessed 2020 Feb 10].

McClellan SA. 2019 Mar. Supply Chain Contracting Forecast for US Offshore Wind Power. Washington (DC): AWEA. [accessed 2020 Mar 17]. https://www.aweablog.org/new-report-u-s-offshore-wind-generates-70-billion-supply-chain-opportunity/.

McEwen M. 2019 Feb 15. Proposed Winkler County refinery could benefit local drivers' pocketbooks. Meridian Energy Group Inc. [accessed 2020 Feb 25].

McKinney A. 2019 Jun 19. Maryland has banned fracking. It shouldn't become a hotspot for natural gas exports. - The Diamondback. [accessed 2020 Mar 26].

McLeod A. 2018 Oct 25. One Step Closer to Wider, Deeper Channels. Norfolk (VA): Virginia Maritime Association. [accessed 2020 Apr 3].

Mercure M. 2021 Jan 14. NYSERDA Selects Proposal to Transition Port of Albany into Offshore Hub | North American Windpower. [accessed 2021 Apr 8]. https://nawindpower.com/nyserda-selects-proposal-to-transition-port-of-albany-into-offshore-hub.

Meridian Energy Group Inc. 2019 Dec 14. Davis Refinery. Meridian Energy Group Inc. [accessed 2019 Dec 10]. https://www.meridianenergygroupinc.com/operations/davis-refinery/.

Meyer R. 2018 Jan 20. After 61 Years, America's Busiest Highway Is Almost Complete. Washington (DC): The Atlantic. [accessed 2020 May 22].

MI News Network. 2019. What are Anchor Handling Tug Supply Vessels (AHTS)? Marine Insight. [accessed 2020 Feb 28].

Miller R. 2017 Jan 15. MJ Painting following boom of natural gas industry. Olean Times Herald. [accessed 2019 Nov 21].

Miller R. 2019 Jul 14. MJ Painting plans second location near Pittsburgh, will also expand locally. Olean Times Herald. [accessed 2019 Nov 21].

Minerals Management Service. 2007. Gulf of Mexico OCS Oil and Gas Lease Sales 2007-2012, Western Planning Area Sales 204, 207, 210, 215, and 218, Central Planning Area Sales 205, 206, 208, 213, 216, and 222: Environmental Impact Statement. New Orleans (LA): US Department of Interior. [accessed 2020 Feb 13].

MJ Painting. 2019a. Industrial Pipeline Coating Services | Epoxy Pipe Coating. MJ Painting Contractor Corp. [accessed 2019 Nov 20]. http://www.mjpaintingcontractor.com/industries/epoxy-pipe-line-coating/.

MJ Painting. 2019b. MJ Painting Contractors' Clients & Past Projects. MJ Painting Contractor Corp. [accessed 2019 Nov 20]. http://www.mjpaintingcontractor.com/clients/.

Mobro Marine. c2020. Barges. Green Cove Springs (FL): Mobro Marine. [accessed 2020 Apr 2]. https://www.mobromarine.com/barges/.

Mohit. 2019 Nov 22. Different Types of Tankers: Extensive Classification of Tanker Ships. Bangalore (India): Marine Insight. [accessed 2020 May 15]. https://www.marineinsight.com/types-of-ships/different-types-of-tankers-extensive-classification-of-tanker-ships/.

Mohr B. 2020. Structural Integrity of Underwater Pipelines. EWI. [accessed 2020 Feb 3]. https://ewi.org/structural-integrity-of-underwater-pipelines/.

Morley H. 2019 Nov 12. Boston wins $20 million DOT grant for terminal expansion. New York (NY): JOC. [accessed 2020 Apr 3].

Mosquet X, Dauner T, Lang N, Rüßmann M. 2015. Revolution in the Driver's Seat: The Road to Autonomous Vehicles. Boston Consulting Group. [accessed 2020 Mar 15].

Mouawad J. 2012 Apr 30. Delta Air Lines Buys an Oil Refinery. The New York Times. [accessed 2019 Dec 16].

Mountain Valley Pipeline. c2020. Mountain Valley Pipeline. Canonsburg (PA): Mountain Valley Pipeline Project. https://www.mountainvalleypipeline.info/.

Mufson S. 2016 Jun 26. An expanded Panama Canal opens for giant ships. Washington DC: The Washington Times. [accessed 2020 Apr 3].

Muoio D. 2019 Mar 19. Hungry for a new offshore wind industry, states pour millions into ports. Politico. [accessed 2020 Mar 27].

Murdock D. 2009 Apr 17. Clean, Safe, and Secure. New York (NY): National Review. [accessed 2020 Feb 19]. https://www.nationalreview.com/2009/04/clean-safe-and-secure-deroy-murdock/.

Murphy P. 2019. Executive Order 8. [accessed 2020 Apr 23]. https://nj.gov/infobank/eo/056murphy/pdf/EO-8.pdf.

Murphy P. 2019 Nov 19. Office of the Governor | Governor Murphy Signs Executive Order to Increase Offshore Wind Goal to 7,500 Megawatts by 2035. State of New Jersey. [accessed 2019 Dec 18]. https://www.nj.gov/governor/news/news/562019/approved/20191119b.shtml.

NACTO [National Association of City Transportation Officials]. c2018. Shared Micromobility in the US: 2018. [accessed 2020 Mar 14]. https://nacto.org/shared-micromobility-2018/.

NaturalGas.org. 2013. » Processing Natural Gas NaturalGas.org. [accessed 2020 May 11]. http://naturalgas.org/naturalgas/processing-ng/.

NaturalGas.org. 2013 Sep 22. Offshore Drilling. Washington (DC): NaturalGas.org. [accessed 2020 Feb 13]. http://naturalgas.org/naturalgas/extraction-offshore/.

NC Clean Energy Technology Center. 2018 Jul 9. Renewable Energy and Energy Efficiency Portfolio Standard - North Carolina. Raleigh (NC): DSIRE. [accessed 2020 Mar 30]. https://programs.dsireusa.org/system/program/detail/2660.

Necci A, Tarantola S, Vamanu B, Krausmann E, Ponte L. 2019. Lessons learned from offshore oil and gas incidents in the Arctic and other ice-prone seas. Ocean Engineering. 185:12–26.

NECEC [New Orleans Clean Energy Connect]. 2020 Feb 20. Maine Business, Environmental and Labor Leaders Gather in Portland to Support Major Renewable Energy Project. Portland (ME): New Orleans Clean Energy Connect. [accessed 2020 Mar 27]. https://www.necleanenergyconnect.org/necec-milestones.

NECEC [New Orleans Clean Energy Connect]. c2020. About the Project. Augusta (ME): New Orleans Clean Energy Connect. [accessed 2020 Mar 27]. https://www.necleanenergyconnect.org/project-overview.

Neilson R. 2016 Mar 3. Oil rigs are built to withstand decades at sea – taking them apart is as tough as they are. Boston (MA): The Conversation. [accessed 2020 Apr 2].

NERC [North American Electric Reliability Corporation]. 2014 May 19. Milestones: NERC Reliability Standards. Atlanta (GA): North American Electric Reliability Corporation. [accessed 2020 Mar 19].

NERC [North American Electric Reliability Corporation]. 2018 Dec. 2018 Long-Term Reliability Assessment. Atlanta (GA): NERC. [accessed 2020 Mar 18].

NERC [North American Electric Reliability Corporation]. 2019. Electricity Supply & Demand (ES&D) [dataset]. Atlanta (GA): NERC. [accessed 2020 Mar 27]. https://www.nerc.com/pa/RAPA/ESD/Pages/default.aspx.

NERC [North American Electric Reliability Corporation]. c2020. Key Players. Atlanta (GA): NERC. [accessed 2020 Apr 6]. https://www.nerc.com/AboutNERC/keyplayers/Pages/default.aspx.

Newport News Shipbuilding. 2020 Feb 1. Fact Sheet. Newport News (VA): Huntington Ingalls Industries. [accessed 2020 Feb 17].

Newport News Shipbuilding. c2020. About Newport News Shipbuilding. Newport News (VA): Newport News Shipbuilding. [accessed 2020 Feb 17]. https://nns.huntingtoningalls.com/who-we-are/.

NGV America. c2020. Fuel. Washington (DC): NGV America. [accessed 2020 Jun 30]. https://www.ngvamerica.org/fuel/.

Nixon B. 2013 Dec. Decommissioning North Sea Giants. London (UK): [accessed 2020 Apr 2]. https://www.ingenia.org.uk/getattachment/Ingenia/Issue-57/Decommissioning-North-Sea-giants/Nixon.pdf.

NOAA. 2017 Apr 5. Largest Oil Spills Affecting US Waters Since 1969. Washington (DC): NOAA. [accessed 2020 Apr 22].

Nobel J. 2019 May 21. Virtual Pipelines: A Dangerous New Way to Transport Fracked Gas by Truck. Seattle (WA): Desmog. [accessed 2020 Jun 30].

Norfolk Southern. c2015. Moving Crude Oil. Norfolk (VA): Norfolk Southern Corp. [accessed 2020 May 21]. http://nssustainability.com/2015_sustainability_report/community/oil.php.

Norris A. 2016. Atlantic Coast Pipeline Feature. Dura-Bond Industries. [accessed 2019 Nov 21]. http://www.dura-bond.com/atlantic-coast-pipeline-feature/.

Norris A. 2018 Sep 24. Dura-Bond Opens Pennsylvania ERW Steel Pipe Mill. Dura-Bond Coating. [accessed 2020 Feb 3]. https://www.dura-bond.com/dura-bond-pipe-mckeesport-pipeline-and-gas-journal-article/.

Northeast Gas Association. c2020. The Role of LNG in the Northeast Natural Gas (and Energy) Market. Needham (MA): Northeast Gas Association. [accessed 2020 Apr 24]. https://www.northeastgas.org/about_lng.php.

NPC [National Petroleum Council]. 2011a. Management of Produced Water from Oil and Gas Wells.

NPC [National Petroleum Council]. 2011b. Waste Management. https://www.npc.org/Prudent_Development-Topic_Papers/2-24_Waste_Management_Paper.pdf.

NTSB [National Transportation Safety Board]. 2020. About the National Transportation Safety Board. Washington (DC): National Transportation Safety Board. [accessed 2020 Apr 30]. https://www.ntsb.gov/about/Pages/default.aspx.

Nummi E. 2016 May 3. The Use of Plastic Pipe in the Mining and Oil and Gas Industries. Advancing Materials. [accessed 2019 Nov 22]. https://www.thermofisher.com/blog/materials/the-use-of-plastic-pipe-in-the-mining-and-oil-and-gas-industries/.

Nunno R. 2019 Dec 19. Trump Administration Loosening Regulations for Rail Transportation of Flammable Natural Gas. Washington (DC): Environmental and Energy Study Institute. [accessed 2020 May 14].

NYSERDA [New York State Energy Research and Development Authority]. 2020 Apr 1. Ports and Infrastructure. New York (NY): New York State (NY.gov). [accessed 2020 Apr 1]. https://www.nyserda.ny.gov/All-Programs/Programs/Offshore-Wind/Economic-Opportunities/Ports-and-Infrastructure.

NYSERDA [New York State Energy Research and Development Authority]. c2019. New York State Offshore Wind. Albany (NY): NYSERDA.ny.gov. [accessed 2019 Dec 16]. https://www.nyserda.ny.gov/All-Programs/Programs/Offshore-Wind.

Ocean News. 2019 Jun 7. Shades of Grey: The Challenges of Unmanned Automation in the Oil and Gas Sector. Stuart (FL): Ocean News & Technology. [accessed 2020 Feb 19].

Oceaneering. c2020. Oil and Gas. Houston (TX): Oceaneering. [accessed 2020 Apr 3]. https://www.oceaneering.com/oil-and-gas/.

Oceanweather, Inc. c2019. CYCLOPS: Tropical Cyclone Operational Prediction System. Stamford (CT): Oceanweather. https://www.oceanweather.com/forecast/CYCLOPS/index.html.

Oceanwide. Oil & Gas personnel. Vlissingen (Netherlands): Oceanwide. [accessed 2019 Dec 4]. https://www.oceanwidecrew.com/services/oil-and-gas-personnel.

OCI. c2019. Crude-by-Rail: Interactive Map. [accessed 2020 May 21]. http://priceofoil.org/rail/.

Offshore. 2005 Jun 1. Swagelok constructs South America-bound oil rigs. Plymouth (MN): Offshore Magazine. [accessed 2020 Feb 17].

Offshore. 2017 Aug 10. Shell's Appomattox platform hull en route to Ingleside. Plymouth (MN): Offshore Magazine. [accessed 2020 Feb 12].

Offshore Energy Today. 2016 Apr 1. Uruguay: First offshore well in years breaks world record. Schiedam (The Netherlands): Offshore-Energy. [accessed 2020 Feb 19].

Offshore Energy Today. 2020 Jan 15. Keppel delivers fifth jack-up rig to Borr Drilling. Schiedam (The Netherlands): Offshore-Energy. [accessed 2020 Feb 22].

Offshore Engineer Staff. 2020 Dec 2. Vineyard Wind Picks GE's Haliade-X Offshore Wind Turbines for US Project. Withdraws COP. Offshore Engineer. [accessed 2021 Apr 10].

Offshore Magazine. 2014 Sep 17. Extended-reach drilling systems address downhole challenges. Offshore. [accessed 2020 May 7].

Offshore Technology. 2019 Feb 11. Inside the first fully automated offshore platform. New York (NY): Offshore-Technology. [accessed 2020 Feb 19]. https://www.offshore-technology.com/features/inside-the-first-fully-automated-offshore-platform/.

Offshore Technology. c2020. Independence Hub, Gulf of Mexico. New York (NY): Offshore-Technology. [accessed 2020 Feb 19]. https://www.offshore-technology.com/projects/independence/.

Ogg M. 2019 Sep 6. East Coast Ports Build Capacity For Growth. Boca Raton (FL): ProduceBusiness. [accessed 2020 Apr 3]. https://www.producebusiness.com/east-coast-ports-build-capacity-for-growth/.

OGJ. 2004 Apr 12. First offshore LNG terminal moves ahead. Tulsa (OK): Oil & Gas Journal. [accessed 2020 Apr 22].

Ohio Department of Natural Resources. 2020 May 28. 2019 Horizontal Production, All Quarters [Dataset]. Columbus (OH): Ohio Department of Natural Resources. [accessed 2020 Aug 4].

O'Neal CH. 2019 Sep 26. Port City: The Port Of Wilmington's Next Phase. Wilmington (NC): WilmingtonBiz. [accessed 2020 Apr 3]. http://www.wilmingtonbiz.com/wilmingtonbiz_magazine/2019/09/26/port_city_the_port_of_wilmingtons_next_phase/19447.

Ophardt CE. c2003. Oil to Petrochemicals. Elmhurst (IL): Elmhurst University. [accessed 2020 Aug 4].

OR&R. 2019 Apr 24. Spill Containment Methods. Washington (DC): NOAA. https://response.restoration.noaa.gov/oil-and-chemical-spills/oil-spills/spill-containment-methods.html.

Paganie D. 2007 Sep. Demand driving port expansion. New York (NY): LexisNexis.

Paganie D. 2007 Dec 1. Independence Hub breaks records through collaboration, innovation. Plymouth (MN): Offshore Magazine. [accessed 2020 Feb 19].

PANYNJ [Port Authority of New York and New Jersey]. c2020. Our Port. New York (NY): Port Authority of New York and New Jersey. [accessed 2020 Apr 1]. https://www.panynj.gov/port/en/our-port.html.

Paris C. 2018 May 31. Philadelphia Shipyard Struggles to Survive on Order Drought. New York (NY): Wall Street Journal. [accessed 2020 Feb 20].

Paul C. 2019 Feb 12. Kenai LNG owner wants to put Alaska terminal back in service for gas imports. New York (NY): S&P Global. [accessed 2020 Apr 30].

PBF Energy. 2019. 2018 Annual Report. [accessed 2019 Dec 17].

PBF Energy. 2011 Oct 7. PBF Celebrates Successful Restart of Its Delaware City Refinery. PBF Energy. [accessed 2019 Dec 16].

PBF Energy. c2019. Refineries. PBF Energy. [accessed 2019 Dec 16]. https://www.pbfenergy.com/refineries.

PennFuture. c2019. Oil Trans: Risking Community and Environmental Health. Philadelphia (PA): PennFuture. [accessed 2020 May 21]. https://www.pennfuture.org/OilTrains.

Perry D. 2020 Jan 24. Bristow and ERA to merge, creating offshore helicopter giant. Sutton (UK): FlightGlobal. [accessed 2020 Apr 4].

PES Essential. 2017. Powering offshore wind developments by LNG. Bristol (UK): Power & Energy Solutions. [accessed 2020 May 5].

Petzet A. 2012 Mar 2. Fist Gulf of Mexico FPSO receiving Cascade oil. Tulsa (OK): Oil & Gas Journal. [accessed 2020 Feb 14].

PHI. c2019. PHI, Inc. Lafayette (LA): PHI. [accessed 2020a Feb 27]. http://www.phihelico.com.

PHI. c2019. Our Fleet. PHI, Inc - The Total Helicopter Company. [accessed 2020b Feb 27]. http://www.phihelico.com/phi-inc/information/our-fleet.

PHI. c2019. PHI Americas. PHI, Inc - The Total Helicopter Company. [accessed 2020c Feb 27]. http://www.phihelico.com/phi-americas.

Phillips 66. c2019. Bayway Refinery. Phillips 66. [accessed 2019 Dec 10]. https://www.phillips66.com/refining/bayway-refinery.

Philly Shipyard. 2019 May 6. Philly Shipyard Q1 2019 Results. Philadelphia (PA): Philly Shipyard. [accessed 2020 Feb 18].

Philly Shipyard. 2020 Feb 11. Philly Shipyard Q4 2019 and Full Year 2019 Results. Philadelphia (PA): Philly Shipyard. [accessed 2020 Feb 18].

Philly Shipyard. c2020. Projects. Philadelphia (PA): Philly Shipyard. [accessed 2020a Feb 18]. http://dev2.zetta.no/www-phillyshipyard-com/s.cfm/4/Projects.

Philly Shipyard. c2020. History. Philadelphia (PA): Philly Shipyard. [accessed 2020b Feb 18]. http://www.phillyshipyard.com/s.cfm/1-9/History.

Philly Shipyard. c2020. Projects Track Record. Philadelphia (PA): Philly Shipyard. [accessed 2020c Feb 20]. http://dev2.zetta.no/www-phillyshipyard-com/s.cfm/4-36/Track-record.

PHMSA [Pipeline and Hazardous Materials Safety Administration]. 2017. Guidance Manual for Operators of Small Natural Gas Systems. [accessed 2020 Jan 28].

PHMSA [Pipeline and Hazardous Materials Safety Administration]. 2019a. Instructions (rev 4--2019) for Form PHMSA F 7100.1 (rev 4-2019) INCIDENT REPORT – GAS DISTRIBUTION SYSTEMS. [accessed 2019 Nov 19].

PHMSA [Pipeline and Hazardous Materials Safety Administration]. 2019b. 2018 Liquefied Natural Gas Annual Data. [accessed 2019 Aug 19]. https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids.

PHMSA [Pipeline and Hazardous Materials Safety Administration]. 2019c. LNG Plants Connected to Natural Gas Pipeline Systems. [accessed 2020 Apr 22].

PHMSA [Pipeline and Hazardous Materials Safety Administration]. 2019d. LNG Plants Connected to Natural Gas Pipeline Systems (Eastern Region). [accessed 2020 Apr 22].

PHMSA [Pipeline and Hazardous Materials Safety Administration]. 2019e. Hazardous Materials: Liquefied Natural Gas by Rail. [accessed 2020 Jun 16].

PHMSA [Pipeline and Hazardous Materials Safety Administration]. 2017 May 3. Pipeline Materials. Washington (DC): US Department of Transportation, Pipeline and Hazardous Materials Safety Administration. [accessed 2020 May 14]. https://www.phmsa.dot.gov/technical-resources/pipeline/pipeline-materials.

PHMSA [Pipeline and Hazardous Materials Safety Administration]. 2019 Feb 14. USDOT Announces Safety Rule to Strengthen Oil Train Spill Response Preparedness. Washington (DC): US Department of Transportation, Pipeline and Hazardous Materials Safety Administration. [accessed 2020 Jun 16].

PHMSA [Pipeline and Hazardous Materials Safety Administration]. 2019 Sep 20. Pipeline Replacement Background | PHMSA. [accessed 2019 Nov 22]. https://www.phmsa.dot.gov/data-and-statistics/pipeline-replacement/pipeline-replacement-background.

PHMSA [Pipeline and Hazardous Materials Safety Administration]. 2020 May 1. Annual Report Mileage Summary Statistics. Washington (DC): US Department of Transportation, Pipeline and Hazardous Materials Safety Administration. [accessed 2020 May 18]. https://www.phmsa.dot.gov/data-and-statistics/pipeline/annual-report-mileage-summary-statistics.

Pirrong C. 2018. Analysis of the RFS Program and the 2019 Proposed Standards. [accessed 2019 Dec 18]. https://www.bauer.uh.edu/spirrong/Exhibit_A_Pirrong_Study.pdf.

Port of Everglades. 2018 Jun 19. Harbor Deepening and Widening. [accessed 2020 Apr 3].

Port of Iberia. c2018. Overview. New Iberia (LA): Port of Iberia. [accessed 2020 Apr 30]. https://www.portofiberia.com/overview/.

PortStrategy. 2020 Feb 18. The US North Atlantic region is targeting a massive development of offshore wind, as New York-based Barry Parker discovers. UK: PortStrategy. [accessed 2020 Apr 1].

Power Technology. 2020c. Block Island Wind Farm. Power Technology | Energy News and Market Analysis. [accessed 2020 Apr 23].

Press Statement. 2020 Feb 28. Virginia to Join Regional Greenhouse Gas Initiative. Chesapeake Bay Foundation. [accessed 2020 Mar 25].

PST. 2015 Sep. Pipeline Briefing Paper #14 - Jurisdictional Issues Relating to Pipelines. Bellingham (WA): Pipeline Safety Trust. [accessed 2020 May 20].

Puder, Veil. 2006. Offsite Commercial Disposal of Oil and Gas Exploration and Production Waste: Availability, Options, and Costs.

Raunek. 2019 Dec 4. The Ultimate Guide to Ship Sizes. Bangalore (India): Marine Insight. [accessed 2020 May 15]. https://www.marineinsight.com/types-of-ships/the-ultimate-guide-to-ship-sizes/.

Rector K. 2019 Mar 20. From tiny Cove Point on the Chesapeake, tankers take natural gas around the world. At what cost? Baltimore (MD): The Baltimore Sun. [accessed 2020 Apr 27].

Reddy C, Ward C. 2018 Apr 25. Reassessing Guidelines for Oil Spill Cleanups. Woods Hole Oceanographic Institution. [accessed 2020 Apr 22]. https://www.whoi.edu/oceanus/feature/reassessing-guidelines-for-oil-spill-cleanups/.

Redfern J. 2019 Dec 2. Time is almost up for US federal income tax credits on new Teslas. Harpenden (UK): Motoring Research. [accessed 2019 Dec 19]. https://www.motoringresearch.com/msn-custom-autos/tesla-federal-income-tax-credit-expiration/.

Renewable Energy: State Activities. 2018. Washington (DC): BOEM. [accessed 2020 Feb 21]. https://www.boem.gov/renewable-energy/state-activities.

Renshaw J, Resnick-Ault J. 2019 Feb 1. Exclusive: Delta trying to unload East Coast refinery - sources - Reuters. Reuters. [accessed 2020 Feb 10].

Rep. Rangel CB. 2008. Energy Improvement and Extension Act of 2008. [accessed 2019 Dec 19]. https://www.congress.gov/bill/110th-congress/house-bill/6049.

Resolve Marine Group. 2017 Jan. Delta Amber and Nicholas. Fort Lauderdale (FL): Resolve Marine Group. [accessed 2020 Apr 3]. https://resolvemarine.com/job-history/delta-amber-nicholas/.

Reuters. 2011 Apr 29. PBF's Delaware City refinery restart coming up. Reuters. [accessed 2019 Dec 16].

Reuters. 2020 Jan 10. US drillers cut oil rigs for third week in a row- Baker Hughes. London (UK): Reuters. [accessed 2020 Feb 20].

RFA [Renewable Fuels Association]. 2017 Nov 2. Pennsylvania's RFS Waiver Request: Separating Fact from Fiction. Renewable Fuels Association (RFA). [accessed 2019 Dec 17].

RFA [Renewable Fuels Association]. 2019. Annual Ethanol Production. Renewable Fuels Association (RFA). [accessed 2019 Dec 16]. https://ethanolrfa.org/statistics/annual-ethanol-production/.

RGGI, Inc. c2020. Elements of RGGI. New York (NY): RGGI. [accessed 2020 Mar 25]. https://www.rggi.org/program-overview-and-design/elements.

Richardson GE, Nixon LD, Bohannon C m., Kazanis EG, Montgomery TM, Gravois MP. 2008 May. Deepwater Gulf of Mexico 2008: America's Offshore Energy Future. Washington (DC): BSEE. [accessed 2020 Feb 14].

Richardson W. 2013 Dec 24. Cianbro lands $100 million contract to build part of wind farm. Bangor (ME): Bangor Daily News. [accessed 2020 Feb 17]. https://bangordailynews.com/2013/12/23/business/cianbro-tapped-to-construct-platform-for-massachusetts-offshore-wind-farm/.

Ricker N-N. 2019 Feb 25. Barge arrives at Cianbro modular facility in Brewer. Bangor (ME): Fox Bangor/ABC 7. [accessed 2020 Feb 17].

Ricker N-N. 2019 Mar 8. 1st load of Cianbro modules leave Brewer. Bangor (ME): Fox Bangor/ABC 7. [accessed 2020 Feb 17]. https://foxbangor.com/news/item/47267-1st-load-of-cianbro-modules-leave-brewer/.

Rigzone. c2020. How Does a Tension Leg Platform (TLP) Work? Houston (TX): Rigzone. [accessed 2020a Feb 14]. https://www.rigzone.com/training/insight.asp?insight_id=305&c_id=.

Rigzone. c2020. How Do Semisubmersibles Work? Houston (TX): Rigzone. [accessed 2020b Feb 14]. https://www.rigzone.com/training/insight.asp?insight_id=338&c_id=.

Rigzone. c2020. How Do Spars Work? Houston (TX): Rigzone. [accessed 2020c Feb 14]. https://www.rigzone.com/training/insight.asp?insight_id=307&c_id=.

Rigzone. c2020. How Do FPSOs Work? Houston (TX): Rigzone. [accessed 2020d Feb 14]. https://www.rigzone.com/training/insight.asp?insight_id=299&c_id=.

Rigzone. 2020c. How Does Directional Drilling Work? | Rigzone. Rigzone. [accessed 2020 Mar 13]. https://www.rigzone.com/training/insight.asp?insight_id=295&c_id=.

Rigzone. c2020. How Does Pipeline Pigging Work? Houston (TX): Rigzone. [accessed 2020e Jun 15]. https://www.rigzone.com/training/insight.asp?insight_id=310&c_id=.

Ritenbaugh S. 2015 Feb 4. Dura-Bond inks $400 million deal to supply steel pipe for natural gas pipeline | Pittsburgh Post-Gazette. Pittsburgh Post-Gazette. [accessed 2020 Feb 3].

Rocky Mountain Institute. 2015 Apr 27. 5 Reasons for North Carolina's Rapid Emergence As A Solar Energy Leader. Basalt (CO): Rocky Mountain Institute. [accessed 2020 Mar 30].

Rodrigue J-P. 2017 Dec 19. Tanker Sizes and Classes. Long Island (NY): Transport Geography. [accessed 2020 May 15]. https://transportgeography.org/?page_id=6877.

Rodrigue J-P. c2020. Evolution of Containerships. Hempstead (NY): The Geography of Transport Systems. [accessed 2020 Apr 2]. https://transportgeography.org/?page_id=2232.

Rosenfield A. SeaxExplorer X2 Multi-mission underwater glider. [accessed 2020 Apr 6].

SafeRack. 2019 Jun 5. Road Tanker Safety - design, equipment and the human factor. Andrews (South Carolina): SafeRack. [accessed 2020 May 14]. https://www.saferack.com/road-tanker-safety-design-equipment-human-factor/.

Safety Management Systems. c2020. Emergency Medical Staffing and Training. Lafayette (LA): Safety Management Systems. [accessed 2020 Feb 27]. https://safetyms.com/services/medical/.

Salvo Grima. c2019. Ship Supply Malta - Chandler service since 1860. Marsa (Malta): Salvo Grima Group. [accessed 2020 Apr 3]. http://salvogrima.com/ship-supply/.

Schlumberger. 2014. The Defining Series: Introduction to Coiled Tubing | Schlumberger. [accessed 2020 Apr 9]. https://www.slb.com/resource-library/oilfield-review/defining-series/defining-coiled-tubing.

Schlumberger. c2020. Drillship. Gatwick (UK): Schlumberger. [accessed 2020 Feb 13]. https://www.glossary.oilfield.slb.com/en/Terms/d/drillship.aspx.

Schlumberger. slim hole well - Schlumberger Oilfield Glossary. [accessed 2020 Apr 8]. https://www.glossary.oilfield.slb.com/en/Terms/s/slim_hole_well.aspx.

Schmidt A. c2020. Power Pole with Transformers. Leeds (UK): Public Domain Pictures. [accessed 2020 Apr 6]. https://www.publicdomainpictures.net/en/view-image.php?image=2802&picture=power-pole-with-transformers.

Schnepf R, Yacobucci B. 2013. Renewable Fuel Standard (RFS): Overview and Issues. [accessed 2019 Dec 17].

SEC [US Securities and Exchange Commission]. 2001. Southern Natural Gas Company, Form 10-K, Fiscal year ended December 31, 2001. Washington (DC): US Securities and Exchange Commission. [accessed 2020 Apr 23].

SEC [US Securities and Exchange Commission]. 2011. Southern Natural Gas Company, Form 10-K, Fiscal year ended December 31, 2011. Washington (DC): US Securities and Exchange Commission. [accessed 2020 Apr 24].

SEC [US Securities and Exchange Commission]. 2019a. Petroleum Helicopters International 10-K Filing for 2018. [accessed 2020 Feb 27].

SEC [US Securities and Exchange Commission]. 2019b. Bristow Group, Inc. 10-K filing for fiscal year ended March 31, 2019. [accessed 2020 Feb 27].

SEC [US Securities and Exchange Commission]. 2019c. Era Group, Inc. 10-K Filing for 2018. [accessed 2020 Feb 27].

SEC [US Securities and Exchange Commission]. 2019d. Hornbeck Offshore Services, Inc. 10-K Filing for 2018. [accessed 2020 Apr 30].

SEC [US Securities and Exchange Commission]. 2020. Era Group, Inc. 10-K Filing for 2019. [accessed 2020 May 4].

SEC [US Securities and Exchange Commission]. 2020 Feb 21. AdvanSix Inc. 10-K filing for fiscal year ended December 31, 2019. Washington (DC): SEC. [accessed 2020 Aug 4].

SEIA. c2020. Top 10 Solar States. Washington (DC): SEIA. [accessed 2019 Dec 18]. https://www.seia.org/research-resources/top-10-solar-states-0.

Sharif MD A, Nvr N, Reddy S S, G V, Sankar K U. 2017. Drilling Waste Management and Control the Effects. J Adv Chem Eng. 07(01). doi:10.4172/2090-4568.1000166. [accessed 2020 Mar 12].

Shaw CJ. 1999. Offshore Industry Requirements and Recent Metocean Technology Developments. [accessed 2020 Apr 3].

Shell. 2019 Jan 25. Appomattox Makes Its Journey Home. Houston (TX): Shell US. [accessed 2020 Feb 12]. https://www.shell.us/energy-and-innovation/energy-from-deepwater/shell-deep-water-portfolio-in-the-gulf-of-mexico/appomattox/appomattox-makes-its-journey-home.html.

Shell. c2017. Appomattox Hull Arrives in Texas. Houston (TX): Shell US. [accessed 2020 Feb 12]. https://www.shell.us/energy-and-innovation/energy-from-deepwater/shell-deep-water-portfolio-in-the-gulf-of-mexico/appomattox/appomattox-hull-arrives-in-texas.html.

Shell. c2019. Appomattox. Houston (TX): Shell US. [accessed 2020 Feb 12]. https://www.shell.us/energy-and-innovation/energy-from-deepwater/shell-deep-water-portfolio-in-the-gulf-of-mexico/appomattox.html.

Shell. c2020. Appomattox Hull Sail Away. Houston (TX): Shell US. [accessed 2020a Feb 20]. https://www.shell.us/energy-and-innovation/energy-from-deepwater/shell-deep-water-portfolio-in-the-gulf-of-mexico/appomattox/appomattox-hull-sail-away.html.

Shell. c2020. Prelude FLNG. Houston (TX): Shell US. [accessed 2020b May 11]. https://www.shell.com/about-us/major-projects/prelude-flng.html.

Shell. Pennsylvania Petrochemicals Complex. The Hague (Netherlands): Shell. [accessed 2020 Aug 4]. https://www.shell.com/about-us/major-projects/pennsylvania-petrochemicals-complex.html.

Shell Oil Company. 2011 Nov 17. Shell Digs Deep Setting World Record. Houston (TX): Rigzone. [accessed 2020 Feb 19].

Shepardson D. 2019 Feb 14. US issues new rules requiring rail oil spill response plans. London (UK): Reuters. [accessed 2020 Jun 16].

Ship Technology. c2020. Pacific Orca Wind Farm Installation Vessel. New York (NY): Ship-Technology. [accessed 2020a Mar 17]. https://www.ship-technology.com/projects/pacific-orca-wind-farm-installation-vessel/.

Ship Technology. c2020. Seacor Cheetah - Crew Ship. London (UK): Verdict Media Limited. [accessed 2020b Feb 27]. https://www.ship-technology.com/projects/seacorcheetah/.

Sikorsky. c2018. Sikorsky S-92 Multi-Mission Brochure. [accessed 2020 Feb 27].

Simpson DA. c2018. Practical Onshore Gas Field Engineering. Houston (TX): Gulf Professional Publishing. [accessed 2020 Mar 2]. https://www.sciencedirect.com/book/9780128130223/practical-onshore-gas-field-engineering#book-description.

S&P Global. 2018 Apr 10. Dominon's delayed Cove Point LNG export project enters commercial service. New York (NY): S&P Global. [accessed 2020 Apr 23].

Stallion Oilfield Services. c2020. Integrated Solutions. Houston (TX): Stallion Oilfield Services. [accessed 2020 Apr 3]. https://www.stallionoilfield.com/integrated-solutions/.

State of Connecticut. 2021 Feb 26. Governor Lamont Announces Host Community Agreement Signed by New London and Ørsted/Eversource Joint Venture. CT.gov - Connecticut's Official State Website. [accessed 2021 Apr 8]. h

Statista. 2016 December 31. Number of container ships in the global fleet as of December 31,2016, by TEU capacity. [accessed 2021 October 29]. https://www.statista.com/statistics/198381/containerships-of-the-global-fleet-by-nominal-teu/

Stell J. 2013 April 15. Subsea tiebacks: The latest strategies. Offshore Engineer. [accessed 2021 October 7].

Stromsta K-E. 2019 Jun 20. Maine's Floating Offshore Wind Project Anticipates New Investor This Year. Boston (MA): Green Tech Media. [accessed 2020 Feb 17].

Stromsta K-E. 2019 Jun 21. Orsted Wins New Jersey's First Offshore Wind Solicitation. Boston (MA): Green Tech Media. [accessed 2020 Mar 13].

Stromsta K-E. 2019 Jul 3. Orsted and Germany's EEW Plan Offshore Win Factory in New Jersey. Boston (MA): Green Tech Media. [accessed 2020 Mar 17].

Stromsta K-E. 2019 Dec 5. Vineyard Wins as Connecticut Chooses 804MW Offshore Wind Project. [accessed 2020 Apr 26].

Stromsta K-E. 2020 Jan 9. New York Confirms Plan for 1GW-Plus Offshore Wind Solicitation in 2020. Boston (MA): Green Tech Media. [accessed 2020 Mar 13].

Stromsta K-E. 2020 Mar 12. Can New England Hang On to Its Offshore Wind Jobs? Boston (MA): Greentech Media. [accessed 2020 Apr 1].

Swire Pacific Offshore. 2020. Pacific Harrier Brochure. [accessed 2020 Feb 28]. https://www.swirespo.com/getmedia/d0c912a2-0a9b-4021-8f48-84197aef932f/Pacific-Harrier_v_7.0.aspx.

Swire Pacific Offshore. c2020. SPO - Offshore Support. Fremantle (Australia): Swire Pacific Offshore. [accessed 2020 Feb 27]. https://www.swirespo.com/Fleet/Services/Offshore-Support.

T M. 2015. Oil Transport. Calgary (Canada): Student Energy. [accessed 2020 May 13]. https://www.studentenergy.org/topics/ff-transport.

Taylor's International Services. c2020. Capabilities. Lafayette (LA): Taylors International Services, Inc. [accessed 2020 Feb 27]. https://taylors-international.com/services/.

T.D. Williamson. c2020. 1200RC Tapping Machine. Tulsa (OK): TD Williamson. [accessed 2020 Feb 19]. http://www.tdwilliamson.com/solutions/hot-tapping-and-plugging/tapping/1200RC-tapping-machine.

Tenaris. 2007. High Specification Pipeline Products for Shallow, Deep and Ultra-Deepwater.

Tenaris. 2019. Research & Development. [accessed 2019 Nov 20]. http://www.tenaris.com/en/RAndD.aspx.

Tenaris. 2019 Apr 5. Tenaris Form 6-K as of April 5, 2019. [accessed 2019 Nov 20].

Tenaris. Double Jointing – Offshore Line Pipe - Tenaris. Tenaris. [accessed 2020 Feb 3]. http://www.tenaris.com/en/Products/OffshoreLinePipe/DoubleJointing.aspx.

The Boston Globe. 2017 Aug 12. Unlovely meter reading drives up gas costs. Boston (MA): The Boston Globe. [accessed 2020 Apr 23].

The Federal Ship Construction Loan Guarantee Program. 2007 Mar 15. Washington (DC): Govinfo.com. [accessed 2020 Mar 12].

The Maritime Executive. 2018 May 22. Philly Shipyard Announces 275 Layoffs. Fort Lauderdale (FL): The Maritime Executive. [accessed 2020 Feb 21].

The Maritime Executive. 2019 May 29. Expansion of the Corpus Christi Ship Channel Begins. Fort Lauderdale (FL): The Maritime Executive. [accessed 2020 Feb 17].

The Maritime Executive. 2019 Aug 22. Fincantieri Bay Shipbuilding to Build LNG Barge for East Coast Route. Fort Lauderdale (FL): The Maritime Executive. [accessed 2020 Jul 22]..

The Maritime Executive. 2020 Feb 12. LNG Bunkering Options Expand Globally. Fort Lauderdale (FL): The Maritime Executive. [accessed 2020 May 5].

The Port of Virginia. 2016 Nov 21. Port, Konecranes Reach Final Agreement on World's Largest Automated-Stacking Cranes Contract; 86 Units Headed for VIG and NIT. Norfolk (VA): The Port of Virginia. [accessed 2020 Apr 3].

The White House. 2011 Jul 11. President Obama Announces Historic 54.5 mpg Fuel Efficiency Standard | whitehouse.gov. [accessed 2019 Dec 16].

The Williams Companies. c2020. Transco. Tulsa (OK): The Williams Companies. [accessed 2020 May 28]. https://www.williams.com/pipeline/transco/.

Thomas L, Tsao S, Meyers E, Anderson J. 2019a Aug 22. US East Coast states to add more than 19,000 MW of offshore wind by 2035. New York (NY): S&P Global. [accessed 2020 Mar 16].

Thomas L, Tsao S, Meyers E, Anderson J. 2019b Aug 22. US East Coast states to add more than 19,000 MW of offshore wind by 2035. New York (NY): S&P Global. [accessed 2020 Mar 30].

Tidewater. Tidewater Marine Services. Houston (TX): Tidewater. [accessed 2020 Feb 27]. https://www.tdw.com/services-fleet/tidewater-marine/overview/services/.

Times-Picayune MS NOLA com | The. 2013. Shale fracking proves $30 billion-a-year boon to waste disposal industry. NOLA.com. [accessed 2020 Apr 1].

Trans Mountain. c2020. Westridge Marine Terminal. Calgary (Canada): Trans Mountain. [accessed 2020 May 19]. https://www.transmountain.com/westridge-marine-terminal.

Transcourt. 2018 Nov 19. How much gas does a tanker truck hold? Oakville (Canada): Transcourt Tank Leasing Inc. [accessed 2020 May 14].

Transocean Ltd. 2018 Jan 30. Transocean Encourage. Steinhausen (Switzerland): Deepwater.com. [accessed 2020 Feb 21].

Transocean Ltd. 2019 Feb. Transocean Fleet Status Report. Steinhausen (Switzerland): Deepwater.com. [accessed 2020 Feb 13].

Transportation Institute. 2019 Oct 11. Promotional Programs - Title XI Shipbuilding. Camp Springs (MD): Transportation Institute. [accessed 2020 Feb 20].

Trenchless Technology. 2016. Drilling Fluids Recycling Systems 101. Trenchless Technology. [accessed 2020 Mar 3].

Tubb R. 2005. Deepwater Gulf Of Mexico Records & Achievements. Houston (TX): Pipeline & Gas Journal. 232(10):73–77.

Tullo AH. 2020 Jun 29. Ineos to buy BP’s chemical unit for $5 billion. Washington (DC): Chemical & Engineering News. [accessed 2020 Aug 4].

Twombly IJ. 2007 Mar 12. Appareo Systems debuts flight monitoring tool. Midland Park (NJ): Aviation International News. [accessed 2020 Apr 30].

Tyler Priest, Lajaunie J. 2014. Gulf Coast Communities And The Fabrication And Shipbuilding Industry: A Comparative Community Study. [accessed 2021 Apr 15].

Uhl W. 1984 Feb 1. More than breaking down a barrel; petroleum refining. National Petroleum News.

United Nations. 2015 Dec 12. Paris Agreement. New York (NY): United Nations. [accessed 2020 May 4].

United Refining Company. c2019. About United Refining. United Refining Company. [accessed 2019 Dec 16]. http://www.urc.com/about_urc/.

United States Bankruptcy Court. 2018. In re: PES Holding, LLC, et al.,. [accessed 2019 Dec 16]. http://www.omnimgt.com/cmsvol2/pub_47219/654434_10.pdf.

United States Census Bureau. NAPCS Product List for NAICS 4883: Support Activities for Water Transportation. Washington (DC): United States Census Bureau. [accessed 2020 Apr 4].

University of Maine. c2019. New England Aqua Ventus I. Orono (ME): UMaine.edu. [accessed 2020 Feb 17]. https://composites.umaine.edu/offshorewind/.

US Bureau of Labor Statistics. 2020 Jul 31. Industries at a Glance: Pipeline Transportation: NAICS 486. Washington DC: US Bureau of Labor Statistics. [accessed 2020 Jul 31].

US Census Bureau Classification Development Branch E. 2020 Jul 8. US Census Bureau Site North American Industry Classification System. Washington DC: Census Bureau. [accessed 2020 Jul 8].

US DOE [US Department of Energy]. 2015a. Quadrennial Energy Review: Energy Transmission, Storage, and Distribution Infrastructure. Washington (DC): US Department of Energy. [accessed 2020 May 19]. https://www.energy.gov/sites/prod/files/2015/09/f26/QER_AppendixB_NaturalGas.pdf.

US DOE [US Department of Energy]. 2015b. Quadrennial Energy Review: Energy Transmission, Storage, and Distribution Infrastructure - Appendix B: Natural Gas. Washington (DC): US Department of Energy. [accessed 2020 May 19].

US DOE [US Department of Energy]. 2019. LNG Monthly. Washington (DC): US Department of Energy, Office of Fossil Energy. [accessed 2020 Jul 10].

US DOE [US Department of Energy]. 2020. LNG Monthly: LNG Annual Report - 2019. Washington (DC): US Department of Energy, Office of Oil & Natural Gas. [accessed 2020 Apr 23].

US DOT [US Department of Transportation]. 2017 Jun 27. US 1: Fort Kent, Maine to Key West, Florida. Washington (DC): US Department of Transportation. [accessed 2020 May 22].

US DOT [US Department of Transportation]. 2019. Moving Goods in the United States - Top commodities moved by mode [dataset]. Washington (DC): US Department of Transportation. [accessed 2020 Jun 29]. https://data.transportation.gov/stories/s/Moving-Goods-in-the-United-States/bcyt-rqmu#.

US EPA [US Environmental Protection Agency]. 2015a. General Information About Injection Wells. US Environmental Protection Agency. [accessed 2020 Apr 9]. https://www.epa.gov/uic/general-information-about-injection-wells.

US EPA [US Environmental Protection Agency]. 2015b. National Pretreatment Program. US Environmental Protection Agency. [accessed 2020 Apr 8]. https://www.epa.gov/npdes/national-pretreatment-program.

US EPA [US Environmental Protection Agency]. 2015 Jun 11. Underground Injection Control Well Classes. US Environmental Protection Agency. [accessed 2020 Apr 9]. https://www.epa.gov/uic/underground-injection-control-well-classes.

US Fish and Wildlife Service. 2018 May 2. Electric Transmission Lines. Washington (DC): US Fish and Wildlife Service. [accessed 2020 Apr 6]. https://www.fws.gov/ecological-services/energy-development/electric-transmission.html.

US OLRC [US Office of the Law Revision Counsel]. 2018. 10 USC §8679: Construction of vessels in foreign shipyards: prohibition. Washington (DC): Office of the Law Revision Counsel. [accessed 2020 Feb 19].

U.S Securities and Exchange Commission. 2019a Dec 31. FINANCIAL REPORTS | Enterprise Products Partners L.P. Washington DC: US SEC. [accessed 2020 Jul 8]. https://ir-west.enterpriseproducts.com/annual-reports.

US Securities and Exchange Commission. 2019 Dec 31. Targa Resource Corp. Form 10-K, Fiscal year ended December 31, 2019. Washington DC: US SEC. [accessed 2020 Jul 8].

U.S Securities and Exchange Commission. 2019b Dec 31. DCP Midstream Files Form 10-K for Fiscal Year 2019 | DCP Midstream, LP. Washington DC: US SEC. [accessed 2020 Jul 30].

USACE [US Army Corps of Engineers]. 2017 Nov 15. Waterborne Commerce of the United States. Washington DC: USACE. [accessed 2020 Feb 18]. https://publibrary.planusace.us/#/series/Waterborne%20Commerce%20of%20the%20United%20States.

USACE [US Army Corps of Engineers]. 2018 Oct 1. The US Waterway System - 2017 Transportation Facts & Information. Washington DC: USACE. [accessed 2020 Feb 18]. https://publibrary.planusace.us/#/series/Fact%20Cards.

USACE [US Army Corps of Engineers]. 2018 Oct 29. Principal ports of the United States, Top_Ports_2017 [dataset]. Washington (DC): USACE. [accessed 2019 Aug 25]. https://usace.contentdm.oclc.org/digital/collection/p16021coll2/id/3114.

USACE [US Army Corps of Engineers]. 2019 Dec 12. Waterborne Commerce Statistics Center: Tonnage for selected US ports in 2018 - IWR Reports - USACE Digital Library. Washington (DC): USACE. [accessed 2021 Apr 7].

USACE [US Army Corps of Engineers]. c2020. Navigation. Washington (DC): US Army Corps of Engineers. [accessed 2020 May 26]. https://www.usace.army.mil/Missions/Civil-Works/Navigation/.

USBLM [US Bureau of Land Management]. 2021 Jan 6. 2021 Coastal Plain Lease Sale Bid Recap. Washington DC: BLM. [accessed 2021 Oct 12].

USBOEM [US Bureau of Ocean Energy Management]. 2021. Questions, Answers, And Related Resources | Bureau of Ocean Energy Management. Washington DC: BOEM. [accessed 2021 Oct 12]. https://www.boem.gov/environment/environmental-assessment/questions-answers-and-related-resources.

USCG [US Coast Guard]. 2007. Photo of lightering operation. [accessed 2020 Apr 3]. https://incidentnews.noaa.gov/incident/7615/517606.

USCG [US Coast Guard]. 2012. 16711 CG-ENG policy letter no. 03-12. [accessed 2020 Apr 30].

USCG [US Coast Guard]. OSRO point of contact [dataset]. Washington (DC): USCG Response Resource Inventory System. [accessed 2019 Oct 2]. https://cgrri.uscg.mil/UserReports/WebClassificationReport.aspx.

USDOC, BIS. 2001 May. National Security Assessment of the US Shipbuilding and Repair Industry. Washington (DC): Bureau of Industry and Security. [accessed 2020 Feb 20].

USDOC, CB [US Department of Commerce, Census Bureau]. 2017. 332812 Metal Coating, Engraving (except jewelry and silverware), and Allied Servcies to Manufacturers - 2017 NAICS Definition. [accessed 2019 Nov 20]. https://www.census.gov/cgi-bin/sssd/naics/naicsrch.

USDOE [US Department of Energy]. 1999. Environmental benefits of advanced oil and gas exploration and production technology. Report No.: DOE-FE-0385, 771125. [accessed 2020 Feb 28].

USDOE [US Department of Energy]. 2020 Apr 27. Long Term Applications Received by DOE/FE to Export Domestically Produced LNG from the Lower-48 States. Washington (DC): US Department of Energy. [accessed 2020 Apr 30].

USDOE O of EP and SA [US Department of Energy, Office of Energy Policy and Systems Analysis]. 2017. Natural Gas Infrastructure Modernization Programs at Local Distribution Companies: Key Issues and Considerations.

USDOE, OFE [US Department of Energy, Office of Fossil Energy]. 2016. Elba Liquefaction Project Environmental Assessment. Washington (DC): US Department of Energy, Office of Fossil Energy. [accessed 2020 May 5].

USDOE, OFE [US Department of Energy, Office of Fossil Energy]. 2011. 15 US Code Chapter 15B - Natural Gas. Washington (DC): Office of Fossil Energy. [accessed 2020 Apr 30].

USDOI [US Department of the Interior]. 2005 May 24. Creating New Opportunities and Challenges: Growing Support Industry. Washington (DC): Bureau of Ocean Energy Management. [accessed 2020 Feb 11].

USDOT [US Department of Transportation]. 1999 Sep. An Assessment of The US Marine Transportation System. Washington (DC): US Department of Transportation. [accessed 2020 Feb 20].

USDOT [US Department of Transportation]. 2020 Jan 15. Port Performance Freight Statistics in 2018. Washington DC: US Department of Transportation. [accessed 2020 Apr 3]. https://rosap.ntl.bts.gov/view/dot/43525.

USDOT, MARAD [US Department of Transportation, United States Maritime Administration]. 2004 Dec. Report on Survey of US Shipbuilding and Repair Facilities. Washington (DC): United States Maritime Administration. [accessed 2020 Feb 14].

USDOT, MARAD [US Department of Transportation, United States Maritime Administration]. 2015 Nov. The Economic Importance of the US Shipbuilding and Repairing Industry. Washington (DC): United States Maritime Administration. [accessed 2020 Mar 13].

USDOT, MARAD [US Department of Transportation, United States Maritime Administration]. 2018a Oct 30. Federal Ship Financing Program (Title XI) Previously Approved Applications, 2002-2016. Washington (DC): MARAD. [accessed 2020 Feb 20].

USDOT, MARAD [US Department of Transportation, United States Maritime Administration]. 2018b Oct 30. Previously Approved Title XI Applications. Washington (DC): United States Maritime Administration. [accessed 2020 Feb 20]. https://www.maritime.dot.gov/grants/previously-approved-title-xi-applications.

USDOT, MARAD [US Department of Transportation, United States Maritime Administration]. 2019 Feb 7. Federal Ship Financing Program (Title XI) Pending Applications. Washington (DC): United States Maritime Administration. [accessed 2020 Feb 20].

USDOT, MARAD [US Department of Transportation, United States Maritime Administration]. 2019 Mar 29. Small Shipyard Grant Availability of Funding Announced. Washington (DC): United States Maritime Administration. [accessed 2020 Feb 19].

USDOT, MARAD [US Department of Transportation, United States Maritime Administration]. 2019 Nov 6. Domestic Shipping. Washington (DC): United States Maritime Administration. [accessed 2020 Feb 19]. https://www.maritime.dot.gov/ports/domestic-shipping/domestic-shipping.

USEIA [US Energy Information Administration]. 2006 Jan 20. Natural Gas Processing: The Crucial Link Between NG Production & Its Transportation to Market. Washington DC: US Energy Information Administration. [accessed 2020 May 11]. https://www.eia.gov/naturalgas/articles/ngprocessindex.php.

USEIA [US Energy Information Administration]. 2015 Nov 6. The Basics of Underground Natural Gas Storage - US Energy Information Administration. Washington DC: US Energy Information Administration. [accessed 2020 Jun 6]. https://www.eia.gov/naturalgas/storage/basics/.

USEIA [US Energy Information Administration]. 2019 Jan. US Energy Information Administration (EIA). Natural Gas Annual Respondent Query System. Washington DC: US Energy Information Administration. [accessed 2020 Jul 8].

USEIA [US Energy Information Administration]. 2019 Feb 14. Natural Gas Processing Capacity - Energy Information Administration. Washington DC: US Energy Information Administration. [accessed 2020 May 12].

USEIA [US Energy Information Administration]. 2019 Nov 4. Associated gas contributes to growth in US natural gas production - Today in Energy - US Energy Information Administration (EIA). Washington DC: US Energy Information Administration. [accessed 2020 Apr 29].

USEIA [US Energy Information Administration]. 2019 Dec 6. Natural gas explained - US Energy Information Administration (EIA). Washington DC: US Energy Information Administration. [accessed 2020 Jun 23].

USEIA [US Energy Information Administration]. 2020 Jan 29. Annual Energy Outlook 2020. Washington DC: US Energy Information Administration. [accessed 2020 Jul 10].

USEIA [US Energy Information Administration]. 2020a May 30. US Underground Natural Gas Storage Capacity. Washington DC: USEIA. [accessed 2020 Jun 6].

USEIA [US Energy Information Administration]. 2020b May 30. US Natural Gas Consumption by End Use. Washington DC: US Energy Information Administration. [accessed 2020 Jun 25]. https://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm.

USEIA [US Energy Information Administration]. 2020a Jun 30. US Natural Gas Liquid Composite Price (Dollars per Million Btu). Washington DC: US Energy Information Administration. [accessed 2020 Aug 1].

USEIA [US Energy Information Administration]. 2020b Jun 30. Petroleum and Other Liquids. Washington DC: USEIA. [accessed 2020 Jul 10].

USEPA [US Environmental Protection Agency]. 1997. Profile of the Shipbuilding and Repair Industry. Washington (DC): US Environmental Protection Agency Report No.: EPA-310-R-97-008. [accessed 2020 Feb 14].

USEPA [US Environmental Protection Agency]. 1999 Dec 1. Understanding Oil Spills and Oil Spill Response. Washington (DC): US Environmental Protection Agency. [accessed 2020 Apr 16].

USEPA [US Environmental Protection Agency]. 2018 Sep 27. Overview of the Cross-State Air Pollution Rule (CSAPR). Washington (DC): US Environmental Protection Agency. [accessed 2020 Jan 1].

USEPA [US Environmental Protection Agency]. 2020 Apr 1. Oil Spills Prevention and Preparedness Regulations. Washington (DC): US Environmental Protection Agency. [accessed 2020 Apr 23].

USEPA [US Environmental Protection Agency]. c2020. When are You Required to Report an Oil Spill and Hazardous Substance Release? Washington (DC): US Environmental Protection Agency. [accessed 2020 Apr 22].

Valentine H. 2015 Aug 26. Super-Size Tugs for Super-Size Barges. Fort Lauderdale (FL): The Maritime Executive. [accessed 2020 May 15].

Valero. 2015. Basics of Refining and Optimization. https://www.valero.com/en-us/Documents/Operations/2015+Barclays+Teach-In+FINAL+2-3-2015.pdf.

Vineyard Wind. 2019 Oct 11. Park City Wind Will Transform Bridgeport into Offshore Wind Hub. Vineyard Wind. [accessed 2021 Apr 8]. https://www.vineyardwind.com/press-releases/2019/10/28/park-city-wind-will-transform-bridgeport-into-offshore-wind-hub.

Virginia General Assembly. 2020 Mar 25. Bill Tracking - 2020 session > Legislation. Virginia's Legislative Information System. [accessed 2021 Oct 12]. https://lis.virginia.gov/cgi-bin/legp604.exe?201+ful+CHAP0451.

Waddams AL. 1969. Chemicals from petroleum: An introductory survey. New York (NY): Chemical Publishing Co., Inc.

Walton R. 2018 Jan 9. Florida Power & Light brings 4 new solar plants online, retires coal facility. Washington (DC): Utility Dive. [accessed 2019 Dec 20].

Weiler S. 2019 Oct 4. PHMSA Issues Three New Rules to Promote Pipeline Safety. Washington (DC): Dorsey & Whitney LLP. [accessed 2020 Jun 12].

Weissman G, Cross RJ, Sargent R. 2018. Wind Power to Spare: The Enormous Energy Potential of Atlantic Offshore Wind. Environment America Research & Policy Center & Frontier Group.

Weissman G, Cross RJ, Sargent R. 2018 Mar. Wind Power to Spare: The Enormous Energy Potential of Atlantic Offshore Wind. Boston (MA): Environment America. [accessed 2020 Mar 31].

Wilds J, Dufour CL, Cowan WG. 1996. Louisiana, Yesterday and Today: A Historical Guide to the State. Baton Rouge (LA): Louisiana State University Press. [accessed 2020 Feb 11].

Wilson GE. 1981. A General Overview of Air Drilling and Deviation Control. Journal of Petroleum Technology. 33(12):2,307-2,315. doi:10.2118/9529-PA.

Wisdom L, Peer E, Bonnifay P. 1998. Cleaner fuels shift refineries to increased resid hydroprocessing. Oil and Gas Journal. 96(6):58–61.

Wolf T. 2017a. Letter to President Trump. [accessed 2019 Dec 17]. https://www.agri-pulse.com/ext/resources/pdfs/w/WolfRFSletter_102417.pdf.

Wolf T. 2017b. Letter to EPA Administrator Pruitt. [accessed 2019 Dec 17]. https://www.epa.gov/sites/production/files/2018-02/documents/ltr-pa-gov-wolf-rfs-waiver-2017-11-02.pdf.

Woods B. 2019 Dec 13. US has only one offshore wind energy farm, but a $70 billion market is on the way. Englewood Cliffs (NJ): CNBC. [accessed 2020 Mar 31].

Wren D. 2020 Jun 29. BP selling SC plant as part of $5B petrochemical exit. Charleston (SC): Post and Courier. [accessed 2020 Aug 4].

Xunpeng S, Variam HMP. 2018. Key elements for functioning gas hubs: A case study of East Asia. Natural Gas Industry B. 5(2):167–176.

Department of the Interior (DOI)

The Department of the Interior protects and manages the Nation's natural resources and cultural heritage; provides scientific and other information about those resources; and honors the Nation’s trust responsibilities or special commitments to American Indians, Alaska Natives, and affiliated island communities.

BOEM
Bureau of Ocean Energy Management

Bureau of Ocean Energy Management (BOEM)

The mission of the Bureau of Ocean Energy Management is to manage development of U.S. Outer Continental Shelf energy and mineral resources in an environmentally and economically responsible way.

BOEM Environmental Studies Program

The mission of the Environmental Studies Program is to provide the information needed to predict, assess, and manage impacts from offshore energy and marine mineral exploration, development, and production activities on human, marine, and coastal environments. The proposal, selection, research, review, collaboration, production, and dissemination of each of BOEM’s Environmental Studies follows the DOI Code of Scientific and Scholarly Conduct, in support of a culture of scientific and professional integrity, as set out in the DOI Departmental Manual (305 DM 3).