# APPALACHIAN HYDROGEN INFRASTRUCTURE ANALYSIS

HARTEJ SINGH, LUKE CLAHANE,
AMANDA HARKER STEELE, CLARE CALLAHAN,
TRAVIS WARNER, ROBERT WALLACE

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**Disclaimer**

***Hartej Singh***[1,2]*: Formal Analysis, Writing - Original Draft;*
***Luke Clahane***[1,2]*: Investigation, Writing - Original Draft;*
***Amanda Harker Steele***[1,2]*: Investigation, Writing - Original Draft;*
***Clare Callahan***[1,2]*: Formal Analysis;* ***Travis Warner***[1,2]*: Formal Analysis;*
***Robert Wallace***[1,2]*: Conceptualization, Formal Analysis, Writing - Original Draft;* ***John Brewer***[2]*: Supervision;* ***Justin M. Adder***[2*]*: Supervision;* ***David Morgan***[2]*: Supervision*

[1]National Energy Technology Laboratory (NETL) support contractor
[2]NETL
*Corresponding contact: justin.adder@netl.doe.gov, 412.386.7309

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# ACRONYMS AND ABBREVIATIONS

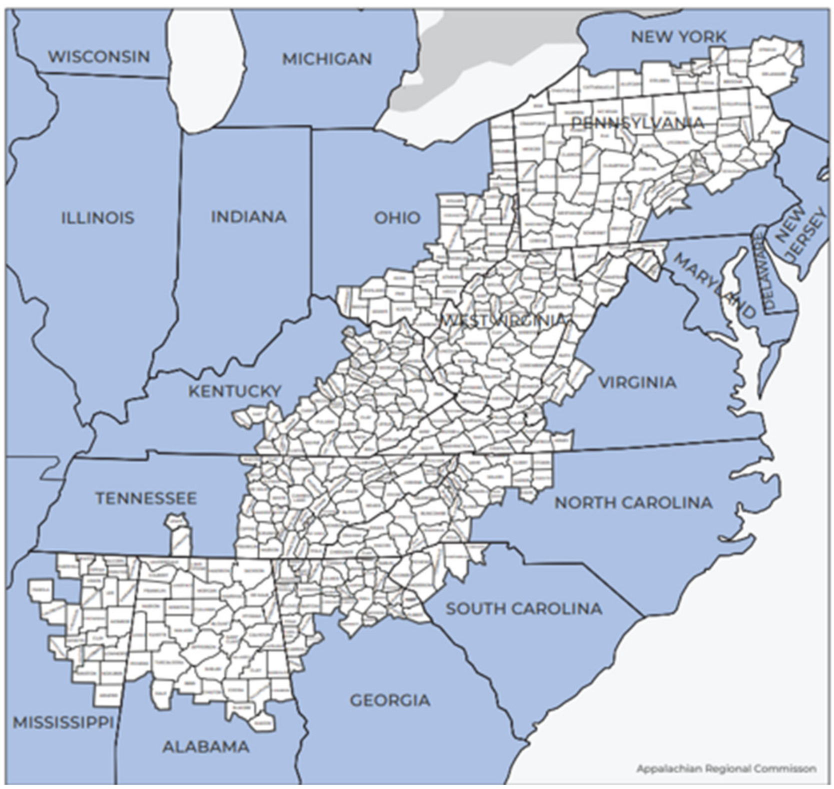
| | |
|---|---|
| °C | Degrees Celsius |
| °F | Degrees Fahrenheit |
| $M | Million U.S. dollars |
| ANSI | American National Standards Institute |
| API | American Petroleum Institute |
| ARC | Appalachian Regional Commission |
| ATR | Autothermal reforming |
| bar | Absolute pressure |
| barg | Gauge pressure |
| Bcf | Billion cubic feet |
| Bcfd | Billion cubic feet per day |
| Bcfy | Billion cubic feet per year |
| BEA | Bureau of Economic Analysis |
| BF | Blast furnace |
| BOF | Basic oxygen furnace |
| BSEE | Bureau of Safety and Environmental Enforcement |
| Btu | British thermal unit |
| CCS | Carbon capture and storage |
| CCUS | Carbon capture, utilization, and storage |
| cf | Cubic feet |
| CFR | Code of Federal Regulations |
| CHP | Combined heat and power |
| CO | Carbon monoxide |
| $CO_2$ | Carbon dioxide |
| COMAR | Code of Maryland Regulations |
| DHS | Department of Homeland Security |
| DOE | Department of Energy |
| DOI | Department of the Interior |
| DOT | Department of Transportation |
| dt | Dry tonne |
| EIA | Energy Information Administration |
| EPA | Environmental Protection Agency |
| FECM | Office of Fossil Energy and Carbon Management |
| FHWA | Federal Highway Administration |
| FRP | Fiber reinforced polymer |
| GE | General Electric |
| Gtonnes | Gigatonnes |
| GWh | Gigawatt hour |
| $H_2$ | Hydrogen |
| H2FC | Hydrogen fuel cell |
| $H_2O$ | Water |
| HCNG | Hydrogen and compressed natural gas |
| HMR | Hazardous Materials Regulations |
| HP | Horsepower |
| hr | Hour |
| in | Inch |
| K | Thousand |
| kg | Kilogram |
| kJ | Kilojoule |
| km | Kilometer |
| kPa | Kilopascal |
| kPag | Kilopascal gauge |
| ksi | kilo-pounds per square inch |
| kW | Kilowatt |
| lb | Pound |
| LDC | Local distribution company |
| LHC | Liquid hydrogen carrier |
| LHV | Lower heating value |
| LNG | Liquified natural gas |
| M | Million |
| m | Meter |
| $m^3$ | Cubic meter |
| MDEA | Methyldiethanolamine |
| mg | Milligram |
| $mi^2$ | Square miles |
| MJ | Megajoule |
| mm | Millimeter |
| MMcf | Million cubic feet |
| MMscfd | Million standard cubic feet per day |
| MOF | Metal-organic framework |
| MPa | Megapascal |
| Mtonnes | Million metric tons |
| MW | Megawatt |
| $N_2$ | Nitrogen |
| NAICS | North American Industry Classification System |

| | |
|---|---|
| NETL | National Energy Technology Laboratory |
| NG | Natural gas |
| NFPA | National Fire Protection Association |
| $Nm^3$ | Normalized cubic meter |
| O&M | Operation and maintenance |
| OCS | Outer Continental Shelf |
| OORP | Office of Offshore Regulatory Programs |
| OSHA | Occupational Health and Safety Administration |
| PHMSA | Pipeline and Hazardous Materials Safety Administration |
| POx | Partial oxidation |
| PSA | Pressure swing absorption |
| psi | Pounds per square inch |
| psig | Pounds per square inch gauge |
| R&D | Research and development |
| RE | Renewable energy |
| SCADA | Supervisory Control and Data Acquisition |
| scfd | Standard cubic feet per day |
| SIPA | (Columbia University) School of International and Public Affairs |
| SMR | Steam methane reforming |
| Tcf | Trillion cubic feet |
| tonnes | Metric tons |
| UPS | Uninterruptible power supply |
| US, U.S. | United States |
| UIC | Underground Injection Control |
| USCG | United States Coast Guard |
| USGS | United States Geological Survey |
| UST | Underground storage tank |

# EXECUTIVE SUMMARY

As large-scale efforts to decarbonize the global economy ramp up in earnest, hydrogen is being positioned as a critical solution for numerous sectors. Hydrogen produced from fossil energy resources with carbon capture and storage (CCS) is viewed as a bridge in the clean energy transition, enabling the development of midstream infrastructure and downstream demand. This transitional use is viewed as necessary while the cost of renewably-driven electrolysis of water to produce hydrogen continues to fall, and capacity can be scaled up. This report highlights the potential for the Appalachian region to develop a hydrogen economy with fossil-derived hydrogen with CCS production (hydrogen from natural gas with carbon capture and storage). The Appalachian region, shown in Exhibit ES-1, is well suited for development into a clean energy hydrogen hub.

***Exhibit ES-1. Map of the Appalachian region***

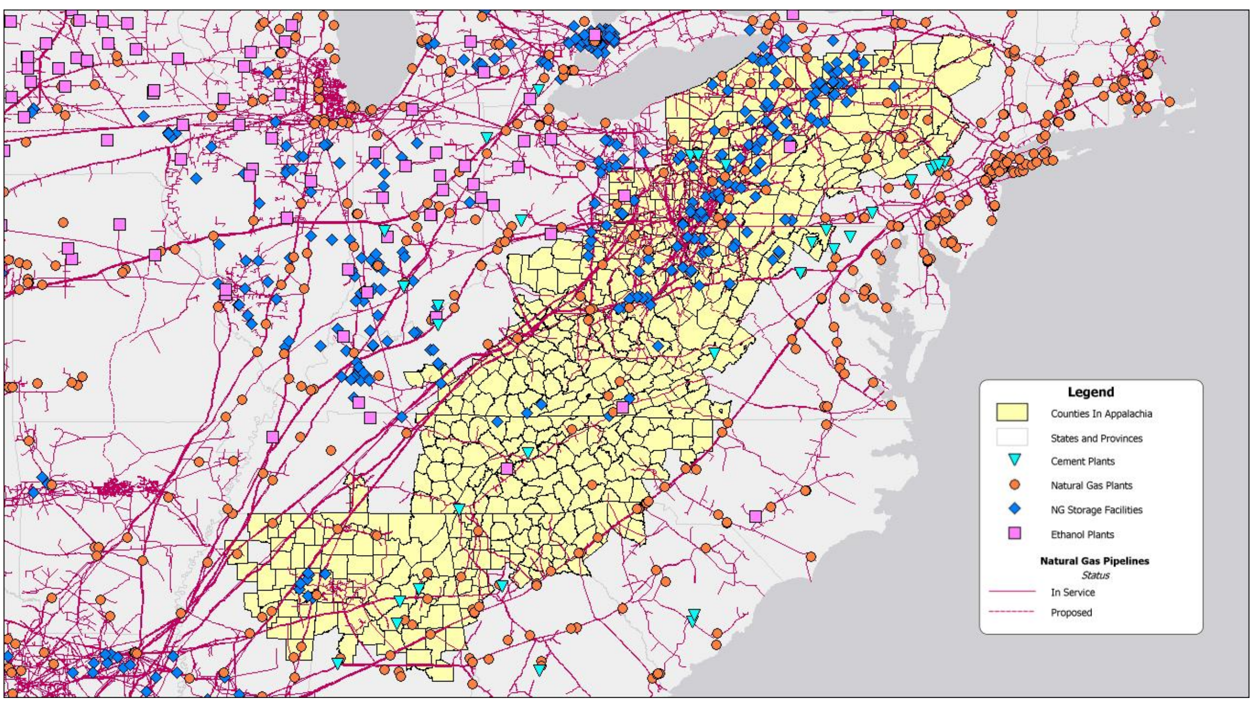



*Used with permission from the Appalachian Regional Commission*

Hydrogen can replace fossil fuels in many aspects of the energy economy, delivering high-quality industrial process heat, onsite industrial electricity generation, large-scale electricity generation, and transportation, and as a building block for thousands of downstream chemicals. While there are multiple pathways to produce hydrogen from water, biomass, and hydrocarbons, the most economical is currently from natural gas through steam methane reforming (SMR) and autothermal reforming (ATR). This hydrogen can be generated with low carbon intensity if SMR and ATR are coupled with CCS. The technologies listed are nonexhaustive and other routes such as partial oxidation (POx) and pyrolysis of methane are also being viewed as commercially relevant. Since CCS can be applied to large-scale electricity generated with fossil fuel, economics are likely to be less favorable using hydrogen derived from fossil fuels for large-scale electricity generation with respect to retrofitting current natural gas generating facilities. However, industrial uses of natural gas for generating high-quality process heat and onsite electricity generation are typically much smaller scale than large-scale fossil fuel power plants and CCS may not be economical at these smaller scales. The concentration, or lack thereof, of carbon dioxide ($CO_2$) being emitted from fossil fuel power plants is a strong driver of economics of CCS. Also, it may be easier and cheaper to transport $CO_2$ for storage if it is generated at a few locations rather than at many locations. For these industrial facilities, switching to hydrogen generated by natural gas with CCS can be a way to lower their carbon intensity.

Appalachia has the natural gas resources, infrastructure, storage capacity, and industrial demand in and around its borders to lead a clean energy revolution using natural gas with carbon capture and storage to sustainably produce hydrogen. The near-term creation of infrastructure to support fossil-derived hydrogen with CCS while meeting near-term goals of an aggressive timeline will also readily facilitate the future deployment of renewable hydrogen. The Appalachian region has significant natural gas storage, pipeline infrastructure, and power production due to the region's large natural gas resources from the Marcellus and Utica gas plays, as seen in Exhibit ES-2.

***Exhibit ES-2. Natural gas pipelines, power plants and storage in Appalachia***



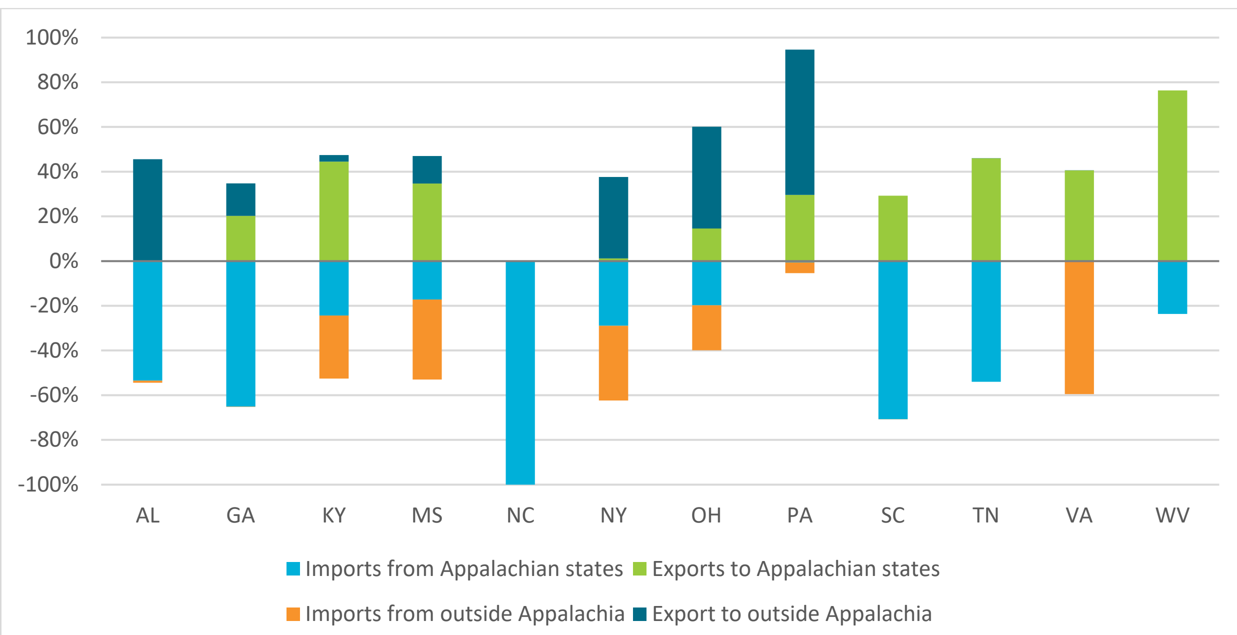

*Source: Hitachi Energy Velocity Suite [1]*

The technology aspects of hydrogen transportation and storage are well known, and advancements are being made by studying the volume of hydrogen that can be blended with natural gas. Pipeline materials and specifications, compressor station requirements, measurements of products in the pipeline throughout the process, and the costs of upgrading the supply chain as hydrogen production accelerates are all issues that are being addressed by industry stakeholders and academia. Physical solutions for improving the pipeline infrastructure and compressor stations are currently in practice, with known costs. Continued momentum through research, development, and deployment efforts is needed to ensure hydrogen transport and storage economics do not inhibit commercial scale-up.

Regulations, particularly across the range of jurisdictions, are extremely complex and situationally specific. However, the regulatory framework does not pose any direct risk to developing a hydrogen economy in the Appalachian region. Currently, Appalachian states have a supportive regulatory environment with respect to fuel production, distribution, and storage. While most of the states have not adopted official regulations for hydrogen, assuming hydrogen would fit into a high-pressure gas category, current regulations on the production, distribution, and storage of natural gas and other liquid fuels are well established.

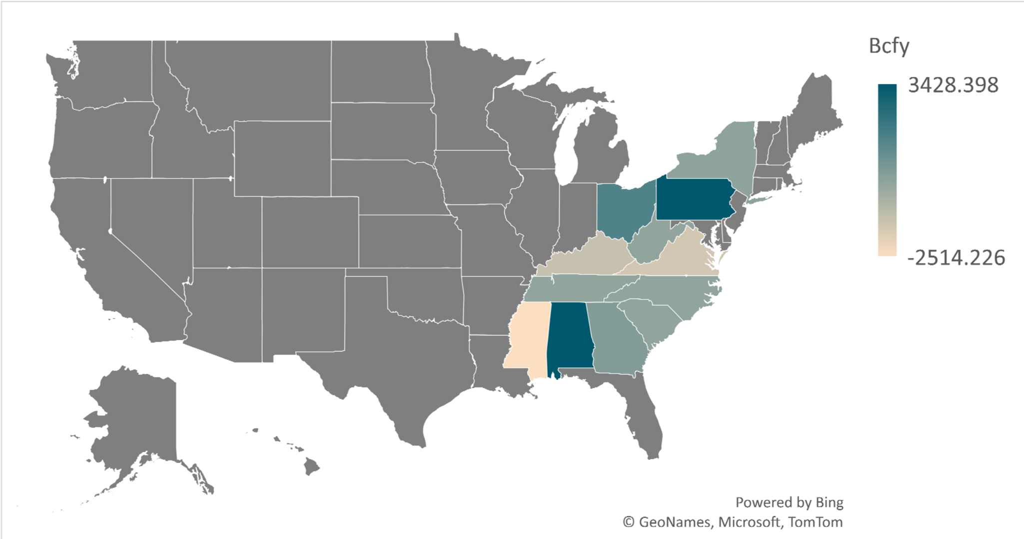
Upon examining the production and consumption, the Appalachian region is a significant exporter of energy. Exhibit ES-3 shows that in 2020, 46 percent of natural gas deliveries (12,900 billion cubic feet per year [Bcfy]) were exported to states outside of the region with a nominal amount (1 percent) delivered to international countries.

***Exhibit ES-3. Appalachian state import/exports [2]***




By volume, Pennsylvania and Alabama are the largest net exporters of natural gas to destinations outside of the Appalachian region, as shown in Exhibit ES-4, and West Virginia supplies the most natural gas to other states within the region.

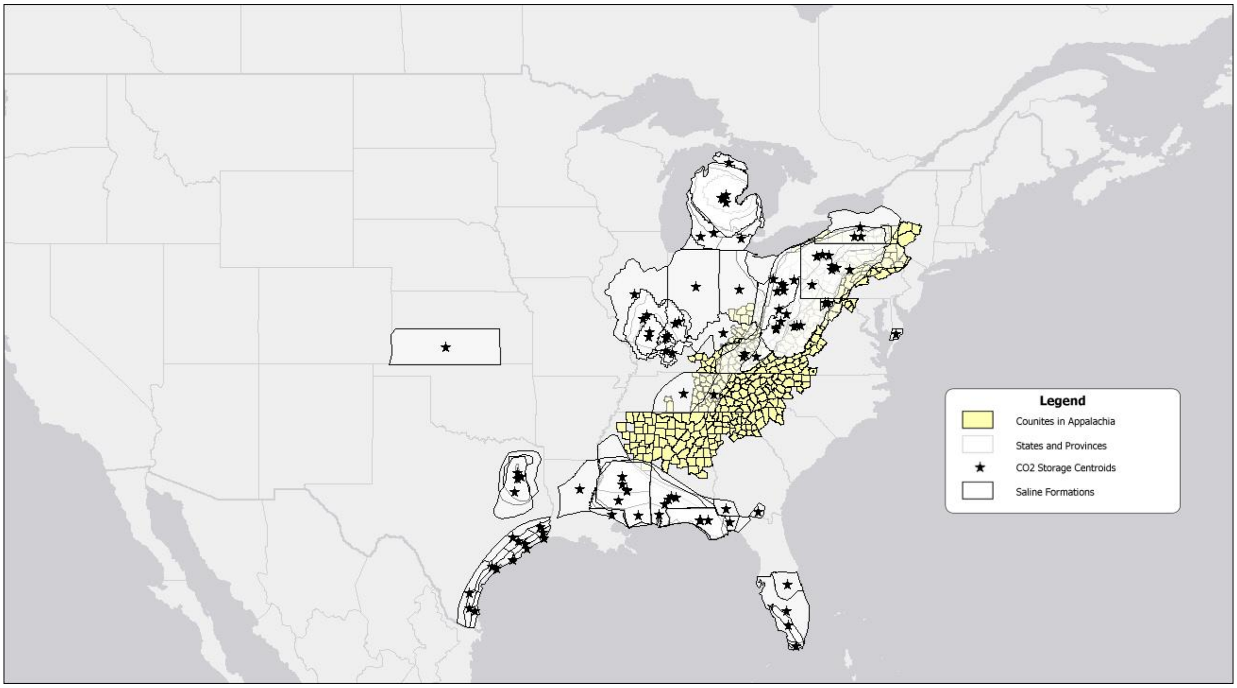
***Exhibit ES-4. Appalachian states by annual natural gas net exports to destinations outside of the region (2020)***




With a combination of energy exports, long-term reduction in natural gas consumption for electricity through grid decarbonization, and utilization of biomass opportunities to produce hydrogen through gasification or renewable natural gas (via pyrolysis), there would be a significant amount of natural gas as feedstock for hydrogen production plants in the region.

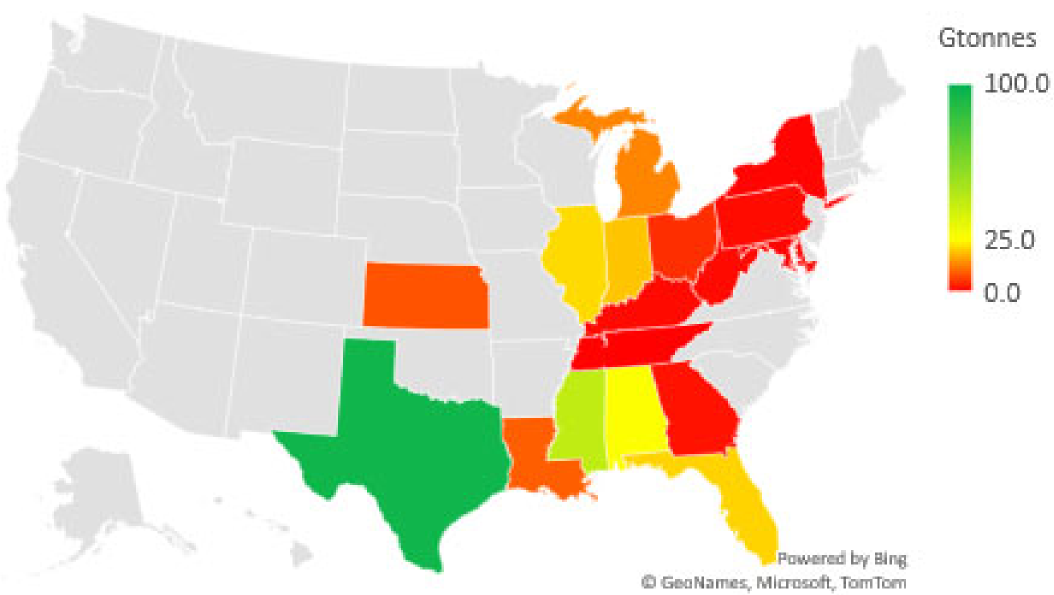
Additionally, opportunities are present for $CO_2$ transport and storage. Section 5.3.2. demonstrates Eastern U.S. saline aquifers in the Appalachian, Midwest, and Southeast storage regions represent over 240 gigatonnes of low-cost (less than $10 per tonne) $CO_2$ storage capacity; results by formation are shown in the Appendix: FECM/NETL $CO_2$ Saline Storage Cost Model Formation Results. Exhibit ES-5 shows the geographic centroids (i.e., the geometric center) of the numerous $CO_2$ storage reservoirs located in and around Appalachia. Exhibit ES-6 provides estimates of potential $CO_2$ storage volumes in the Appalachian storage region and surrounding Midwest and Southeast storage regions, by state, after accounting for the potential impact of pressure interference between multiple $CO_2$ storage projects within the same geologic reservoir at the same time. Accounting for the potential impact of pressure interference would reduce the number of $CO_2$ storage projects that could simultaneously operate at economical injection rates, lowering each reservoir's effective total $CO_2$ storage capacity.

***Exhibit ES-5. Storage centroids in and around the Appalachian region, Gulf Coast, and Midwest***



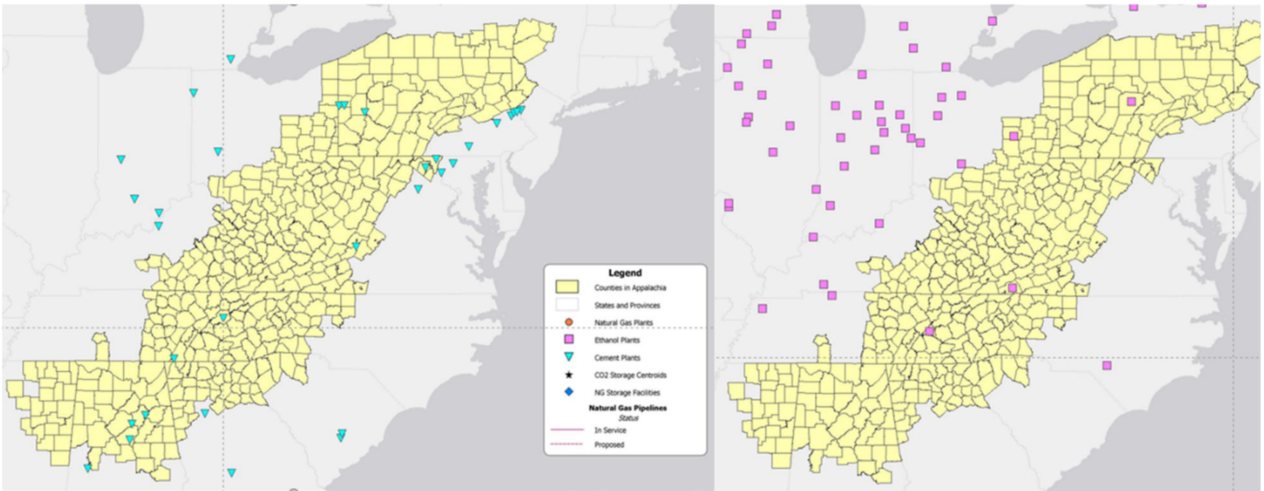

*Source: Hitachi Energy Velocity Suite [1]*

***Exhibit ES-6. Potential $CO_2$ storage capacity in Appalachian, Midwest, and Southeast storage regions, by state***



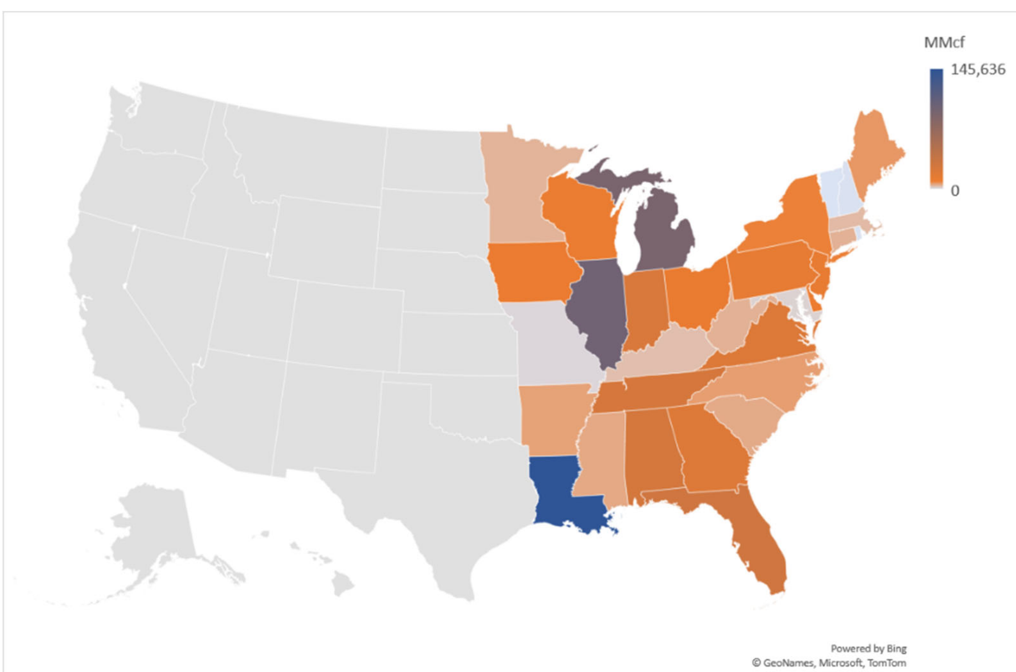

To complement the natural resources and infrastructure that exist in Appalachia, there exists robust market potential throughout the region and beyond. Just as Appalachia exports natural gas throughout the country, so could the region export hydrogen to satisfy the demand of the ethanol and cement industries that could replace natural gas with hydrogen, shown in Exhibit ES-7, as well as the agricultural industry, the steel industry, and other energy-intensive industries throughout the Appalachian region and beyond. An important consideration for the Appalachian region that must be considered is the more favorable economics for transport and storage of hydrogen to more concentrated end-users than more dispersed end-users. In the case of the Appalachian region, cement plants are more closely concentrated than ethanol plants.

***Exhibit ES-7. Cement plants (left) and ethanol plants (right) in and around Appalachia***




In 2020 alone, there was a demand of 626 billion cubic feet (Bcf) of natural gas in and around the Appalachian region that natural gas from Appalachia, when converted to hydrogen, could meet. Exhibit ES-8 shows the natural gas demand from industrial boiler processes in the eastern and midwestern United States.

***Exhibit ES-8. Natural gas industrial boilers in and around the Appalachian region***



The Appalachian region has had a strong workforce to meet the challenges of creating and managing oil and gas production and distribution, which could transition to a hydrogen economy and create jobs across the Appalachian region economy. Data suggests nationally for every million dollars in output generated by industries (identified as likely to be involved in the supply chain for hydrogen, in response to increased hydrogen availability from the development of advanced hydrogen infrastructure in the Appalachian region), the following number of jobs will be supported for each industry, as seen in Exhibit ES-9.

***Exhibit ES-9. Summary of national data from BEA on employment and output by industry used to estimate potential jobs supported from advanced hydrogen infrastructure development***

| Industrial Sector | 2017 NAICS Code | Industry Output ($M) 2019 | Employment (K) (2019) | Number of Employees Per $M in Industry Output |
|---|---|---|---|---|
| Oil and gas extraction | 211 | 372,818 | 490.3 | 1.32 |
| Support activities for mining | 213 | 102,460 | 379.2 | 3.70 |
| Utilities | 22 | 563,178 | 591.3 | 1.05 |
| Petroleum and coal products manufacturing | 324 | 378,024 | 1,548.1 | 4.10 |
| Chemical products manufacturing | 325 | 366,142 | 1,098.5 | 3.00 |
| Fabricated metal product manufacturing | 332 | 583,231 | 120.2 | 0.21 |
| Computer and electronic products manufacturing | 334 | 777,777 | 896.8 | 1.15 |
| Rail transportation | 482 | 85,412 | 176.1 | 2.06 |
| Water transportation | 483 | 59,308 | 73.4 | 1.24 |
| Truck transportation | 484 | 402,313 | 2,327.1 | 5.78 |
| Pipeline transportation | 486 | 58,829 | 52.3 | 0.89 |
| Warehousing and storage | 493 | 153,015 | 1,340.9 | 8.76 |

Note: Jobs are rounded to the nearest whole number.

The Appalachian region possesses the resources to support a fossil-derived hydrogen with CCS economy: sufficient natural gas pipeline, truck, barge, and rail distribution infrastructure that can slowly blend hydrogen into the system and transform with the demand for hydrogen as the market grows. However, a large-scale increase in hydrogen supply and demand will shift the current hydrogen market, and those changes need to be analyzed across a spectrum of supply/demand/costs scenarios, considering environmental incentives and penalties at the federal through corporate levels. Additionally, research into the methods and limits of adapting or repurposing existing midstream infrastructure and technology such as pipelines and storage is well underway to further accelerate hydrogen deployment and lower the potential cost of adoption.

Developing a pathway to create a hub for hydrogen production in the Appalachian region will require a combination of public/private partnerships to drive the current momentum forward.

Currently, in the Appalachian region, multiple hydrogen projects have been proposed. These projects, discussed further in Section 3.3.2, are providing the groundwork for hydrogen to be used for power, steelmaking, vehicles, and low-carbon intensive products using CCS. Continued public sector support by leveraging research, development, and demonstration can help bring many of these proposals to fruition.

This report is phase 1 in a multi-phase analysis into the feasibility of successfully developing a hydrogen hub in the Appalachian region. Section 7 details additional areas of analysis as well as more in-depth analysis of topics found in this report. Ideas to be investigated include:

- Additional conversion technologies
- Blending of H2 in pipelines
- H2 storage costs
- CO2 storage options
- Job creation across the entire supply chain
- H2 production tax credits available within the Inflation Reduction Act
- End users
- Concentrating on the northern Appalachia region where natural gas is being produced
- Energy and environmental justice

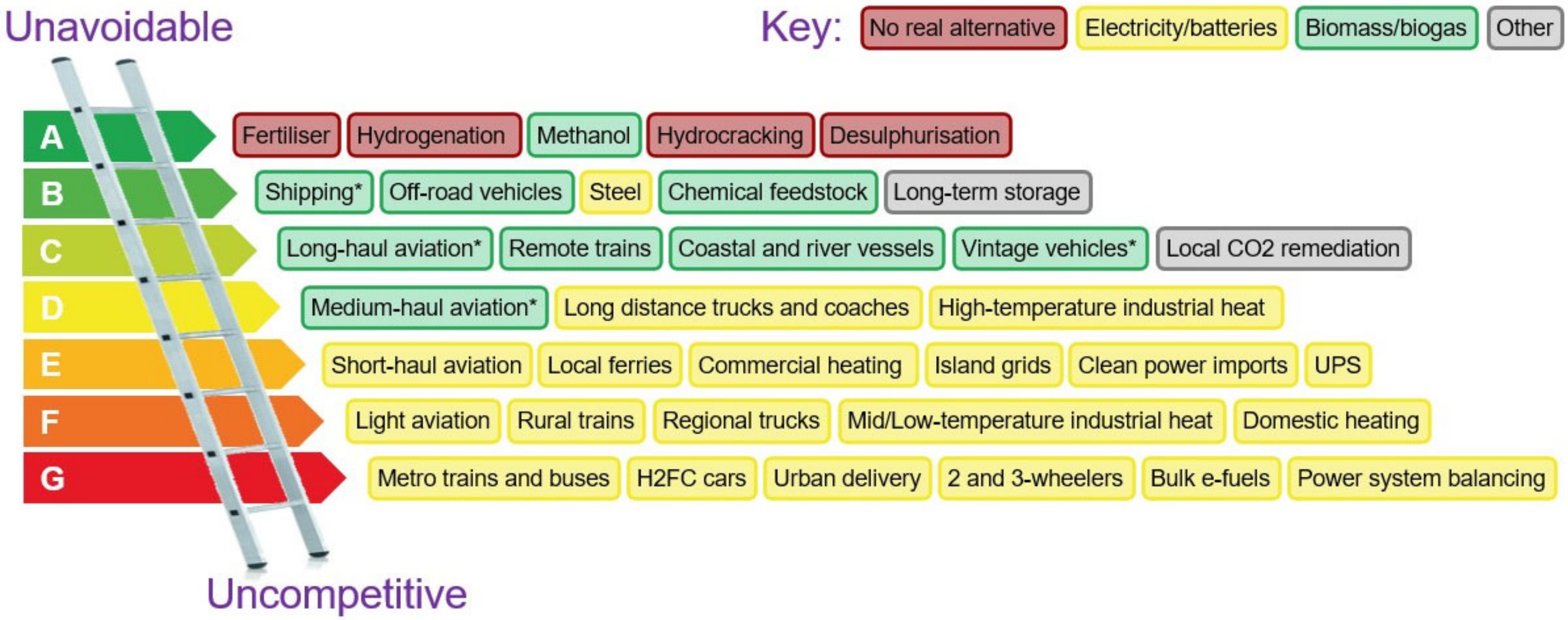
# 1 Introduction

## 1.1 Background

As large-scale efforts to decarbonize the global economy ramp up in earnest, hydrogen ($H_2$) is being positioned as a critical solution for numerous sectors. Hydrogen produced from fossil energy resources is commonly viewed as a bridge in the clean energy transition, enabling the development of midstream infrastructure and downstream demand while the cost of renewably driven electrolysis of water to produce renewably sourced hydrogen (hydrogen from electrolysis powered by renewable generation) continues to fall. Hydrogen can replace fossil fuels in many aspects of the energy economy, delivering high-quality industrial process heat, onsite industrial electricity generation, large-scale electricity generation, and transportation, and as a building block for thousands of downstream chemicals. While there are multiple pathways to produce hydrogen from water, biomass, and hydrocarbons, including partial oxidation and methane pyrolysis, the most economical is currently from natural gas through steam methane reforming (SMR) and autothermal reforming (ATR). This hydrogen can be generated with low carbon intensity if SMR and ATR are coupled with carbon capture and storage (CCS). However, industrial uses of natural gas for generating high-quality process heat and onsite electricity generation are typically much smaller scale than large-scale fossil fuel power plants and CCS may not be economical at these smaller scales. Also, it may be easier and cheaper to transport carbon dioxide ($CO_2$) for storage if it is generated at a few locations rather than at many locations. For these industrial facilities, switching to hydrogen generated by natural gas with CCS can be a way to lower their carbon intensity.

Research into the methods and limits of adapting or repurposing existing midstream infrastructure and technology options such as pipelines and storage are well underway to further accelerate hydrogen deployment and lower the potential cost of adoption. In existing strategy documents, the Department of Energy (DOE) and the Office of Fossil Energy and Carbon Management (FECM) have each identified a range of challenges and opportunities related to fossil-based hydrogen production, transport, and storage. [3] [4] Hydrogen has a number of applications and end-uses, some of which have competing technologies that have been proposed for decarbonization. Exhibit 1-1 prioritizes hydrogen in different end-use applications, as well as highlighting the most prominent “alternative” to hydrogen being proposed in academia or industry for that specific end-use.

***Exhibit 1-1. Hydrogen "ladder": competing technologies and end-use cases***

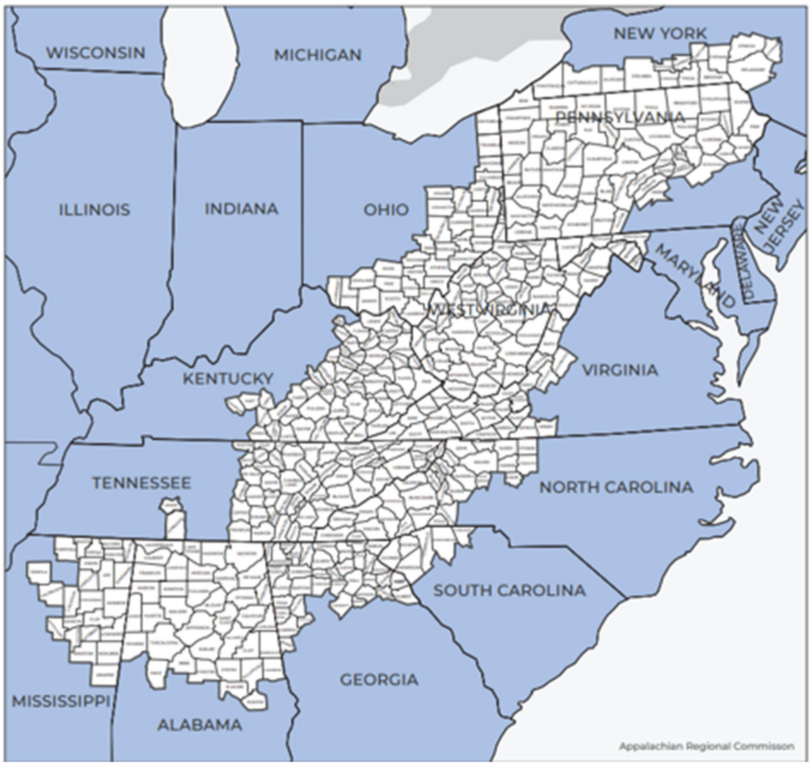



** Via ammonia or e-fuel rather than H2 gas or liquid*

*Source: Liebreich Associates (concept credits: Adrian Hiel/Energy Cities & Paul Martin)*

The objective of the activity reported here is to develop technical pathways for the development and transition to a hydrogen economy with a focus on hydrogen transportation and storage in the Appalachian region, a region in the eastern part of the United States consisting of 423 counties across 13 different states: Alabama, Georgia, Kentucky, Maryland, Mississippi, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Virginia, and West Virginia as defined by Exhibit 1-2. [5] The associated $CO_2$ infrastructure needed for future hydrogen production from fossil fuels with carbon capture is also briefly discussed in this report but will be addressed in greater detail in a separate study to be conducted at a later date.

***Exhibit 1-2. Map of the Appalachian region***




*Used with permission from the Appalachian Regional Commission*

Specifically, the activity will provide hydrogen transport and storage infrastructure pathways in support of a broader hydrogen economy. These pathways will be consistent with existing and potential technologies and regulations and provide valuable guidance for the investment and research and development potential for transportation and storage of hydrogen in Appalachia.

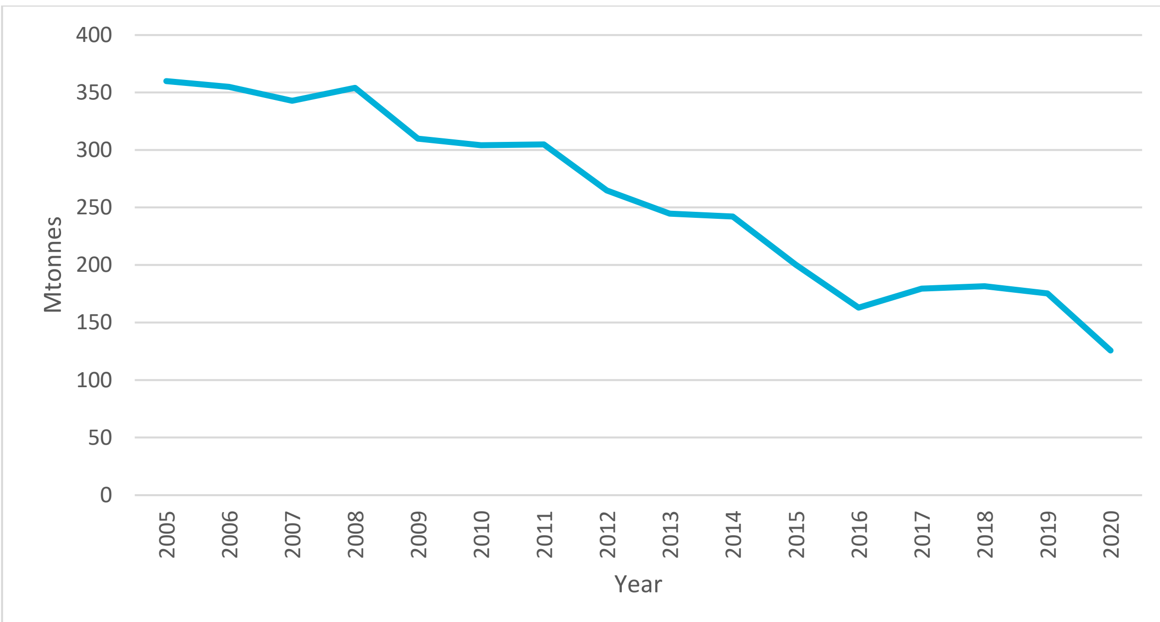
## 1.2 Revitalizing Appalachia

The Appalachian Regional Commission (ARC) estimates between 2015 and 2019 there were approximately 25.7 million (M) people living in Appalachia. [6] Around 9.7 M of those people were considered members of the civilian labor force of prime working age (between the ages of

25 and 64).[a] [6] Only 73.3 percent of these identified persons were considered to be participating in the labor force, meaning they were either working or actively looking for work at the time. [6] Labor force participation in the region between 2015 and 2019 was nearly 5 percentage points below the national average of 77.9 percent for the same persons. [6]

Recent declines in coal production (i.e., post 2005) have been identified as a potential reason for low levels of labor force participation across the region.[b] The Appalachian region has been a major supplier of coal for more than two centuries and according to the U.S. Energy Information Administration (EIA) supplied nearly 26 percent of the nation's coal in 2020. [7] Coal production in Appalachia, however, has been declining since 2005, as seen in Exhibit 1-3. [8]

***Exhibit 1-3. Coal production in the Appalachian coal region [9]***



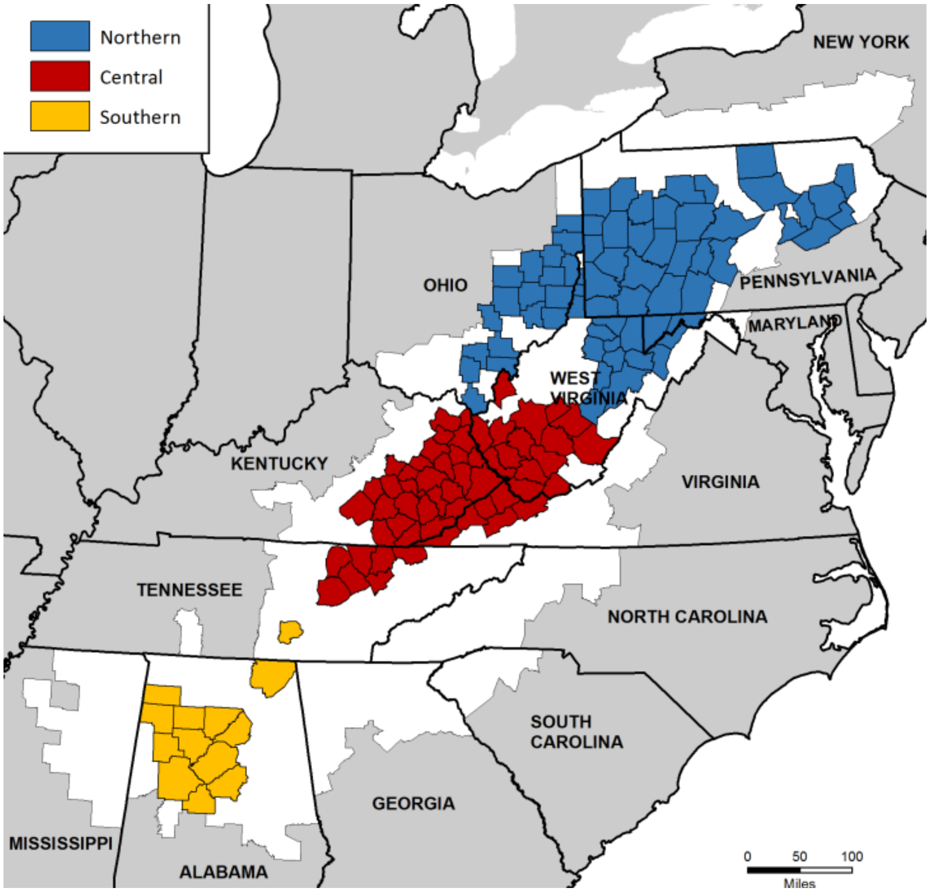

Coal producing counties in the Appalachian coal region are highlighted in Exhibit 1-4.[c] [8]

[a] Members of the civilian labor force, which includes individuals who are not currently institutionalized (i.e., are not currently in prison, a mental hospital, or a nursing home).

[b] According to ARC, the region's reliance on steel manufacturing and coal mining in the 1980s was a major contributing factor to more than 9 percent of the region's labor force being unemployed during the early 1980s recession (1980–1984). [192]

[c] Similar production declines have occurred throughout the United States in response to lower priced natural gas for electricity production and a regulatory environment that has increased the cost of burning coal to generate electricity. [8]

***Exhibit 1-4. Coal producing counties in the Appalachian coal region***




Note: This figure includes only counties that according to the Mine, Safety, and Health Administration had non-zero coal production or more than 10 coal-mining employees between 2005 and 2020. Although they meet the preceding criteria, two counties in Mississippi are not highlighted because they are not part of the Appalachian coal region as defined by EIA. *Source:* Used with permission from ARC. [8]

Declining coal production has decreased coal industry employment in the region, which between 2005 and 2020 declined by nearly 54 percent. [8] Industry employment losses were concentrated in central Appalachia coal mining counties (see Exhibit 1-4). [8] Private sector employment in these counties has also been declining in recent years.[d] [8] In 2005, coal mines accounted for more than 10 percent of the total employment in 38 of the coal producing counties outlined in Exhibit 1-4. [8] The counties where coal mines accounted for more than 20 percent of total employment in 2005 were concentrated in the central Appalachian coal region, which is also where coal mine production has been declining significantly. [8] Total private sector employment has also declined in central Appalachia but has remained relatively flat for the region as a whole since 2005. [8]

The development of advanced hydrogen infrastructure pathways within the Appalachian region presents opportunity to improve the economic status of counties located in the region where

[d] 'Private sector' refers to economic activity not under direct government control. 'Industry' includes private sector and also includes economic activity under government control.

the infrastructure will be developed. Successful development of advanced hydrogen within the region, however, depends on multiple factors, which are outlined in this report.

## 1.3 Roadmap of Report

This report is organized into five further sections. Section 2 through Section 4 identify current and planned hydrogen infrastructure in the Appalachian region to assess technological advances that can enable the transition to a hydrogen economy by repurposing existing infrastructure and blending to identifying possible transportation and storage corridors. Of equal importance, Section 3 addresses regulatory authority among federal, state, and local agencies that can impact current and future build-out pathways discussed in Section 5. Section 6 provides preliminary economic justification for the Appalachian Hydrogen Initiative plan. Section 7 provides suggestions for future work and Section 8 provides conclusions.

### 1.3.1 Section 2 – Hydrogen

This section presents an overview of the hydrogen economy focusing on the industries involved in the hydrogen supply chain. While the production of and end-use applications for hydrogen form critical components to the overall hydrogen economy, this report pays special attention to the transportation and storage segments of the supply chain. This includes a particular focus on the potential for these segments in the Appalachian region.

### 1.3.2 Section 3 – Assess the Hydrogen Landscape (Technology)

This section centers around understanding the current state-of-the-art and the potential future technological advances that can enable the transition to a hydrogen economy, meeting DOE's goal of $1 per kilogram (kg) $H_2$ production by 2030. [4] An evaluation of the following is provided:

- Hydrogen transportation using existing pipelines, including the potential and constraints on blending hydrogen with other products
- New or adapted pipeline requirements for hydrogen transportation
- Hydrogen storage using existing storage facilities, including the potential of and constraints on blending hydrogen with other products
- New or adapted storage requirements for hydrogen
- Existing and potential transportation routes/corridors in the Appalachian region

### 1.3.3 Section 4 – Assess the Hydrogen Landscape (Regulatory)

Transportation of materials falls under myriad regulations at federal, state, and local levels depending on routes and modes. This includes fixed infrastructure such as pipelines as well as mobile approaches such as trucks and tankers over road, rail, or waterways. Storage technologies bring their own set of regulations whether above or below ground or in constructed facilities or utilizing natural formations (e.g., underground storage in salt caverns or reservoirs). Regulations, particularly across the range of jurisdictions, is extremely complex and situationally specific. Under this task, this section considers the major high-level regulatory implications on transportation and storage of hydrogen (or hydrogen blended with other products). Among the implications are

- Constraints that affect blending potential
- Potential adaptations and modification for hydrogen use in existing infrastructure
- Requirements specific to hydrogen on transportation and storage
- Requirements across different modes of transportation or types of storage

### 1.3.4 Section 5 – Develop Pathways Consistent with the Landscape

With the understanding of the current and potential technology options, considering applicable regulations, this section develops possible pathways of hydrogen transportation and storage infrastructure deployment. These pathways consider the possibility of utilizing existing infrastructure though such means as blending of hydrogen with the existing product (such as methane), repurposing existing infrastructure, or adapting such infrastructure if modifications are required to carry hydrogen safely and properly.

### 1.3.5 Section 6 – Estimated Jobs Supported Through Deployment of an Appalachian Hydrogen Infrastructure

At the highest level, an estimate of jobs created/supported is provided by first calculating the value of the output of hydrogen from the planned Appalachian Hydrogen Infrastructure. This section provides a first pass at estimating the jobs created by development of hydrogen infrastructure within the Appalachian region.

### 1.3.6 Section 7 – Follow-on Phases for $H_2$ Infrastructure in Appalachia

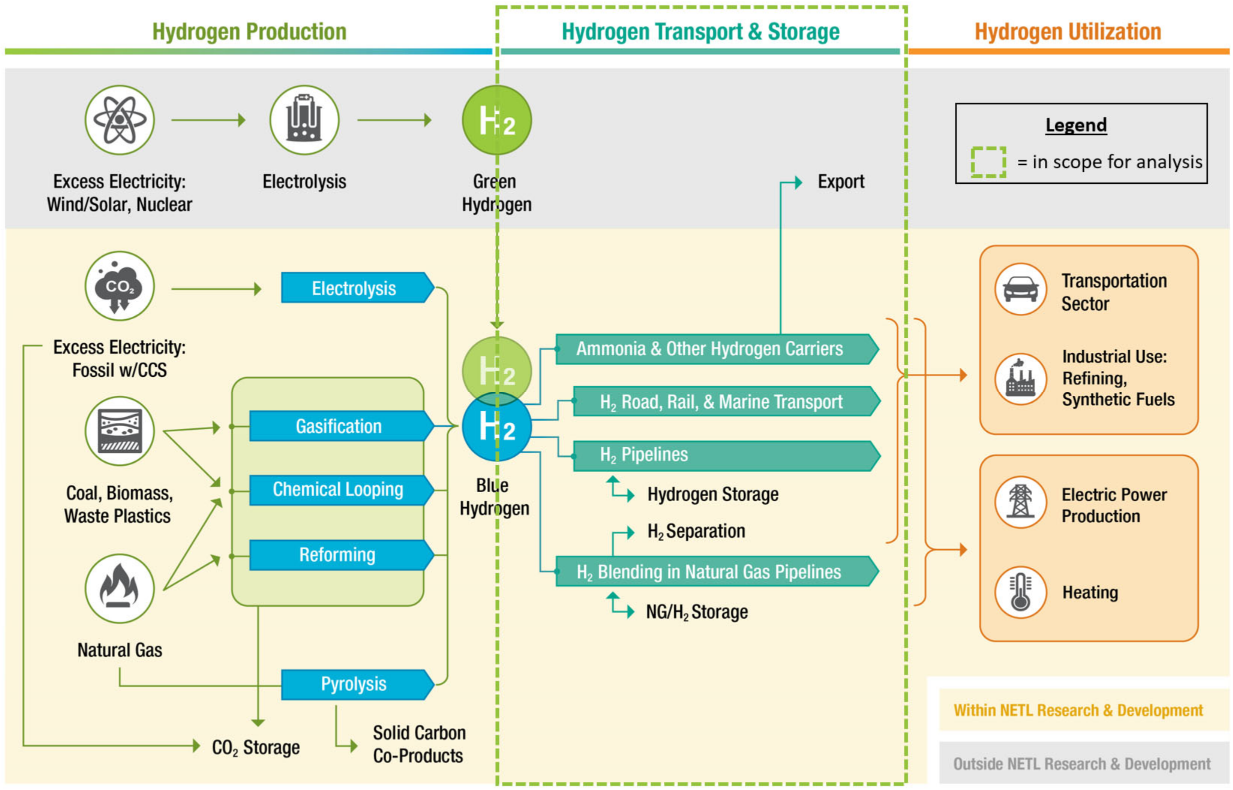
This section outlines areas of additional analyses that were not in the original scope of this study. Additionally, this section outlines areas within this study where more in-depth analysis can be performed, but wasn't due to original scope limits, budget, and time. Some of these analyses were discovered as this report was being researched and others were added from inciteful internal and external reviewer's suggestions.

# 2 HYDROGEN

## 2.1 HYDROGEN SUPPLY CHAIN

Supply chains are used frequently to depict the system of connections between organizations, activities, and resources who source, produce, and transport goods from suppliers to end consumers. The hydrogen supply chain, shown in Exhibit 2-1, comprises the processes needed to produce, transport and store, and utilize resultant hydrogen. [10]

***Exhibit 2-1. Depiction of representative hydrogen supply chain***




Numerous hydrogen production pathways exist including renewable liquid and fossil-fuel reforming, gasification, electrolysis, and fermentation. [11] The two most common means for producing hydrogen in the United States are reforming and electrolysis. [12] Nearly 95 percent of the hydrogen produced domestically is made from natural gas reforming. [13] SMR and ATR of natural gas are discussed in greater detail in Section 5.2. Producing hydrogen via electrolysis involves splitting hydrogen from water using an electric current. [12] Producing hydrogen via gasification involves reacting solid wastes, biomass, or coal with steam to produce syngas [$H_2$ + carbon monoxide (CO)], which can be further reacted with steam to produce additional hydrogen. [11]

According to DOE's Office of Energy Efficiency and Renewable Energy, "most hydrogen used in the United States is produced at or close to where it is used—typically at large industrial sites." [11] Hydrogen can be delivered via pipeline, high-pressure tube trailers, or via liquefied hydrogen tankers. To date, about 1,600 miles of dedicated pipelines for hydrogen delivery exist within the United States and the majority of the pipelines are located around the Gulf Coast near large petroleum refineries. [11] The absence of dedicated pipelines for hydrogen is a challenge, but does not entirely prevent the transport of hydrogen, as there is potential for hydrogen to be transported via existing pipeline infrastructure.

The two main factors that contribute to the cost of transporting hydrogen are the amount of hydrogen being transported and the delivery distance. [14] Determining the least-cost method of transportation, therefore, depends on how much hydrogen is being moved and the distance between the location of the source and the sink (i.e., end-use industry). Transportation costs are generally described in the literature considering the capital cost of a transportation option (e.g., purchasing the tanker truck) separate from the operation and maintenance (O&M) costs, which include the costs of labor. [14] [15]

A study by Li et al. (2020) summarizes recent estimates of transporting compressed gas hydrogen and liquid hydrogen, respectively, via gas tube trailer and liquid trailer. The cost of transporting hydrogen via gas tube trailer includes capital costs that range $783–1,080 per kg of hydrogen transported and O&M costs that range $0.20–1.34 per kg of hydrogen transported per 100 kilometers (km) traveled. [15] The range of the capital costs estimates presented depend on the capacity of the trailers considered, which ranged in size from 200 to 1,200 kg. [15] Estimates for the cost of transporting hydrogen via liquid trailer include capital costs that range $167–300 U.S. dollars per kg of hydrogen transported and O&M costs that range $0.01–0.10 per kg of hydrogen transported per 100 km traveled. [15] It is important to also note the high energy cost of hydrogen liquefaction, which tends to drive industry toward compressed gas transportation.

Demir and Dincer [16] attempt to generate a series of estimates for the levelized cost of delivering hydrogen ($/kg) via gas tanker, liquid tanker, and pipeline. Their results suggest the levelized cost of delivering hydrogen ranged $2.86–8.02/kg for a fixed roundtrip transport distance of 100 km. However, results consider the potential for all three transportation options to be used simultaneously and depend on an extensive list of scenario assumptions holding.[e]

Attempts to estimate the cost of transporting hydrogen via pipeline rely heavily on estimates of the capital costs associated with pipeline construction. [14] [15] In cases where natural gas pipelines are going to be utilized, capital cost estimates for natural gas pipelines are typically used as a proxy. [14] Because pipeline capital costs can be substantial, transportation by pipeline is generally suggested as the lowest cost means for transporting large volumes of hydrogen. [11] The delivery cost estimates produced depended on multiple factors including the capital costs of the pipeline, delivery distance, depreciation rate of the pipeline, and compression costs among other assumptions.[f] [15]

End-use applications for hydrogen include but are not limited to petroleum refining, chemical and petrochemical production, food processing such as the production of hydrogenated

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[e] Papadias et al. [202] produced a series of estimates for the levelized cost of transporting hydrogen (i.e., the levelized cost of distributing hydrogen as an energy resource) but by energy carrier. Estimates, however, are specific to the scenarios considered and depend on the type of energy carrier examined (e.g., methanol or ammonia).

[f] For more information see Table E.8 of Li et al. [15]

vegetable oils, production of metals and electronics, and various energy applications including direct use as a transportation fuel or heating fuel, renewable diesel production, ammonia and methanol production, and fuel cell applications. [17] Consumption of hydrogen by end-use application in the United States between 2010 and 2020 was dominated by consumption for ammonia and methanol production. Between 2010 and 2020, on average approximately 58 and 9 percent of the hydrogen consumed in the United States was consumed to produce ammonia and methanol, respectively.[g] [18] Hydrogen in the United States over the same period was also consumed by electronics and the production of metals. [18] Hydrogen consumption for ammonia, methanol, and electronics, is projected to increase between 2020 and 2025, growing at an average annual growth rate of 2.2 percent, 12.2 percent, 4.2 percent respectively over the forecast period of 2020–2025. [18]

## 2.2 DOE FECM HYDROGEN R&D

DOE, in particular FECM, is well positioned to advance fossil-derived hydrogen with CCS for industrial energy in the United States (U.S.) given its pioneering efforts and collaborations with industry in direct use of hydrogen for electricity generation and industrial use. Efforts have focused on several technology areas, including (not prioritized):

- Hydrogen combustors and turbines to supplant natural gas turbines
- Advanced sensors and controls for hydrogen production
- Gasification and syngas technologies enabling hydrogen and high hydrogen syngas production for electricity generation, industrial use (e.g., chemical and fuel production)
- Solid oxide fuel cells and solid oxide electrolysis cells for fossil-derived hydrogen with CCS utilization and production, respectively
- Coproduction of electricity, heat, and fuels
- Gasification of mixed feedstocks (waste coal, biomass, plastics, and other wastes) to generate electricity and other products while enabling waste reduction and significant carbon reduction potentials [19]

DOE FECM also has devoted major efforts over the past 20 years to developing technologies to enhance the deployment and adoption of carbon capture, utilization, and storage (CCUS). Carbon capture research and development (R&D) has focused on both advanced materials and processes to lower the cost of capturing and storing these emissions. The overall cost reductions have focused on decreasing the energy penalty of these systems and their large capital investments. Progress made in this area can be leveraged to the challenge of decarbonizing the U.S. industrial sector.

Carbon utilization R&D has focused on developing new and improved materials, equipment, and processes that produce value-added goods and services using $CO_2$ or CO as a feedstock. $CO_2$ utilization pathways to generate products are diverse and can include carbon uptake to grow algae, chemical and biological conversion, and mineralization. The development of technologies that lead to revenue-generating products can help support broader carbon emissions reduction

[g] Methanol and ammonia consumption of hydrogen that includes blue, grey, and brown hydrogen.

strategies—such as CCS and hydrogen production—and lead to more sustainable power generation and industrial and agricultural practices.

DOE FECM has been studying injection of $CO_2$ into deep subsurface saline aquifers for long-term or permanent storage of these captured $CO_2$ emissions since 1997, significantly advancing the knowledge base and developing and validating storage technologies through industry cost-shared technology development projects, university research grants and cooperative agreements, and collaborative work with other national laboratories. The technologies being developed and the small- and large-scale injection projects have increased understanding of the behavior of $CO_2$ in the subsurface and identified geologic reservoirs appropriate for $CO_2$ storage, benefiting existing and future applications of diverse energy applications including fossil-derived hydrogen with CCS production and use.

DOE launched the Earthshot initiative on June 7, 2021, aiming to reduce the cost of clean hydrogen to $1 per 1 kilogram in 1 decade ("1 1 1").[h] The DOE Hydrogen Program Plan[i] details the DOE's coordinated cross-office research, development, and demonstration efforts in areas of hydrogen production, storage, delivery, and end-use—all aimed at enabling a future for the nation in which clean hydrogen technologies are affordable, widely available and reliable, and are an integral part of multiple sectors of the economy.

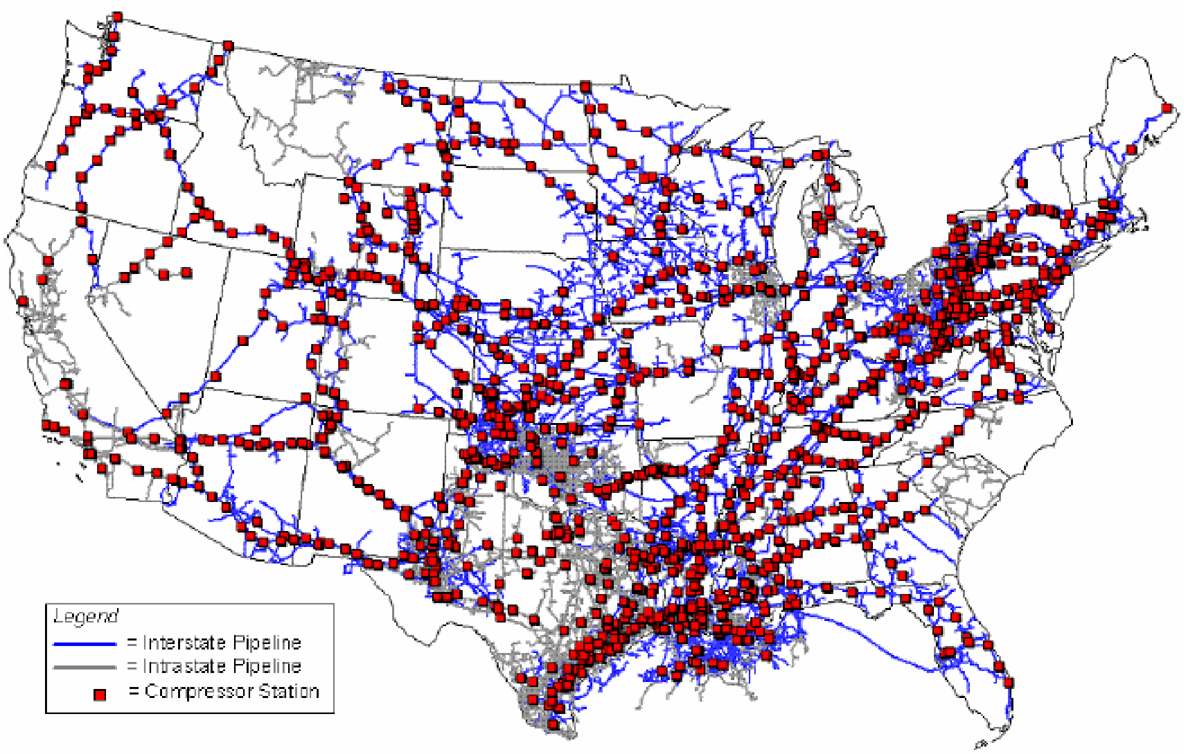
[h] The hydrogen goal was launched as the first of the DOE's Energy Earthshots [4]

[i] The DOE Hydrogen Program Plan, 2020 is available at https://www.hydrogen.energy.gov/pdfs/hydrogen-program-plan-2020.pdf.

# 3 Assess the Hydrogen Landscape (Technology)

A productive and valuable hydrogen economy will depend on efficient transport and storage of hydrogen once it is produced. Large-scale hydrogen deployment requires significant infrastructure to deliver it from where it is produced to where it will be used. Typically transported and stored under very high pressure as a compressed gas, the logistical factors of deployment can influence the viability of hydrogen production. For example, logistical considerations of transportation and storage may offset economies of scale that come from producing hydrogen at a large, centralized facility. This section explores these aspects of hydrogen infrastructure, including potentially already-existing pipeline infrastructure that can be repurposed and new requirements that need to be considered to accommodate hydrogen. Existing natural gas infrastructure (an example of which is shown in Exhibit 3-1) is often discussed as a way to enable the transition to large-scale hydrogen deployment since much of the capital expenditure has already been invested. This section will also explore this dynamic between existing natural gas infrastructure and the gaps that exist to effectively accommodate hydrogen.

***Exhibit 3-1. Map of U.S. natural gas pipelines and compressor stations***

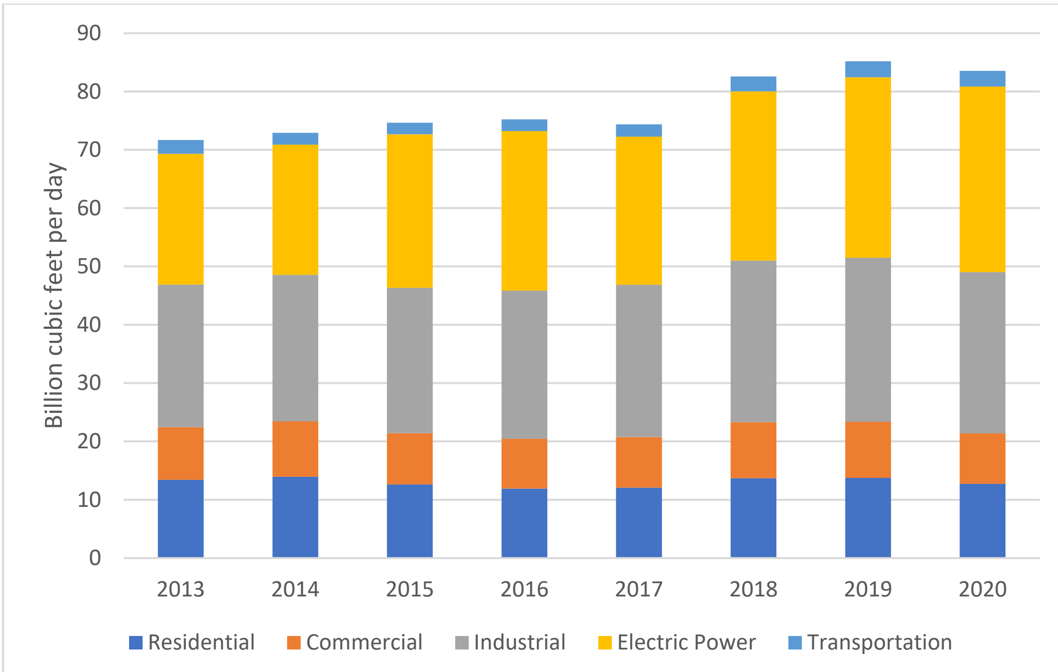



*Source: EIA [20]*

## 3.1 Hydrogen Transportation Using Existing Pipelines

The U.S. natural gas pipeline network is a highly integrated network that moves natural gas throughout the continental United States. The pipeline network has about 3 M miles of mainline and other pipelines that link natural gas production areas and storage facilities with consumers. In 2019, this natural gas transportation network delivered about 30.5 trillion cubic feet (Tcf) of natural gas to about 76.9 M customers across multiple sectors shown in Exhibit 3-2. [21]

***Exhibit 3-2. U.S. natural gas consumption by sector***




Transporting natural gas from production areas to consumers involves a series of steps that are generally carried out in the following order:

1. Gathering systems, primarily made up of small-diameter (6–20 inches), low-pressure pipelines, move raw natural gas from the wellhead to a natural gas processing plant or to an interconnection with a larger mainline pipeline.
2. Natural gas processing plants separate hydrocarbon gas liquids, nonhydrocarbon gases, and water from the natural gas before the natural gas is delivered into a mainline transmission system.
3. Wide-diameter, high-pressure interstate transmission pipelines that cross state boundaries and intrastate transmission pipelines that operate within state boundaries transport natural gas from the producing and processing areas to storage facilities and distribution centers. Natural gas is compressed in transmission pipelines to pressures typically ranging 500–1,400 pounds per square inch (psi) and a diameter of 20–42 inches. Compressor stations (or pumping stations) on the pipeline network keep the natural gas flowing forward through the pipeline system.
4. Local distribution companies (LDC) deliver natural gas to consumers through small-diameter, lower pressure service lines. [22]

### 3.1.1 Natural Gas System and Constraints Overview

Natural gas is moved through pipelines as a result of a series of compressors creating pressure differentials—the gas flows from an area of high pressure to an area of relatively lower pressure. Compressor stations on transmission pipelines are generally built every 50–100 miles along the length of a transmission pipeline, allowing pressure to be increased as needed to keep the gas moving. [22] Compressors are powered by electric motors or natural gas-fired engines that compress or squeeze incoming gas and push it out at a higher pressure. Compressor stations for large transmission lines are much bigger than the compressors used to move the gas through the small distribution lines to residential areas. Some gathering systems do not need compressors because the pressure of the gas coming out of the wells is enough to move the gas through the gathering lines.

Some gas transmission pipelines are bi-directional, meaning gas can be coming from both ends of the pipeline and, depending on where gas is removed and where the compressors create the pressure differential, gas may flow either direction. These bi-directional pipelines boast of greater flexibility in both supply and price to customers. Many gas transmission pipelines are "looped." Looping is a pipeline section laid parallel to the main gas pipeline. It is implemented to increase flow efficiency of the pipeline or for reducing (decreasing) the pipeline pressure loss, as well as for spacing extension—the distance between the neighboring compressor stations and their reduction in number. The gas pipeline section with a looping has a lower flow rate of the product being conveyed via the main gas pipeline, which leads to the reduction of the total gas pressure loss for flow resistance overcoming.

Gas pipeline operators monitor for any problems and handle the flow of gas through the pipeline using a Supervisory Control and Data Acquisition (SCADA). Operational data that SCADA provides include pipeline pressure, flow rate, gas composition, and equipment status. Maintaining appropriate pressures in the pipeline is essential to ensure safety, maximize throughput, and provide reliability of service. Flow rates are determined on the basis of energy as well as volume and are used to balance system demands and supplies. Gas composition is required to maintain appropriate combustion characteristics, screen for undesirable contaminants, and balance gas transmission on a thermal basis. Equipment status, such as valve position and compressor information, is used to confirm that the system is configured to meet operational objectives.

This information allows pipeline operators to know what is happening along the pipeline and allows quicker reactions for normal operations and to equipment malfunctions and releases. Some SCADA systems also incorporate the ability to remotely operate certain equipment, including compressors and valves, allowing operators in a control center to adjust flow rates in the pipeline as well as to isolate certain sections of a pipeline. [22]

The "city gate" is where a transmission system feeds into a lower pressure distribution system that brings natural gas directly to homes and businesses. At the city gate, the pressure of the gas is reduced, and it is normally the location where odorant (typically mercaptan) is added to the gas, giving it the characteristic smell of rotten eggs so leaks can be detected. While transmission pipelines may operate at pressures over 1,000 psi, distribution systems operate at much lower pressures. Some gas mains (2–24 inches in diameter) in a distribution system may operate up to 200 psi, but the small service lines that deliver gas to individual homes are typically well under 10 psi. [22]

Once the gas is delivered to the local gas utility at the city gate, the gas utility's control center monitors flow rates and pressures at various points in its system. The operators must ensure that the gas reaches each customer with sufficient flow rate and pressure to fuel equipment and appliances. They also ensure that the pressure stays below the maximum pressure for each segment of the system. As gas flows through the system, regulators control the flow from higher to lower pressures. If a regulator senses that the pressure has dropped below a set point, it will open accordingly to allow more gas to flow. Conversely, when pressure rises above a set point, the regulator will close to adjust and moderate this pressure. [23] As an added safety feature, relief valves are installed on pipelines to vent gas if a line becomes over pressured and the regulators malfunction. Exhibit 3-3 highlights key constraints for gas to be considered "pipeline quality" before it enters the natural gas pipeline network. [24]

***Exhibit 3-3. Design constraints for pipeline natural gas***

| Characteristics and Components | Limit | Value |
|---|---|---|
| Wobbe Index[A] | Minimum/ Maximum | 46.6/52 MJ/$m^3$ |
| Carbon Dioxide | Maximum | 3.0 mole percentage |
| Oxygen | Maximum | 0.2 mole percentage |
| Hydrogen Sulfide | Maximum | 5.7 mg/$m^3$ |
| Total Sulfur | Maximum | 50 mg/$m^3$ |
| Water Content | Maximum | Dew Point 0°C at highest Maximum Allowable Operating Pressure in transmission system (never more than 112 mg/$m^3$) |
| Hydrocarbon Dew Point | Maximum | 10°C between the pressures of 1,000 kPag and 10,000 kPag |
| Total Inert Gas | Maximum | 7.0 mole percentage |

[A]The Wobbe Index or Wobbe number is an indicator of the interchangeability of fuel gases such as natural gas, liquefied petroleum gas, and town gas and is frequently defined in the specifications of gas supply and transport utilities. The higher a gas's Wobbe number, the greater the heating value of the quantity of gas that will flow through a hole of a given size in a given amount of time.

Most transmission and gathering pipelines are now made from high carbon steel. Pipe sections are fabricated in steel rolling mills and inspected to assure they meet government and industry safety standards. Generally, between 40 and 80 feet in length, they are designed specifically for their intended location in the pipeline. A variety of soil conditions and geographic or population characteristics of the route will dictate different requirements for pipe size, strength, and wall thickness. [22]

Distribution pipelines may also be made of steel but increasingly, high strength plastic or composites are being used. Older distribution pipelines were frequently made of cast iron. Cast iron becomes brittle with age and can be susceptible to fractures when subjected to ground movement from freeze/thaw cycles or other causes. Some states require regular frost surveys during winter months in hopes that leaks formed from pipes cracking resulting from frost heaves are found and repaired quickly. Some plastics are also known to become brittle with age. The National Transportation Safety Board has long recommended replacement of Aldyl-A type plastic pipes in distribution systems. [22]

Several different types of coatings may be used to protect the exterior of steel pipe from corrosion. The most common coatings are fusion-bonded epoxy or polyethylene heat-shrink sleeves. Many coatings are now installed in the factory, but field coating application is still required in these instances in the areas where the pipes are welded together. Prior to field application, the bare pipe is thoroughly cleaned to remove any dirt, mill scale, or debris. The coating is then applied and allowed to dry. After field coating and before the pipe is lowered into the trench, the entire coating of the pipe is inspected to ensure that it is free from defects. Older pipelines may be uncoated or have coal tar or enamel wrap coating. Unprotected steel pipelines are susceptible to corrosion, and without proper corrosion protection, every steel pipeline will eventually deteriorate. [22]

### 3.1.2 Incorporating Hydrogen

There are about 1,600 miles of hydrogen pipelines already in the United States, mostly in the refinery-heavy areas of the Gulf Coast. [25] The U.S. Department of Transportation (DOT) Pipeline and Hazardous Material Safety Administration (PHMSA) already regulates about 700 miles of these pipelines, with the remainder being regulated by state and local agencies in collaboration with the federal government. [26] Meanwhile, there are about 48 hydrogen refueling stations in the United States—mostly in California, with a few dozen more in various stages of construction or planning. [27] Currently, no hydrogen fueling stations exist in the Appalachian region. Exhibit 3-4 illustrates a hydrogen pipeline completed in 2012 by industrial gas company Air Products, highlighting recent commercial investment in this area. By building a 180-mile (290-km) pipeline that connects their existing Texas and Louisiana systems, 22 hydrogen plants and 600 miles (965 km) of pipeline were united, with a total capacity of over one billion (B) standard cubic feet per day (scfd) (1.3 M normalized cubic meters [$Nm^3$] per hour [hr]). [28]

***Exhibit 3-4. Example of current hydrogen infrastructure in U.S. Gulf Coast***


*Used with permission from Air Products*

Since hydrogen infrastructure and production at the commercial scale necessary to fully replace fossil fuels in these applications is still decades away, one proposed solution has been to blend hydrogen into natural gas, similar to how ethanol is presently blended into gasoline across the country.[j] To operate safely, energy companies need to understand the difference between using hydrogen and using natural gas or other fossil fuels, along with considerations involved with blending. Several large utility companies including Southern California Gas Co., NextEra Energy Inc., and Xcel Energy Inc. have kicked off pilot projects for mixing hydrogen and natural gas, with more expected to follow. [27] Blends of hydrogen with natural gas, commonly known as 'hythane' (up to 20 percent hydrogen by volume) or hydrogen and compressed natural gas (HCNG) blend (30–50 percent hydrogen by volume), have emissions and efficiency benefits in internal combustion engines compared to pure natural gas and provide greater range than 100 percent hydrogen due to the higher energy density of natural gas compared to gaseous hydrogen at pressure. HCNG can also serve as a bridging technology to promote hydrogen fueling infrastructure build-out prior to the widespread availability of polymer electrolyte membrane fuel cells. In buildings, hydrogen could be blended into existing natural gas networks, with the highest potential in multi-family and commercial buildings, particularly in dense cities while longer-term prospects could include the direct use of hydrogen in hydrogen boilers or fuel cells. [29]

Currently, industry is looking at blending hydrogen into natural gas pipelines at less than 20 percent. Most gathering and transmission lines are already made of high-carbon steel, providing relatively easy transitioning to pure hydrogen. However, blending volumes greater than 20 percent could create significant challenges for distribution lines, such as embrittlement and significant changes to compressor stations. [30]

Below 20 percent, the limit on the ratio of hydrogen to methane depends on the machines and home appliances, like water heaters, at the end of the pipe. The appliances in residential homes can handle only a modest amount of hydrogen blended in with natural gas. Natural gas transmission lines are more complex to deal with because they operate under much higher pressures; at high pressures, embrittlement can aggravate small cracks and dents in older pipes, which could lead to leaks or even ruptures. Depending on the quality of the steel and potential exposure to hydrogen, in principle, embrittlement can accelerate propagation of cracks, reducing the pipeline's service life by 20–50 percent. This is only likely, however, if the pipeline already has fractures and is subjected to dynamic stresses due to fluctuating internal pressure while at the same time being exposed to atomic hydrogen. [29]

## 3.2 New or Adapted Pipeline Requirements for Hydrogen Transportation

While the profile of a gas or gas blend can be improved to meet specifications such as a maximum inert gas content through pre-treatment and contaminant removal, other more inherent properties are more difficult to modify if a new type of gas blend were to enter today's

[j] The difference being that hydrogen and natural gas are being proposed to blend in the pipeline, where gasoline and ethanol are blended at facilities, then transported by truck to refueling stations. Ethanol does not flow in liquid oil or gasoline pipelines.

natural gas pipeline. As Exhibit 3-5 illustrates, staying within the minimum-maximum threshold, the design characteristic of the Wobbe Index (46.6–52 megajoule [MJ] per cubic meter [$m^3$]) should not present significant challenges, regardless the percentage of hydrogen blended into natural gas. Other inherent aspects of hydrogen's physical and chemical properties, however, make its use in current pipeline infrastructure more challenging. The key challenge arises from the fact that hydrogen contains a fraction of the energy natural gas does for a given unit of volume, illustrated by the red line in Exhibit 3-5 and the comparison table in Exhibit 3-6. [31]

***Exhibit 3-5. Heating value and Wobbe Index properties of gas mixtures***

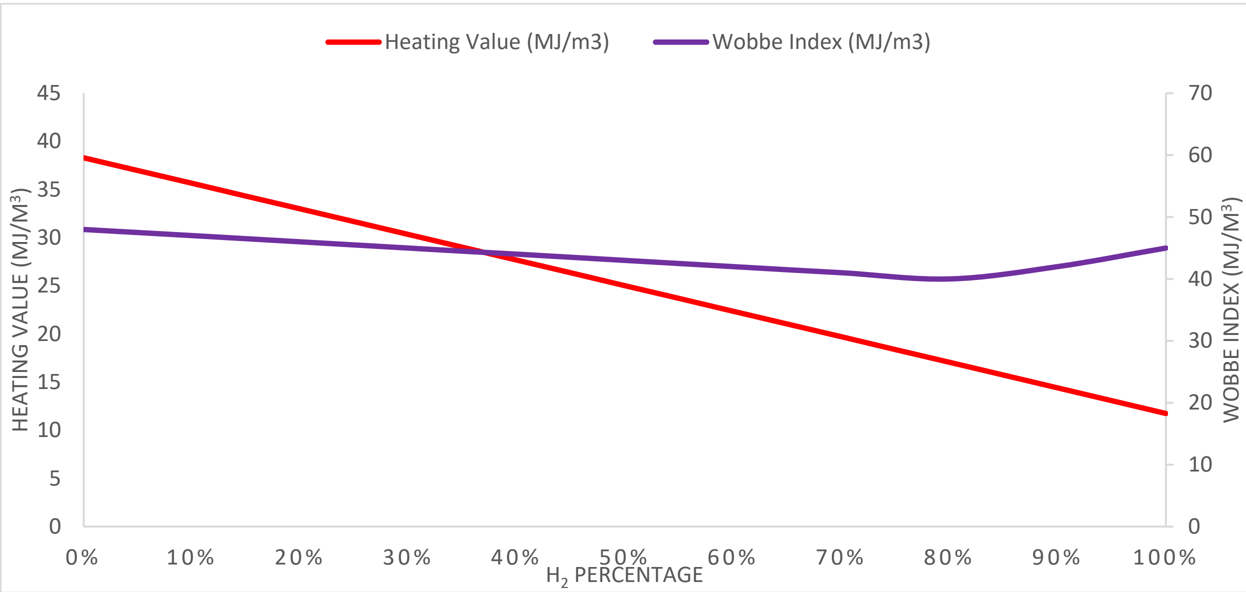



***Exhibit 3-6. Comparison of physical properties for various fuels***

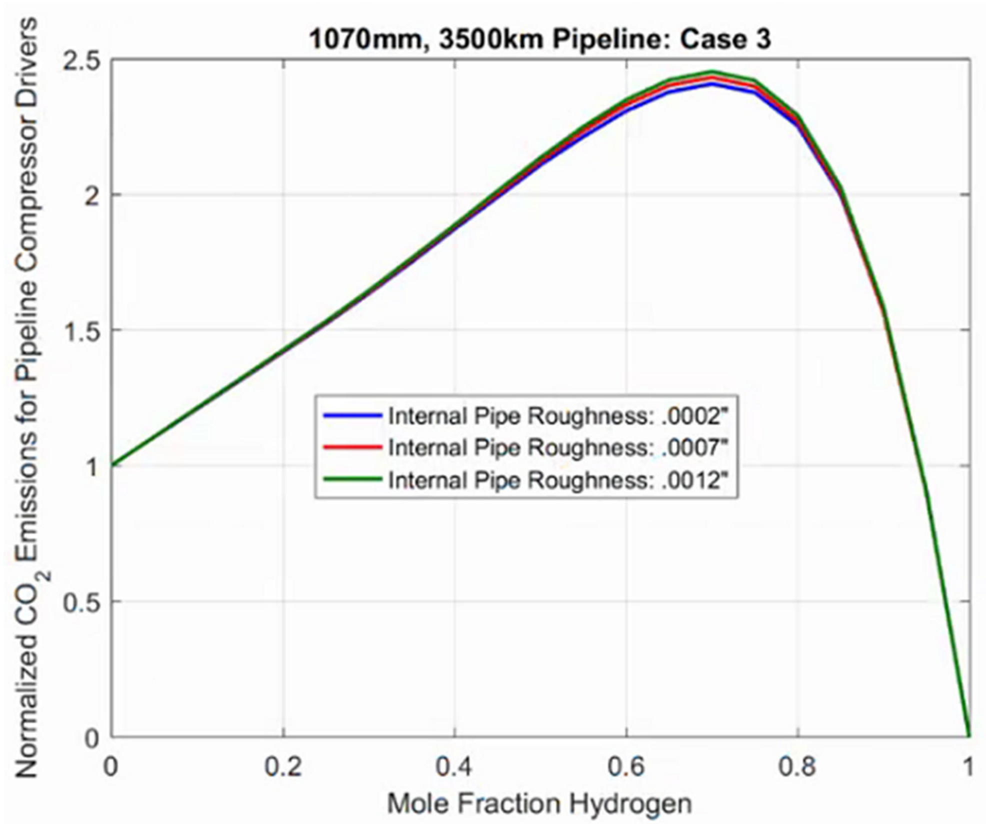
| Property | Hydrogen | Comparison |
|---|---|---|
| Density (gaseous) | 0.089 kg/$m^3$ (0 °C, 1 bar) | 1/10 of natural gas |
| Density (liquid) | 70.79 kg/$m^3$ (-253 °C, 1 bar) | 1/6 of LNG |
| Molecular weight | 2.016 grams per mole | 1/8 of natural gas |
| Boiling Point | -252.76 °C (1 bar) | 90 °C below LNG |
| Energy per unit Mass (LHV) | 120.1 MJ/kg | 3-times that of gasoline |
| Energy Density (ambient condition, LHV) | 0.01 MJ/L | 1/3 of natural gas |
| Specific Energy (liquified, LHV) | 8.5 MJ/L | 1/3 of LNG |
| Flame Velocity | 346 centimeter/second | 8-times natural gas |
| Ignition Range | 4–77% in air by volume | 6-times wider than natural gas |
| Ignition Energy | 0.02 MJ | 1/10 of natural gas |

To compress the hydrogen to the operating pressure of the pipeline, compressor stations are required along the way of pipeline systems. If hydrogen is mixed with methane and the existing compressors for natural gas are kept in place, some parts might need to be adapted, depending on the admixture of hydrogen. Reciprocating compressors are currently the most cost-effective choice for pipelines delivering pure, 100 percent hydrogen. The gas is compressed efficiently in the cylinders using reciprocating compressors. Increased cylinder count and drive power, as well as a parallel arrangement of compressors, allow for a practical transport capacity of up to 750,000 $Nm^3$/hr. Hydrogen compression by turbocompressors is more difficult. While centrifugal compressors have been employed in downstream and petrochemical applications for decades, their efficiency is significantly less than that of reciprocating compressors. The pressure rise in a turbocompressor is directly proportional to the molecular weight of the gas at a particular impeller tip speed. Hydrogen has a molecular weight of approximately 1/8 that of methane, which means that achieving a pressure ratio comparable to that of an existing natural gas line would require significantly higher impeller tip speeds or a significantly greater number of compressor stages in multiple compressor casings. [32]

Mechanical strength restrictions for impellers are directly proportional to tip speed. The impeller's maximum permitted tip speed varies according on the material utilized. Typically, when constructing compressors for use with air, $CO_2$, or natural gas, these material strength constraints are ignored. They can, however, be addressed in the case of low-weight gas compositions such as hydrogen. Thus, the design of a compressor for hydrogen operation is controlled less by aerodynamic constraints than by the mechanical strength of the impellers. Extensive research into the design of blades and impeller geometry has demonstrated that by utilizing high-strength titanium alloys, these stress levels can be decreased to allow for pressure ratios of up to 1.45:1 each stage. Thus, a 6-stage machine with a total pressure ratio of 4:1 is technically feasible when using 100 percent hydrogen. Commercial availability of these machines is expected to increase in the coming years as the market requires them. In general, the extent to which compression equipment must be changed will depend on the hydrogen content of the pipeline. If the admixture contains less than 10 percent hydrogen, the compressor can be operated normally. When the admixture contains less than 40 percent hydrogen, the compressor housing can be left alone; nevertheless, the impellers, feedback stages, and gears must be adjusted. For pipes with a hydrogen level greater than 40 percent, the entire compressor must be replaced due to the factors noted above. [32]

An ancillary but critical concern related to using existing compressors with mixtures of hydrogen and natural gas is the power requirements for compressors to effectively transport hydrogen. As described above, the density of hydrogen in both gas and liquid form is a fraction of that of natural gas, necessitating more compression power for transportation. Assuming compressors are powered by grid electricity or gas-fired engines (as the majority are today), blending hydrogen into natural gas initially increases emissions related to gas compression in pipeline transport, as shown in Exhibit 3-7. [32]

***Exhibit 3-7. Compressor-related $CO_2$ emissions for blended gas [33]***




Note: "1" on the vertical axis represents the baseline compressor emissions of 100 percent natural gas. Analysis uses an equal HHV energy basis.

To illustrate the capital expenditures and energy requirements of compressors stations, the compressor stations in the states that make up only the Appalachian region. Analysis of compressor stations showed them to have a capital cost of more than $13 B, and currently use more than 112 thousand dekatherms of gas and 2,320 gigawatt hours (GWh) of power for compression. A transition to high-percentage hydrogen blended gas would have significant implications for necessary capital investment and net energy use for compression. If gas mixtures contained less than 10 percent hydrogen, there would be little-to-no additional capital investment needed at compressor stations, but there would be an increase in operating costs as the added hydrogen would require more energy to compress. However, as noted above for gas blends containing more than 40 percent hydrogen, the entire compressor must be replaced; if this took place in Appalachian region, it would require the replacement of more than $13 B of capital assets in compressor stations, significantly higher operating expenses, and almost double the $CO_2$ emissions from compressor stations (as seen in Exhibit 3-7).

Because metering in natural gas network is based on the flow rate of gas, differences between the energy content of blended gas and natural gas will require changes in metering or changes in billing systems. Hydrogen has a lower heating value than natural gas. This means the volume of blended gas is slightly higher, when compared to 100 percent natural gas, in order to deliver the same amount of gas energy to a customer. But this does not imply the customer must pay more. Some gas utilities in Australia, for example, will adjust the pressure correction factor to ensure the amount of gas energy the customer is billed for remains the same as if they were using 100 percent natural gas, even if the gas meters record a slightly higher volume of blended gas. [34]

Additionally, gas meters themselves may not need to be replaced for certain blend compositions; a 2020 study carried out a metrological and statistical analysis to establish whether the addition of hydrogen affects the durability of gas meters over time. The most important conclusion resulting from the conducted study indicates that, for the tested gas meter specimens, there was no significant metrological difference between the obtained changes of errors of indications after testing the durability of gas meters with varying hydrogen content (0–15 percent). For gas blends more than 15 percent, more research is needed to determine to evaluate if current gas meters are sufficient. [35]

Another consideration is the introduction of additives in gas mixtures; because hydrogen is odorless and invisible when burning, odorants and flame enhancement additives are likely to be needed. Some additional aspects that might influence new or adapted pipeline requirements for hydrogen include:

- The potential for hydrogen to embrittle the steel and welds used to fabricate the pipelines
- The need to control hydrogen permeation and leaks
- The need for lower cost, more reliable, and more durable hydrogen compression technology

### 3.2.1 Materials to Accommodate Hydrogen in Pipelines

Carbon steel is the alloy family most commonly used in hydrogen gas transmission pipelines. The choice of the specific grade will depend on many factors including the severity of the service, availability, and relative cost. In general, the common carbon steel piping grades such as American Petroleum Institute (API) 5L X52 (and lower strength grades) and American Society for Testing and Materials A 106 Grade B have been widely used in hydrogen gas service with few reported problems. This service is attributed to the relatively low strength of these alloys, which imparts resistance to hydrogen embrittlement and the other brittle fracture mechanisms. These requirements help ensure base metal and weld hardness are maintained at acceptable values and hydrogen embrittlement concerns are minimized. Furthermore, some pipeline operators utilize design stress values lower than standard values, resulting in a heavier wall, lower stress pipeline than would be required by typical national codes. One approach is to limit the hoop stress[k] at normal operating pressure to less than 30 percent of the minimum specified yield strength of the alloy or 20 percent of the specified minimum ultimate tensile strength, with a 6.4 millimeter (mm) (0.250 inch) minimum wall thickness. This lower stress design is used

[k] Hoop stress occurs along the pipe's circumference when pressure is applied. It acts perpendicular to the axial direction and is tensile generated to resist the bursting effect that results from the application of pressure.

primarily to mitigate third-party damage to the pipeline, but the low stress also reduces the potential for hydrogen pipeline damage. [36]

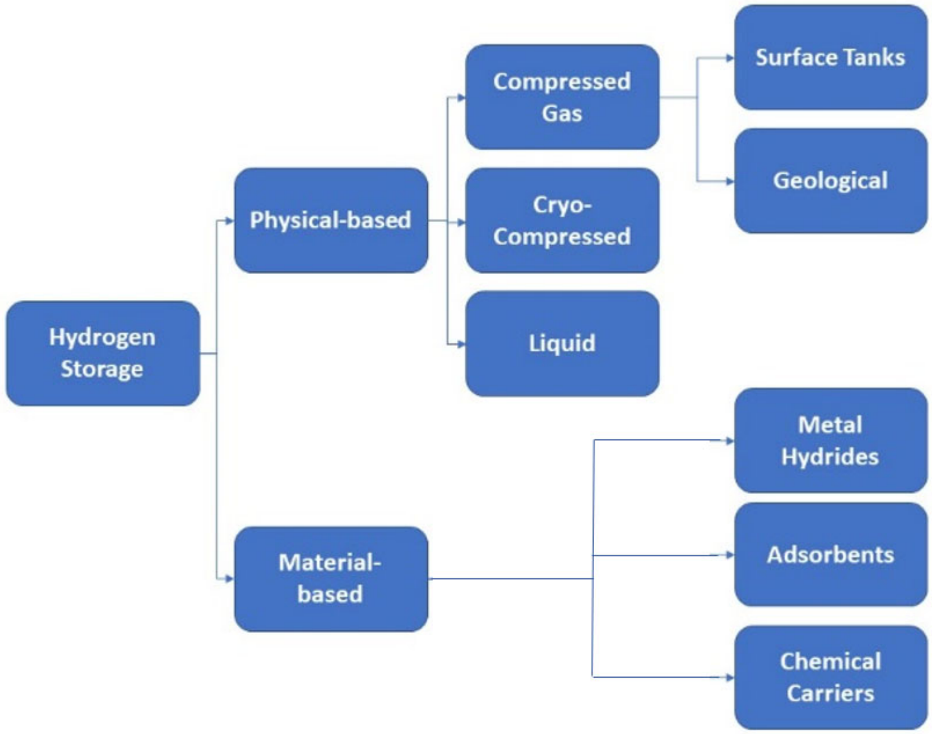
The carbon steel alloy grade that is selected should have the lowest possible tensile strength consistent with the actual application. Because of greater susceptibility to some forms of corrosion in a hydrogen environment, substituting a higher strength material is not an improvement. A maximum tensile strength of 800 megapascal (MPa) (116 kilo-pounds per square inch) is recommended. As the hydrogen pressure increases, toughness is increasingly important. Generally, the mill forms that must meet impact toughness requirements are made from deoxidized steel per a fine grain practice. It is recommended that toughness requirement be considered on certain steel mill forms to be used in hydrogen pipeline applications. It is especially important for applications at pressures of 5 MPa (50 bar) and above. [36]

As noted above, most gathering and transmission lines are already made of high-carbon steel, providing relatively easy in transitioning to hydrogen. More challenges arise in repurposing distribution pipelines; potential solutions include using fiber reinforced polymer (FRP) pipelines for hydrogen distribution. The installation costs for FRP pipelines are about 20 percent less than that of steel pipelines because the FRP can be obtained in sections that are much longer than steel minimizing welding requirements. The lower installation costs can help compensate for the increased materials costs of FRP pipelines. Current capital cost (materials and installation) for 4-inch inner diameter, 1000 psi-rated FRP piping is $50,000–100,000 per mile; transmitting hydrogen with FRP pipelines to a population of 100,000 would require five 4-inch inner diameter pipelines, at an approximate capital cost of $250,000–500,000 per mile. This estimate is well below the DOE 2015 target for hydrogen delivery ($800,000 per mile). [37]

## 3.3 Hydrogen Storage

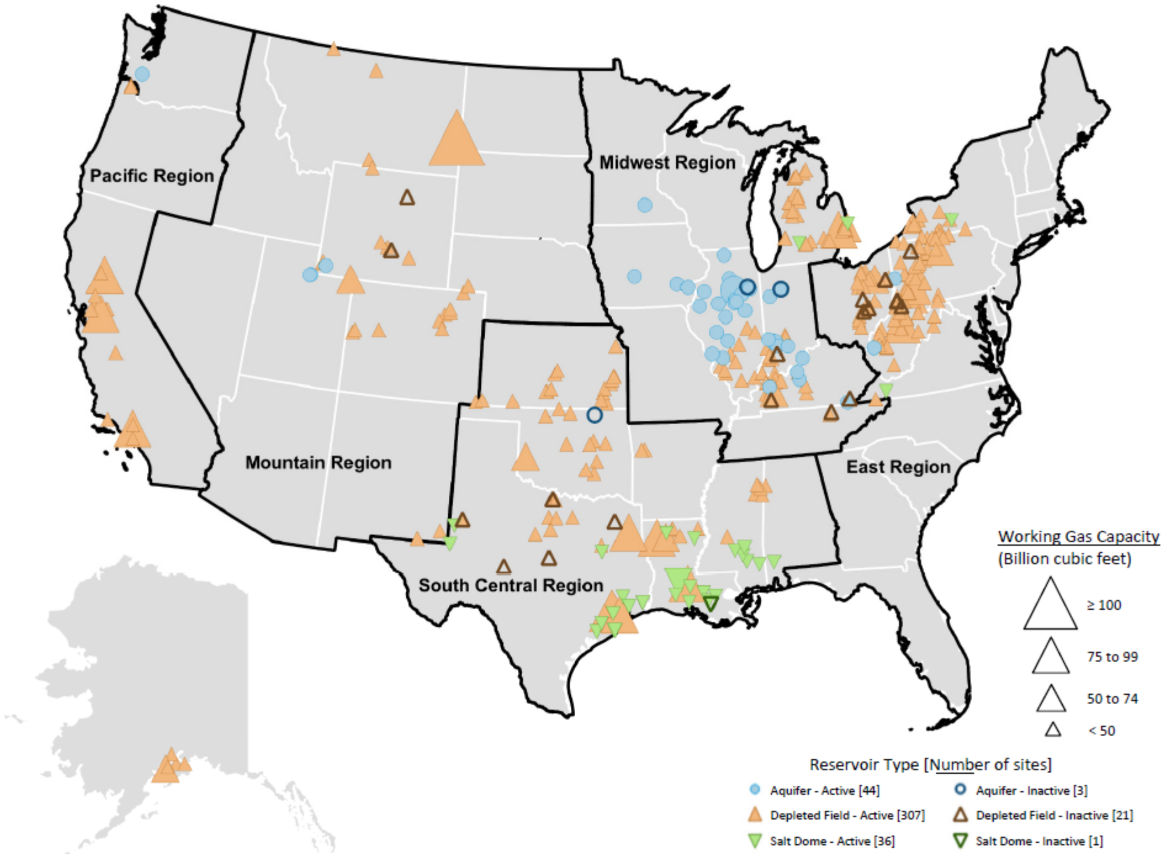
There are several methods to approach the storage of hydrogen. Because of the inherent volatile characteristics of hydrogen, virtually all involve a physical or chemical transformation of the component into a more stable form. An overview of the various approaches can be found in Exhibit 3-8.

***Exhibit 3-8. Illustration of hydrogen storage approaches***




A national hydrogen infrastructure program could require geologic (underground) bulk storage to handle variations in demand throughout the year. In some regions, naturally occurring geologic formations, such as salt caverns and aquifer structures, might be used, while in other regions, specially engineered hard rock caverns are a possibility. Geologic bulk storage is common practice in the natural gas industry and there are four existing salt caverns used in the United States for hydrogen storage today. Storing fuel in salt caverns is not a new technology, as the U.S. Strategic Petroleum Reserve has long stored emergency crude oil in underground salt caverns on the Gulf Coast, and notes they cost 10 times less than above ground tanks and 20 times less than hard rock mines. The Reserve has 60 large caverns, typically 200 feet wide and 2,500 feet high. [38] The use of geologic storage for hydrogen used in fuel cell electric vehicles and other applications requires further investigation into the possible impurities that could be introduced by underground storage. Exhibit 3-9 shows a map of the potential U.S. locations for geologic hydrogen storage.

***Exhibit 3-9. Potential geologic storage areas in the U.S. for hydrogen***




*Source: EIA [39]*

Although the storage of gaseous hydrogen in salt caverns already is used on a full industrial scale, the approach is not fully applicable in all regions due to varying geological conditions. Therefore, other storage methods are necessary. On-site hydrogen storage is used at central hydrogen production facilities, transport terminals, and end-use locations. Storage options today include insulated liquid tanks and gaseous storage tanks. The four types of common high-pressure gaseous storage vessels are shown in Exhibit 3-10. [38]

***Exhibit 3-10. Four types of high-pressure gaseous storage vessels***

| | |
|---|---|
| **Type I** | All-metal cylinder |
| **Type II** | Load-bearing metal liner hoop wrapped with resin-impregnated continuous filament |
| **Type III** | Non-load-bearing metal liner axial and hoop wrapped with resin-impregnated continuous filament |
| **Type IV** | Non-load-bearing, non-metal liner axial and hoop wrapped with resin-impregnated continuous filament |

Type I cylinders are the most common. Currently the costs of Type III and Type IV vessels are greater than those of Type I and II vessels. It is expected that with additional cost, reductions in carbon fiber, and improved manufacturing methods, these technologies could ultimately cost less than the traditional metal Type I cylinders. These tanks can store 0.5–210 tons of $H_2$ depending on the type and pressure in the tank. [40]

Cryogenic liquid storage tanks, also referred to as dewars, are the most common way to store large quantities of hydrogen. Super-insulated low-pressure vessels are needed to store liquid hydrogen at -253°C. The pressure of liquid hydrogen is no more than 5 bar. Regardless of the quality of the insulation, however, some heat will reach the tank over time and cause the liquid hydrogen to boil. The result is that hydrogen gas accumulates at the top of the liquid tank and causes the pressure inside the tank to increase. To keep the pressure from rising above the limits of the tank, the gaseous hydrogen must be vented from the liquid tank and either released or recompressed by a boil-off compressor to be stored as gaseous hydrogen. [38] The National Aeronautics and Space Administration has been on the forefront of liquid hydrogen storage. The Kennedy Space Center in Florida has had the largest liquid hydrogen storage tanks in the world since the 1960s, when they were initially built to store the propellants that fueled the Saturn V Moon rocket. Now, the National Aeronautics and Space Administration has constructed a new tank capable of holding 1.25 M gallons of liquid hydrogen—roughly 50 percent larger than its 1960s predecessors.

### 3.3.1 Hydrogen Carriers

Hydrogen carriers store hydrogen in some other chemical state rather than as free hydrogen molecules. Additional research and analysis are underway to investigate novel liquid or solid hydrogen carriers for use in delivery. Carriers are a unique way to deliver hydrogen by hydriding a chemical compound at the site of production and then dehydriding it either at the point of delivery or once it is on-board the fuel cell vehicle. Potential carriers include metal hydrides, carbon or other nanostructures, and reversible hydrocarbons or other liquids, among others in the early stages of research. Using such novel carriers would constitute a significant departure from the way transportation fuels are delivered today. To speed up the adoption of hydrogen, the cost associated with delivery needs to be reduced significantly. Various novel carriers were proposed for this, such as metal-organic frameworks (MOFs), hydrides and liquid carriers. High costs associated with MOFs and slow reaction kinetics of hydrides paved the way for liquid hydrogen carriers (LHCs) as a preferred method to transport hydrogen. [41]

Note that, relative to hydrogen and natural gas, ammonia can exist as a liquid at modest temperature and pressure conditions and require a fraction of the compression and pumping power for transport. The properties of ammonia compared to hydrogen and natural gas are shown in Exhibit 3-12. [42] The advantage of using ammonia as a carrier of hydrogen is that significant infrastructure for transport and storage of ammonia already exists due to its use for decades as a fertilizer in the agricultural industry. In 2020, there were about 3,000 miles (4,828 km) of 6–8-inch (152–203 mm) diameter carbon steel pipelines in the United States that transport about 2 M tons of ammonia per year. This was equivalent to transporting ∼350,000 tons of hydrogen per year. [43] Important to note is that one of two major pipelines composing this 3,000-mile total was recently retired from service, leaving about 2,000 miles of operational ammonia pipeline capacity. Ammonia pipelines normally operate at 250 psi (1,723 kilopascal [kPa]) pressure. Additionally, trade networks for ammonia already exist, as global maritime trade totals approximately 18 M tons of ammonia per year enabled by over 120 ports and 170 ships globally that are equipped to handle ammonia. [42]

While the synthesis costs of ammonia and LHCs compare well with the cost of liquefying hydrogen, use of these liquid carriers introduces an extra step of converting the carrier back to hydrogen; the cost and efficiency losses associated with this reconversion step remain a barrier to commercial adoption. (Exhibit 3-11 illustrates the process of using LHCs.) Several areas of direct end use of ammonia as fuel are being developed, including furnaces/combustors, gas turbines, fuel cells, and engines. These applications do not rely on converting/cracking ammonia back to hydrogen and could help avoid costs and efficiency losses associated with reconversion to hydrogen. Exhibit 3-12 shows the specifications and relative costs compared to natural gas. As such, much R&D in this area has focused on improving the chemistry of hydrogen release through catalyst development. Infrastructure considerations for wide-spread adoption of this approach include the need for models of either centralized dehydrogenation ("de-$H_2$") at ports or other facilities for local distribution as hydrogen gas, or decentralized hydrogen release at refueling stations. Nonetheless, LHCs remain an intriguing option for transport and storage of hydrogen, particularly when considering logistics related to enabling utilization low-carbon energy from resource rich regions to resource poor regions.

***Exhibit 3-11. Illustration of value proposition of liquid $H_2$ carriers***

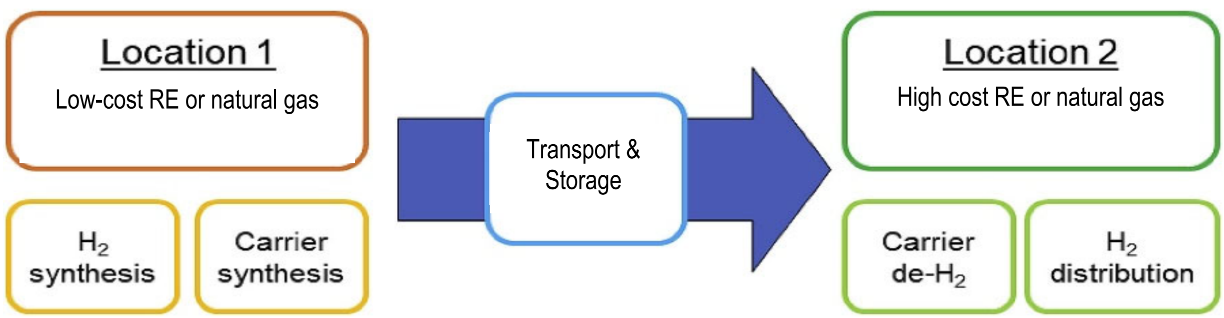


***Exhibit 3-12. Energy sources comparison***

| Product | Boiling Point, °F (°C) | Density (at 900 psig, 60 °F), lb/cf (kg/m³) | Energy Density[A] (at 900 psig, 60 °F), Btu/cf (kJ/m³) | Specific Energy, Btu/lb (kJ/kg) | Mass Flow Rate[B], lb/hr (kg/hr) | Pipeline size, in | Power Required, HP[C] (kW) | Relative Costs |
|---|---|---|---|---|---|---|---|---|
| Natural Gas | -260 at 0 psig (-160 at 0 barg) | 3.39 (54.3) | 75,600 (2,814,000) | 22,300 (51,820) | 310,400 (140,800) | 16 | 4,820 (3,600) | Base |
| Ammonia | 84 at 150 psig (29 at 10 barg) 213 at 900 psig (101 at 62 barg) | 38.5 (616) | 372,700 (13,860,000) | 9,680 (22,500) | 716,500 (325,000) | 12 | 1,610 (1,200) | 0.5 |
| Hydrogen | -423 at 0 psig (-253 at 0 barg) | 0.32 (5.16) | 19,360 (721,110) | 60,130 (139,750) | 113,650 (51,550) | 18 | 17,850 (13,320) | 2.2 |

Note: Data from Black & Veatch [44]
[A] HHV
[B] Equivalent to 1,200 MW power generation fuel supply at 60% efficiency
[C] Based on 100 km pipeline

### 3.3.2 Commercial Activity

Japanese company Chiyoda Corporation undertook the first ever bulk shipment of hydrogen using its SPERA Hydrogen technology based on toluene liquid carriers, transporting and storing over 100 tons of $H_2$ over a 10-month period. [45] German company Hydrogenious LOHC Technologies GmbH started commercializing its dinbenyltoluene-based technology for storing and transporting hydrogen. It has also collaborated with Framatome's energy storage brand Covalion, which provides LHC-based solutions. $H_2$-Industries SE, another German company, is also active in this domain. French company HySiLabs uses a regenerating siloxane-based carrier for transportation and storage of hydrogen. Siemens is exploring the possibility of using its green ammonia technology to store and transport hydrogen. [46] Air Products, in conjunction with ACWA Power and NEOM, is constructing a $5 B commercial-scale green hydrogen-based ammonia production facility powered by renewable energy. It will include the innovative integration of over 4 gigawatts of renewable power from solar, wind and storage; production of 650 tons per day of hydrogen by electrolysis using ThyssenKrupp technology; production of nitrogen by air separation using Air Products technology; and production of 1.2 M tons per year of green ammonia using Haldor Topsoe technology. The project is scheduled to be online in 2025. [47] In the United States, there are several hydrogen storage projects in construction. Mitsubishi Power Americas Inc., a subsidiary of Japan's Mitsubishi Heavy Industries is developing a 1,000-megawatt (MW) storage project in Delta, Utah that would harness hydrogen from excess wind and solar power using electrolysis and store it in an existing underground salt dome.

In the Appalachian region, multiple hydrogen projects have been proposed. Long Ridge Energy, located in Hannibal, Ohio, currently operates a 485 MW natural gas combined cycle plant and is planning to transition it to run off hydrogen in collaboration with New Fortress Energy and GE, Long Ridge. [48] Another project is seeking investors in Clinton, Ohio. KeyState Zero currently has a natural gas liquification plant operated by Frontier Natural Resources on site. The company plans to include production of fossil-derived hydrogen with CCS for hydrogen fuel cell vehicles and power generation, and a number of other low-carbon-intensive products using carbon capture and storage. [49] The project is estimated to cost $400 M while generating $260 M in annual economic income and to have 150–200 direct permanent jobs. US Steel has entered into a memorandum of understanding with Norwegian oil and gas producer Equinor ASA to explore converting Appalachia's natural gas to cleaner fossil-derived hydrogen with CCS to possibly replace using natural gas in the steel-making process. [50] Also, EQT recently joined Equinor, GE Gas Power, Marathon Petroleum,[l] Mitsubishi Power, Shell Polymers, and US Steel in a newly formed alliance to establish a low-carbon and hydrogen industrial hub aiming to decarbonize the industrial base in the northern Appalachian region. The newly formed alliance will work with stakeholders to establish a hub in Ohio, Pennsylvania, and West Virginia to not only decarbonize the industrial base and power generation in the northern Appalachian region but also serve as a national model for sustainable energy and production systems. [51] There are also a number of regional interest groups and workshops in the hydrogen space, including the *Ohio River Valley Hydrogen and CCS Hub Market Formation* workshop, *A Low Carbon Energy*

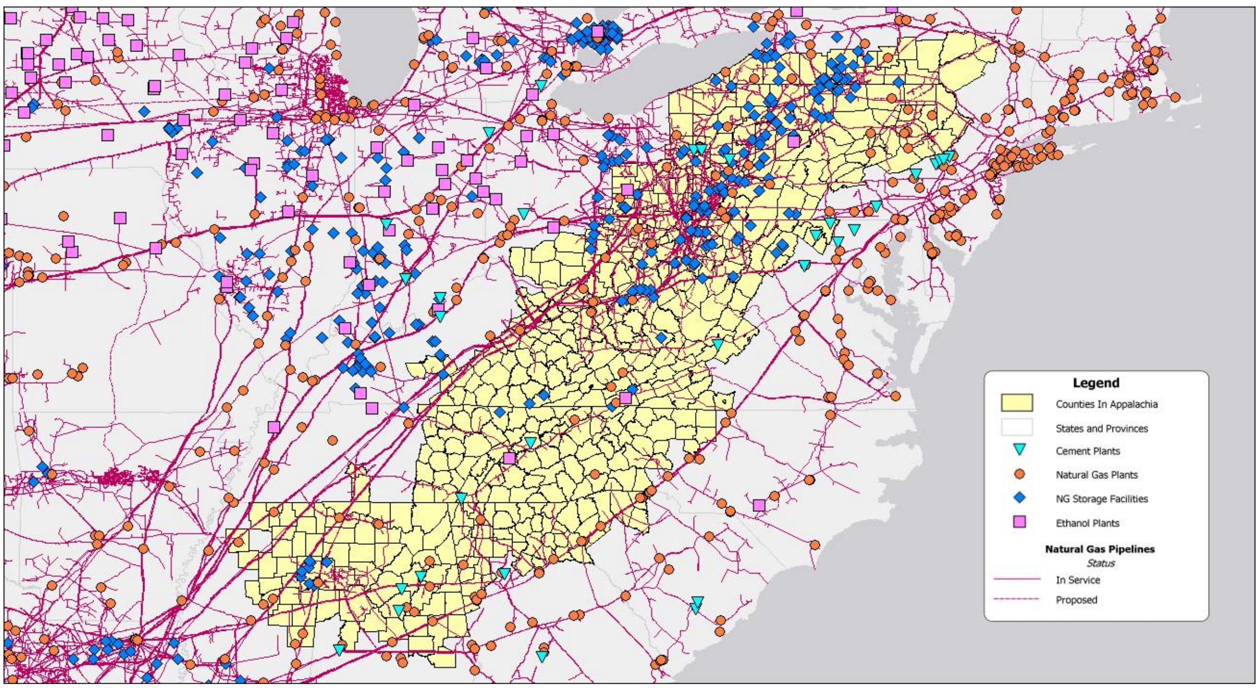
[l] Marathon Petroleum in Catlettsburg, KY, produces hydrogen for use at its refinery on the Ohio River.

*Transition in Southwest Pennsylvania* from Harvard and Carnegie Mellon University, and the *Marshall Plan for Middle America*.

## 3.4 Existing and Potential Transportation Routes in the Appalachian Region

The Appalachian region offers several synergies that make it attractive for hydrogen deployment. Along with a highly skilled labor force from decades of coal industry experience, a substantial number of power plants exist in the region that run on natural gas, which has led to significant infrastructure (pipeline, storage facilities, and power plants) already being implemented (Exhibit 3-13). This includes a history of natural gas production in the Marcellus and Utica shale regions and associated workforce and infrastructure build-out.

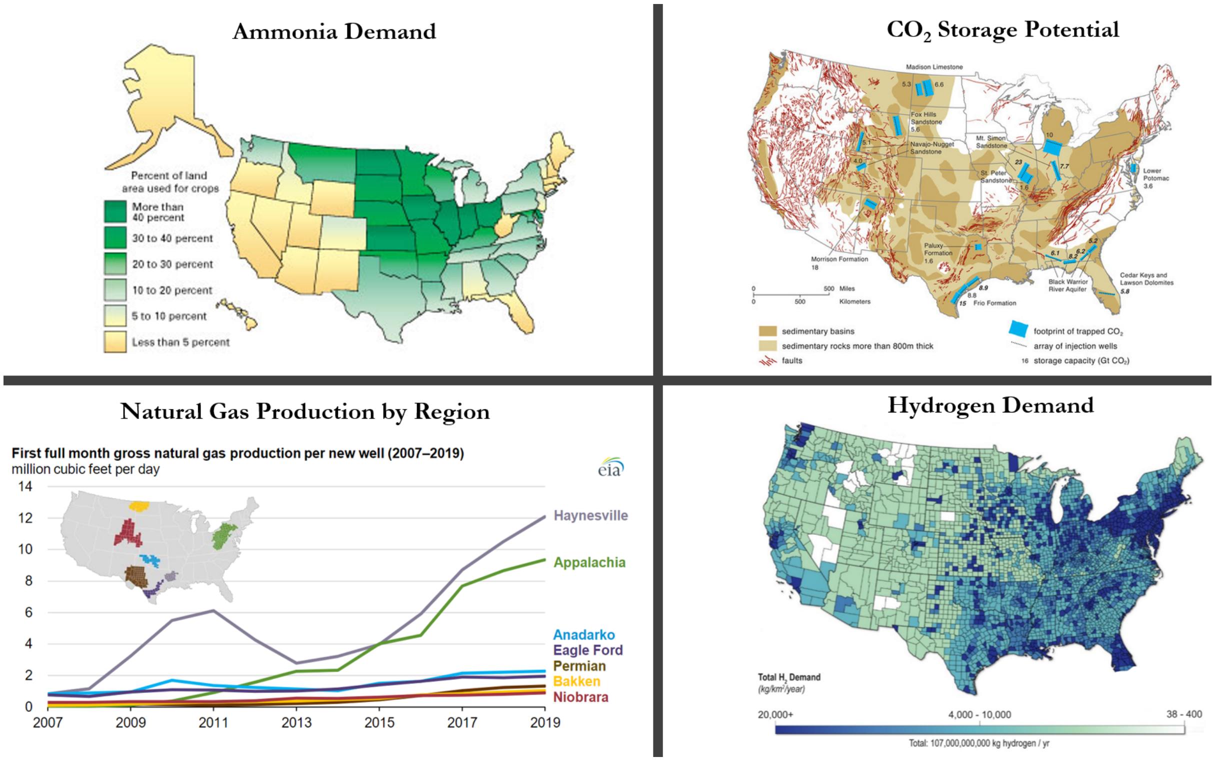
***Exhibit 3-13. Current natural gas infrastructure in the Appalachian region and surrounding region***




*Source: Hitachi Energy Velocity Suite [1]*

Another key synergy for the Appalachian region is its proximity to major markets for hydrogen current and future consumption. When considering ammonia as an LHC, it is an added benefit that the Appalachian region is close to agricultural centers in the Midwest, where the majority fertilizer consumption occurs. From a geologic perspective, the Appalachian region boasts ample sites for hydrogen storage and $CO_2$ sequestration, as well as low-cost abundant natural gas supply. Exhibit 3-14 illustrates some of the many synergies that exist in the Appalachian Basin.

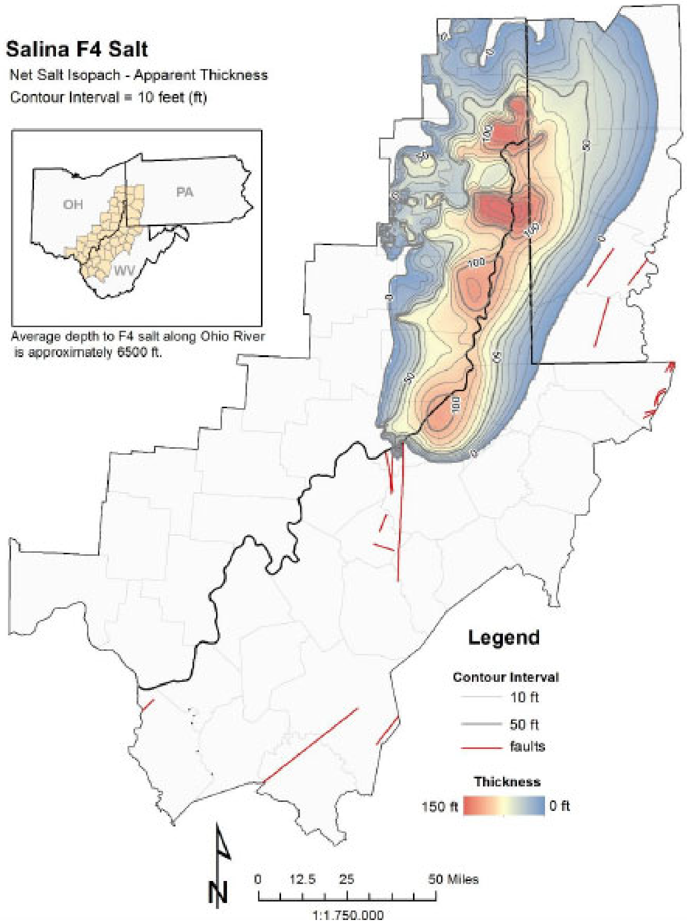
***Exhibit 3-14. Appalachian Basin synergies for hydrogen deployment***




*Source: EIA*

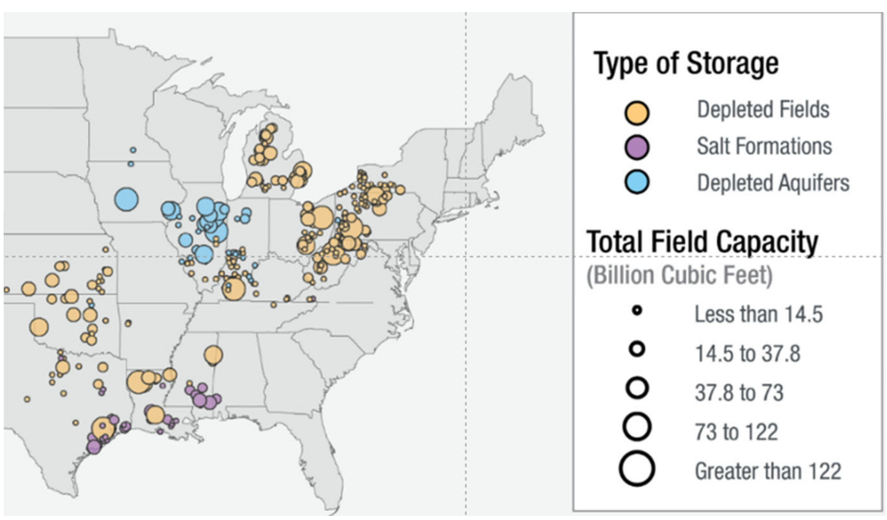
Related to hydrogen storage, the Appalachian Basin boasts a unique combination of salt caverns and depleted gas fields, both of which could be utilized to store vast quantities of hydrogen. Exhibit 3-15 and Exhibit 3-16 illustrate these storage opportunities.

***Exhibit 3-15. Salt caverns in the Appalachian Basin***




*Used with permission from West Virginia Geological and Economic Survey [52]*

***Exhibit 3-16. Existing storage and pipeline assets in the Appalachian Basin***




*Source: EIA*

# 4 ASSESS THE HYDROGEN LANDSCAPE (REGULATORY)

The United States lacks a sophisticated and organized regulatory framework for hydrogen, and as a result, regulations tend to be scattered between federal, state, and local jurisdictions. Most regulations on hydrogen were not specifically written for hydrogen, but rather could cover hydrogen in their scope such as hazardous materials, pipeline transportation of gases, and storage of liquefied gases. This section seeks to provide a summary of present regulations that would affect development of hydrogen infrastructure both at a federal and state level for the Appalachian region, while also mentioning regulations that may not currently apply to hydrogen but could do so with slight modification of language. It is important to note that these sections contain current regulations and that new rules may likely be instated as a hydrogen economy begins to build out.

## 4.1 FEDERAL REGULATIONS

### 4.1.1 Maritime Transportation of Hydrogen

The maritime transportation of hydrogen is mostly covered under the Department of Homeland Security (DHS) United States Coast Guard (USCG). Code of Federal Regulations (CFR) 33 Part 154 regulates the transferring of hazardous materials to a vessel from a facility and discharging from a vessel to a facility, while part 156 regulates oil and hazardous materials transfers to and from vessels with a 250 barrel or more capacity. [53] [54] [55]

46 CFR regulates maritime shipments of hazardous materials via vessel. Part 38 gives the USCG the authority to regulate the transportation of liquified or compressed gases that represent a flammability hazard, while part 150 and 151 cover the rules for transporting these hazardous materials aboard tanks or as bulk cargo that are loaded and discharged while still on the vessel. [56] [57] [58] Part 154 also extends these regulations to bulk liquefied gases stored as cargo, cargo residue, or vapors. [59] [55]

All USCG regulations apply to Appalachian waterways, including areas such as the Great Lakes (USCG 9$^{th}$ district) or river transportation, regardless of the size of the vessel. [60]

Although not specifically listed in federal regulations, the USCG is also responsible for the enforcement of pipeline-to-maritime transport export terminals after they are constructed, as well as the enforcement of day-to-day safety regulations and security for waterfront facilities. The USCG also works jointly with the Maritime Administration to license deep-water port facilities such as oil and gas drilling rigs. The Maritime Administration also provides support and partners with federal, state, and local agencies to research hydrogen power fuel cell designs for maritime applications. [55]

Transmission and gathering pipelines in federal waters on the Outer Continental Shelf (OCS) are regulated by the Department of Interior (DOI) Bureau of Safety and Environmental Enforcement (BSEE) Office of Offshore Regulatory Programs (OORP). 43 USC Part 29 also dictates that DOI BSEE OORP, DHS, and USCG, along with federal and state agencies, manage compliance programs governing oil, gas, and mineral operations on the OCS, but this mainly pertains to oil and gas drilling rigs and, therefore, does not apply to hydrogen. [61] [55]

DOT PHMSA Hazardous Materials Regulations (HMR) 49 CFR 178 specifies requirements for packaging and containers used for transportation of hazardous materials. This regulation is not method specific and can be applicable for all transportation methods. [62] [55]

### 4.1.2 Land Transportation of Hydrogen

The DOT Federal Highway Administration (FHWA) requires that additional equipment on commercial vehicles does not reduce the overall safety of the vehicle through 49 CFR Part 390. [63] This regulation could be interpreted to include any additional equipment required for hydrogen transportation by road but does not specifically name hydrogen. 23 CFR Part 924 regulates highway safety including bridges, tunnels, and other associated elements, but does not provide any language for the transportation of hazardous materials. [64] This regulation would likely assign control of highway safety protocols for hydrogen transportation to the DOT FHWA but does not provide any specific rules. [55]

The DOT Federal Motor Carrier Safety Administration regulates motor carrier routing and safety when transporting hazardous materials through 49 CFR Parts 356 and 389, respectively. [65] [66] These include rules governing safest routes when transporting hazardous materials, as well as safety practices. 49 CFR Part 397 gives driving and parking rules for transportation of hazardous materials, such as safety protocols for vehicle storage while hazardous materials are still loaded on the vehicle. [67] [55]

The DOT Federal Transit Administration provides guidance for rail fixed guideway systems and safety oversights through safety and security assessments through 49 CFR Part 659. [68] Although hydrogen is not specifically listed, this regulation is not fuel specific and, therefore, could apply to hydrogen. 49 USC 5329(e), or the National Public Transportation Safety Plan, includes safety performance criteria for all public transportation modes including maritime vessels. [69] Although alternative fuels are noted, hydrogen is not specifically mentioned. [55]

DOT PHMSA approves currently prohibited hazardous materials by rail by special permit via 49 USC 5117, or the DOT Federal Railway Administration can approve them as well. However, a special permit from DOT PHMSA overrides the need for DOT Federal Railway Administration approval. [70] 49 CFR Part 192 is the governing law for transportation of natural gas and other gases via pipeline within the limits of the OCS. [71] This regulation also gives inspection and enforcement of pipelines after construction to the DOT PHMSA, which accounts for approximately 700 miles of 1,600 total miles of hydrogen pipelines. Regulation of intrastate pipelines is shared via an agreement between states but maintained by the DOT PHMSA, accounting for the remaining approximately 900 miles of hydrogen pipelines. Transmission and gathering pipelines in federal waters on the OCS are also covered in this regulation, as well as by the DOI BSEE OORP, and pipelines closer to shore in state waters are also covered. 49 CFR Part 193 extends these regulations to pipeline facilities that transport liquified natural gas (LNG) in pipelines, which includes liquid hydrogen. [72] 49 CFR Part 195 extends the scope of materials transported via pipelines to include hazardous liquids, which includes hydrogen as well. [73] [55] [74]

The DOT PHMSA HMR regulates transportation of hydrogen over roads as cargo within tanker trucks through 49 CFR Subchapter C. [75] 49 CFR 172 regulates materials that the PHMSA has designated as hazardous materials for purposes of transportation. [76] Codes T75 and TP5 of this regulation cover portable tanks and the fill rate of liquid hydrogen tankers. [76] 49 CFR 173 adds specific requirements for using insulated MC-338 cargo tanks for cryogenic hydrogen transportation, as well as requirements for bulk cylinders for compressed, non-cryogenic hydrogen transportation. [77] 49 CFR 174 regulates approval of rail transportation of hazardous materials, which includes hydrogen. [78] 49 CFR 178 specifies requirements for packaging and containers used for transportation of hazardous materials. [62] This regulation is not location specific and can be applicable for all transportation methods. 49 CFR 179 authorizes the manufacture and use of double-walled, insulated tank cars for cryogenic hydrogen, known as DOT-113A60W, and outlines required methods of construction and qualification, while 49 CFR 180 extends this to all hazardous material transportation via DOT-113A60W tank cars. [79] [80] DOT PHMSA also imposes requirements for the transportation of compressed gases, including hydrogen, through 40 CFR 173.301. [81] [55] [74]

### 4.1.3 Air Transportation of Hydrogen

The DOT Federal Airline Administration regulates minimum intraline separation distance requirements between liquid hydrogen storage and incompatible energetic liquids through 14 CFR Part 420. [82] This regulation also regulates the proximity of an explosive hazard facility to other hazard facilities and public traffic routes. [55]

DOT PHMSA HMR 49 CFR 178 specifies requirements for packaging and containers used for transportation of hazardous materials. [62] This regulation is not method specific and can be applicable for all transportation methods. [55]

### 4.1.4 Hydrogen End-Use

The Federal Energy Regulatory Commission regulates energy sales and distribution of natural gas through 18 CFR Part 284. [83] This regulation is not hydrogen ready, however, as it only contains requirements specifically for natural gas. Regulation of siting, routing, and construction of natural gas pipeline systems as well as siting, construction, modification, and operation of near and offshore natural gas import/export facilities, is covered under 18 CFR Part 153, but again does not include any language specific to hydrogen, only natural gas. [84] 18 CFR Part 292 applies to cogeneration and small power production facilities that include equipment to produce electricity or thermal energy for the grid and includes specific references to fuel cells in definitions of electrical generation equipment. [85] [55]

The Occupational Health and Safety Administration (OSHA) provides safety requirements for structural components and operations of gaseous and liquid hydrogen for storage and delivery through 29 CFR Part 1910 Subpart H, but the scope is dependent on whether the hydrogen is in gaseous or liquid form. [86] OSHA also regulates the installation of hydrogen systems including location, containers and piping characteristics, safety relief devices, equipment assembly, and other rules through 29 CFR Subpart 1910.103. [87] There are also other miscellaneous safety standards from OSHA relating to compressed gases and flammable liquids, which would likely cover hydrogen as it is stored in a compressed gas or liquefied form. [55] [74]

Hydrogen fuel cell vehicles are regulated by the United Nations Economic Commission for Europe Global Technical Regulation (GTR) Number 13: Global Technical Regulation on Hydrogen and Fuel Cell Vehicles, which governs vehicles with a gross vehicle mass (GVM) of 4,536 kg (10,000 pounds) or less. This document was adopted by the United States to serve as the basis for national regulations on Fuel Cell Electric Vehicles (FCEV) safety. GTR Number 13 Section 5 sets performance requirements for the compressed hydrogen storage system, including extreme pressure tests and ability to withstand impacts. Much the same way as underground storage tanks must have release systems to prevent over pressurization, this regulation dictates emergency relief and discharge systems for the fuel cell, as well as leakage detection. GTR Number 13 Section 6 outlines test conditions and procedures, including crash tests for fuel system integrity and fuel cell performance under suboptimal conditions. GTR Number 13 Section 7 extends these performance and testing requirements to vehicles with liquid hydrogen storage systems. [88] [89]

The DOT Federal Motor Vehicle Safety Standards specify performance and safety requirements for vehicles, but there are currently no specific federal rules for hydrogen fuel cell systems. [55]

### 4.1.5 Environmental Regulations

DOE FECM regulates use of alternative fuels and hydrogen blending via 10 CFR Parts 503 (new facilities) and 504 (existing power plants), which are set for facilities required to meet Title VIII of the National Energy Conservation Policy Act, which prohibits these specific power plants from burning natural gas or petroleum as its primary energy source. [90] [91] [55]

The Environmental Protection Agency (EPA) regulates hydrogen production facilities through 40 CFR Section 98 Subpart P, which states that facilities that produce hydrogen that is sold as a product to other entities, process units that produce hydrogen, and hydrogen production facilities located within another facility must report emissions from hydrogen production processes and all other source categories at the facility. [92] The source categories and emissions thresholds are defined in 40 CFR Section 98.2. [93] Standards for chemical risk management are also regulated through 40 CFR Part 68 relating to storing of hazardous substances above a certain threshold, which is over 10,000 pounds (lb) in the case of hydrogen. [94] [55] [74]

Pipeline developers may seek authorization to construct new pipelines within state borders from the state's regulatory agency, but they must also comply with federal laws such as the Endangered Species Act, National Historic Preservation Act, Coastal Zone Management Act, the Clean Water Act, or the National Environmental Policy Act. [55]

### 4.1.6 Pipeline Permitting Process

All pipeline permits, regardless of the substance being transported, must be submitted via application through DOE FECM. These applications are public information. Pipeline developers can pre-file an application for large projects with FERC to start discussion about proposed routes and permitting requirements, which is meant to address issues with proposed construction that may disrupt landowners, communities, or have potential environmental impacts. This process typically lasts 6–12 months. [95]

After the pre-filing process, a formal application is filed by the developer with FERC. Under the National Environmental Policy Act (NEPA), FERC must assess the project's impact on human health and the environment, as well as review the pipeline's proposed route and propose alternative routes to mitigate environmental impacts. Federal and state agencies are both a part of this process, and state laws can change where the pipeline can be constructed beyond federal laws. The developer must work with federal, state, and local permitting agencies to obtain any necessary authorizations and permits. This process typically takes well over a year. [95]

Once all requirements are met, FERC will issue a certificate that states the conditions for construction of the pipeline. Temporary approval may also be granted via a certificate of public convenience and necessity, but this depends on market support to support financing. The developer must acquire all outstanding authorizations or permits prior to construction. [95]

At this point, there are no specific differences between application processes for hydrogen pipelines and natural gas pipelines. However, hydrogen has different mechanical and chemical properties than natural gas, which may present issues when using existing pipelines such as embrittling steel and welds, permeation and leaks, and compression. These differences may require regulators to adapt conditions to account for hydrogen. DOE and other private organizations are researching a number of solutions to these problems, such as using fiber reinforced polymer (FRP) pipelines to minimize welding requirements [96] and converting existing natural gas pipelines to carry a blend of both natural gas and hydrogen (about 15 percent hydrogen). [97] [95]

## 4.2 Appalachian Region State Regulations Overview

State regulations for hydrogen very rarely reference hydrogen by name, and usually apply to pipelines or underground storage of hazardous materials. Most of these regulations fall under environmental protection, protected land rules, or public service commissions. Some states provide additional regulations for transportation via maritime or road/rail as well, but generally will adopt federal regulations instead. For the purposes of this report, state regulations with the sole purpose of adopting federal regulations will not be reported to avoid repetition, as they already appear in the previous section. The states listed in this section constitute what is known as the Appalachian region (Exhibit 1-2), although the region does not cover all parts of the states listed.

### 4.2.1 Alabama

Alabama's Department of Conservation and Natural Resources State Lands Division regulates pipeline right-of-way contracts for submerged and non-submerged lands via Sec. 220-4-.02 and 220.4.14, respectively. Both submerged lands and non-submerged lands regulations set the maximum time of 10 years for right-of-way contracts, with an option to renew on the same terms as the original agreement. For both submerged and non-submerged lands, the terms for the right-of way include the depth the pipeline must be buried, pressure testing criteria, pipeline fabrication and construction protocols, leak prevention, and rules for the ways in which the pipeline must be buried so as not to destroy the natural habitat. [98] [99]

Alabama's State Oil and Gas Board regulates the design, installation, construction, and maintenance of intrastate gathering lines through Sec. 400-1-8-.03 in what it refers to as "generally accepted industry standards." [100] This rule also states the design, construction, and operation of gathering lines transporting hydrocarbons that contain hydrogen sulfide concentrations at or greater than 100 parts per million must comply with Rule 400-1-9-.02 for hydrogen sulfide safety procedures. [101] Sec. 400-2-8-.01 mandates that operators must conduct a survey of shallow hazards within a quarter-mile radius of a proposed pipeline installation. [102] General design and development of an underground storage facility for gas is regulated under Sec. 400-5-3-.01, which mandates an engineer or geologist experienced in the development and operation of an underground storage facility must perform a feasibility investigation of the site first. [103] The maximum and minimum operating pressures of an underground storage facility are also to be determined by an engineer or geologist following Rule 400-5-3-.01 under Sec. 400-5-4-.01. [103] [104] This rule also sets maximum allowable stabilized reservoir pressures and average storage reservoir pressure limits. Sec. 400-5-6-.01 sets forth casing requirements for underground storage wells, adopting Rule 400-1-4-.09 [105] or Rule 400-2-4-.09 [106] for casing and cementing programs except for specific requirements for surface casing and API standards for pressure. [107] Sec. 400-5-6-.02 sets requirements for newly converted wells so that injection does not result in fluids moving into underground sources of drinking water. [108] Testing requirements for internal mechanical integrity prior to storing gas and verification every 5 years are mandated under Sec. 400-5-7-.01. [109] These regulations refer to the storage and transportation of gas but do not specify the type of gas, so hydrogen gas would likely be included in scope.

Alabama's Department of Transportation regulates both maritime and road transportation of hazardous materials. Sec. 450-3-1-.08 outlines conditions for permitting the movement of sealed containerized ocean-going cargo units. Sealed containerized cargo units cannot exceed a maximum weight of 100,000 lb and must be moved on highways from port to port, and permits are required for the movement of these units subject to minimum vehicle construction and safety standards. [110]

Alabama's Liquefied Petroleum Gas Board regulates the storage and handling of liquefied petroleum gas and liquefied petroleum gas piping through Sec. 530-X-2-.06 and Sec. 530-X-2-.08 by adopting the National Fire Protection Association (NFPA) 58 and 54 and any supplementary rules and regulations. [111] [112] This regulation specifically references petroleum gas and would likely need to have language added to accommodate hydrogen. Additionally, Sec. 530-X-2-.09 prohibits new 12-gas containers with a working pressure of less than that required for a 200-type container. [113]

### 4.2.2 Georgia

Georgia's State Department of Transportation regulates transportation of hazardous materials and movement of petroleum via pipeline. Rule 672-10-.02 requires permits for all loads of LNG, polychlorinated biphenyl, and radioactive materials transported on an exclusive use vehicle in large quantities. [114] These large quantities are defined in 49 CFR. Hydrogen is not directly referenced, so the rule would need to be modified to include hydrogen. These permits are not required for DOE or government owned vehicles moving weaponry or other classified loads as outlined in Rule 672-10-.03, but it is unclear whether these regulations would apply to shipments of hydrogen on DOE-owned vehicles. [115] Additionally, Rule 672-10-.04 invalidates permits for travel into or through the area around the City of Atlanta bypass (I-285) unless the vehicle is making pickup or delivery in the area. [116] Rule 672-13-.02 pertains to the exercise of eminent domain for construction of petroleum pipelines, and grants petroleum pipeline companies the power to acquire property or interests in property by eminent domain for the purpose of expansion, extension, maintenance, or construction of new petroleum pipelines subject to Official Code of Georgia Sections 22-3-80 through 85. [117] It is unclear whether this regulation would also apply to hydrogen pipelines, or whether language would need to be added to accommodate hydrogen.

### 4.2.3 Kentucky

Kentucky's Department of Environmental Protection sets standards for control of emissions from new storage vessels for petroleum liquids through Sec. 401 KAR 59:050. [118] This regulation only applies to facilities with storage capacities of less than 40,000 gallons, and it is unclear whether this regulation would apply to hydrogen storage or need to have language added to accommodate hydrogen. Leaks from gasoline tank trucks are regulated under Sec. 401 KAR 63:031, which provides for the control of volatile organic compound emissions from leaks and applies to each facility that loads gasoline onto tank trucks. [119] It is unclear whether this regulation would also apply to hydrogen gas, as the language specifically references gasoline.

The Division of Oil and Gas establishes requirements for the protection of the integrity of gas storage reservoirs by requiring certain techniques of drilling, casing, operating, and plugging through Sec. 805 KAR 1:080. [120] The language is not specific to the type of gas stored and, therefore, would likely also apply to hydrogen gas.

### 4.2.4 Maryland

The Maryland Aviation Administration adopts the NFPA Uniform Fire Code through 11.03.01.01-1 [121], and specifically chapters 10 and 34 relating to the storage of combustible materials in hangars through 11.03.01.03. [122] This regulation also states that flammable and combustible liquids, gases, explosives, signal flares, and other similar devices must be stored in accordance with the Code of Maryland Regulations (COMAR) 29.06.01. [123] 11.03.01.03-1 also requires the storage, retaining, handling, using, dispensing, or transporting of explosive or hazardous materials to have a special permit under COMAR 29.06.01. [123] [124] Explosive cargo transported to and from designated parking areas must be done in vehicles equipped in accordance with federal regulations under this rule as well.

The Maryland Port Administration prohibits any liquid hydrogen moving into the port under a federal DOT exemption unless a permit has been obtained under 11.05.02.06. [125] Maryland's Transportation Authority prohibits class 1-9 explosives from entering tunnels unless they are contained in the vehicle's fuel system under 11.07.01.04. [126] Hydrogen is included in the scope of class 1-9 explosives.

### 4.2.5 Mississippi

Mississippi's Commission on Environmental Quality Underground Storage Tanks (UST) Regulations defines performance standards and general requirements for all UST systems. Sec. 11-5-2.2-280.20 requires USTs to prevent leaks due to structural failure, corrosion, or spills and overfills by tanks and pipes being properly designed and constructed and protected from corrosion. [127] Sec. 11-5-2.4-280.40 requires owners and operators to provide methods of leak detection that can detect a leak from any portion of the tank and connected piping. [128] Sec. 11-5-2.4-280.41 sets specific requirements for hazardous substance UST systems, requiring secondary containment systems be designed, constructed, and installed to contain leaked substances and be checked every 30 days. [129] The term hazardous substance would likely apply to storage of hydrogen.

Mississippi's Oil and Gas division regulates underground storage wells of liquefied compressed gases, crude oils, refined hydrocarbons, compressed air, and natural gases in reservoirs dissolved in salt beds through Rule 26-2-1.64. Liquefied compressed gases likely includes liquefied hydrogen in scope. This regulation mandates an engineer or geologist to perform a feasibility investigation and design analysis before construction, the walls to be washed with a blanket material to prevent leaching, components that are rated to exceed maximum operating pressure conditions, and safety control sensing devices. [130]

Mississippi's Rules and Regulations Governing Oil and Gas Drilling, Producing and Pipeline Operations in Submerged Offshore Land mandates that pipelines must be protected from the loss of metal by corrosion, water currents, storm scouring, soft bottoms, and other environmental factors through Rule 26-3-1.10. [131]

### 4.2.6 New York

New York's Department of Public Service requires pipes for distribution of gas be designed with sufficient wall thickness to withstand anticipated external pressures and loads after installation through Title 16 Chapter III Subchapter C Sec. 255.103. [132] Title 16 Chapter III Subchapter C Sec. 255.143 also requires each component of a pipeline be able to withstand operating pressure and other anticipated loadings, as well as corrosion control. [133] This regulation likely covers hydrogen gas in scope. Title 16 Chapter III Subchapter C Sec. 257.1 requires all liquid propane gas facilities be constructed, operated, and maintained in accordance with the Standard for Storage and Handling of Liquefied Petroleum Gases at Utility Plants (American National Standards Institute [ANSI]/NFPA 59). [134] This regulation specifically refers to liquefied petroleum, so it is unclear whether it would also apply to hydrogen.

### 4.2.7 North Carolina

North Carolina's Boiler and Pressure Vessel division incorporates ANSI/NB-23 National Board Inspection Code Parts 2 and 3, The American Society of Mechanical Engineers Boiler and Pressure Vessel Code, and the North Carolina State Building Code by reference, including subsequent amendments through Title 13 Chapter 13.0103. [135] Title 13 Chapter 13.0401 mandates the design, construction, installation, inspection, stamping, and operation of all boilers and pressure vessels conform to all rules and accepted design and construction code. [136] Title 13 Chapter 13.0403 sets the limit for pressure vessels at their maximum allowable working pressure [137], and Title 13 Chapter 13.0404 requires all pressure vessels have a pressure relief device, pressure gauge, and drain valves. [138] Title 13 Chapter 13.0405 requires these pressure relief devices not be set at greater than the maximum allowable working pressure. [139]

North Carolina's Underground Storage Tanks regulations require wells used for monitoring or testing of ground water must be sampled and tested every 14 days for the presence of stored hazardous substances from nearby storage tanks through Title 15A Chapter 02N.0504. [140] This regulation's reference to hazardous substances likely includes hydrogen in scope. Title 15A Chapter 02N.0904 requires pipes have double-walled construction and anti-corroding materials, and that pipes buried underground be locatable after installation. [141]

### 4.2.8 Ohio

Section 901:6-5-02 of the Ohio Administrative Code requires hydrogen fuel sales be done in kg. [142] Permits are also required to move and store combustible gases through Section 1301:7-7-01, which also sets limits on the total amount to be stored based on temperature and pressure. [143]

Ohio's Division of the Fire Marshall requires compressed gas be stored in accordance with the specifications of the canister in which it is being held and that the canister must be protected from corrosion through Section 1301:7. This section also requires underground storage systems be registered with the state, tested regularly, and double-walled, compressed gases be placed in an area to prevent damage and protected from leaks or explosions, and corrosive and flammable gases be stored, transported, and secured to ensure safety of workers, buildings, and surrounding areas. [144]

Section 1501 requires pipelines for the use, operation, and transportation of oil/natural gas be designed to withstand the maximum anticipated pressure in accordance with current industry design practices and be buried at least 24 inches below the ground. [145] [146] [147] This regulation would likely need to have language added to accommodate hydrogen. Underground injection for wells is mandated to avoid water supplies under Section 3745-34, but hydrogen or compressed gas are not specifically listed in this regulation. [148]

### 4.2.9 Pennsylvania

Title 67: Chapter 175 of the Pennsylvania Code relating to vehicle equipment and inspection requires compressed gas storage containers be marked and meet industry standards for pressure and temperature of the gas being stored, and pipes attached to these containers must be designed to withstand the largest range of temperatures and pressures possible. Additionally, this regulation requires vehicle transportation of compressed gas to be installed with as much road clearance as practicable but not less than the minimum road clearance of vehicle under maximum spring deflection. [149]

The Pennsylvania Administration of Storage Tank and Spill Prevention Program requires storage tanks to be certified by the state through Title 25: Chapter 245. [150] Title 25: Chapter 78 lists requirements for operating around gas storage locations and sets the maximum pressure of gas storage at the natural maximum pressure unless tested. [151] [152] This regulation also defines what types of soil can be used around pipelines.

### 4.2.10 South Carolina

Chapter 121-8.22 for underground injection for enhanced recovery, saltwater and oil-field wastes, and hydrocarbon storage states that injection cannot enter drinking water, wells should be constructed to prevent leaks or loss of injection materials, pending permits must be made publicly available, and the regulation defines maximum pressures based on location. [153] Chapter 121-8.26 pertaining to environmental protection and safety mandates water be protected from production operation or exploration, and that owners of storage or pipes containing gas report accidents such as fires, breaks, or leaks. [154] Chapter 63-361 requires movement of road machinery exceeding a specified size or weight be permitted first, which could loosely apply to movement of large quantity hydrogen storage tankers. [155]

### 4.2.11 Tennessee

Chapter 0400-18-01 gives requirements for underground storage tanks containing liquid petroleum, including requirements for corrosion controls, pipe construction, and that pipes and tanks both be double walled. [156] These regulations specifically apply to liquid petroleum and would need to be modified to include hydrogen. Chapter 0400-45-06 classifies wells based on the material being injected, and provides requirements, regulations, and permits based on the well classification. [157] Injection of hydrogen would constitute a Class V well, and construction of the well would need to meet industry standards and be monitored for leaks.

Tennessee's Division of Air Pollution Control regulates leaks from natural gas facilities, including steps for identifying leaks, what constitutes a leak, and what to do when a leak occurs through Chapter 1200-03. [158] This regulation would need to have modified language to include hydrogen.

### 4.2.12 Virginia

Title 4, Agency 25 requires that pipelines be permitted and sets their minimum distance from buildings or railroads. It also dictates that if a pipeline is buried it must be detectable, pipelines must be tested to maintain 110 percent of maximum pressure, storage facilities must include discharging controls, and tanks for storage must be constructed to hold the material without discharging the excess. [159] [160]

Title 20, Agency 5, Chapter 335 sets a timeline for energy storage projects to be constructed and operated by utilities, starting in 2025 and increasing every 5 years until 2035. Each utility differs in how much storage they can maintain, but they cannot own more than 65 percent of the storage. [161]

### 4.2.13 West Virginia

Series 35-03 dictates that any pipeline not covered by the DOT must be buried (except in certain instances) and that the owner must ensure the surface and groundwater will not be contaminated prior to construction. [162] Section 35-04 dictates that reclamations of oil and gas well locations should prevent leakage, spilling, or overflow, operators should ensure that surface and ground water will not be impacted before drilling, and high-pressure wells should have equipment in place to prevent blowouts. [163]

# 5 Develop Pathways Consistent with the Landscape

Hydrogen can replace fossil fuels in many aspects of the energy economy, delivering high-quality industrial process heat, onsite industrial electricity generation, large-scale electricity generation, and transportation, and as a building block for thousands of downstream chemicals. Since natural gas is a primary feedstock for hydrogen production, the supply chain needs start with an ample supply of natural gas from the region, the potential for renewable natural gas resources, and natural gas pipelines and intermediate storage to buffer variations in natural gas supply and demand. Hydrogen economy supply chain needs also include the ability to produce and transport hydrogen, the latter of which could follow natural gas pipeline rights-of-way, and intermediate storage options to buffer variations in hydrogen supply and demand. Ample $CO_2$ storage capacity to store hydrogen byproduct emissions is also a supply chain need for a hydrogen economy. Additional supply chain needs are a regulatory framework that will not inhibit construction and operation of natural gas-to-hydrogen plants; a robust end use market for hydrogen; and a workforce that can provide the skilled labor.

The Appalachian region consists of 420 counties across 13 different states including Alabama, Georgia, Kentucky, Maryland, Mississippi, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Virginia, and West Virginia. [5] Building a hydrogen economy in the Appalachian region will require having the entire supply chain in place. This section discusses the Appalachian region's unique position to be a leader in developing the hydrogen economy.

Pipeline materials and specifications, compressor station requirements, measurements of products in the pipeline throughout the process, and the costs of upgrading the supply chain as hydrogen production accelerates are all issues that are being addressed by industry stakeholders. Physical solutions for improving the pipeline infrastructure and compressor stations are currently in practice, with known costs. However, a large-scale increase in hydrogen supply and demand will shift the current hydrogen market, and those changes need to be analyzed across a spectrum of supply/demand/costs scenarios, considering environmental incentives and penalties at the federal through corporate levels.

The regulatory framework does not pose any direct threats to developing a hydrogen economy in the Appalachian region. Currently, Appalachian states have a regulatory friendly perspective with respect to fuel production, distribution, and storage. While most of the states have not adopted official regulations for hydrogen, assuming hydrogen would fit into a liquid fuel category, current regulations on the production, distribution, and storage of natural gas and other liquid fuels are well established. While more specific hydrogen regulations may be implemented as hydrogen production scales up, regulations for $CO_2$ may also come into play in these states as well.

## 5.1 Natural Gas Resources and Infrastructure

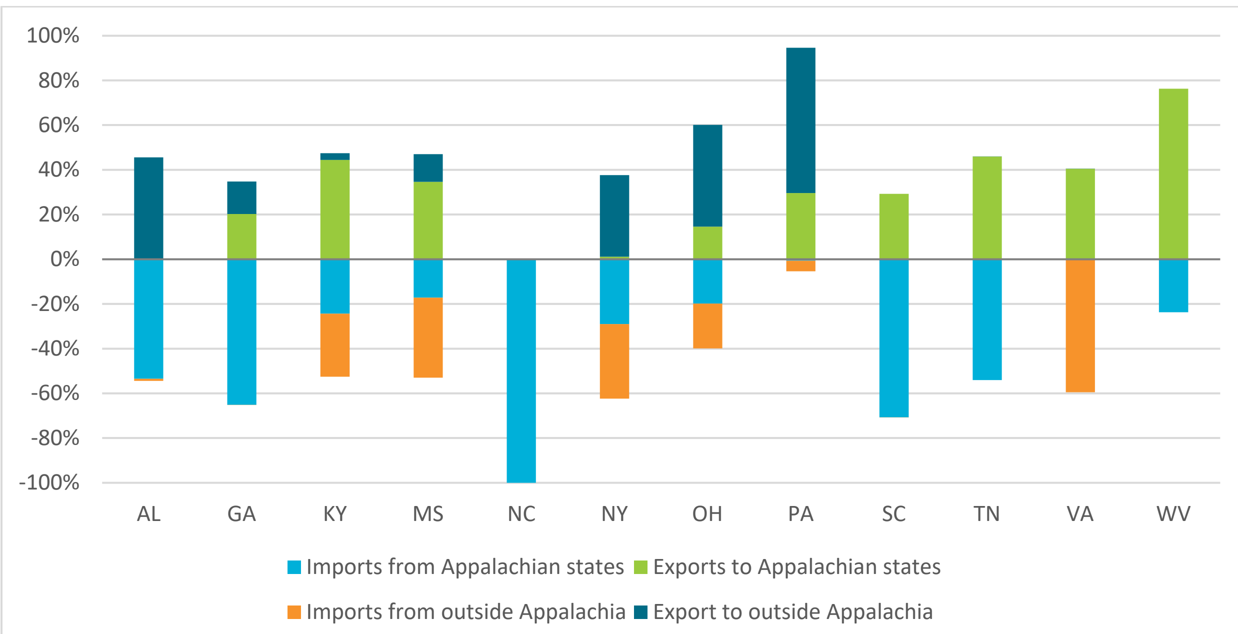
The Appalachian region is well seated to become a production hub for hydrogen from natural gas. The region is a major natural gas producer, with the Utica and Marcellus shale regions, located in Ohio, West Virginia, and Pennsylvania producing 33.6 billion cubic feet (Bcf) per day

(Bcfd) (12,264 billion cubic feet per year [Bcfy]) in 2020. [164] Of the 5,000 Bcfy of natural gas being processed in the Appalachian region, only 1,608 Bcfy is being consumed in the region.

The following analysis was performed using state-level international and interstate natural gas receipts (imports) and deliveries (exports) from the 2020 EIA-176, "Annual Report of Natural and Supplemental Gas Supply and Disposition"—as EIA-176 reports on an aggregated state basis. For the purpose of the analysis of the EIA-176 data, a state is included in the 'Appalachian region,' if any county in that state is listed in ARC's 2009 Subregions in Appalachian classification. [165]

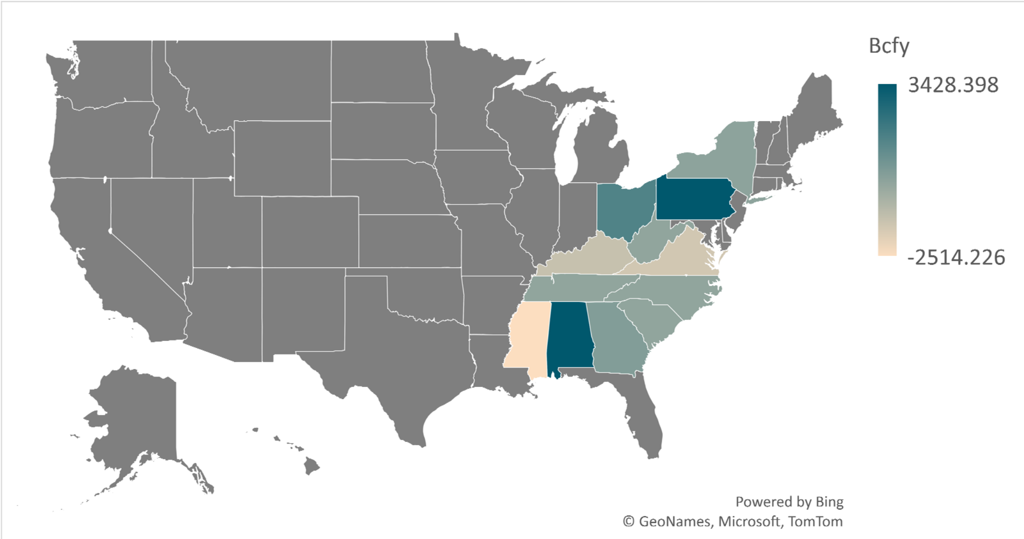
In 2020, 54 percent of the Appalachian region's combined natural gas exports, approximately 15,000 Bcfy, were delivered to states within the region. The remaining 46 percent of natural gas deliveries (12,900 Bcfy) were exported to states outside of the region with a nominal amount (1 percent) delivered to international countries. Of the 12 Appalachian states, 5 imported 20–60 percent of net imports from areas outside of the Appalachian region (Exhibit 5-1).

***Exhibit 5-1. Appalachian state import/exports [2]***



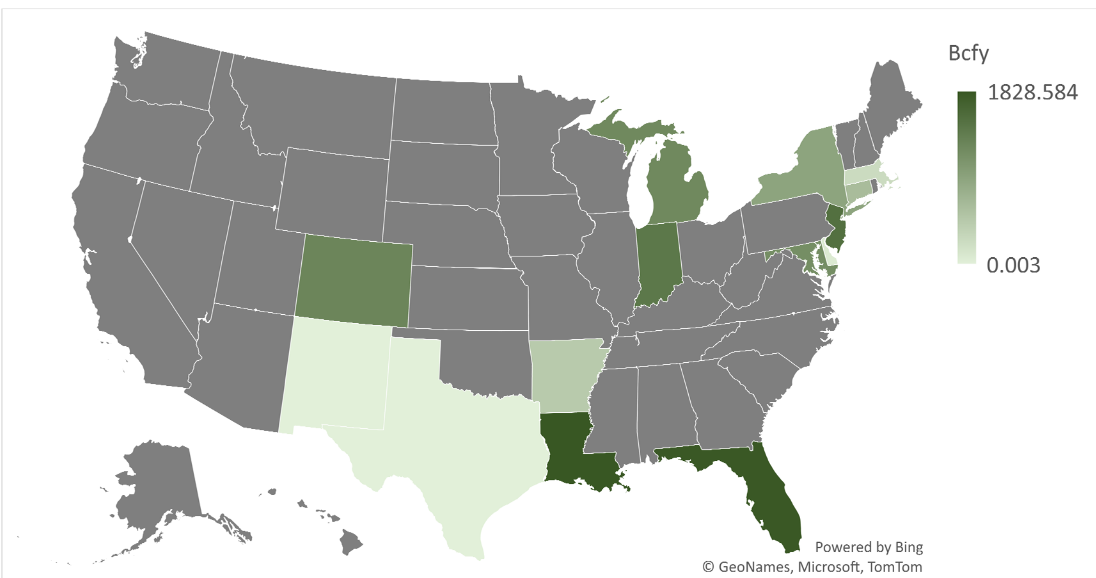

By volume, Pennsylvania and Alabama are the largest net exporters of natural gas to destinations outside of the Appalachian region, whereas Mississippi, Kentucky, and Virginia are the region's largest importers of natural gas from locations outside of the region (Exhibit 5-2). Within the United States, Louisiana and Florida are the largest recipients of natural gas from the Appalachian region (Exhibit 5-3).

***Exhibit 5-2. Appalachian states annual natural gas net exports to destinations outside of the region (2020)***



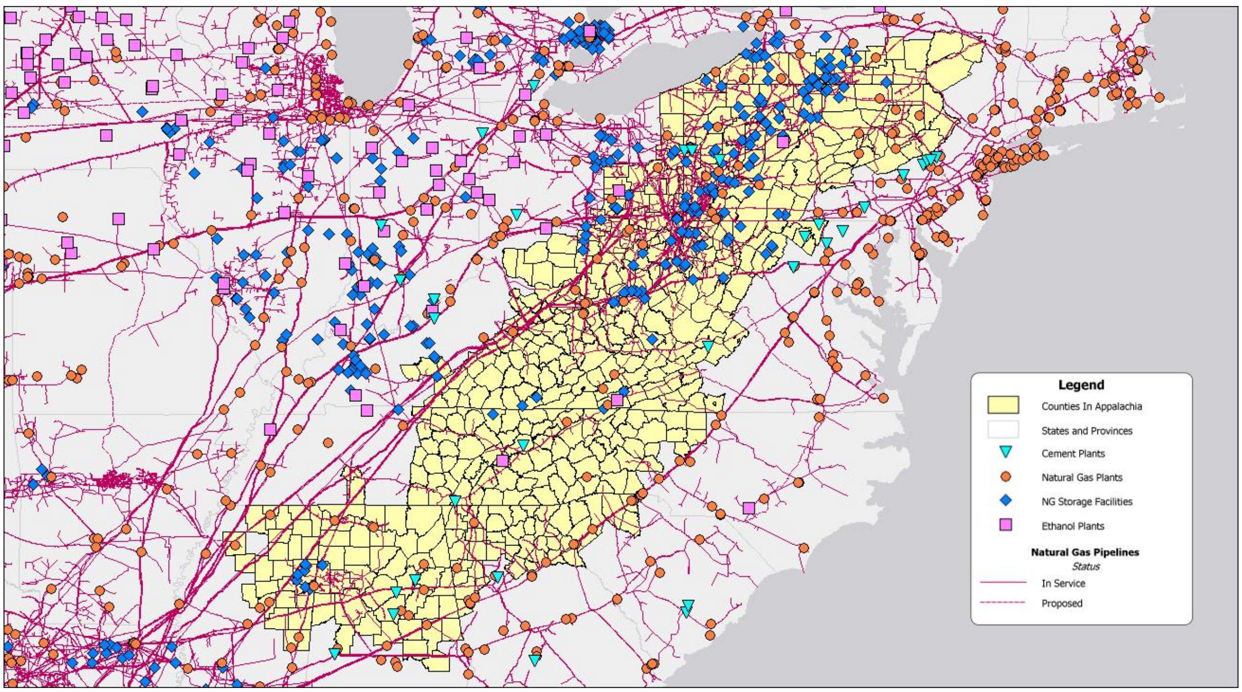

However, Exhibit 5-3 also shows that Illinois, New Jersey, Michigan, and Colorado were major importers of natural gas from the Appalachian region. Colorado, in particular, is a key point in natural gas distribution throughout the western United States.

***Exhibit 5-3. Interstate recipients of Appalachian natural gas (2020)***




Within Appalachian counties, the primary use of natural gas is electricity generation. Exhibit 5-4 shows the complex natural gas infrastructure, along with natural gas power plants and gas storage throughout and surrounding Appalachia. In addition to the region's production, the Appalachian corridor has a major natural gas pipeline network with over 45 processing plants that process 13.7 Bcfd (5,000 Bcfy). [1] Exhibit 5-4 shows that the Marcellus and Utica plays have become a central point for natural gas distribution in the eastern half of the United States, with connections westward. The Appalachian region can deliver natural gas and has the potential to deliver hydrogen-blended natural gas or pure hydrogen to most of the major population and industry centers throughout the northeast and Midwest. Major pipelines run across the eastern border from the Gulf Coast, feeding numerous power plants along the eastern seaboard. There is also significant infrastructure centered in north-central Appalachia surrounded by significant capacity of storage and natural gas power plants. The pipeline and storage infrastructure throughout Pennsylvania, along with production capacity, allow it to be a major exporter to the north, west, and west.

***Exhibit 5-4. Natural gas pipelines, power plants, and storage in Appalachia***



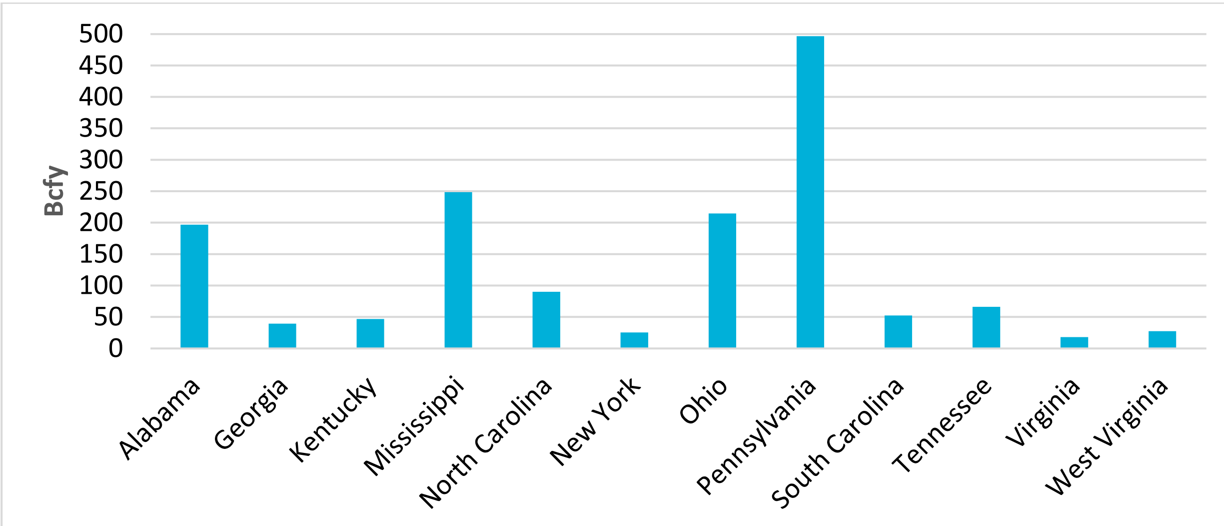

*Source: Hitachi Energy Velocity Suite [1]*

Exhibit 5-5 [166] and Exhibit 5-6 show 2020 natural gas consumption for counties listed in ARC's 2009 Subregions of Appalachia classification.[m] [165] State groupings reported in both exhibits are only inclusive of ARC identified Appalachian counties. The exhibits indicate natural gas consumption for electricity and commercial, industrial, and residential use makes up only 4.4 Bcfd (1,608 Bcfy) in the Appalachian region. Of the natural gas that is utilized in the Appalachian region, 94.6 percent is used to generate electricity. While using hydrogen from natural gas for electricity production is exceedingly expensive as a source of clean energy due to the added capital and operating costs to convert the methane to hydrogen and capture carbon—as opposed to just capturing carbon from natural gas—using hydrogen as a replacement for

[m] On November 15, 2021, U.S. Congress signed Public Law 117-58, which added Catawba and Cleveland County in North Carolina and Union County in South Carolina. The report and analysis were drafted prior to the addition of these counties and use the 2009 subregional definitions.

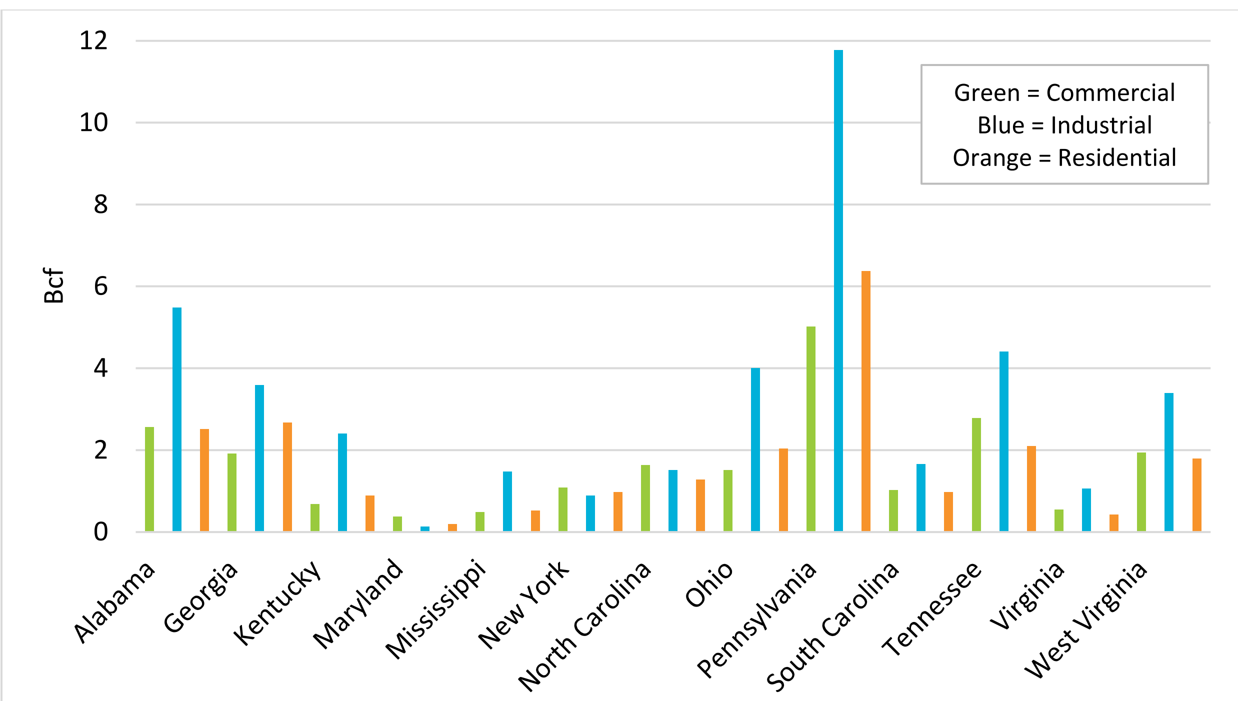
natural gas for industrial consumption for heat and power, while more expensive, can help industries that have made decarbonization goals reach those goals.

***Exhibit 5-5. Natural gas consumption for electricity production in the Appalachian counties clustered by state (2020) [166]***




Industrial natural gas use makes up 48.5 percent of the non-electricity natural gas consumption, with residential and commercial nearly split with 26.4 percent and 25 percent, respectively. The Pennsylvania counties in the Appalachian region accounted for the largest consumers in all three consumption categories (Exhibit 5-6). [1]

***Exhibit 5-6. Natural gas consumption for commercial, industrial, and residential users in the Appalachian region***



With nearly 4.41 Bcfd (3,400 Bcfy) more produced than consumed, the region has ample natural gas production and reserves to produce fossil-derived hydrogen with CCS to meet industrial energy demands currently being met by natural gas.

In addition to natural gas being produced in the shale regions, the Appalachian region has ample biomass that can be converted to renewable natural gas. Exhibit 5-7 and Exhibit 5-8 highlight the potential to use agricultural feedstocks like hybrid poplar and willow, and forest residues, respectively, as feedstocks to produce hydrogen through biomass gasification.

***Exhibit 5-7. Agricultural biomass in Appalachia at $60/dry tonne (dt) [167]***

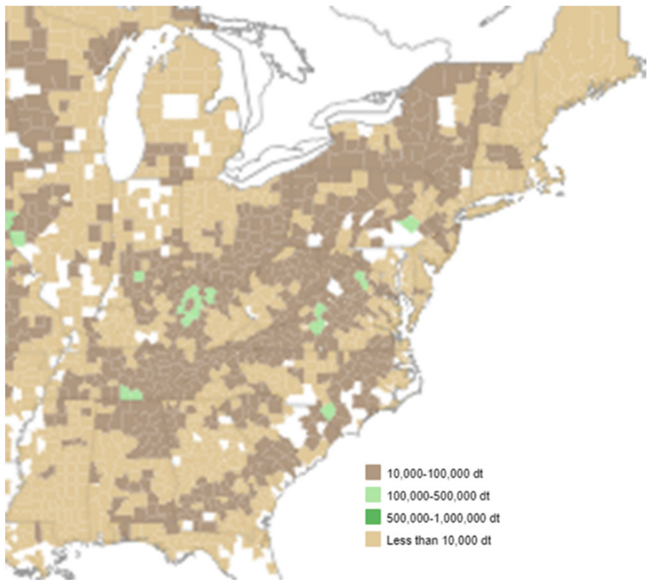
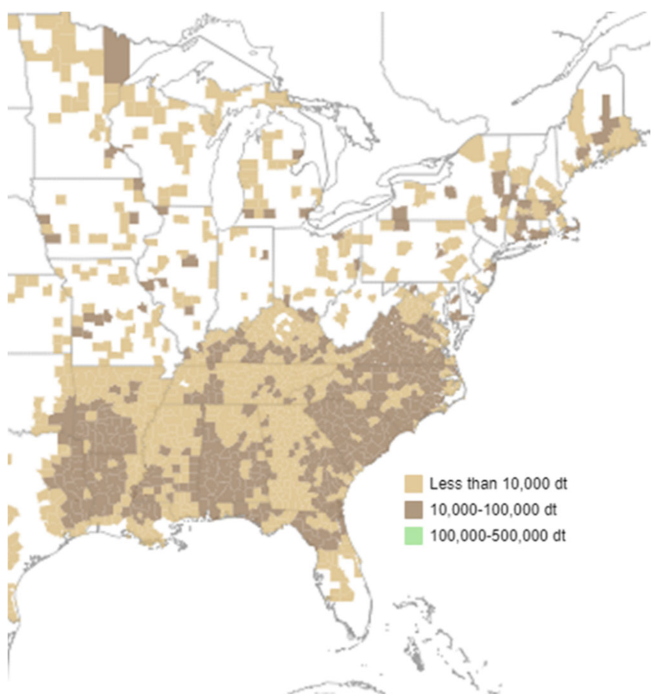



***Exhibit 5-8. Forestry biomass in Appalachia at $60/dt [167]***



## 5.2 Hydrogen Production

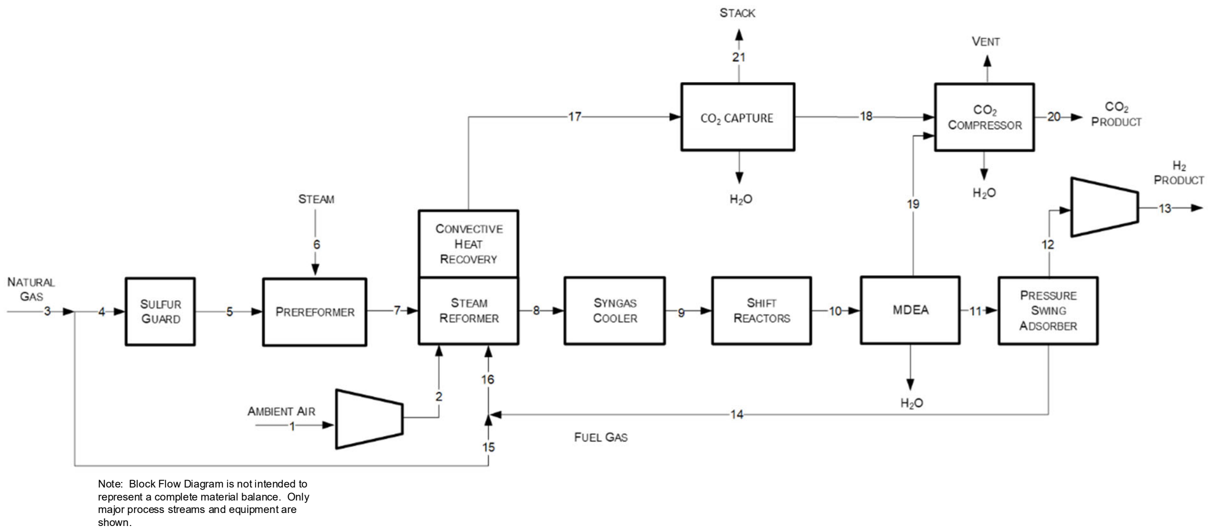
Fossil-derived hydrogen with CCS is hydrogen produced from natural gas, with the capture and permanent storage of process $CO_2$ emissions. This natural gas is converted into hydrogen and $CO_2$ through a variety of processes, including SMR and ATR. While this section only details hydrogen production pathways for which NETL has performed thermodynamic modeling and technoeconomic analyses, other routes such as partial oxidation (POx) and pyrolysis of methane are also being viewed as commercially relevant. The SMR plant production capacity modeled is 200 million standard cubic feet per day (MMscfd) to maximize economies of scale with a single-reactor arrangement. This capacity reflects the upper range of commercially operating SMR plants today. The single-train design capacity of ATR with CCS, unconstrained by the scale-up limitations inherent to SMR, matches the hydrogen production output of the coal gasification cases and results in a hydrogen production rate of 274 MMscfd. This capacity falls within the expected plant sizes of the projects under development. [168] NETL is modeling fossil-derived hydrogen with CCS systems that use pressure swing absorption (PSA) to purify hydrogen with different carbon capture rates as described in Exhibit 5-9.

***Exhibit 5-9. NETL fossil-derived hydrogen with CCS processes using SMR and ATR***

| Feedstock | Reformer Type | Natural Gas Consumption | $H_2$ Purification | Hydrogen Production Capacity | $CO_2$ Capture Rate | $CO_2$ Captured Mass Flow Rate |
|---|---|---|---|---|---|---|
| Natural Gas | SMR | 166,387 lb/hr | PSA | 44,369 lb/hr | 96.2% | 424,198 lb/hr |
| | ATR | 213,694 lb/hr | | 60,627 lb/hr | 94.5% | 534,424 lb/hr |

Most hydrogen production in the United States is from natural gas SMR. Natural gas is first reformed with steam at high temperatures (700–800°C) with a nickel catalyst, followed by supplementary steps to achieve the desired product composition and purity. These combined steps can deliver, on average, an 80 percent hydrogen yield or higher at 99.99–99.9999 percent purity. By products from the SMR process include water ($H_2O$), $CO_2$, nitrogen ($N_2$) and Argon. A high-level diagram of one potential configuration of the SMR process is shown in Exhibit 5-10.

***Exhibit 5-10. Block flow diagram, sample SMR plant with $CO_2$ capture***




ATR uses oxygen and $CO_2$ or steam in a reaction with methane to form syngas, primarily a mixture of $H_2$ and CO. The reaction takes place in a single chamber where the methane is partially oxidized. The reformer itself comprises a refractory-lined vessel that contains the catalyst, together with an injector located at the top of the vessel. The reaction is exothermic due to the oxidation. Exhibit 5-11 shows the ATR process. The primary difference between ATR and SMR is that SMR does not use or require oxygen. The advantage of ATR is that the ratio of hydrogen to CO can be varied without the secondary step needed in SMR, which makes it intriguing for a variety of applications. Further, with the incorporation of carbon capture, the ATR has one stream from which to capture $CO_2$, whereas the SMR has two, yielding ATR units that are slightly more cost effective in producing fossil-derived hydrogen with CCS than SMR units at the scale the two technologies were modeled.

***Exhibit 5-11. Block flow diagram, sample ATR plant with $CO_2$ capture***

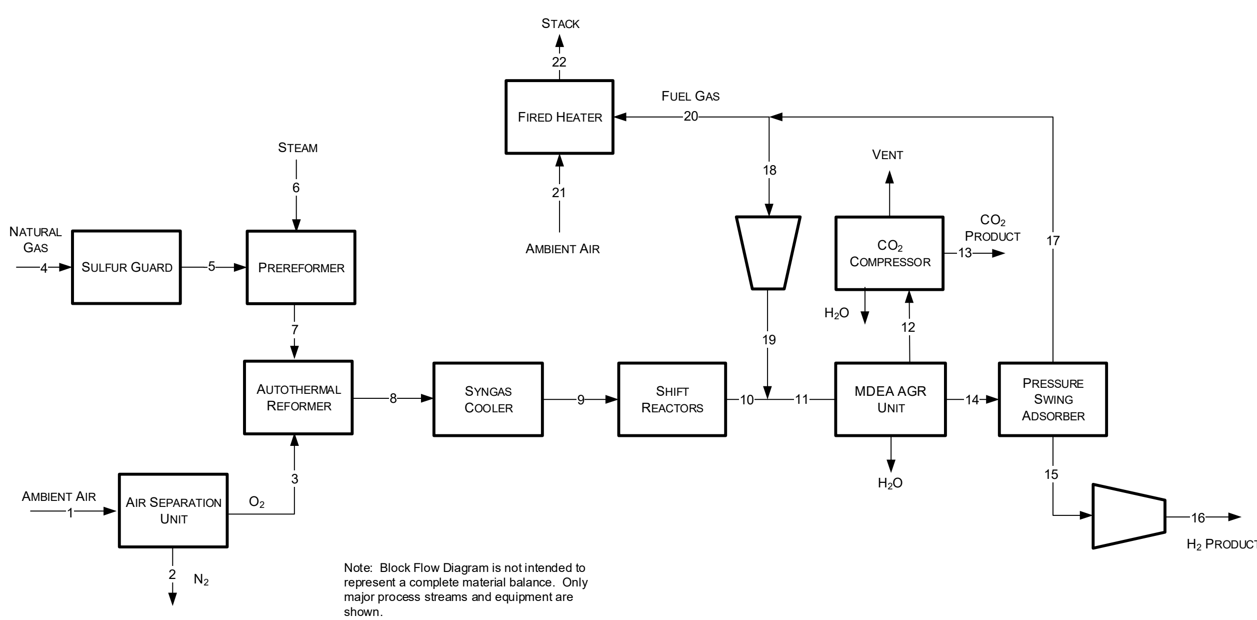


Exhibit 5-12 shows that Appalachian region industrial consumers used over 1.7 Tcf of natural gas in 2020. [169] If the 1.7 Tcf of industrial natural gas consumption in Appalachian states were split evenly between SMR and ATR production pathways, with attributes as shown in Exhibit 5-9, it would require 27 SMR and 21 ATR plants to consume the quantity of natural gas; producing 9.81 Mtonnes of hydrogen annually, capturing 0.90 gigatonnes (Gtonnes) of $CO_2$ annually. As discussed in Section 5.3.2, the Eastern United States (Appalachian, Midwest, and Southeast storage regions) has ample low-cost $CO_2$ storage capacity to store 0.90 Gtonnes annually.

***Exhibit 5-12. 2020 natural gas delivered to Appalachian region industrial consumers, by state [169]***

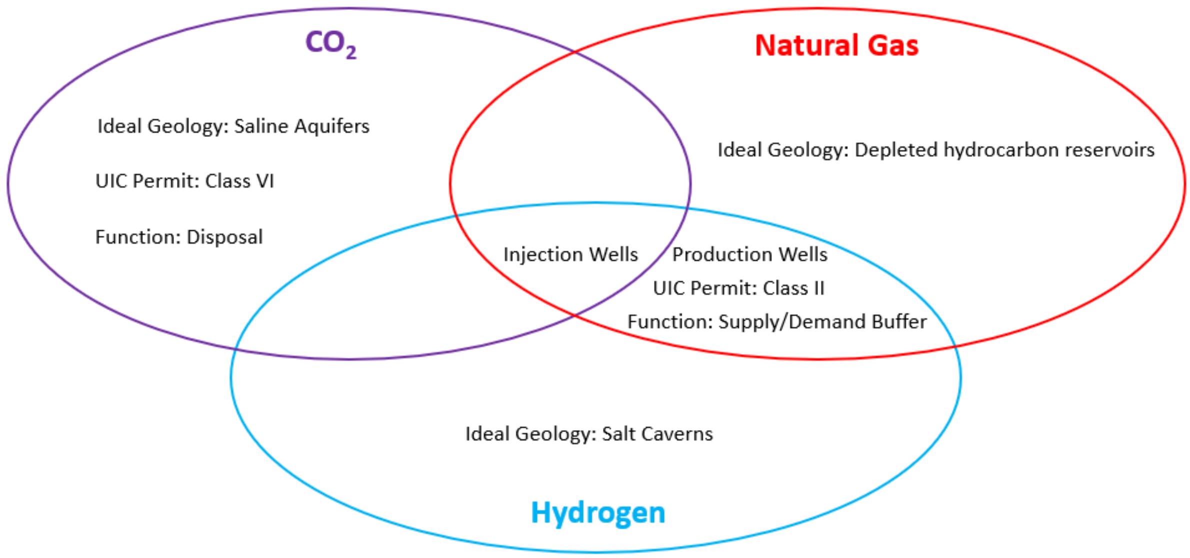
| State | Natural Gas Delivered to Industrial Consumers (MMcf) |
|---|---|
| Alabama | 207,207 |
| Georgia | 152,810 |
| Mississippi | 131,219 |
| South Carolina | 95,145 |
| North Carolina | 115,346 |
| Kentucky | 116,778 |
| Tennessee | 145,855 |
| Virginia | 104,257 |
| West Virginia | 34,950 |
| Ohio | 282,004 |
| Pennsylvania | 215,664 |
| New York | 86,401 |
| Maryland | 17,069 |
| Appalachia | 1,704,705 |

## 5.3 Natural Gas, Hydrogen, and $CO_2$ Storage Potential

An Appalachian hydrogen economy supply chain includes aspects of subsurface (geologic) storage of hydrogen production feedstock (natural gas), hydrogen itself, and hydrogen production byproducts ($CO_2$). To discuss the Appalachian region's storage capacity potential for natural gas, hydrogen, and $CO_2$ storage, it is important to first compare the three types of storage.

Natural gas storage buffers relatively consistent natural gas supply with seasonal fluctuation in demand and is therefore critical for the operational health of the natural gas market, [170] and hydrogen production projects that utilize natural gas as a feedstock. Hydrogen storage would serve a similar supply-demand buffer role for the hydrogen market. [171] $CO_2$ storage disposal via geologic storage, necessary for hydrogen production projects that utilize CCS, on the other hand has no supply-demand buffer functionality. [170] Storage geology, permitting, function, and well requirements for natural gas, hydrogen, and $CO_2$ are compared in Exhibit 5-13.

***Exhibit 5-13. Venn diagram comparing natural gas, $CO_2$, and hydrogen storage***




Four aspects to consider when assessing geologic storage for natural gas, hydrogen, or $CO_2$ are containment, injectivity, capacity, and deliverability: the latter two aspects impact whether the storage best services peak or base demand. Three main types of geologic storage are prevalent in the United States: depleted hydrocarbon (natural gas and/or oil) reservoirs, saline aquifers, and salt caverns.

Depleted hydrocarbon reservoirs are ideal for natural gas storage because natural gas containment has been previously demonstrated (naturally, over geologic time), and because there is preexisting deliverability infrastructure and reservoir capacity characterization from previous oil and gas extraction operations. [172] Depleted hydrocarbon reservoirs are geographically restricted primarily to sedimentary basins with oil and gas accumulations. Depleted hydrocarbon reservoir caprock (typically mudstone) is ideal for natural gas containment, and in most cases, $CO_2$ containment; [170] however, it may not be ideal for hydrogen containment due to mudstone being relatively permeable to hydrogen. [171]

Saline aquifers are reservoirs containing water with greater than 10,000 parts per million total dissolved solids (i.e., not underground sources of drinking water). Saline aquifers have lower injectivity and deliverability relative to depleted reservoirs due to in situ formation fluids and pressure but generally have higher total field capacity and are, therefore, good for servicing base demand. [170] Saline aquifers are used for natural gas storage in areas where depleted hydrocarbon fields are geologically unavailable—notably, in the central Midwest Region of the United States.

Salt caverns are solution-mined voids in rock salt beds or caverns. Salt is highly impermeable to nearly any fluid; therefore, salt caverns offer the best containment of any geologic reservoir. Salt caverns are, therefore, ideal for natural gas, hydrogen, $CO_2$, and any other fluid (like oil). [171] Salt caverns offer significantly higher daily injectivity and deliverability (i.e., good for servicing peak supply and/or demand), relative to depleted hydrocarbon reservoirs, but generally have much lower total field capacity, since the caverns are man-made. [170] Salt caverns are geographically restricted to regions where bedded salt and salt caverns are geologically present, notably in the Gulf Coast region. [173]

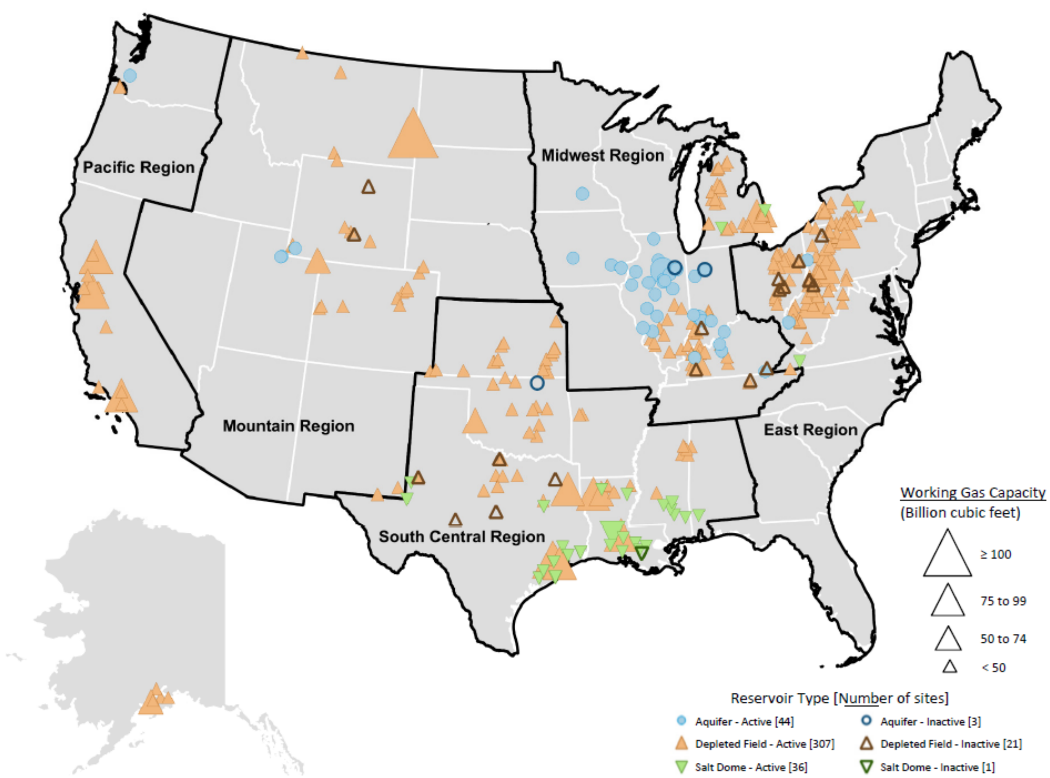
### 5.3.1 Natural Gas Storage Potential

Natural gas intermediate storage potential is critical to buffering supply and demand variations for hydrogen production pathways reliant on natural gas as a feedstock (as well as any infrastructure that uses natural gas for power, related to a hydrogen economy).

Nationally, according to 2020 U.S. natural gas storage data from EIA, there are 412 natural gas storage fields; 80 percent are depleted hydrocarbon fields, 11 percent are saline aquifers, and 9 percent are salt caverns. [174]

In the East Region (Exhibit 5-14), analogous to the Appalachian region in this report, there are 133 natural gas storage fields; 97 percent of the fields are depleted hydrocarbon fields, which contribute 99.5 percent of the total natural gas storage capacity in the region. Two natural gas storage fields operate in aquifers in the region (one in PA, one in WV); two natural gas fields operate in salt caverns in the region (one in New York, one in Virginia). [174]

***Exhibit 5-14. U.S. underground natural gas storage facilities, by type and working gas capacity (December 2020)***




*Source: EIA [175]*

The Appalachian region has significant natural gas intermediate storage capacity (24 percent of the total U.S. natural gas storage capacity in 2019) [175], operated primarily in depleted hydrocarbon reservoirs, to buffer any natural gas supply and demand variations associated with a hydrogen economy.

It is important to reiterate that the Appalachian region's depleted natural gas storage reservoirs are not candidates for intermediate hydrogen storage (Exhibit 5-13).

## 5.3.2 $CO_2$ Storage Potential

$CO_2$ storage in the United States that would be associated with the hydrogen economy is assumed to utilize saline aquifers. Depleted hydrocarbon reservoirs and salt caverns are assumed to be unavailable for $CO_2$ storage due to their existing high demand for more economical natural gas storage projects, and in the case of salt caverns, intermediate storage of other commercial fluids (e.g., ethane, oil, hydrogen).

To calculate the $CO_2$ storage potential in Appalachia and its surrounding regions, the FECM/NETL $CO_2$ Saline Storage Cost Model ("CO2_S_COM") was used. CO2_S_COM is a techno-economic model for a $CO_2$ saline storage project. [176] The model includes all the activities and costs associated with $CO_2$ saline storage including 1) selecting and characterizing the site; 2) designing the $CO_2$ injection well system, designing the system to monitor the evolution of the $CO_2$ plume and check for leaks, and obtaining the necessary permits; 3) drilling wells and installing monitoring equipment; 4) injecting $CO_2$ and implementing the monitoring program; 5) ending $CO_2$ injection and plugging injection wells; 6) implementing the post-injection site care plan, which involves continued monitoring; and 7) closing the site after the regulatory authority issues a finding of non-endangerment. [177] The model includes the costs needed to comply with the U.S. Environmental Protection Agency (EPA) Underground Injection Control (UIC) Class VI regulations and with Subpart RR of the Greenhouse Gas Reporting Rule. This model includes the costs (such as a trust fund or insurance) to comply with the financial responsibility requirements of the Class VI injection well regulations. [177]

CO2_S_COM is a cash flow model that assumes the site operator sets a price in the first year of the project for injecting $CO_2$. This price is multiplied by the average annual rate of $CO_2$ injection to give the annual revenues for the project. Additional cash flows include capital costs and O&M costs. These cash flows are initially determined in constant or real dollars and then escalated to nominal dollars. The nominal capital costs are depreciated, and taxes are calculated. Nominal earnings after debt payments are revenues minus capital costs, O&M costs, taxes, and principal and interest payments on debt. The nominal earnings after debt payments are discounted using the minimum desired internal rate of return on equity as the discount rate to give cash flows in present value dollars. These present value cash flows are summed to give the net present value for the project. If net present value for the project is greater than zero, the price charged for storing $CO_2$ is high enough to bring in sufficient revenue to offset all costs including financial costs and give equity investors their desired minimum rate of return. The lowest price a $CO_2$ saline storage operator can charge and still have a viable project (if just barely viable) is the $CO_2$ price that results in the net present value of the project equal to zero. This very informative metric is referred to as the first-year break-even $CO_2$ price.

The costs of a $CO_2$ storage project and its first-year break-even $CO_2$ price depend on variables, such as the $CO_2$ plume area and number of injection wells, which depend on the geologic properties of a potential storage formation. CO2_S_COM has geologic data for 314 storage formations in the lower 48 states. The geologic data includes the surface area, depth to the top, thickness, porosity, and permeability of each storage formation. These formations cover large areas: 90 percent of the formations exceed 1,450 square miles ($mi^2$), 50 percent of the formations exceed 6,900 $mi^2$, and 10 percent of the formations exceed 23,000 $mi^2$. For perspective, the average area of a county in the United States is about 1,100 $mi^2$. In addition to calculating variables that depend on geology and are project-specific, CO2_S_COM also estimates the maximum mass of $CO_2$ that can be stored in the entire $CO_2$ saline storage formation (also known as its storage capacity). Most storage formations can store the $CO_2$ mass associated with multiple $CO_2$ injection projects.

These formations were placed into one of seven storage regions: Appalachian, Midwest, Southeast, Southwest, Williston, Northwest, and California. Exhibit 5-15 shows the delineation of regions, using the United States Geological Survey (USGS) National Oil and Gas Assessments' province outlines [178] to guide boundary selection. The data presented in Exhibit 5-15 indicates that all storage formations but one are within one of these seven storage regions.[n]

***Exhibit 5-15. Storage centroids in the seven storage regions***

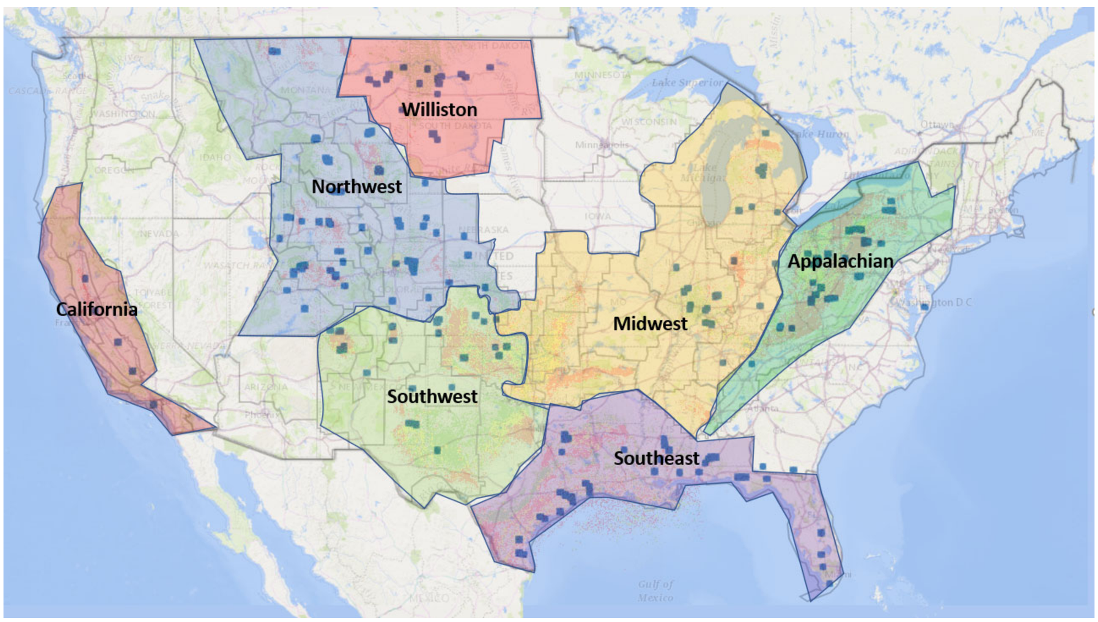
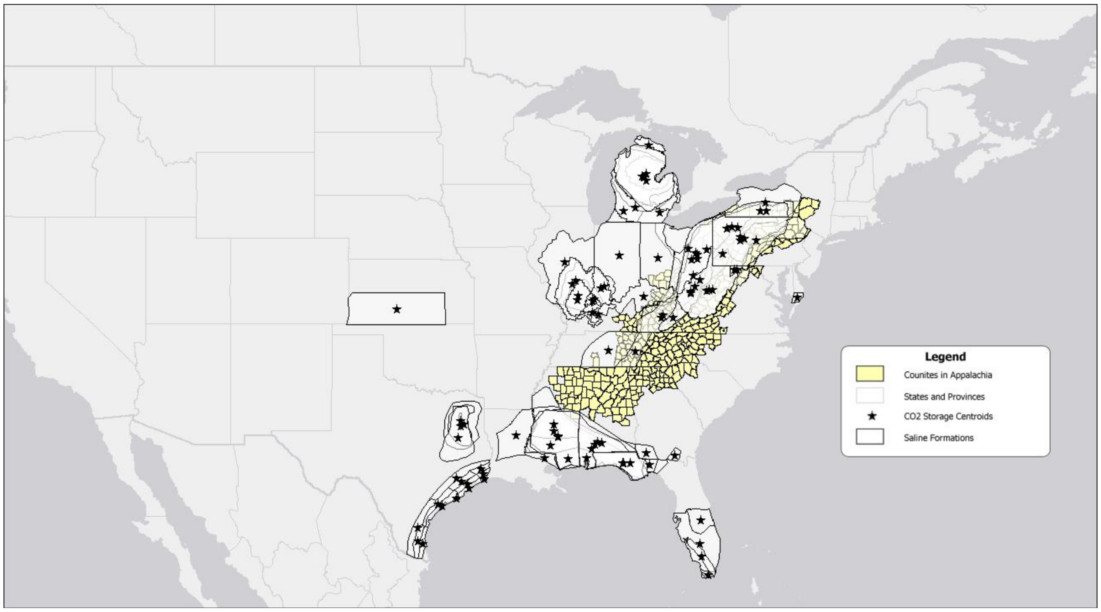



Exhibit 5-16 overlays maps of Appalachian region counties [179] and potential $CO_2$ storage formation geographic centroids in and near the Appalachian region [176] to demonstrate the abundance of candidate $CO_2$ storage formations. Each formation can potentially host multiple $CO_2$ storage sites.

[n] This is the storage formation along the eastern seaboard in Maryland, near Delaware, which was included in the "Appalachian storage region."

***Exhibit 5-16. Storage centroids in and around the Appalachian region***




CO2_S_COM was used to analyze all the potential saline aquifer storage formations in the model's database to estimate the storage capacity in each formation and the first-year break-even $CO_2$ price of storage in each formation. In the analysis, a storage project was evaluated with the following characteristics. The project would inject 4.5 million metric tons (Mtonnes)/year for 30 years with a capacity factor of 90 percent, which yields a maximum $CO_2$ mass flow rate of about 5 Mtonnes/year—consistent with the maximum $CO_2$ mass flow rate in the National Energy Technology Laboratory (NETL) baseline studies for carbon capture from coal-fired power plants. [180] Injecting 4.5 Mtonnes of $CO_2$ each year for 30 years results in 135 Mtonnes of $CO_2$ being stored. It was assumed that the maximum size of a $CO_2$ project is 1,000 $mi^2$.

To derive total storage capacity in each formation, a pressure interference correction based on the work of Teletzke et al., (2018) [181] was performed during post-processing of CO2_S_COM results. When a storage project begins injecting $CO_2$, the injection starts to increase the pressure in the formation. Pressures will increase over time and eventually stabilize. According to the Class VI injection well regulations, $CO_2$ injection wells must maintain pressures in the injection formation below 90 percent of the fracture pressure, which is a localized property of the formation. Pressure increases propagate faster and farther than the propagation of the $CO_2$ plume. If multiple $CO_2$ injection projects are implemented in the same storage formation at the same time, the pressure increases from the different projects will propagate and be observed at nearby $CO_2$ storage projects increasing the pressure at these nearby projects. This effect of a $CO_2$ storage project affecting the pressure at a nearby $CO_2$ storage project is referred to as pressure interference in this report. If the projects are operating with pressures near the maximum allowed pressure, this presents an issue to the $CO_2$ storage projects. The projects could all reduce their injection rates to keep the pressures under the allowable pressure or basin-scale management could be imposed that limits the number of projects that can be implemented in the same storage formation at the same time. In this study, it was assumed the latter approach is implemented with each storage project injecting $CO_2$ at their design rate with minimal pressure influence from other projects operating in the same storage formation. A pressure interference correction factor was calculated using documented permeability values for each formation in the CO2_S_COM geologic database, and calculations from Teletzke et al., (2018) [181] to reduce the maximum storage capacity in a storage formation to an effective pressure influenced storage capacity.

Exhibit 5-17 summarizes the total potential $CO_2$ storage capacity and the number of formations that host this capacity in each of the storage regions within the United States. The storage capacity is first presented without considering pressure interference and then considering the possible effect of pressure interference; the latter being a more applicable, but conservative, storage capacity to consider since it accounts for multiple storage projects within the same formation able to operate at economical injection rates. When accounting for pressure interference, the estimated total storage capacity in the lower 48 states is approximately 764 Gtonnes; the Eastern U.S., consisting of the Appalachian, Midwest, and Southeast storage regions, accounts for 266 Gtonnes of total $CO_2$ storage capacity. Storage capacity results by individual formation are provided in Exhibit A-1 in the Appendix: FECM/NETL $CO_2$ Saline Storage Cost Model Formation Results.

***Exhibit 5-17. $CO_2$ storage capacity with and without pressure interference by storage region***

| Broad Region | Storage Region | Regional Dip Structure, Without Pressure Interference Correction | | Regional Dip Structure, with Pressure Interference Correction | |
|---|---|---|---|---|---|
| | | Total $CO_2$ Storage Capacity by Formation-Structure Combo (Gtonnes) | Saline Storage Formation Count | Total $CO_2$ Storage Capacity by Formation-Structure Combo (Gtonnes) | Saline Storage Formation Count |
| Eastern U.S. | Appalachian | 60 | 33 | 4 | 16 |
| | Midwest | 337 | 29 | 66 | 25 |
| | Southeast | 564 | 43 | 196 | 41 |
| | *Subtotal* | *961* | *105* | *266* | *82* |
| Western U.S. | Southwest | 1,030 | 54 | 141 | 47 |
| | Williston | 350 | 19 | 55 | 18 |
| | Northwest | 599 | 91 | 86 | 75 |
| | California | 639 | 33 | 216 | 33 |
| | *Subtotal* | *2,618* | *197* | *498* | *173* |
| **Contiguous U.S.** | **Total** | **3,579** | **302** | **764** | **255** |

Exhibit 5-18 shows the cumulative $CO_2$ storage capacity in the Eastern U.S. storage regions by state, accounting for the potential impact of pressure interference.

***Exhibit 5-18. Potential $CO_2$ storage capacity in Appalachian, Midwest, and Southeast storage regions, by state, accounting for potential impact of pressure interference***

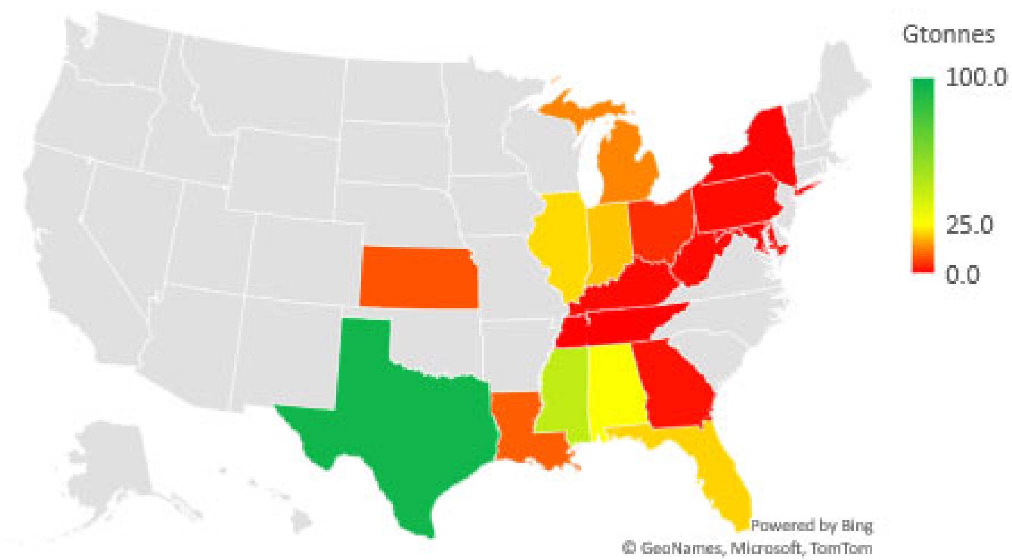
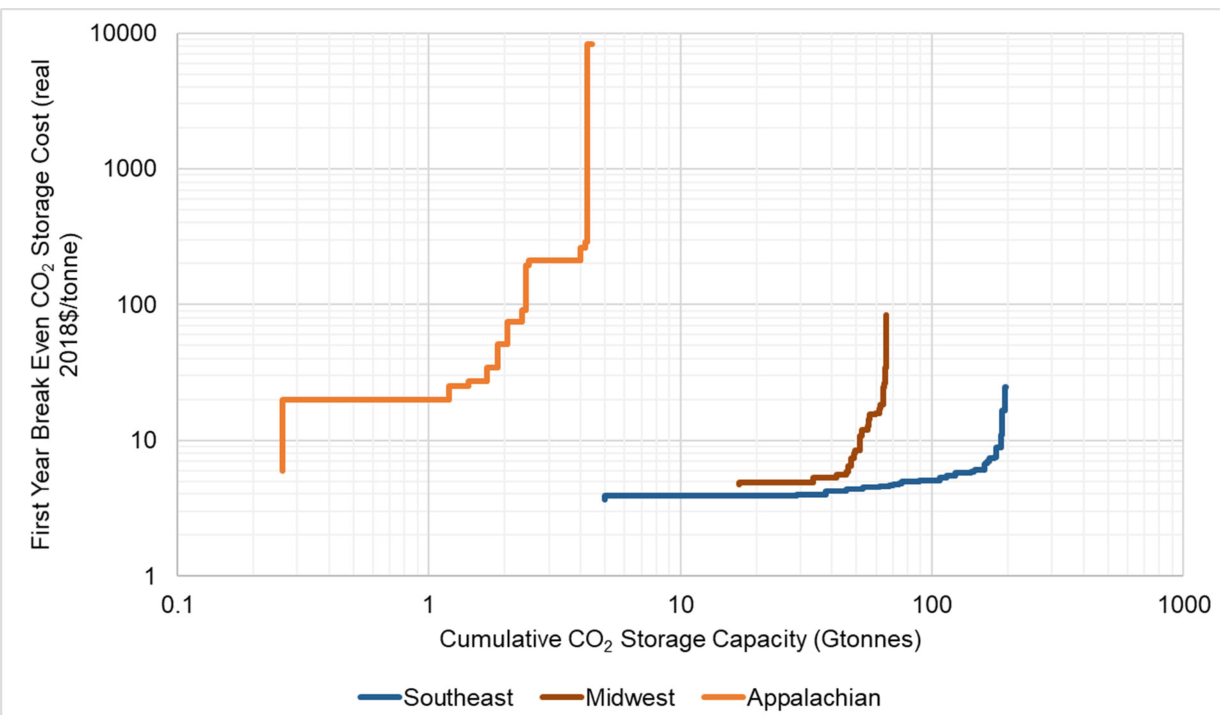



Exhibit 5-19 shows the cumulative $CO_2$ storage capacity that could be deployed in each of the three Eastern U.S. storage regions as a function of first-year breakeven storage cost on a 2018$/tonne basis. Storage cost results by individual formation are provided in Exhibit A-1 in the Appendix: FECM/NETL $CO_2$ Saline Storage Cost Model Formation Results.

***Exhibit 5-19. $CO_2$ storage capacity supply by storage region, accounting for potential impact of pressure interference***



Relative to the Midwest and Southeast, the Appalachian storage region does not itself offer much $CO_2$ storage capacity (only 4 Gtonnes, accounting for pressure interference; Exhibit 5-18), and that storage capacity is relatively high-cost (Exhibit 5-19). However, Appalachian region $CO_2$ emission point sources can leverage the adjacent Midwest and Southeast storage regions' ample low-cost $CO_2$ storage capacity; 240 Gtonnes of the 266 Gtonnes of total storage capacity in the Eastern U.S. is economical at $CO_2$ storage costs below $10 per tonne (in 2018$). High-capacity $CO_2$ trunklines could provide low-cost $CO_2$ transport options from multiple $CO_2$ emission point sources in the Appalachian region to low-cost $CO_2$ storage projects in the Midwest and/or Southeast storage regions. [182]

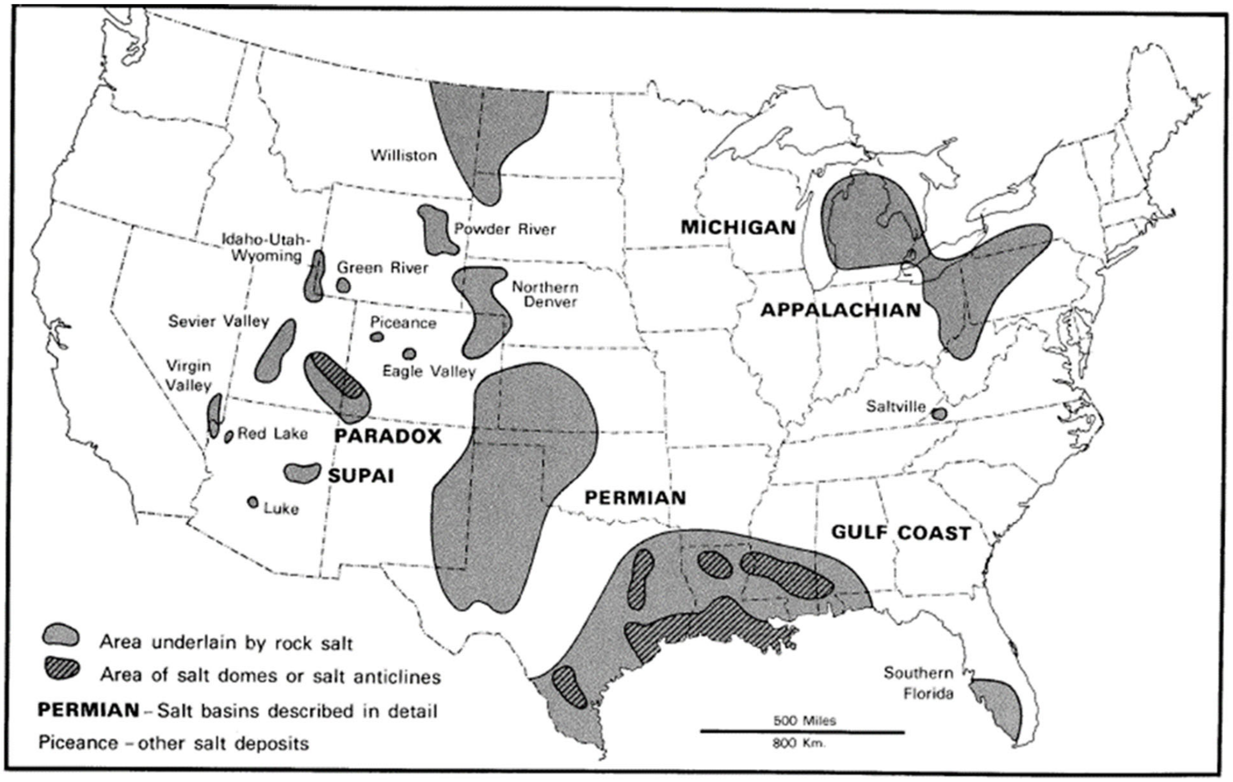
As discussed in Section 5.2 (Exhibit 5-12), the Appalachian region's industrial consumers used 1.7 Tcf of natural gas in 2020. [169] If that natural gas consumption were instead split evenly between SMR and ATR hydrogen production pathways that incorporated CCS (Exhibit 5-9), the resulting annual $CO_2$ capture rate in need of permanent storage would be 0.90 Gtonnes, therefore, as shown in Exhibit 5-17 and Exhibit 5-19, the Eastern U.S.'s Appalachian, Midwest, and Southeast storage regions have ample low-cost $CO_2$ storage capacity.

### 5.3.3 Hydrogen Storage Potential

Intermediate (temporary) storage of hydrogen may be needed to buffer a hydrogen economy's hydrogen supply and demand during peaks of demand, or alternatively, periods of underproduction of hydrogen.

Small-scale intermediate hydrogen storage can be accomplished with above ground steel tanks. For larger-scale intermediate hydrogen storage needs, subsurface salt beds or and/or salt structures, like diapirs or domes, are needed due to rock salt being the only rock type that can reliably contain hydrogen. [171] Nationally, rock salt is most abundant in the Gulf Coast, as shown in Exhibit 5-20 (equivalent to the Southeast storage region in Exhibit 5-15). Gulf Coast salt domes are used for intermediate storage of natural gas (see Exhibit 5-14) and oil.

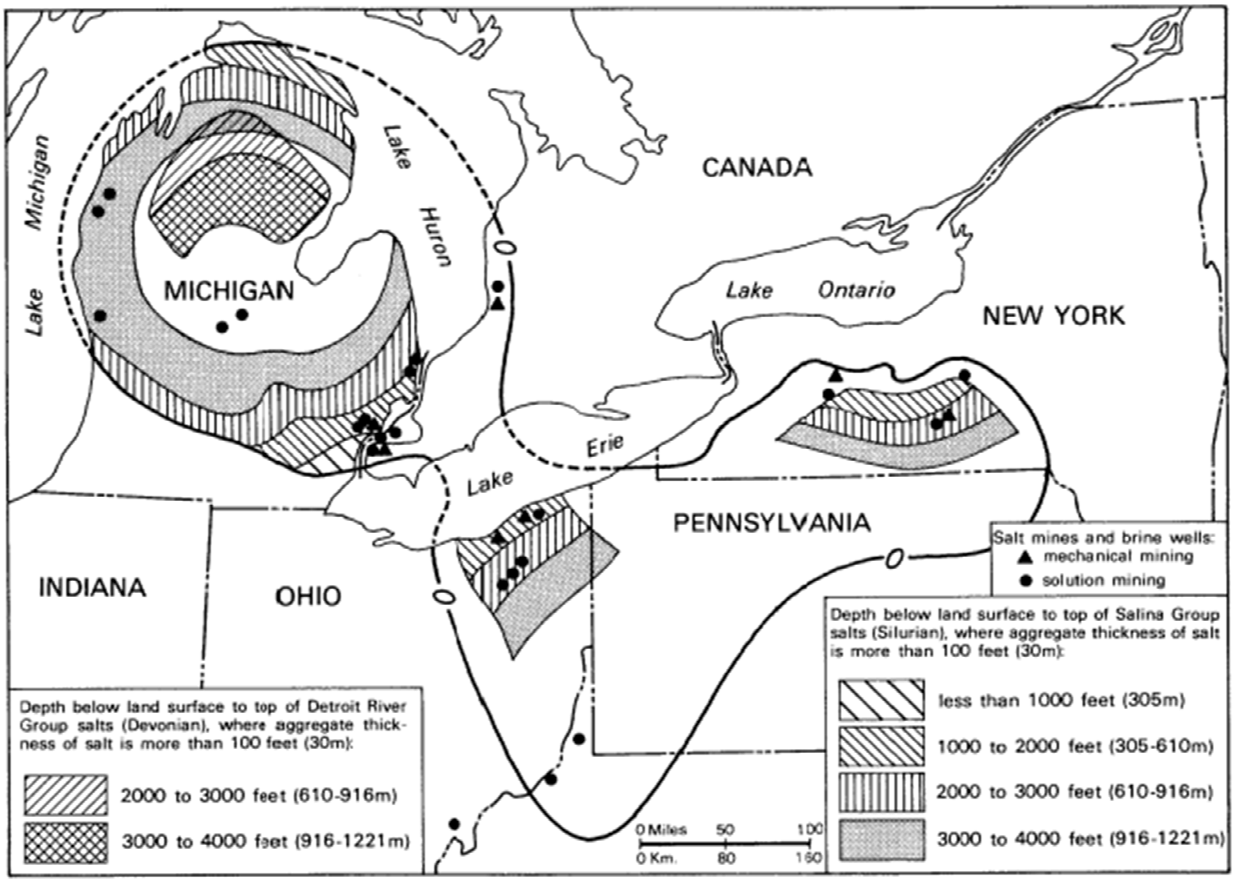
***Exhibit 5-20. Rock salt deposits in the contiguous U.S.***




*Source: Oak Ridge National Laboratory [171]*

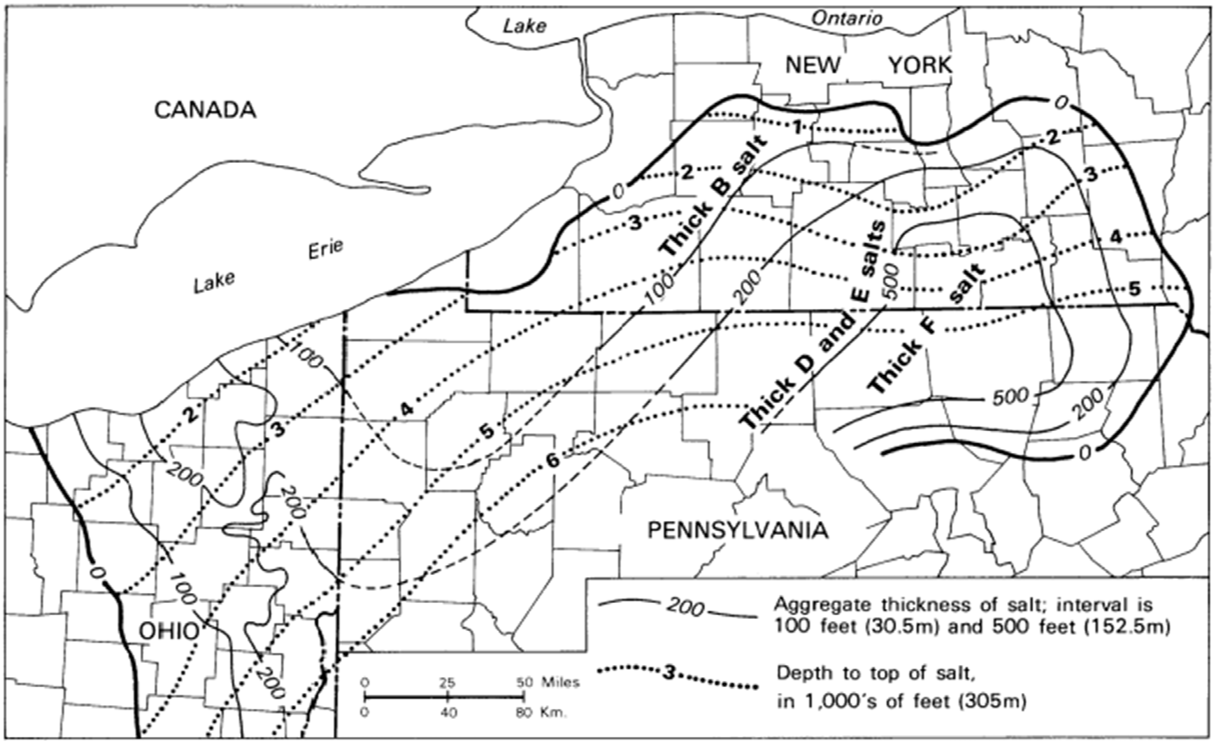
Locally, the Appalachian sedimentary basin and the Michigan sedimentary basin have underlying thick, homogenous, bedded salts, notably, the Silurian-aged salt deposits like the Salina Group and the Detroit River Group. [173] Salt beds are thick and homogenous enough to be utilized for hydrogen salt cavern storage in parts of New York, Michigan, and Ohio (Exhibit 5-21 and Exhibit 5-22), but could extend further (evidenced by solution mining, as shown by black circles in Exhibit 5-21) in parts of Ohio, Pennsylvania, and West Virginia.

***Exhibit 5-21. Distribution and depth of Silurian and Devonian salt deposits in Michigan, New York, Ohio, and Pennsylvania***




*Source: Oak Ridge National Laboratory [173]*

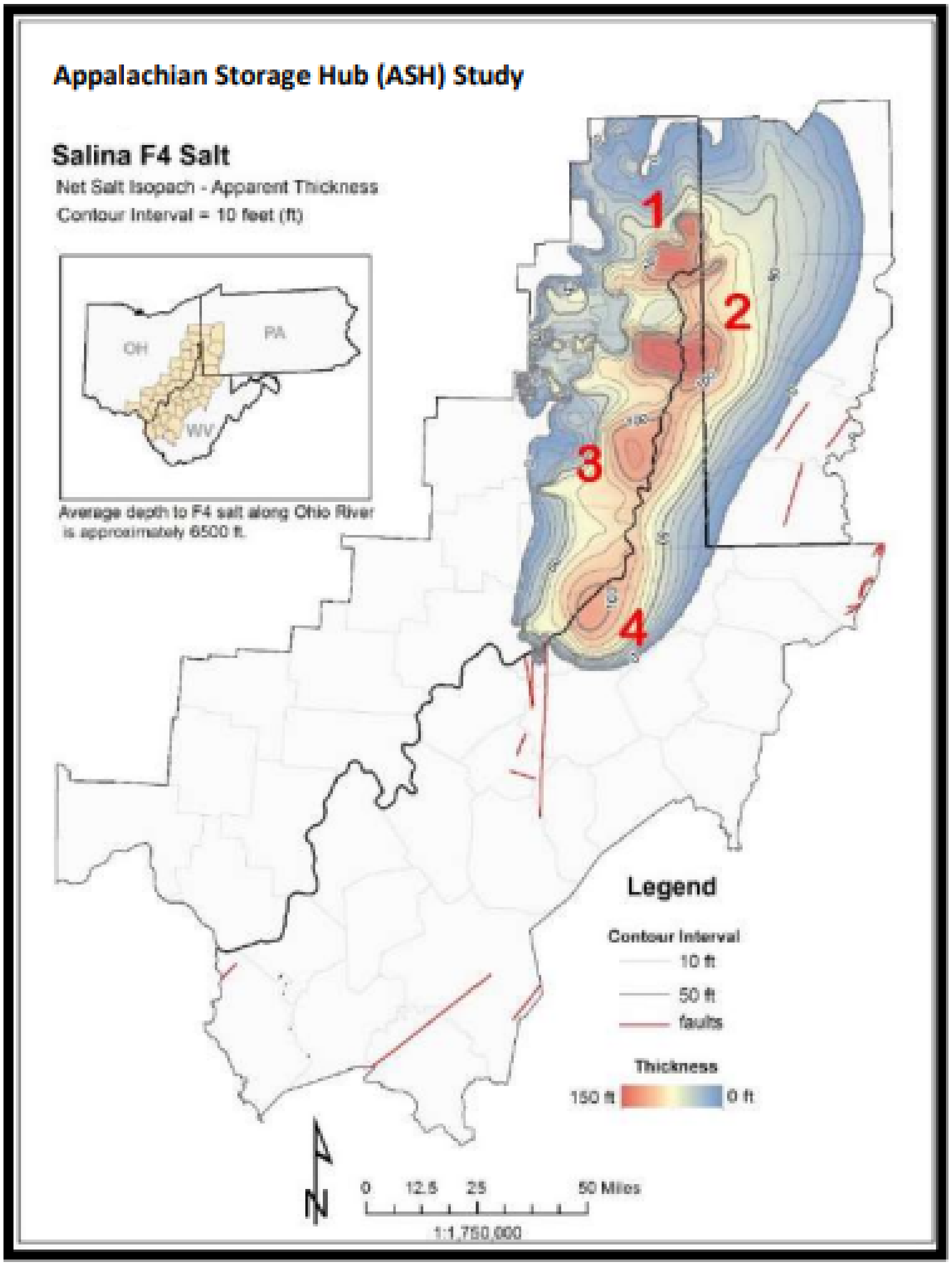
***Exhibit 5-22. Map of aggregate thickness and depth to Salina Group's B, D, and E, and F salt beds in the Appalachian basin***




*Source: Oak Ridge National Laboratory [173]*

An example of salt bed prospecting for storage in the Appalachian sedimentary basin is the Appalachian Storage Hub Study, which assessed the tristate region (Ohio, Pennsylvania, and West Virginia) for natural gas liquid (e.g., ethane) storage potential. [183] The Appalachian Storage Hub Study demonstrated the Salina F4 salt along West Virginia's northern panhandle had the net thickness (greater than 100 feet) and well-defined lateral extent needed for vertically and laterally confined salt cavern development (Exhibit 5-23). Salt cavern prospects number 1 and 2 ranked among the top prospects for ethane storage. [183]

***Exhibit 5-23. Four salt cavern storage prospect areas in the Tristate area based on Salina F4 salt net thickness greater than 100 feet***




*Used with permission from Appalachian Oil & Natural Gas Research Consortium* [183]

Bedded salt prospects in the Appalachian and Michigan sedimentary basins are the likeliest nearby options for large-scale intermediate storage of hydrogen, [173] if needed for a hydrogen economy centered in the Appalachian region and its surrounding areas. The scale of intermediate storage needed depends on the variations anticipated between hydrogen peak demand and peak production potential. [171]

## 5.4 END USE MARKETS FOR HYDROGEN AND CO-PRODUCTS

The market for hydrogen will be driven by federal, state, and corporate decarbonization targets. Currently, there are thousands of industrial boilers in the ethanol, cement, steel, agricultural processing, and many other industries that currently use fossil fuels to power their boilers; these are prime areas for hydrogen to be deployed as a low-emissions replacement. Additionally, hydrogen has potential use-cases in power generation (as a means to bridge intermittent renewable generation) and transportation, as well as residential commercial/heating.

### 5.4.1 Replacement of Fossil-fuel Generated Process Heat with Hydrogen

The demand for hydrogen continues to steadily rise as potential use cases increase and the call for decarbonization becomes increasingly more prevalent. Hydrogen is a versatile fuel that offers ways to decarbonize a range of sectors by generating high-quality industrial heat. In industries that produce glass, cement, iron, and steel, a considerable amount of energy is used to create the high-temperature environments needed to produce these products. Currently, hydrocarbons are used to generate this heat, burdening these industries with large carbon footprints. In the production of cement, 0.8 tons of $CO_2$ are generated for every ton of cement. [184] With about 4 B tons of annual cement production, this industry has a large carbon footprint. For steel production, 1.85 tons of $CO_2$ is produced per ton of steel. [185] Replacement of hydrocarbons with fossil-derived hydrogen with CCS (hydrogen from natural gas with CCS) for high-quality heat generation will allow these industries the opportunity to significantly reduce their carbon footprint without radically changing their existing process equipment. While there may be a higher associated operating expense involved with switching fuels, the capital expenses needed for this switch would be relatively low as opposed to other alternatives for these sectors, such as electrification. There also exists an opportunity for industrial facilities to use hydrogen to generate on-site electricity for back-up power applications, either through hydrogen combustion or fuel cells.

Industrial sector heavy industry (cement, steel, petrochemicals, glass and ceramics, and oil refining)—as defined in a Columbia University School of International and Public Affairs (SIPA) Center on Global Energy Policy report—produces roughly 22 percent of global $CO_2$ emissions, of which roughly 40 percent (about 10 percent of total emissions) is the direct consequence of fossil fuel combustion to produce high-quality heat. [30] Recognizing the crucial need for decarbonization of this sector, SIPA assessed possibilities for industrial/process heat decarbonization for these key industries through six main approaches, one of which is fossil-derived hydrogen with CCS:

- Hydrogen combustion, including hydrogen produced from fossil-fuels with carbon capture (fossil-derived hydrogen with CCS)
- Hydrogen combustion with hydrogen produced from electrolysis of water using renewable power (renewably sourced hydrogen)
- Biomass and biofuel combustion

- Electrical heating (including electrical resistance heating and radiative heating, e.g., microwaves)
- Nuclear heat production (including conventional and advanced systems)
- The application of carbon capture to fossil-fuel-based heat generating processes at industrial facilities with subsequent use or storage of the captured $CO_2$

The Columbia team also focused on substitutions and retrofits to existing facilities and on four primary concerns: cost, availability, viability of retrofit/substitution, and life-cycle footprint. Their findings may be summarized as follows: [30]

- Hydrogen combustion provides the readiest source of heat of all the options assessed, is the simplest to apply (including retrofit), and is the most tractable according to life-cycle basis. Today, hydrogen produced from reforming natural gas and decarbonized with CCS (fossil-derived hydrogen with CCS) has the best cost profile for most applications and the most mature supply chain compared to the other options noted above.
- Most substitute supply options for low-carbon heat appear more technically challenging and expensive than retrofits for CCUS. CCUS would have the added benefits of being immediately actionable, and of capturing emissions from by-product industrial chemistry, which can represent 20–50 percent of facility emissions and would not be captured through heat substitution alone.
- All approaches have substantial limitations or challenges to commercial deployment, mainly in terms of difficulty of substitutions (especially steelmaking, due to emissions inherently being a product of the chemical reactions to make steel), increase of production costs and price of products, and uncertainty about life-cycle carbon footprints or efficiency of unconventional heat sourcing.
- Most of the other options, such as electrification of industrial heat production, appear to add substantially to final production costs—commonly twice that of fossil-derived hydrogen with CCS substitution or CCUS—and are more difficult to implement.
- New policies specific to heavy industry heat and decarbonization are required to stimulate market adoption.

### 5.4.2 Replacement of Process Feedstocks

A unique feature of hydrogen is its chemical energy can be used to generate power or heat, but hydrogen's chemical energy also makes it a very reactive reagent for chemical conversions. Hydrogen is currently used by the petrochemical industries for chemical transformations, with hydrogen as a reactant to create higher value products. Hydrogen is also essential for hydrogenation of oil produced for food products. Because of its high reactivity, hydrogen will also play an important role in the conversion of $CO_2$ into valuable chemicals enabling effective recycling options for $CO_2$. In some of these applications, utilization of fossil-derived hydrogen with CCS represents replacement of a more carbon-intensive reagent with a less carbon-intensive reagent.

Certain industrial processes that have traditionally used carbon-intensive fossil fuels as process feedstocks can be supplanted by alternatives that use natural gas and increasing amounts of hydrogen, thereby allowing for significant decarbonization. The iron and steel industry are notable in this respect, using hydrogen as a reducing agent in the production of iron ores to produce iron and steel.

For example, the traditional iron and steelmaking route utilizes blast furnace (BF) and basic oxygen furnace (BOF) to reduce iron ore to iron and refine further into steel. The BF uses large quantities of coke made from coal as fuel, and results in 1,600–2,000 kg $CO_2$/ton steel. One alternative to the BF and BOF route is a natural gas process that reforms natural gas into a mixture of $H_2$ and CO (i.e., syngas), and directly reduces iron ore in a shaft furnace. This process is well established, and some plants have used rather high levels of hydrogen (~75 percent). Typically, this process reduces $CO_2$ emissions 50–80 percent over the traditional blast furnace and BOF. However, it is possible for the process to operate with 100 percent $H_2$ input that would reduce emissions still further. This necessitates suitable $H_2$ supply at competitive price (given the tight margins on iron and steel production economics). [186] Newer plants operating with this process are constrained by the available $H_2$ supply.

Hydrogen could also be used in the cement industry as a fuel providing high-grade heat cement kilns and in the ethanol industry through the use of hydrogen as a feedstock via the gas fermentation process [187]. As Exhibit 5-24 shows, both industries have considerable presence in and around Appalachia.

***Exhibit 5-24. Ethanol plants (right) and cement plants (left) in and around Appalachia***

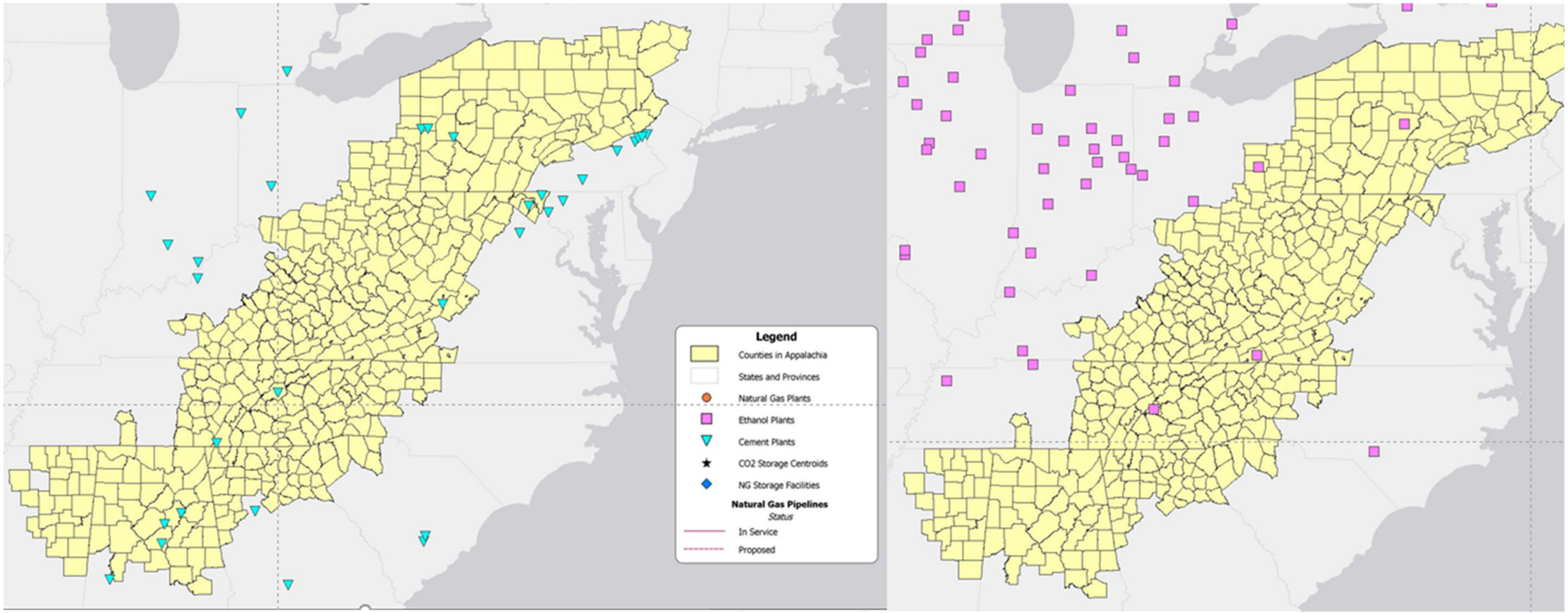
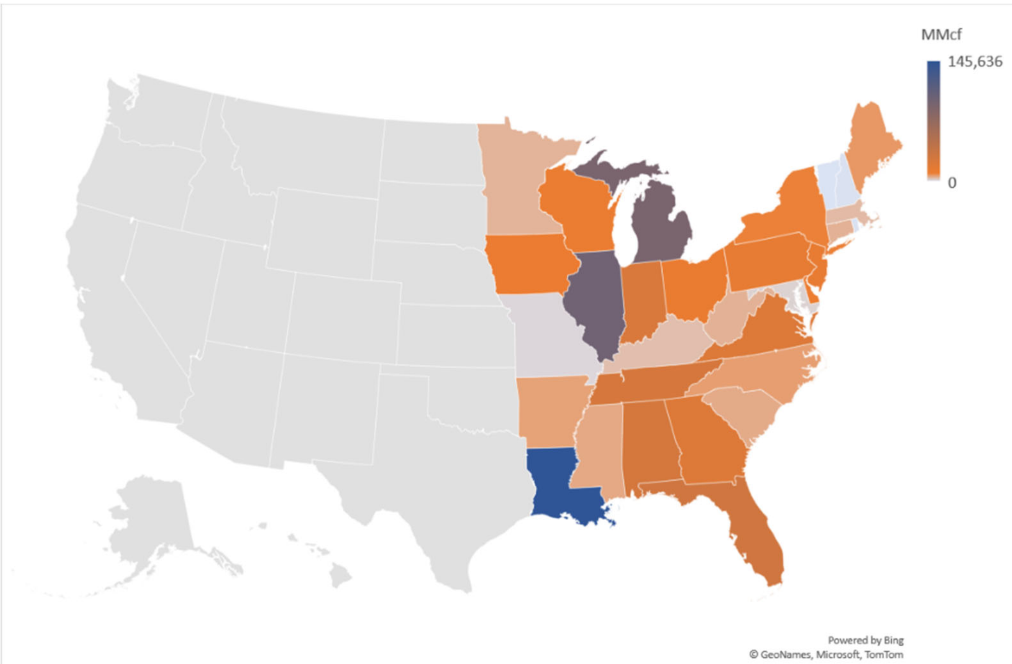


Exhibit 5-25 shows the amount of natural gas used in industrial boilers in 2020. Exhibit 5-25 does not include other types of fossil or renewable industrial boilers. The Appalachian region and surrounding regions could replace up to 626 Bcfy of natural gas. This would equate to 14 hydrogen plants, producing 59 M tons of hydrogen per year. This would equate to a reduction of 33.75 B kg of $CO_2$ annually, assuming a 90 percent carbon capture rate. [188] When combined with demand for hydrogen from ethanol plants, cement plants and steel mills, there is significant demand in and around the Appalachian region to support a robust hydrogen economy.

***Exhibit 5-25. Natural gas industrial boilers in and around the Appalachian region***




## 5.4.3 Decarbonization of On-Site Power Generation in the Industrial Sector

A significant fraction (16.5 percent) of electricity consumed by major industrial sectors is generated onsite. The motivation by industry for utilizing on-site power plants consists of several factors:

- Combined heat and power (CHP)—many types of industries have demand for both large quantities of process heat and process steam as well as electric power. A dedicated on-site CHP plant can be sized and configured to provide both the electricity and heat duty needed for site processes, often with significant cost savings given the characteristically high efficiency of CHP plants (~90%).
- On site fuel availability—industries like oil refineries and petrochemical plants may generate large quantities of byproduct fuel gases that can be gainfully utilized to fuel an on-site power plant or CHP plant. Fluctuating amount and quality of such gases may dictate that the industry own/control the power plant given the high degree of process

integration demanded. It also affords them increased control/options for overall emissions controls plant wide. An example of this work (described in Section 3.3.2) is Marathon Petroleum that will begin using hydrogen to supply heat at its refinery in KY.

- Safety concerns—some plants such as chemical plants may always require power availability for hazard avoidance, to the extent that relying solely on utility grids (subject to risk of blackout) would be unacceptable.
- Onsite power is mainly due to available heat and other fuels not needed for the process.

Vendors offer a wide range of smaller and mid-sized power generation and CHP units for industry. These typically are based on aeroderivative turbines or industrial gas turbines, and could be simple cycle or combined cycle, and vary in size typically from several MW to ~200 MW in capacity. [189] The trend in recent years has been strongly toward natural gas turbines in the United States, given the current market's low natural gas prices.

An opportunity for decarbonization of on-site power generation is hydrogen turbine utilization. Given the widespread reliance on conventional gas turbines in on-site power plants, the possibility of retrofit of the turbines for hydrogen combustion or substitution with hydrogen turbines could be deployed without significant challenges. Fossil-derived hydrogen with CCS prepared regionally would be sourced as fuel. Certain sites with hydrogen production capability and capacity (mainly oil refineries and chemical plants) could generate fossil-derived hydrogen with CCS onsite to execute a more thorough decarbonization scheme, possibly involving a comprehensive slate of fossil-derived hydrogen with CCS uses as process feedstock, power plant, and/or CHP plant fuel, and offering excess fossil-derived hydrogen with CCS as a product for sale.

DOE has supported development of hydrogen turbines for many years. Activity in commercial development of 100 percent hydrogen turbines is evident from several vendors including Mitsubishi Hitachi Power Systems, General Electric (GE) Power, Siemens Energy, and Ansaldo Energia. [190] Among these, Siemens is said to be working toward 25–50 MW hydrogen-burning gas technology by ~2022, opining that the initial focus will likely be on units smaller than 70 MW regarding the commercialization of hydrogen power. This bodes well for on-site industrial power generation, which tends toward these smaller unit sizes (as opposed to large central utility power plants that use larger turbines such as the GE H class [~500 MW combined cycle]).

As hydrogen technologies become more prominent, DOE is supporting development of practices and procedures that will enable safety in operating, handling, and using hydrogen and hydrogen systems. Infrastructure is a key area of research to aid the development and maturity of hydrogen technology by ensuring safe transport and utilization of hydrogen. As new applications of hydrogen are explored, gaps and barriers must be identified in existing infrastructure and technology to bring hydrogen to its full potential.

### 5.4.4 Hydrogen's Role in the Transportation Sector

Hydrogen has a role in the transportation sector with the potential to significantly reduce air pollution from trucks, buses, and offroad and heavy construction vehicles, as well as through aviation and maritime travel. While hydrogen may struggle to compete with batteries for light duty vehicles, the combination of hydrofuel cells and batteries in light duty vehicles can extend vehicle range. Batteries, however, are not as efficient in off-road/construction vehicles and large commercial trucks and compressed hydrogen can play significant role in replacing fossil fuels used in those industries.

### 5.4.5 Appalachia's Position to be a Hydrogen Economy Leader

Physical solutions for improving the pipeline infrastructure and compressor stations are currently in practice, with known costs. However, a large-scale increase in hydrogen supply and demand will shift the current hydrogen market, and those changes need to be analyzed across a spectrum of supply/demand/costs scenarios, considering environmental incentives and penalties at the federal through corporate levels.

# 6 ESTIMATED JOBS SUPPORTED THROUGH DEPLOYMENT OF AN APPALACHIAN HYDROGEN INFRASTRUCTURE

From 2015 to 2019, it was estimated that there were approximately 25.7 M people living in the Appalachian region. [6] Approximately 9.7 M of those people were considered members of the civilian labor force of prime working age (between the ages of 25 and 64).[o] [6] The average employment rate for these identified persons was estimated to be 96.6 percent, which closely mirrored the employment situation nationally, for the same group of people over the same period. [6]

While the current employment situation in the Appalachian region is consistent with the national employment situation, this has not always been the case for Appalachia. According to ARC, the early 1980s recession resulted in more than 9 percent of the Appalachian region's labor force being unemployed during each year between 1980 and 1984. [191] The region's reliance on steel manufacturing and coal mining in the 1980s is identified as a one of the leading contributing factors to employment declines in the region. [191]

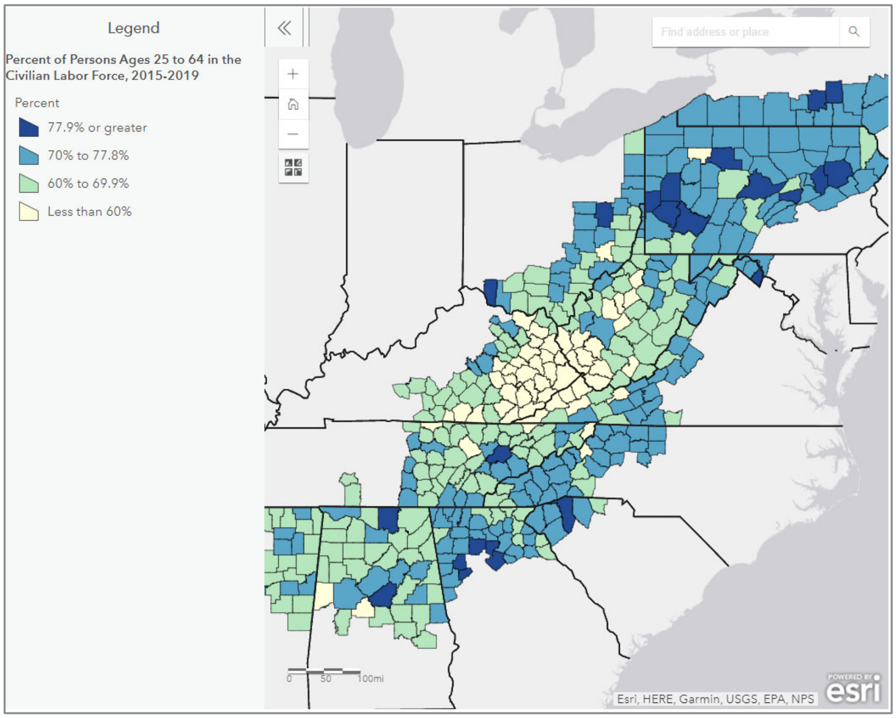
Job losses in the coal mining industry were particularly difficult for the region because the industry supplied high-paying jobs and served as a source of family-sustaining wages, according to ARC. [192] Across the Appalachian region, between 2000 and 2019, wages and salaries per job were higher in mining counties compared to non-mining counties, likely a result of the higher wages being offered by the coal mining industry. [8] Wages and salaries in Appalachian mining counties, however, were well below the wages and salaries for the non-Appalachian counties of the states considered to be part of the region. [8]

Moreover, compared to the rest of the nation, since 1965 the Appalachian region has experienced larger income disparity and a greater outmigration of people. New job creation in the region remains an area of focus, as the rate of new job creation in the region differs drastically from the national rate of new job creation. [193] It was estimated that between 1975 and 2015, the number of new jobs made available in the Appalachian region grew by only 50 percent, while new job creation nationally grew by 86 percent. [193]

Labor force participation in the region between 2015 and 2019 was estimated to be equal to 73.3 percent, which was lower than labor force participation across the country over the same period, which was estimated to be equal to 77.9 percent. [193] Labor force participation rate by county in the Appalachian region between 2015 and 2019 is outlined in Exhibit 6-1.

[o] Members of the civilian labor force, which includes individuals who are not currently institutionalized (i.e., are not currently in prison, a mental hospital, or a nursing home).

***Exhibit 6-1. FY20 labor force participation rate by county***

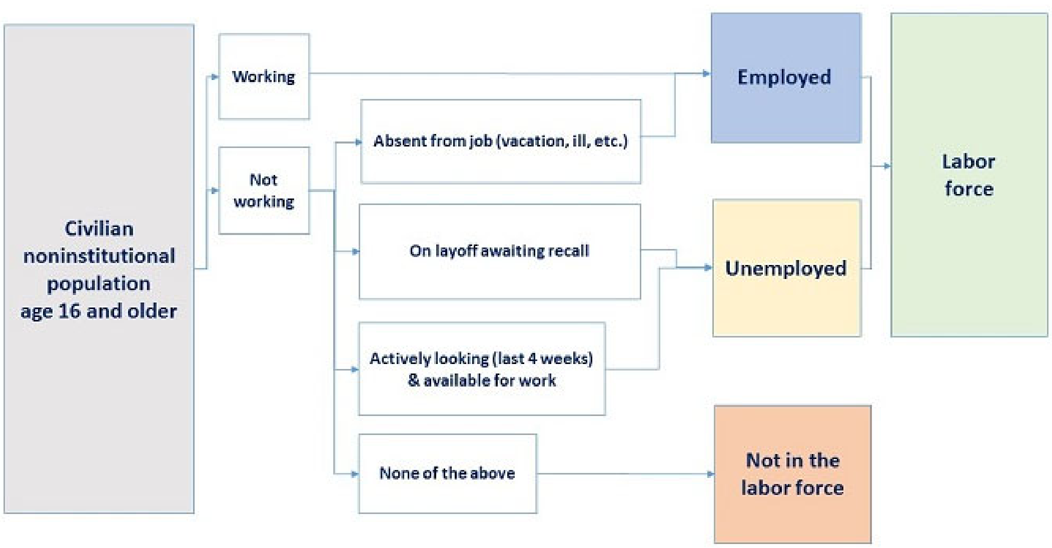



*Used with permission from ARC [194]*

As described in Exhibit 6-1, the labor force participation rate between 2015 and 2019 was lowest for counties located in the central Appalachian region.

The different sub-groups of individuals considered to be participants and non-participants of the labor force, data on which is used to estimate the labor force participation rate, are outlined in Exhibit 6-2.

***Exhibit 6-2. Sub-groups of individuals by labor force participation status***

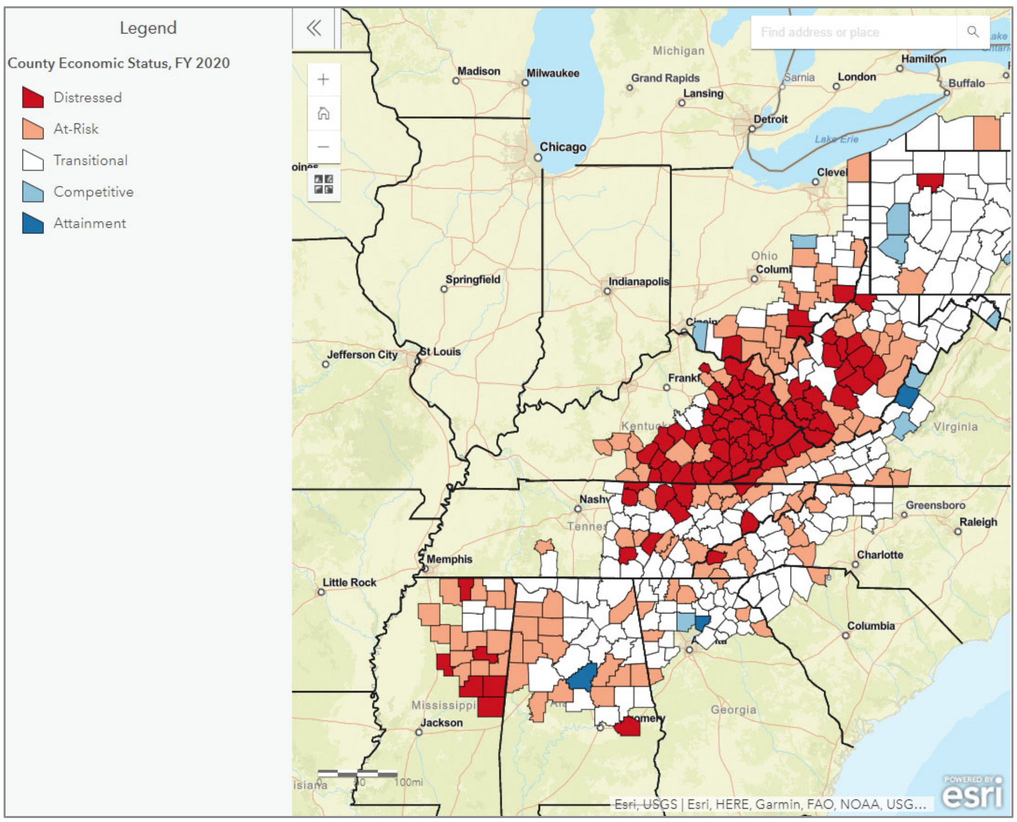



*Source: Bureau of Labor Statistics [195]*

As described by Exhibit 6-2, those in the labor force include non-institutionalized individuals of working age (aged 16 years and older) who are currently working, laid off but awaiting recall, or actively looking for work. [195] It does not include individuals who want jobs but have not applied for any jobs in the past four weeks (i.e., those who are discouraged). [195] Discouraged workers are common in the Appalachian region, as many wish to be employed but have stopped applying for work because they feel there are no jobs available. [196] [197] Hydrogen infrastructure development could generate new jobs or support jobs for individuals living in the region, resulting in potential positive impacts for the labor force in the region.

The county economic classification system developed by ARC suggested for the 2020 fiscal year 80 counties in the region were considered economically "distressed," as described in Exhibit 6-3 by ARC's *County Economic Status in Appalachia*.[p] [q] [198]

***Exhibit 6-3. FY20 economic status of counties according to ARC's County Economic Classification System***




*Used with permission from ARC [198]*

[p] The 2020 fiscal year runs from October 1, 2019, to September 30, 2020.

[q] Distressed counties are those who rank in the worst 10 percent economically of the nation's counties. At-risk counties include those at risk of becoming economically distressed. They rank between the worst 10 percent and 25 percent of the nation's counties. Transitional counties rank between the worst 25 percent and the best 25 percent of the nation's counties. Competitive counties are those that are able to compete in the national economy but are not in the highest 10 percent of the nation's counties. Attainment counties are the economically strongest counties, ranking in the best 10 percent of the nation's counties. The status of each county was determined based on reported values from ARC's County economic classification system, which generates an index value for each county based on how the county's three-year average compares to the national average. [198]

The number of distressed counties by state within the region are included in Exhibit 6-4.

***Exhibit 6-4. Number of "distressed" counties by state within the Appalachian region (FY20)***

| State | Number of "distressed" counties by state | Total number of counties by state considered to be part of the Appalachian region | Total number of counties in each state |
|---|---|---|---|
| Mississippi | 6 | 24 | 82 |
| Alabama | 1 | 37 | 67 |
| North Carolina | 1 | 31 | 100 |
| Tennessee | 9 | 52 | 95 |
| Kentucky | 38 | 54 | 120 |
| West Virginia | 16 | 55 | 55 |
| Pennsylvania | 1 | 52 | 66 |
| Ohio | 4 | 32 | 88 |
| Virginia | 4 | 25 | 95 |
| Total | 80 | | |

Note: The list of states does not include all states within the Appalachian region as some states did not have any "distressed" counties. Number of counties by state represents a count of the distressed counties by state in Exhibit 6-3.

The development of advanced hydrogen infrastructure pathways within the Appalachian region presents opportunity to improve the economic status of counties located in the region where the infrastructure will be developed.

## 6.1 Types of Industries Involved in the Hydrogen Supply Chain

The hydrogen supply chain, described in Section 2.1 consists of many interconnected industries. The industries identified as likely to be involved in the supply chain for hydrogen if hydrogen were to be sourced from natural gas processing are outlined in Exhibit 6-5. Descriptions are based on reported information from the 2017 North American Industry Classification System (NAICS). [199]

***Exhibit 6-5. Industries likely to be involved in the hydrogen supply chain assuming hydrogen is supplied via natural gas processing***

| Supply Chain Segment | Industrial Sectors | 2017 NAICS Codes | Description |
|---|---|---|---|
| Production | Oil and Gas Extraction | 211 | Comprises establishments primarily engaged in the operation and/or development of oil and gas field properties. Such activities may include exploration for crude petroleum and natural gas; drilling, completing, and equipping wells; operating 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 from the producing property |
| | Support Activities for Mining | 213 | Comprises establishments primarily engaged in providing support services, required for the mining, and quarrying and for the extraction of oil and/or gas |
| Transportation | Pipeline Transportation | 486 | Comprises establishments primarily engaged in the transportation of products, such as crude oil, natural gas, refined petroleum products, and slurry |
| | Truck Transportation | 484 | Comprises establishments who provide support for over-the-road transportation of cargo using motor vehicles, such as trucks and tractor trailers |
| | Rail Transportation | 482 | Comprises establishments who provide support for rail transportation of passengers and/or cargo using railroad rolling stock |
| | Water Transportation | 483 | Comprises establishments who provide support for water transportation of passengers and cargo using watercraft, such as ships, barges, and boats |
| Storage | Warehousing and Storage | 493 | Comprises establishments primarily engaged in operating warehousing and storage facilities |
| End-Use Applications | Utilities | 22 | Comprises establishments who provide electric power, natural gas, steam supply, water supply, and sewage removal through a permanent infrastructure of lines, mains, and pipes. Includes establishments primarily engaged in generating, transmitting, and/or distributing electric power. Establishments in this industry group may perform one or more of the following activities: 1) operate generation facilities that produce electric energy, 2) operate transmission systems that convey the electricity from the generation facility to the distribution system, and 3) operate distribution systems that convey electric power received from the generation facility or the transmission system to the final consumer |
| | Petroleum and Coal Products Manufacturing | 324 | Comprises establishments involved in the transformation of crude petroleum and coal into usable products. The dominant process is petroleum refining |

| Supply Chain Segment | Industrial Sectors | 2017 NAICS Codes | Description |
|---|---|---|---|
| | Chemical Products Manufacturing | 325 | Comprises establishments involved in the transformation of organic and inorganic raw materials by a chemical process and the formulation of products |
| | Fabricated Metal Product Manufacturing | 332 | Comprises establishments primarily engaged in manufacturing one or more of the following metal valves: 1) industrial valves, 2) fluid power valves and hose fittings, 3) plumbing fixture fittings and trim, and 4) other metal valves and pipe fittings |
| | Computer and Electronic Products Manufacturing | 334 | Comprises establishments primarily engaged in manufacturing computers, computer peripherals, communications equipment, and similar electronic products, and establishments. that manufacture components for such products. |

The industrial sectors described above will likely support jobs in response to hydrogen infrastructure development in the Appalachian region, assuming the hydrogen is used both inside and outside of the region.

## 6.2 Estimated Jobs Supported by Advanced Hydrogen Infrastructure Development

To estimate the jobs capable of being supported from the development of advanced hydrogen infrastructure in the Appalachian region, data were collected for employment and output by industry in 2019 from Bureau of Economic Analysis (BEA). [200] [201] Data were used to estimate the average number of employees supported for every million dollars in output by industry.[r] Data are representative of the United States as a whole and, therefore, serve as only an approximation for the Appalachian region. A summary of the data is presented in Exhibit 6-6.

***Exhibit 6-6. Summary of national data from BEA on employment and output by industry used to estimate potential jobs supported from advanced hydrogen infrastructure development***

| Industrial Sector | 2017 NAICS Code | Industry Output ($M) 2019 | Employment (K) (2019) | Number of Employees Per $M in Industry Output |
|---|---|---|---|---|
| Oil and gas extraction | 211 | 372,818 | 490.3 | 1.32 |
| Support activities for mining | 213 | 102,460 | 379.2 | 3.70 |
| Utilities | 22 | 563,178 | 591.3 | 1.05 |
| Petroleum and coal products manufacturing | 324 | 378,024 | 1,548.1 | 4.10 |

[r] Employment estimates are provided from the SAEMP25N Total Full-Time and Part-Time Employment by NAICS tables generated by the BEA, which employees who are paid wages and salaries, as well as proprietor employees. [204]

| Industrial Sector | 2017 NAICS Code | Industry Output ($M) 2019 | Employment (K) (2019) | Number of Employees Per $M in Industry Output |
|---|---|---|---|---|
| Chemical products manufacturing | 325 | 366,142 | 1,098.5 | 3.00 |
| Fabricated metal product manufacturing | 332 | 583,231 | 120.2 | 0.21 |
| Computer and electronic products manufacturing | 334 | 777,777 | 896.8 | 1.15 |
| Rail transportation | 482 | 85,412 | 176.1 | 2.06 |
| Water transportation | 483 | 59,308 | 73.4 | 1.24 |
| Truck transportation | 484 | 402,313 | 2,327.1 | 5.78 |
| Pipeline transportation | 486 | 58,829 | 52.3 | 0.89 |
| Warehousing and storage | 493 | 153,015 | 1,340.9 | 8.76 |

Results outlined in Exhibit 6-6 suggest nationally for every million dollars in output generated by industries, (identified as likely to be involved in the supply chain for hydrogen, in response to increased hydrogen availability from the development of advanced hydrogen infrastructure in the Appalachian region) the following number of jobs will be supported for each industry:

- Oil and gas extraction: 1 job per million U.S. dollars ($M) in industry output
- Support activities for mining: 4 jobs per $M in industry output
- Utilities: 1 job per $M in industry output
- Petroleum and coal products manufacturing: 4 jobs per $M in industry output
- Chemical products manufacturing: 3 jobs per $M in industry output
- Fabricated metal product manufacturing: <1 job per $M in industry output
- Computer and electronic products manufacturing: 1 job per $M in industry output
- Rail transportation: 2 jobs per $M in industry output
- Water transportation: 1 job per $M in industry output
- Truck transportation: 6 jobs per $M in industry output
- Pipeline transportation: 1 job per $M in industry output
- Warehousing and storage: 9 jobs per $M in industry output[s]

[s] Jobs are rounded to the nearest whole number.

# 7 FOLLOW-ON PHASES FOR $H_2$ INFRASTRUCTURE IN APPALACHIA

This report discussed many major topics that are critical to the development of a hydrogen hub in the Appalachian region. However, in both the writing of the report and through thorough internal and external review, several topics that could be analyzed more and additional topics for analysis came to light. While some of the topics were originally discussed, they were not included in this version due to original scope and resources. This section will highlight topics that are still in need of analysis and should be investigated in a 2$^{nd}$ phase to this study. The topics are broken down throughout the supply chain.

## 7.1 REGIONALITY

The current report assesses the entire Appalachia region. However, the Bipartisan Infrastructure Law (BIL) contains language for a hydrogen hub to be in a region where natural gas is currently being produced. The Northern Appalachia region (WV, OH, PA) is the region where natural gas production has skyrocketed since 2008 and made the U.S. the largest natural gas producer in the world.  Therefore, a concentrated analysis of the benefits of a hydrogen hub located in the Northern Appalachian region would be beneficial.

An investigation on the hydrogen producers in the region, including oil and gas refiners, and other chemical industries throughout the region should take place. This will provide an understanding of how much, who, and where hydrogen is being produced, as well as who the current purchasers of the hydrogen are.

## 7.2 HYDROGEN PRODUCTION

In this report, as noted in Section 5, the technologies discussed were SMR and ATR with CCS. However, there are multiple routes to make hydrogen from natural gas and they need to be analyzed as well.  Therefore, a deeper look into modeling POx, pyrolysis, chemical looping, in-situ reforming, and dry reforming of methane, along with respective life cycle assessments of these technologies is critical.

Pyrolysis is a unique conversion strategy as it would not produce $CO_2$, with carbon black being the co-product of $H_2$. Carbon black has a range of uses and is a known commodity with developed pricing and demand in the auto industry where it is used to make tires, a commodity produced throughout Northern Appalachia.

Hydrogen could also be used to generate commercial-scale power. Initial analysis showed that making power is not competitive with other power produced using NG with CCS when using the assumptions for CCS. However, since ATR has more concentrated $CO_2$ than NGCC, utilizing CCS could lower the cost of the process. Performing the research and analysis of using a more concentrated $CO_2$ stream with ATR or other technologies could potentially show in some cases, power from $H_2$ can be competitive with natural gas + CCS.  Further, hydrogen fired turbines have some flexible operation capabilities relative to CCS-equipped units that power producers desire.

Additional analyses at the electricity grid scale should take place to compare power from hydrogen to conventional power from natural gas, renewables + battery storage and peakers, to see if power from hydrogen could have market penetration.

## 7.3 Transportation

Further analysis with respect to blending hydrogen in natural gas pipelines should be performed. In particular, an analysis of the age and materials of construction of intrastate and interstate transmission pipelines, as well as distribution pipelines needs to take place to understand which of these pipelines could blend hydrogen and to what percent. A similar analysis should be performed on the compressor stations located throughout the transmission supply chain.

Further investigation into potential leakage through the transportation of hydrogen is critical. Leakage is both a loss of investment and potential hazard, and to a lesser extent, a GHG emission.

Finally, an assessment of the energy and environmental justice impacts of using existing pipelines to support a hydrogen economy must be completed.

## 7.4 Storage

Additional analysis on both $CO_2$ and hydrogen storage should be undertaken.

- This report briefly touched on above ground hydrogen storage and hydrogen carriers. However, additional analyses should concentrate on the different sizes, pressure allowances and costs of hydrogen storage technologies and match these storage technologies with the demands of end users. In addition, an analysis of the potential for pipeline storage should be included. Finally, hydrogen carriers, like ammonia, etc., that were mentioned earlier should be investigated deeper with respect to cost, stability, hazard potential, etc.
- This report discussed onshore storage for CO2, much of which is located in the central U.S. Additional analysis should concentrate on the feasibility of offshore $CO_2$ storage along the Atlantic shelf.

## 7.5 End Use

The current report discussed only a few end-user markets for hydrogen; ethanol, cement, and steel. However, Northern Appalachia is a highly industrialized region with numerous industries that could use hydrogen as a feedstock for production, or heat and power for their process. These industries include, but are limited to:

- The auto industry
- Chemical manufacturers
- Transportation industry (off road and heavy duty)

- Power production
- Glass

Also, understanding who the largest $CO_2$ emitters in the region, and looking at which would benefit from hydrogen can identify more industrial users.

## 7.6 Jobs Creation and Economic Development

The current report takes a high-level look into job creation. A deeper investigation should take place to determine job creation by parts of the hydrogen supply chain. This should also include indirect jobs that may result from a hydrogen hub.

Jobs and economic development are often spurred by policy. The proposed hydrogen production tax credit (45V) in the Inflation Reduction Act may affect rate of investment and growth of the development of a hydrogen hub. In addition to analyzing its potential, state and local tax incentives should be investigated.

By identifying the end-users throughout the supply chain and the industries that could use hydrogen, beyond transportation present in the Appalachia and assessing the economic impacts of investing in those areas, the benefits of a hydrogen hub could be fully realized.

# 8 CONCLUSIONS

As large-scale efforts to decarbonize the global economy ramp up in earnest, hydrogen is being positioned as a critical solution for numerous sectors. Hydrogen produced from fossil energy resources is commonly viewed as a bridge in the clean energy transition, enabling the development of midstream infrastructure and downstream demand while the cost of renewably driven electrolysis of water to produce renewably sourced hydrogen continues to fall.

The Appalachian region is well suited for development into the nation's clean energy hydrogen hub. Appalachia has the natural gas resources, infrastructure, storage capacity, and industrial demand in and around its borders to lead a clean energy revolution using natural gas with carbon capture and storage to produce hydrogen in the years and decades ahead. The near-term creation of infrastructure to support fossil-derived hydrogen with CCS while meeting near-term goals of an aggressive timeline will also readily facilitate the deployment of renewable hydrogen.

The technology aspects of hydrogen transportation and storage are well known, and advancements are being made by studying the volume of hydrogen that can be blended with natural gas. Pipeline materials and specifications, compressor station requirements, measurements of products in the pipeline throughout the process, and the costs of upgrading the supply chain as hydrogen production accelerates are all issues that are being addressed by industry stakeholders. Physical solutions for improving the pipeline infrastructure and compressor stations are currently in practice, with known costs.

The regulatory framework does not pose any direct risk to developing a hydrogen economy in the Appalachian region. Currently, Appalachian states have a regulatory friendly perspective with respect to fuel production, distribution, and storage. While most of the states have not adopted official regulations for hydrogen, assuming hydrogen would fit into a liquid fuel category, current regulations on the production, distribution, and storage of natural gas and other liquid fuels are well established.

Upon examining the production and consumption, the Appalachian region is a significant exporter of energy. With a combination of energy exports, long-term reduction in natural gas consumption for electricity through grid decarbonization, and utilization of biomass opportunities to produce renewable natural gas, there would be a significant amount of natural gas as feedstock for hydrogen production plants in the region. The opportunities are present for $CO_2$ transport and storage. There is enough potential $CO_2$ storage for 60 plants to last 28 years. A strong potential market exists for hydrogen in the industrial processing sector as natural gas and other fossil fuels are phased out. With 626 Bcf of natural gas demand alone from industrial boilers, 14 hydrogen plants consuming 59 M tons of $H_2$ annually could meet that demand, eliminating approximately 33.75 B kg of $CO_2$ annually, assuming a 90 percent carbon capture rate.

The Appalachian region has had a strong workforce to meet the challenges of creating and managing oil and gas production and distribution, which could transition to a hydrogen economy and create jobs across the Appalachian economy.

The Appalachian region possesses sufficient pipeline, truck, barge, and rail distribution infrastructure to grow a hydrogen economy from the region's abundant fossil fuels reserves. However, more analyses need performed to understand how a large-scale increase in hydrogen supply and demand will affect the current hydrogen market.

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# APPENDIX: FECM/NETL $CO_2$ SALINE STORAGE COST MODEL FORMATION RESULTS

***Exhibit A-1. Storage capacity results by CO2_S_COM saline storage formation***

| Formation Identification | State | Storage Region | Formation Centroid | | First Year Break-Even Price (real 2018$/tonnes $CO_2$) | $CO_2$ Storage Capacity of Formation-Structure Combination (Mtonnes) | $CO_2$ Storage Capacity, After Pressure Interference Correction, of Structure Combination (Mtonnes) |
|---|---|---|---|---|---|---|---|
| | | | Latitude | Longitude | | | |
| Waste Gate1 | MD | Appalachian | -75.5115 | 38.23738 | 5.97 | 1350 | 262 |
| Copper Ridge4 | OH | Appalachian | -81.7448 | 40.03234 | 19.86 | 3780 | 944 |
| Rose Run3 | PA | Appalachian | -78.8689 | 40.92619 | 25.33 | 3510 | 229 |
| Copper Ridge3 | WV | Appalachian | -81.2369 | 39.06625 | 27.27 | 1080 | 270 |
| Basal Sandstone TN Zone 2 | TN | Appalachian | -85.0865 | 35.73744 | 30.30 | 1080 | capacity less than 135 Mtonnes |
| Basal Sandstone TN Zone 1 | TN | Appalachian | -86.6669 | 35.78516 | 34.17 | 2430 | 173 |
| Rose Run4 | PA | Appalachian | -79.6929 | 41.4617 | 37.71 | 1350 | capacity less than 135 Mtonnes |
| Rose Run5 | WV | Appalachian | -81.5349 | 38.75022 | 47.31 | 1620 | capacity less than 135 Mtonnes |
| Rose Run2 | OH | Appalachian | -81.7317 | 40.0362 | 51.11 | 2700 | 177 |
| Copper Ridge2 | PA | Appalachian | -79.9023 | 40.29013 | 69.47 | 357 | capacity less than 135 Mtonnes |
| Copper Ridge1 | OH | Appalachian | -81.6781 | 39.29277 | 71.38 | 177 | capacity less than 135 Mtonnes |
| Lockport02 | OH | Appalachian | -81.4016 | 40.27273 | 74.45 | 920 | capacity less than 135 Mtonnes |
| Lockport03 | WV | Appalachian | -80.6993 | 38.61868 | 74.45 | 1840 | 131 |
| Lockport04 | PA | Appalachian | -78.6483 | 41.00153 | 74.45 | 2265 | 161 |
| Lockport01 | KY | Appalachian | -82.8504 | 37.30154 | 75.25 | 212 | capacity less than 135 Mtonnes |
| Rose Run1 | KY | Appalachian | -83.4608 | 37.41813 | 76.78 | 1292 | capacity less than 135 Mtonnes |
| Lockport06 | NY | Appalachian | -77.3133 | 42.27949 | 82.76 | 495 | capacity less than 135 Mtonnes |
| Conasauga1 | OH | Appalachian | -81.9665 | 40.52311 | 91.78 | 1142 | capacity less than 135 Mtonnes |
| Oriskany6 | WV | Appalachian | -80.508 | 38.612 | 196.29 | 1076 | capacity less than 135 Mtonnes |
| Medina01 | OH | Appalachian | -81.487 | 40.32532 | 210.96 | 5535 | 360 |
| Medina02 | WV | Appalachian | -80.8703 | 38.58098 | 210.96 | 8235 | 535 |
| Medina04 | PA | Appalachian | -78.883 | 41.07212 | 210.96 | 9585 | 623 |
| Oriskany2 | OH | Appalachian | -81.4325 | 40.06116 | 223.32 | 50 | capacity less than 135 Mtonnes |
| Medina03 | MD | Appalachian | -79.2002 | 39.54255 | 261.05 | 270 | capacity less than 135 Mtonnes |

| Formation Identification | State | Storage Region | Formation Centroid | | First Year Break-Even Price (real 2018$/tonnes $CO_2$) | $CO_2$ Storage Capacity of Formation-Structure Combination (Mtonnes) | $CO_2$ Storage Capacity, After Pressure Interference Correction, of Structure Combination (Mtonnes) |
|---|---|---|---|---|---|---|---|
| | | | Latitude | Longitude | | | |
| Medina05 | NY | Appalachian | -77.6707 | 42.30407 | 261.05 | 2835 | 184 |
| Oriskany4 | PA | Appalachian | -77.9292 | 40.91741 | 288.24 | 882 | capacity less than 135 Mtonnes |
| Oriskany3 | OH | Appalachian | -80.8555 | 40.4786 | 339.83 | 110 | capacity less than 135 Mtonnes |
| Oriskany5 | PA | Appalachian | -78.9989 | 41.5045 | 349.70 | 356 | capacity less than 135 Mtonnes |
| Oriskany7 | WV | Appalachian | -81.7982 | 38.45524 | 403.84 | 184 | capacity less than 135 Mtonnes |
| Potsdam1 | PA | Appalachian | -79.3774 | 41.5384 | 1174.25 | 274 | capacity less than 135 Mtonnes |
| Rome Trough Sst1 | KY | Appalachian | -83.5416 | 37.3138 | 1209.20 | 169 | capacity less than 135 Mtonnes |
| Rome Trough Sst2 | WV | Appalachian | -81.795 | 38.54603 | 1651.00 | 35 | capacity less than 135 Mtonnes |
| Rose Run6 | NY | Appalachian | -77.3662 | 42.67377 | 8322.27 | 3240 | 211 |
| Mount Simon3 | IL | Midwest | -89.239 | 39.91991 | 4.78 | 53190 | 17038 |
| Mount Simon6 | IN | Midwest | -86.0531 | 40.20573 | 4.87 | 67095 | 16748 |
| Arbuckle4 | KS | Midwest | -99.2057 | 37.69502 | 5.36 | 67095 | 8106 |
| Mount Simon7 | MI | Midwest | -85.7774 | 42.28556 | 5.64 | 10935 | 3503 |
| Mount Simon5 | IN | Midwest | -86.9464 | 38.74752 | 5.88 | 9045 | 1093 |
| Mount Simon2 | IL | Midwest | -88.5947 | 39.04116 | 6.54 | 10530 | 1272 |
| Knox3 | IN | Midwest | -87.1143 | 38.69935 | 7.43 | 4725 | 1314 |
| Knox5 | KY | Midwest | -87.2952 | 37.48242 | 8.09 | 2160 | 478 |
| Knox1 | IL | Midwest | -88.8089 | 38.88472 | 8.44 | 8775 | 1943 |
| St.Peter7 | MI | Midwest | -84.296 | 45.37212 | 10.57 | 1485 | 371 |
| Mount Simon8 | MI | Midwest | -83.6668 | 42.22536 | 10.91 | 2700 | 865 |
| Knox4 | IN | Midwest | -87.6386 | 38.08516 | 11.71 | 675 | capacity less than 135 Mtonnes |
| Knox6 | KY | Midwest | -87.624 | 37.54151 | 11.73 | 810 | capacity less than 135 Mtonnes |
| Mount Simon10 | OH | Midwest | -83.7602 | 40.09284 | 11.96 | 9315 | 2984 |
| Knox2 | IL | Midwest | -88.4987 | 38.15315 | 12.87 | 2970 | 460 |
| Mount Simon11 | KY | Midwest | -84.5965 | 38.29133 | 14.37 | 3915 | 473 |
| Niagaran01 | MI | Midwest | -84.5489 | 43.87649 | 15.53 | 20655 | 1363 |
| St.Peter9 | MI | Midwest | -84.4456 | 43.70743 | 15.63 | 9045 | 1633 |
| Sylvania1 | MI | Midwest | -84.6962 | 43.91304 | 15.84 | 7560 | 1887 |

| Formation Identification | State | Storage Region | Formation Centroid | | First Year Break-Even Price (real 2018$/tonnes $CO_2$) | $CO_2$ Storage Capacity of Formation-Structure Combination (Mtonnes) | $CO_2$ Storage Capacity, After Pressure Interference Correction, of Structure Combination (Mtonnes) |
|---|---|---|---|---|---|---|---|
| | | | Latitude | Longitude | | | |
| Mount Simon4 | IN | Midwest | -87.5189 | 38.1741 | 16.44 | 1080 | capacity less than 135 Mtonnes |
| St.Peter10 | MI | Midwest | -84.4233 | 44.03515 | 17.25 | 6480 | 783 |
| Mount Simon9 | MI | Midwest | -84.5774 | 43.87578 | 18.43 | 25515 | 1674 |
| St.Peter8 | MI | Midwest | -85.0621 | 42.44389 | 24.82 | 2295 | 476 |
| St.Peter1 | IL | Midwest | -88.8089 | 38.88472 | 26.47 | 1620 | 404 |
| Mount Simon1 | IL | Midwest | -88.4439 | 38.32195 | 26.50 | 2295 | 151 |
| BassIsland01 | MI | Midwest | -84.5488 | 43.87649 | 34.25 | 4320 | 424 |
| St.Peter2 | IL | Midwest | -88.4987 | 38.15315 | 49.92 | 480 | capacity less than 135 Mtonnes |
| St.Peter3 | IN | Midwest | -87.1143 | 38.69935 | 83.45 | 212 | capacity less than 135 Mtonnes |
| St.Peter5 | KY | Midwest | -87.2952 | 37.48242 | 124.29 | 57 | capacity less than 135 Mtonnes |
| Frio2 | TX | Southeast | -97.9289 | 27.50536 | 3.66 | 19980 | 4987 |
| Frio3a | TX | Southeast | -94.2383 | 30.23141 | 3.88 | 7155 | 5410 |
| Frio6 | TX | Southeast | -95.376 | 29.67148 | 3.90 | 10395 | 8013 |
| Frio9a | TX | Southeast | -96.7746 | 28.60495 | 3.90 | 13500 | 10407 |
| Frio12a | TX | Southeast | -97.94 | 26.86519 | 3.96 | 11475 | 8846 |
| Frio12b | TX | Southeast | -97.9446 | 26.85713 | 4.26 | 10530 | 8044 |
| Frio7a | TX | Southeast | -95.0427 | 29.54311 | 4.34 | 9450 | 7145 |
| Frio10 | TX | Southeast | -96.5001 | 28.51526 | 4.49 | 11745 | 8779 |
| Frio13a | TX | Southeast | -97.6582 | 26.76322 | 4.57 | 8100 | 6125 |
| Frio4 | TX | Southeast | -94.0547 | 30.0272 | 4.63 | 2835 | 2092 |
| Washita-Fredericksburg1 | AL | Southeast | -87.4539 | 31.3942 | 4.72 | 55350 | 3798 |
| Frio1 | TX | Southeast | -95.6624 | 29.79566 | 4.85 | 9720 | 2426 |
| Frio3b | TX | Southeast | -94.2397 | 30.23141 | 4.95 | 3240 | 2422 |
| Frio13b | TX | Southeast | -97.6582 | 26.76322 | 4.96 | 7425 | 5550 |
| Frio9b | TX | Southeast | -96.7746 | 28.60495 | 5.01 | 6345 | 4798 |
| Lower Tuscaloosa2 | AL | Southeast | -87.9806 | 30.73692 | 5.03 | 7155 | 4091 |
| Lower Tuscaloosa1 | AL | Southeast | -87.0544 | 31.45445 | 5.07 | 22005 | 14276 |
| Washita-Fredericksburg2 | FL | Southeast | -85.7796 | 30.5111 | 5.30 | 35100 | 2430 |

| Formation Identification | State | Storage Region | Formation Centroid | | First Year Break-Even Price (real 2018$/tonnes $CO_2$) | $CO_2$ Storage Capacity of Formation-Structure Combination (Mtonnes) | $CO_2$ Storage Capacity, After Pressure Interference Correction, of Structure Combination (Mtonnes) |
|---|---|---|---|---|---|---|---|
| | | | Latitude | Longitude | | | |
| Frio13c | TX | Southeast | -97.6582 | 26.76322 | 5.37 | 6750 | 4981 |
| Lower Tuscaloosa10 | MS | Southeast | -89.0783 | 30.72522 | 5.52 | 12015 | 8736 |
| Frio11 | TX | Southeast | -95.6678 | 28.86067 | 5.59 | 945 | 676 |
| Lower Tuscaloosa8 | MS | Southeast | -89.9133 | 32.33224 | 5.81 | 21060 | 16235 |
| Cedar Keys-Lawson2 | FL | Southeast | -81.2459 | 26.76048 | 5.83 | 35370 | 2820 |
| Frio8 | TX | Southeast | -94.9457 | 29.33855 | 5.92 | 3915 | 2846 |
| Paluxy5 | FL | Southeast | -85.851 | 30.5223 | 5.94 | 21600 | 1722 |
| Lower Tuscaloosa3 | FL | Southeast | -85.8026 | 30.51301 | 6.03 | 18360 | 10497 |
| Paluxy4 | AL | Southeast | -87.3213 | 31.48569 | 6.04 | 35775 | 2852 |
| Lower Tuscaloosa4 | FL | Southeast | -84.2473 | 30.43247 | 6.66 | 2160 | 1401 |
| Paluxy6 | MS | Southeast | -89.649 | 31.76677 | 6.87 | 49815 | 3971 |
| Frio5 | TX | Southeast | -94.0488 | 29.77822 | 7.09 | 540 | 379 |
| Lower Tuscaloosa5 | GA | Southeast | -84.4594 | 31.00808 | 7.09 | 2700 | 1752 |
| Cedar Keys-Lawson1 | FL | Southeast | -81.2325 | 27.83961 | 7.36 | 7695 | 613 |
| Lower Tuscaloosa9 | MS | Southeast | -90.0943 | 31.36406 | 7.36 | 14175 | 7107 |
| Washita-Fredericksburg3 | MS | Southeast | -89.6805 | 31.73526 | 7.59 | 42660 | 2981 |
| Cedar Keys-Lawson3 | FL | Southeast | -80.7661 | 25.3186 | 7.87 | 1080 | capacity less than 135 Mtonnes |
| Frio7b | TX | Southeast | -95.0427 | 29.54311 | 8.14 | 1755 | 1312 |
| Lower Tuscaloosa6 | LA | Southeast | -92.1292 | 31.7967 | 8.90 | 12690 | 8233 |
| Lower Tuscaloosa7 | LA | Southeast | -90.4419 | 30.7702 | 11.05 | 3780 | 944 |
| Sunniland1 | FL | Southeast | -81.1378 | 26.15994 | 14.08 | 2160 | 172 |
| Eutaw1 | MS | Southeast | -89.8942 | 31.99428 | 16.67 | 10395 | 4414 |
| Eutaw2 | AL | Southeast | -87.6484 | 31.18116 | 20.80 | 2025 | 860 |
| Eutaw4 | GA | Southeast | -82.7556 | 30.86045 | 21.07 | 270 | capacity less than 135 Mtonnes |
| Eutaw3 | FL | Southeast | -85.4061 | 30.50372 | 24.68 | 2430 | 1032 |

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