An Evaluation of Regulatory Frameworks for the Development of Interstate Hydrogen Infrastructure in the United States

by

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Abstract

Markets for natural gas, electric power, and oil, and associated regulatory frameworks for the development of infrastructure to move said commodities in the United States, are mature – having developed over the last century and a half. In this thesis, I frame hydrogen as a fundamentally different energy commodity than those currently under the purview of federal regulators and assess potential regulatory frameworks for the development of interstate hydrogen transmission infrastructure. This thesis combines qualitative and quantitative methods to assess the use of regulatory frameworks to enable the development of such an interstate hydrogen transmission network. I conduct a historical analysis of commodity market, and infrastructure, development in the United States for the oil, natural gas, and electric power sectors. I then conduct a cross-sectional analysis of other countries' stated hydrogen strategies to assess why the United States might consider using hydrogen in their energy sector. In order to justify an investigation into regulatory frameworks for the development of interstate hydrogen network development, I develop a linear program to evaluate the hydrogen transmission network which serves to minimize total expenditures on hydrogen based on power price and hydrogen demand assumptions. I find there are many cases in which the construction of a substantial hydrogen transmission network minimizes total expenditure on hydrogen within the United States. The thesis concludes with an evaluation of regulatory frameworks for the development of hydrogen transmission infrastructure. Across all frameworks assessed, I find an act of Congress is likely necessary if hydrogen is to play a substantive role in the United States' future energy sector.

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To MITEI, thank you for your support during my two years at MIT – I will cherish the opportunity to have had worked amongst such brilliant and passionate people for the rest of my life.

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Contents

List of Figures

List of Tables

Chapter 1

Introduction

1.1 The Hydrogen Economy

"Hydrogen economy is an economy that relies on hydrogen as the commercial fuel that would deliver a substantial fraction of a nation's energy and services."
- Nehrir and Wang, 2016 [64]

The notion that one might leverage hydrogen as an energy vector is not a new one. One may argue this is for good reason. The characteristics of the element are quite appealing: hydrogen abundant in our environment, hydrogen production is not limited to specific locations based on geology, and the combustion of hydrogen yields no carbon emissions [67][69][51].

Excitement around hydrogen has waxed and waned across the world over the last 30 years, but the most recent period of excitement which concentrated focus on the use of hydrogen as an energy vector occurred in the early 2000s [54]. Hydrogen had taken an especially prominent role when discussing the future energy system in the United States. The early 2000s were a time of relative energy insecurity within the United States – as demand for oil within the transport sector continued to increase, the United States found itself susceptible to geopolitical risk from the import of oil supplies from volatile regions of the world [44]. This period is highlighted in figure 1-1 below.

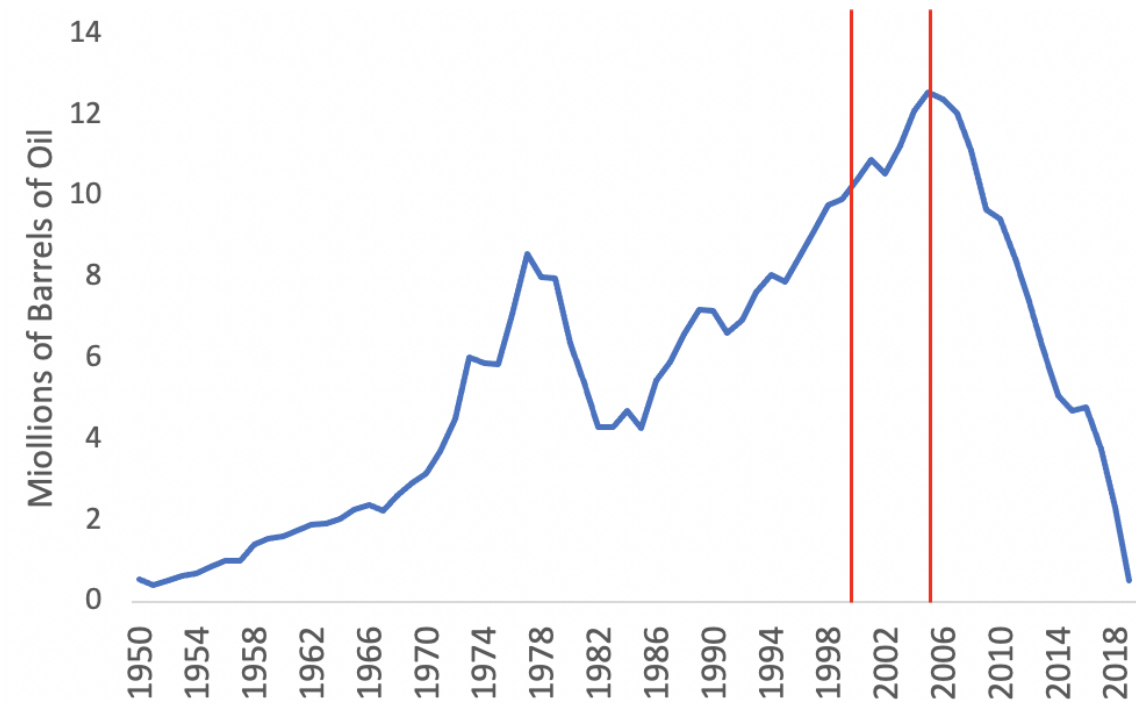

Figure 1-1: United States Oil Net Imports (1950-2019); Red bars indicate last period of hydrogen push in United States. Recreated from [28]

Concern over oil imports, and, by proxy, interest in hydrogen, percolated from the boardroom all the way to the United States federal government as hydrogen was ubiquitous in the Energy Policy Act of 2005 [8]. At the time, hydrogen was meant, primarily, to serve as a substitute for gasoline and diesel to fuel the transport sector.

Shortly after the Energy Policy Act of 2005 was passed, the United States entered a period of energy transition that would fundamentally change how the United States evaluated the future of the energy sector. The late 2000s saw the shale revolution flourish in the United States. The advent of this new supply of oil and gas led prices of these commodities to stabilize (and some cases decrease) – see figure 1-2. In a dramatic shift, the United States turned from an oil importer to an exporter. This change led concerns over energy security to diminish – along with diminishing concerns of energy security came diminished interest in consuming hydrogen in the transport sector.

However, recently many governments throughout the world have begun to take

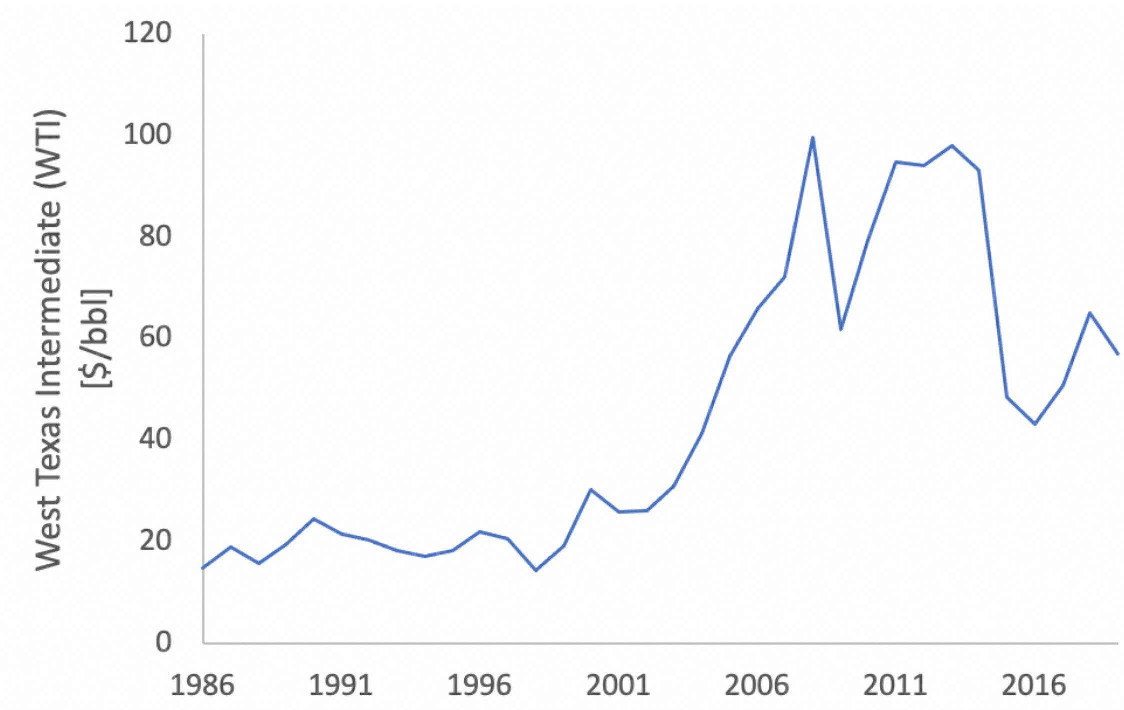

Figure 1-2: Prices of West Texas Intermediate Crude Oil (WTI). Recreated from [27]

another look at hydrogen. Two key developments have driven this newfound interest in hydrogen. First, while past interest in hydrogen had been primarily driven by geopolitical pressures and the desire to minimize dependency on foreign energy imports, countries are now looking to hydrogen as an energy vector to help decarbonize their societies and achieve net-zero emission targets in an effort to minimize the heating impact from greenhouse-gas emissions. Second, the economics of hydrogen produced via renewable energy ("green hydrogen") are becoming more favorable as a key feed-stock – power from variable renewable energy (VRE) resources – costs are declining throughout the world.

Today, hydrogen is not simply being considered as a substitute for oil in the transportation sector. Rather, hydrogen is seen as a compliment to electric power in the effort to fully decarbonize society. It is unclear how demand for hydrogen will ultimately materialize, but it is clear green hydrogen has the potential to decarbonize difficult-to-electrify sectors.

Breaking the barriers historically seen between the energy consuming sectors of the economy – namely electricity, heating and cooling, transport and industrial consumption processes – is commonly referred to as "sector coupling." Hydrogen enables sector coupling. Countries around the world are developing strategies to extract the maximum value from sector coupling and dramatically accelerate the decarbonization of their societies.

While the United States' Department of Energy released their Hydrogen Program Plan in November 2020, the plan is primarily a technical document which focuses on technological barriers that exist along the hydrogen value chain. The document features a brief discussion concerning regulatory issues that need to be addressed in order to enable the diffusion of hydrogen throughout the energy sector, but this discussion is limited to what needs to be done rather than how one might do it. [74]

This thesis is meant to fill this gap. Specifically, this thesis focuses on the justification and introduction of a regulatory framework meant to enable the development of large-scale hydrogen infrastructure within the United States to enable cost-effective interstate hydrogen commerce.

1.2 Structure of the Thesis

The United States responded to this new phase of hydrogen interest in November 2020 by releasing a detailed research and development plan across the hydrogen value chain [74]. This strategy was written to ensure hydrogen is a technologically feasible energy vector within the United States but says nothing concerning the regulatory treatment of hydrogen.

The central focus of this thesis is to analyze regulatory frameworks under which a midstream hydrogen transmission network might grow and how said frameworks affect the development of a hydrogen market in the United States. In order to fully understand the impact of regulatory structures on an energy commodity's market development, this thesis first provides background information on the hydrogen value chain and economic issues impeding the development of a hydrogen market in the United States.

Secondly, I conduct a historical analysis on the development of oil, natural gas, and electric power markets within the United States to provide historical context for energy market development in the United States and introduce pitfalls one should avoid when designing a regulatory framework for hydrogen infrastructure and market development.

Following this analysis, this thesis provides a review of the published hydrogen strategies for the the European Union, the Netherlands, Germany, Japan, and Australia and directional statements from China and Russia in order to develop an understanding of how different countries throughout the world are assessing and planning for the future of hydrogen within their respective energy sectors.

Based on findings from both the historical analysis of energy commodity market development in the United States and the cross-sectional analysis of different countries' published hydrogen strategies, I developed a linear program, which minimizes the United States' the total expenditure on hydrogen based on 2050 estimates for electric power prices and hydrogen demand within each region delineated in the United States Energy Information Agency's (EIA) 2020 Annual Energy Outlook (AEO). This model is meant to prompt discussions of an interstate hydrogen transmission regulatory framework. If this model shows there are cost savings could be realized through the construction of a network, the Federal government should consider the creation of a regulatory framework for hydrogen infrastructure development in the United States.

Following the results from this case study, this thesis develops arguments concerning three proposed regulatory frameworks for the development of a hydrogen transmission infrastructure in the United States. Each assessment discusses the political feasibility, benefits associated with a potential framework, and cons of said frameworks.

This thesis should be read across three phases: (i) What, (ii) Why, and (iii) How:

1. Chapters 2 and 3 discuss "What"

2. Chapter 4 discusses "Why"

3. Chapter 5 discusses "How"

The thesis concludes with a discussion of key takeaways and areas for future thought, research, and discussion.

Chapter 2

The Hydrogen Value Chain and Hydrogen Market Development

While hydrogen is abundant, it does not naturally exist in its pure form. Therefore, hydrogen cannot be produced via either mining or drilling. Rather, one must extract hydrogen from an existing molecule. This means hydrogen is not an energy source, rather it is a secondary energy source similar to electric power – commonly referred to as an energy vector. At standard temperature and pressure, hydrogen exists in gaseous form. Therefore, the movement and storage of hydrogen requires specialized technologies. Furthermore, while hydrogen has the potential to serve many end-use applications, it is not a matter of simply substituting hydrogen in for energy sources currently used in these applications. New technologies must be developed to consume hydrogen and take advantage of its positive attributed. The rest of this section provides detail around the hydrogen value chain, including how different elements of the value chain have developed over time and the future of each element.

2.1 Upstream

There are many pathways through which hydrogen can be produced – some pathways are considerably more carbon-intense than others. Historically, in the United States, the majority of hydrogen has been produced through a process called steam methane reforming (SMR). An SMR unit uses water and heat to reform a methane (CH_4) molecule into component parts. This process is quite carbon-intense – for each kilogram of hydrogen produced, 7 kilograms of carbon dioxide are produced.[90] It is possible to combine the SMR process with carbon capture technology to minimize emissions from this process.[47] While emissions from this process are considerably lower than SMR without carbon capture, emissions are not entirely eliminated.[99]

Hydrogen can also be produced using electricity via an electrolyzer. An electrolyzer takes in feedstock flows of electric power and water. The electric power is used to power a cathode and an anode which then split the water molecule into its constituent hydrogen and oxygen. The hydrogen is then captured and can be sold to end-use customers.

While less than 1% of global hydrogen is currently produced via electrolysis, it is projected that decreases in hydrogen production costs via an electrolyzer will drive demand for hydrogen produced via an electrolysis process. A Sankey diagram representing the present hydrogen market is shown below in figure 2-1. This figure shows the current sources of hydrogen supply on the left and the current demand for hydrogen broken down by sector.

While there are many electrolyzer technologies, two main technologies are currently used to produce hydrogen: alkaline and proton exchange membrane (PEM). Alkaline electrolyzers are the more mature of the two technologies. Put simply, an alkaline electolyzer consists of an anode and cathode and uses electric power to split water into hydrogen and oxygen. PEM electrolyzers similarly produce hydrogen through the splitting of water into hydrogen and oxygen. However, a PEM electrolyzer separates the anode and cathode with a polymer membrane which only allows the positively-charged hydrogen molecules to move from the anode to the cathode.

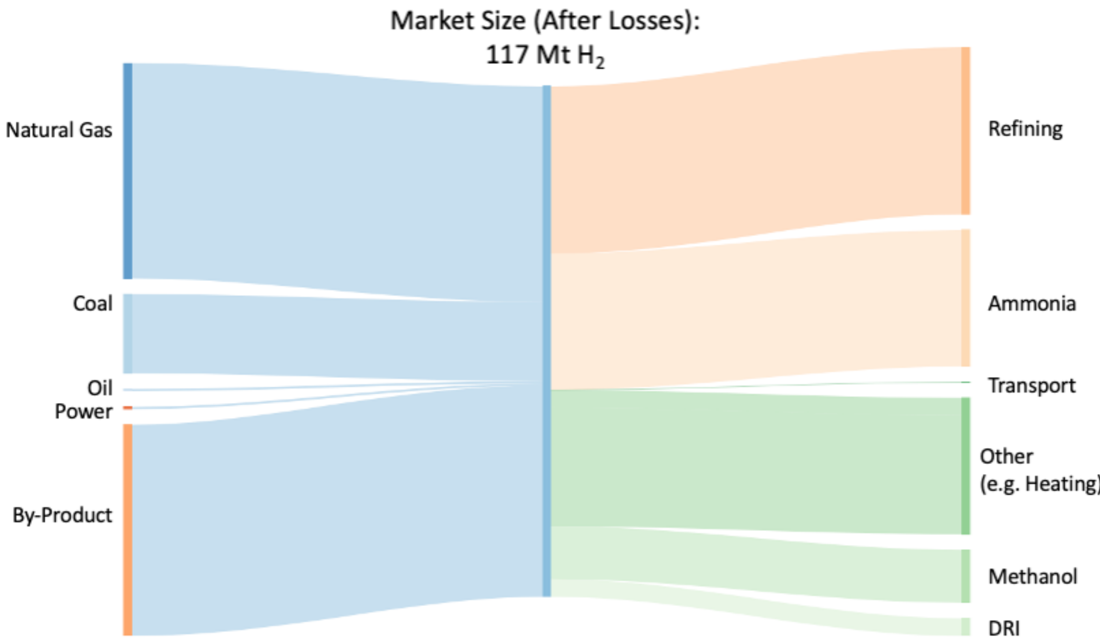

Figure 2-1: Current Supply Modes and Demand Sectors for Hydrogen, Adapted from [4]

Concerns Facing the Future of Hydrogen Production Costs

Many have asked whether electrolysis technologies will see cost reduction curves similar to solar panels (solar) or wind turbines (wind). While it may be tempting to assume electrolysis costs will decline at rates similar to energy technologies of the recent past, it is important to realize these technologies produce fundamentally different products.

Unlike solar or wind, electrolysis produces a nascent product. Power from solar and wind serves the same demand for electric power as dispatchable production assets. Power markets in the United States are mature and infrastructure exists to allow for the diffusion of new energy technologies. Ready access to a market, offered by this infrastructure, allowed for the power produced from these new energy technologies to be sold to end consumers. As installations of solar and wind increased, the cost for these technologies decreased due to "learning by doing" and economies of scale. [87]

Hydrogen, on the other hand, is different. Nearly all hydrogen production capacity in the US reserved for use in industrial activities. In 2014, crude oil refining made up 70% of demand for hydrogen and ammonia production for fertilizer manufacturing made up 20%. [73] Moreover, 95% of hydrogen is produced via a steam methane reformer (SMR) in the US. [70] This demand is realized through bilateral contracts between hydrogen suppliers and consumers -– more succinctly, each kilogram of hydrogen is produced for a specific customer as there is no liquid market for hydrogen akin to the power market. Even if demand for hydrogen grew beyond these industrial consumers, the minimal hydrogen infrastructure in place only connects existing hydrogen supply to large hydrogen customers on the Gulf Coast.

Understanding the nuance of the comparison, the question shifts from "will electrolysis technologies see cost reduction curves similar to solar and wind" to "what changes are required to see cost reductions for electrolysis technology?"

If cost reductions for electrolyzers are meant to be driven by "learning by doing" and economies of scale, similar to other energy technologies, it is imperative that market structure for hydrogen transactions and infrastructure to move the gas be built. Even in a world where a market is established and infrastructure exists, there are still regulatory issues around hydrogen production that must be resolved before any substantial cost decreases for electrolyzer technologies will be realized. Ownership of these assets is at the top of this list.

It may make sense to regulate ownership of electrolysis assets similar to natural gas production wells. After all, hydrogen would likely directly compete with natural gas in many applications.

Who would own this electrolysis production capacity? Using natural gas production as a proxy, let's compare how state-level regulatory structures might shape this question.

Consider the state of Texas. Natural gas production in Texas is regulated by the Railroad Commission through the issuance of drilling permits. Specifically, Statewide Rule 5 mandates any entity seeking to drill a new well in the state requires a permit from the Railroad Commission – permits are subject to other rules that dictate technical elements of the specific proposal.[52] If demand for hydrogen were to grow beyond industrial applications in Texas, would a new statute need to be drafted by the Texas legislature giving the Railroad Commission jurisdiction over issuing permits to construct hydrogen production facilities? In Texas' deregulated power market, there is precedent to assume a utility might not own an electrolysis asset based on restructuring. However, there is little reason to assume there would be strict limitations concerning ownership of these assets otherwise. [53]

Contrasting with Texas, consider the state of Massachusetts. Massachusetts, has no natural gas reserves or production. [25] In a regulatory sense, the comparison between hydrogen and natural gas production is not possible in the context of Massachusetts: regulatory agencies do not have any regulations for natural gas extraction. Therefore, there are no regulations to compare hydrogen production against. So, in the case of Massachusetts, who would have the right to own hydrogen production capacity? As a point of reference, if an offshore wind project wanted to maximize revenue by incorporating an electrolyzer to produce hydrogen when power prices were not high enough, there is no regulatory precedent to determine whether they would be allowed to do so. The rules have yet to be written.

So, returning to the initial point, the notion that costs for hydrogen electrolysis will decrease similar solar and wind technologies is dubious. This assessment is based on the fact that hydrogen production is feeding into a fundamentally different and nascent market. Given hydrogen will likely displace natural gas for many applications, it is possible that regulation of hydrogen production may look similar to that of natural gas production. However, using the frameworks which regulate natural gas production as a proxy for hydrogen production is not a feasible for all states, as there are many states that do not have any existing policies concerning natural resource extraction.

Will electrolyzer technologies see declining cost curves similar to those of solar and wind? Maybe they will – but, there are layers of market, infrastructure, and regulatory uncertainties that must be addressed.

2.2 Midstream

The midstream element of the hydrogen value chain includes both the transportation and storage of hydrogen. Broadly, transportation encapsulates the movement of hydrogen from a production site to the demand center while storage relates to the bulk storage of hydrogen. Transportation and storage of hydrogen are detailed in the sections below.

2.2.1 Transportation

Hydrogen is currently moved in either dedicated pipeline systems or tanks loaded on large trucks, similar to natural gas. However, the volumetric energy density of gaseous hydrogen is around a third of methane. In order to serve a similar energy load, roughly three times as much hydrogen must be moved relative to natural gas on a volumetric basis.

The potential for transporting hydrogen through either a pipeline or in a compressed tank loaded on a truck is addressed below along with short-comings for both long-distance shipping and local distribution of hydrogen.

Pipeline

Pipeline transmission of hydrogen dates back to the 1930s.[38] Dedicated hydrogen pipelines are technically feasible and are currently in commercial operation throughout the world. As an example, Air Liquide owns and operates a dedicated hydrogen pipeline in the Gulf Coast region in the United States to serve their industrial customers in the region.[57]

While these pipeline systems are operational, they are owned by private entities and used to balance their own supply and demand for hydrogen. Moreover, the installed hydrogen pipeline length is dwarfed by the natural gas system. In the United States, on the order of 1,600 linear miles of dedicated hydrogen pipelines are currently in operation.[68] The natural gas system consists of 300,000 linear miles of pipeline.[72]

Unless a situation arises in which green hydrogen produced from otherwise curtailed VREs is aggregated, it might not be economic to construct a dedicated pipeline to move the green hydrogen to a demand center. While pipelines are assets with long life-cycles and low operating costs, high capital costs hinder the economic feasibility of moving hydrogen in a pipeline.[4] Estimates for new construction of a hydrogen pipeline range between $1M and $6M per mile and total costs will depend on the nature of the specific project.[104][31][94] To this end, if there is not enough supply flowing through the pipeline, the delivered hydrogen could potentially be too expensive for end-customers' applications.

An alternative to constructing a new pipeline to move hydrogen would be retrofitting existing natural gas infrastructure. There are many technological concerns associated with moving hydrogen on existing infrastructure; however, key issues include material embrittlement of the steel as a result of moving hydrogen and the potential escape of hydrogen through flanges on the pipeline system. While a retrofit is technically feasible, it has not been commercially proven yet. The "hydrogen backbone" study, sponsored by some of Europe's largest gas network system operators, relies heavily on the retrofit of Europe's existing natural gas infrastructure in building out the continent's hydrogen future.[42] This option affords a potentially more cost-effective alternative to building out new dedicated hydrogen transmission infrastructure.

Trucking

An alternative to constructing a capital-intensive hydrogen pipeline is to move hydrogen in compressed tanks on-board trucks. Hydrogen is commercially moved by truck throughout the world today. Unlike a pipeline, moving hydrogen via a truck affords the flexibility to move hydrogen between producers and suppliers without relying on a centralized delivery point. Moreover, the up-front capital cost associated with procuring a truck is considerably lower than that of building a hydrogen pipeline.[104] The versatility of hydrogen delivery via truck is an appealing attribute when delivering hydrogen short distances to a number of different locations or customers. However, using trucks to deliver hydrogen across longer distances quickly becomes a less attractive alternative to a hydrogen pipeline. The operating cost of a pipeline is considerably lower than that of a truck. This competitive advantage makes the pipeline a more feasible transportation medium across long distances. [1] [4]

2.2.2 Storage

Above-Ground

Hydrogen is commercially stored in above-ground tanks, much like other industrial gases. These tanks can store either gaseous hydrogen in a compressed tank or liquified hydrogen in a tank outfit with refrigeration technology. For reference, figure 2-2, below, shows an above-ground hydrogen storage tank owned and operated by Linde, one of the largest industrial gases companies in the world.

Given the technical maturity of above-ground storage, compressed and refrigerated tanks offer an option to store hydrogen today. Moreover, above-ground hydrogen storage affords the opportunity to store hydrogen regardless of geologic constraints – see underground storage section below. While it is easier to construct one of these tanks, the levelized cost of energy stored in these tanks is more expensive than geologic hydrogen storage. Estimates of hydrogen storage cost via above-ground compressed range from \$6,000 to \$10,000 per MWh of hydrogen stored.[3]

Underground

Underground, or geologic, storage of hydrogen is a commercially viable technology. Hydrogen is currently stored in underground salt caverns throughout both the US

[1] "Long distances" are generally on the order of hundreds of miles

Figure 2-2: Photo of Pressurized Hydrogen Storage Tank [56]

and Europe. Underground storage sites are generally much larger than above ground storage and have the capacity to store magnitudes more hydrogen, on an energy basis.[59][3]

Given this hydrogen storage medium relies on the geology of a potential site, locations in which these salt caverns can be mined are limited. Figure 2-3, below, shows salt beds and salt domes in the United States.

Salt caverns offer the only technically feasible underground hydrogen storage medium.[59] [5] These caverns are mined through a process called leaching. In short, a hole is drilled into the salt dome and fresh water is used to leach away the salt until a cylindrical cavern has been mined. A stylized rendition of a salt cavern used for hydrogen storage is seen below in Figure 2-4.

As a point of reference, natural gas is stored underground throughout the US. However, these storage sites are not limited only to the salt domes. In 2011, salt caverns made up only 23% of all underground natural gas storage daily delivery in

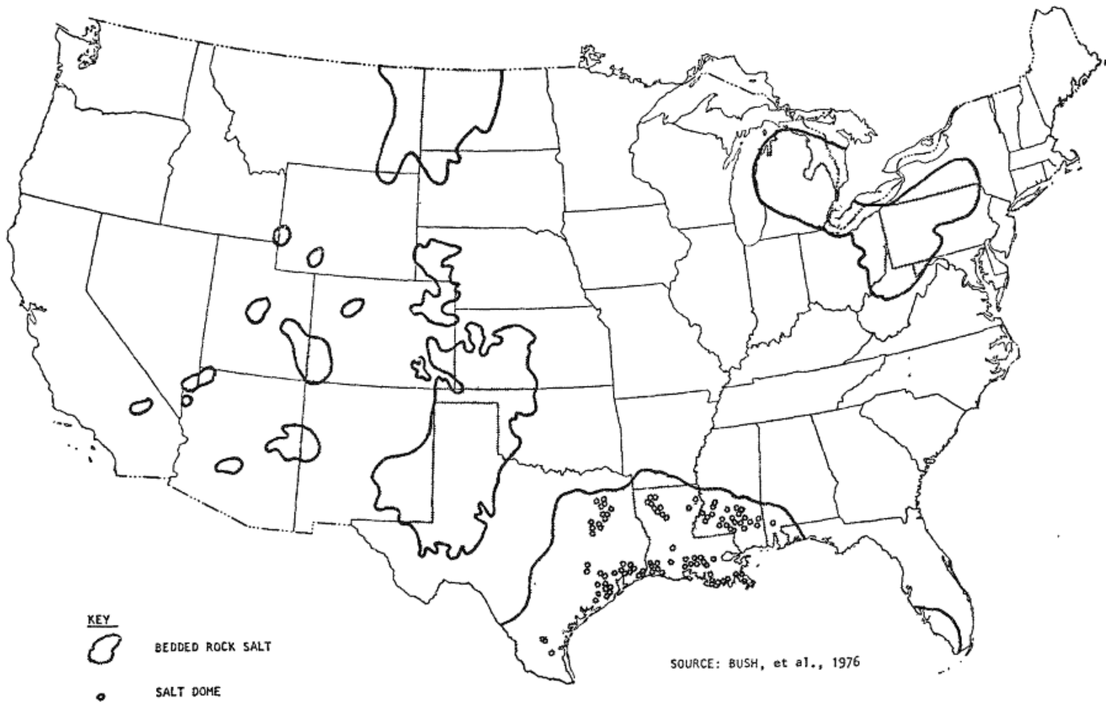

Figure 2-3: Salt Deposits in the United States [35]

the US. Natural gas is also stored in depleted oil and gas reservoirs, aquifers, and hard rock caverns. Hydrogen can only be stored in salt caverns based on the physical properties of the gas. Namely, there are issues with the reactivity of hydrogen and the physical size of the molecules leading to leaks in underground sites.

2.3 Downstream

The downstream element of the hydrogen value chain consists of the consumption of hydrogen. The downstream element of the hydrogen value chain is more diverse than either the upstream or midstream elements. Revisiting figure 2-1, hydrogen is currently consumed in a handful of sectors. Demand is driven primarily by oil refining, ammonia production for fertilizer production, and direct reduction of iron (DRI) in the steel-making process. Current global demand for hydrogen is on the order of 117 million tons per year [4]. While demand in these sectors is not anticipated

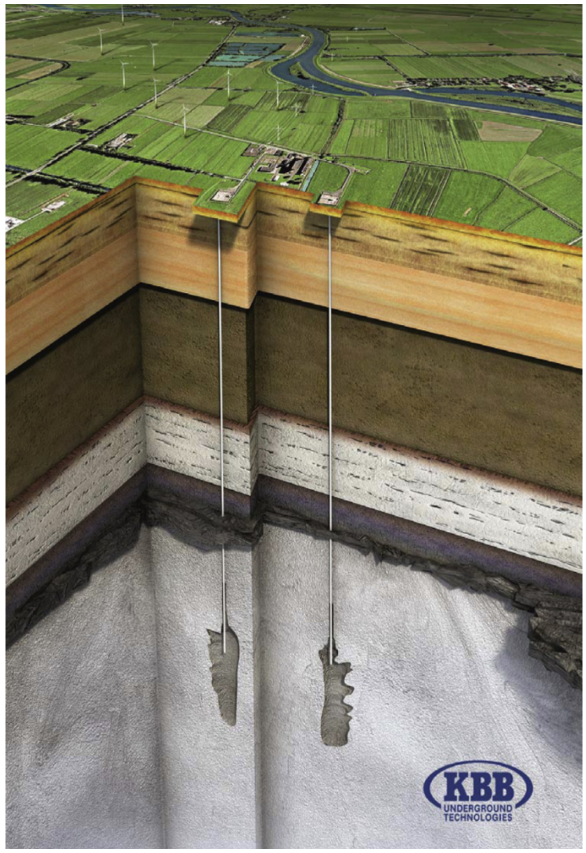

Figure 2-4: Stylized Representation of Underground Salt Cavern [103]

to precipitously decline, there is a market to shift away from carbon-intensive grey hydrogen to more low-carbon blue or green hydrogen. Moreover, demand for hydrogen is anticipated to grow in the following sectors: (i) heat for industrial processes, (ii) land-based transportation (light and heavy-duty vehicles), (iii) bulk storage of electric power, (iv) residential and commercial space heating, (v) bulk transportation (rail, aviation, maritime), and (vi) international exports.

2.3.1 Heat for Industrial Processes

Currently, there is no dedicated hydrogen production for industrial process heating. However, demand for heating via hydrogen combustion is likely to increase so long as it can compete economically with alternatives [4].

2.3.2 Land-based Transportation (Light and Heavy-duty Vehicles)

Hydrogen has been discussed as an alternative to gasoline or diesel for decades – as mentioned earlier in the introduction. However, actual demand for hydrogen-fueled fuel cell electric vehicles (FCEV) for personal use has not quite materialized. As of December 2020, there were fewer than 9,000 FCEV on the road in the United States [82]. On the contrary, over 300,000 electric vehicles (EV) were sold within the United States in 2019 alone [67]. While it appears EVs have proven to be a more competitive substitute for conventional internal combustion engines (ICE) than FCEV for light-duty applications, there is potential for hydrogen to fuel heavy-duty vehicles as original equipment manufacturers look to decarbonize their heavy-duty fleets. Hydrogen offers a shorter refuelling time than EVs and the overall weight of a hydrogen-fueled heavy-duty vehicle is less than a heavy-duty EV [4]. However, the development of a ubiquitous hydrogen refueling station network is more difficult than the development of a similar EV recharging network since the transmission and distribution infrastructure used to move electric power already exists.

2.3.3 Bulk Storage of Electric Power

Currently, hydrogen plays no role in the storage of electric power on the bulk power system. However, the demand for a low-carbon, long-duration, energy storage medium will grow as the share of VRE grows. Hydrogen can store electric power through the production of hydrogen, storage of the hydrogen, and ultimate power production via hydrogen in either a gas turbine or stationary fuel cell.

Key Takeaways from the MIT Energy Initiative's Future of Storage Chemical Energy Storage Chapter

While the use of hydrogen as a long-duration energy storage medium is feasible, the MIT Energy Initiative Future of Storage report, on which I was a co-author of the chemical energy storage chapter, lays out the following key takeaways after studying hydrogen as an energy storage medium:

- The low energy cost associated with storing hydrogen makes the molecule a viable long-duration energy storage medium.
- Hydrogen is currently produced, transported, and sold to end-use consumers as a feedstock for numerous industrial processes.
- A hydrogen value chain consists of commercially proven technologies.
  - Electrolyzers, which split water molecules into their constituent elements of hydrogen and oxygen, are currently produced by numerous OEMs. The capital cost associated with installing an electrolyzer has decreased over time and is anticipated to decrease precipitously into the mid 21st century.
  - Thousands of miles of dedicated hydrogen pipelines are in operation throughout the world. While research is necessary to ensure natural gas pipelines can be retrofitted to move hydrogen, the construction of new hydrogen pipelines has been proven.
  - The liquefication of hydrogen and transporation via truck has been commercially proven.
  - The storage of hydrogen, whether above ground compressed hydrogen storage tanks or underground in salt caverns, has been techni-

cally proven and many bulk hydrogen storage facilities are operational throughout the world.

- Strides have been taken toward the development of technologies that produce power using hydrogen as a fuel.
  - Many gas turbine OEMs are pushing to develop 100% hydrogen-fueled gas turbines and combined cycle units which would produce electric power via the combustion of hydrogen. This mode of power production relies on proven technologies; however they must be adapted to accommodate hydrogen's longer flame length and subsequent NOx emissions. To this end, cost reductions associated with this technology are marginal as the technology itself is mature.
  - Stationary fuel cells are also being developed. These fuel cells produce power via the synthesis of water and the combination of hydrogen and oxygen. This mode of power production is very expensive relative to more mature combustion technologies. Given the physical structure of these this technology is similar to that of an electrolyzer, it is estimated the cost of fuel cells will decline precipitously.
- While the low energy cost associated with storing hydrogen makes it an appealing energy storage vector for long-duration applications, the actual power produced using hydrogen as a fuel is quite expensive relative to power produced via natural gas. Moreover, the total cost associated with producing electric power via hydrogen is very sensitive to the capacity factor of the power production asset.
- "When it comes to hydrogen demand, energy storage is more likely the tail than the dog."
  - Hydrogen allows for the indirect electrification of difficult to elec-

trify sectors. This said, demand for hydrogen will likely be driven by sectors such as industrial process heating, heavy-duty trucking, aviation, and maritime shipping. So long as cheap natural gas-fueled power generation assets remain on the power system, it will be difficult for power produced via hydrogen to compete in the power market.

2.3.4 Residential and Commercial Space Heating

While hydrogen currently plays no role in residential and commercial space heating applications, many utilities are fighting to leverage their existing gas network to move and sell green hydrogen to their end-customers. [91] Utilities believe hydrogen could play a role in the decarbonization of the space heating in very cold regions where heat pumps do not perform well. Time will tell how this demand might materialize. If utilities decide to blend hydrogen directly into their existing gas networks, there is a "blend-wall" near 15% hydrogen by volume beyond which their customers will need to replace their appliances [61]. Utilities must decide whether they will blend hydrogen on their system or retrofit their entire system to move 100% hydrogen instead.

2.3.5 Bulk Transportation (Rail, Aviation, Maritime)

Current use of hydrogen in rail, aviation, and maritime applications is limited to small demonstration projects with few exceptions. Hydrogen has the potential to play a substantial role in these applications given its energy density and mass relative to electric power substitutes – similar to heavy-duty vehicle applications. These sectors are likely to be difficult to electrify given the long-haul, high-payload nature of their applications [4].

2.3.6 International Exports

The United States could theoretically export hydrogen, similar to oil and natural gas, if the global market were to materialize. These exports could take the form of liquefied hydrogen or liquid organic hydrogen carriers (LOHCs). The liquefaction of hydrogen is not a new concept, much of the hydrogen transported today in the United States is liquefied prior to being loaded on a tanker truck. However, the temperature at which hydrogen transitions from a gas to a liquid is considerably lower than that of natural gas (-423 °F for hydrogen vs. -260 °F for natural gas) and the liquefaction of hydrogen consumes about 30% of the energy content of the hydrogen being liquefied. [71] [58] Alternatively, hydrogen exports could rely on LOHCs such as Ammonia or Toluene. These chemicals do not require such low temperatures to liquefy and ship between continents; however, there is an added efficiency loss associated with the production of these LOHCs and splitting of hydrogen from the LOHCs at the cargo's destination. [65]

Given the United States' geographic position in the world, it is well suited to supply markets throughout Europe, Africa, Central America, and South America. The United States would likely face competition from Australia to meet demand in the Asia-Pacific region.

2.4 Nexus of Market Development and Regulation of Hydrogen Market in the United States

The current market for hydrogen in the United States is roughly 10 million tons per year – of which 6 million tons are consumed in the oil refining sector and 3 million tons are consumed in the fertilizer manufacturing sector [74]. Hydrogen is supplied by industrial gas manufacturers and it is primarily produced via SMR units without carbon capture technology – "gray hydrogen." The contractual relationships of these producers and consumers is asset specific. For example, if an oil refinery is considering an expansion which would require extra hydrogen they work directly with an industrial gas provider to either install an SMR on-site at a given refinery or purchase hydrogen from a centralized hydrogen production site which is then shipped to the site either via a truck and trailer or dedicated hydrogen pipeline – all owned by the industrial gas producer.

While this bilateral contracting model is sufficient for the relatively small hydrogen demand in the United States today, it is possible this model would need to change to allow for more free trade of hydrogen in the market as it grows and serves different end use sectors. Ultimately the materialization of this market will depend on actual demand for hydrogen. The market itself could serve to increase the economic competitiveness of hydrogen, relative to other substitutes, via competition between suppliers and consumers of hydrogen. Free-market pricing signals could drive new entry into the market by firms who otherwise would not know there was unsatisfied demand for hydrogen.

If demand for hydrogen diversifies across end-uses, it is likely the asset specificity driving investment in individual hydrogen production assets will also decrease. The geographic shift in demand from localized demand hubs to ubiquitous demand for hydrogen throughout the country would drive demand for seamless transmission, distribution, and storage of hydrogen within the market regardless of how hydrogen supply diversity develops. An optimized and planned transmission network could serve to minimize the overall delivered cost of hydrogen at the user's gate by ensuring the most cost-effective VRE assets are available to produce the cheapest green hydrogen. However, this network need not be a country-wide interstate hydrogen network similar to the natural gas system in the United States. Overbuilding of such a system could serve to counteract the cost reductions from producing power via cheaper VRE sources. It is possible that hydrogen valleys – similar to what is being proposed in the European Union – may materialize to provide the most cost-effective hydrogen for end-users across the country. [17]

To date, hydrogen is not regulated as an energy vector within the United States – similar to either natural gas or electric power. Hydrogen has the potential to aid in the deep decarbonization of the United States' broader energy sector (beyond transportation) and steps should be taken to develop a regulatory framework for hydrogen. When hydrogen is an economically feasibly alternative to existing fuels or energy vectors, this framework will allow relevant parties to avoid political and regulatory risk when weighing their investment decisions. Proactive regulation of the sector could also potentially stimulate the hydrogen market by minimizing regulatory risk associated with market development. The United States has an opportunity to circumvent market develop issues faced in the 20th century as oil, natural gas, and electric power all moved from local nascent markets to interstate commerce.

Chapter 3

Background on Energy Market Development

“A condition for a widespread use of hydrogen as an energy carrier in the EU is the availability of energy infrastructure for connecting supply and demand.”
- European Commission, July 2020 [16]

The European Commission included the above quote in their 2020 publication *A hydrogen strategy for a carbon-neutral Europe.* [16] The quote highlights the importance of midstream infrastructure – a critical point often overlooked by energy technologists. While the demand for hydrogen in the United States' energy sector faces a "chicken and egg" problem, low-cost transportation and storage of hydrogen could serve to stimulate demand through minimization of hydrogen costs.

The midstream element of the hydrogen value chain encompasses the transportation of hydrogen from production sites to demand centers and the bulk storage of hydrogen on the network. If hydrogen is to play a central role in the United States' energy sector, it is imperative legislators and regulators act to circumvent potential inefficiencies and anti-trust actions within the midstream hydrogen sector.

The United States is home to expansive energy transmission networks that seamlessly move oil, natural gas, and electric power from production sites to load centers throughout the country. Each of these energy transmission networks serves a similar purpose – to connect suppliers and consumers. Yet the development of regulation guiding the construction of infrastructure and the market for these commodities fundamentally differ. In order to adequately establish a market for hydrogen and construct required infrastructure one must analyze the development of the United States' the oil, natural gas, and electric power transmission infrastructure, and the resulting markets. From this analysis, one will have a better understanding of what has worked, what has not worked, and what should, ultimately, be considered when developing a hydrogen transmission network and market.

Of similar importance, it is imperative to evaluate how other countries are establishing goals concerning hydrogen diffusion throughout their respective energy systems. Many countries have released detailed hydrogen strategies laying the groundwork for a hydrogen future within their country. [22]

The rest of this chapter (i) highlights the development of oil, natural gas, and electric power markets in the United States, (ii) details the hydrogen strategies of countries throughout the world to see how they have approached introducing hydrogen into their energy systems, and (iii) summarizes the findings from the historical and international analysis to establish critical areas to consider as the United States looks to integrate hydrogen into its energy sector.

3.1 Historical Development of Oil, Natural Gas, and Power Markets in the United States

3.1.1 Midstream Oil Market Development

The modern oil industry in the United States was born in Pennsylvania in the 19th century as Edwin Drake aimed to exploit the oil that naturally seeped from the ground. From humble beginnings, demand for oil quickly expanded as society realized oil could be utilized for a multitude of applications. This rapid expansion enabled the growth of the oil industry and, in particular, the industrial tycoon John D. Rockefeller as Standard Oil took hold. [105]

The demand for crude oil is driven by industrial customers who take raw crude and refine it into usable products. To this end, the system that has developed over the past 150 years has galvanized routes connecting ports where oil is imported, supply regions where oil is drilled within the US, and major industrial hubs throughout the United States where crude oil is "consumed." This system is shown below in figure 3-1

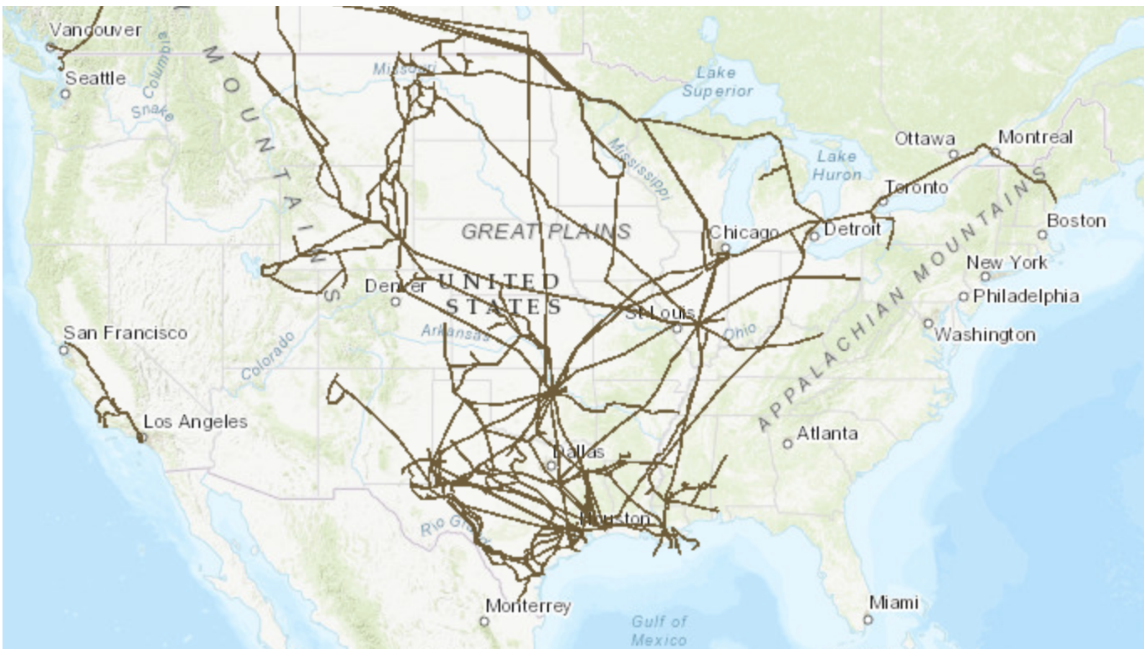

Figure 3-1: Map of United States' Crude Oil Transmission Pipeline System; Source: United States Energy Information Agency

Standard Oil and the Hepburn Act of 1906

While other companies were operating in this space, Standard Oil was the epitome of a vertically integrated oil company – Standard Oil owned oil production, oil transport, oil storage, and oil refining capacity. Ownership of these assets quickly led to multiple market power issues wherein Standard Oil was able to push competitors out of business.

This market power was exerted through numerous business practices, but key market power issues arose as a result of Standard Oil's ownership of oil pipelines which connected their production sites to their refineries and ultimately led to complete dominance of the US's oil market. The United States Congress ultimately responded to this market power in the early 20th century through the passing of the Hepburn Act in 1906 and subsequent Hepburn Amendment which amended the Interstate Commerce Act of 1887. [19]

Spearheaded by Theodore Roosevelt's desire to break Standard Oil's monopoly, the Hepburn Act ultimately gave the Interstate Commerce Commission (ICC) the right to set the maximum rates a railroad could charge to move a customers goods from one place to another. However, the original Hepburn Act did not include a provision which explicitly ceded the regulation of interstate oil sales to the ICC. This was rectified by an amendment, introduced by Henry Cabot Lodge, which clearly stated the interstate sale of oil also fell under the purview of the ICC. The ICC then went on to set maximum allowable rates to be charged by a pipeline owner to move oil on their system – such a system is referred to as a "common carriage." [60]

The Commodities Clause

Shortly thereafter, Senator Stephan Elkins from West Virginia introduced what was called the "commodities clause." The commodities clause, in short, restricts the owner of a railroad to the operation for which the railroad was constructed – moving freight. Many railroads had moved into the business of buying and moving their own commodities on their rail lines rather than providing the right service to their customers. Senator Knute Nelson was quick to understand such a clause would also be critical to the regulation of oil pipelines and the overall effectiveness of the Hepburn Act in combating the monopolization of the oil sector. Senator Nelson is quoted as saying "[w]hether the Standard Oil Company or the pipe lines which it owns is a common carrier or not, unless you divorce production from transportation, the [Hepburn] amendment is of no practical value." Even as Senator Nelson argued for the inclusion of the commodities clause for pipelines, the congress neglected including the clause in the act. This, unsurprisingly, led to re-integration of the oil industry by the 1930s. [60]

The ICC was responsible for dealing with the oil industry actively circumventing rules set out to regulate their operations and curb market power until these responsibilities were ultimately handed over to FERC in the 1978. In the 1980s, the majority of pipeline capacity in the US was owned by 18 different integrated oil companies. While these companies may have potentially held market power, there were no shippers either looking to buy or sell the oil on their pipelines. These companies were the agents transacting on their own pipelines. So, even if FERC wanted to intercede there was no organized party to actively argue against the oil company's hold on the industry. [60]

3.1.2 Midstream Natural Gas Market Development

The natural gas transmission system in the United States is an expansive network of high-pressure pipelines used to connect major natural gas supply regions to either metropolitan or industrial customers. Figure 3-2 below shows the degree to which this system interconnects the entire United States.

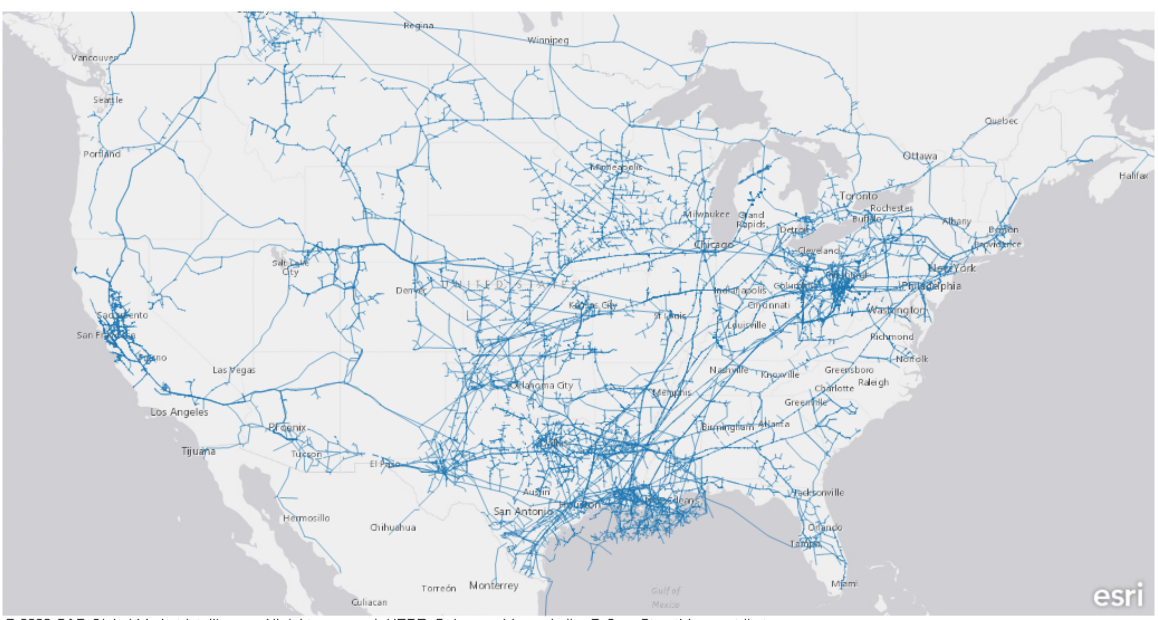

Figure 3-2: Map of United States' Natural Gas Transmission Pipeline System; Source: SNL

Notice, relative to the map of crude oil transmission pipelines in the United States, see figure 3-1, the natural gas transmission pipeline system is much more diffused. Contrary to the crude oil pipeline system, which connects supply regions and industrial centers, the natural gas system connects supply regions to both industrial centers are metropolitan areas. Interestingly, while the natural gas and oil transmission pipeline networks are functionally similar, the difference in customer-base played a key role in differentiating the development of the natural gas market from that of the development of the oil market, albeit on similar timelines.

Public Utility Holding Company Act of 1935

Similar to the oil industry, the original legislation written to regulate the natural gas transmission sector was meant to curb monopoly power within the industry. As a part of the New Deal, congress passed the Public Utility Holding Company Act of 1935 (PUHCA). The "fundamental purpose of PUHCA was 'to free utility operating companies from the absentee control of holding companies, thus allowing them to be more effectively regulated by the states.'" [92] At this time, public utility holding companies owned all elements of the natural gas value chain from production to ultimate sale of natural gas to residential customers. The PUHCA gave the Securities and Exchange Commission (SEC) the right to investigate and simplify a holding company's structure and reorganize the firm's structure as the commission saw fit. The SEC's goal was to establish "integrated distribution systems... confined to a single regional area and ensure that no holding company was so large as to impair local management, effective operation, or effective regulation." [60] In practice, the PUHCA delineated and separated the local distribution companies from the interstate pipeline companies.

The Natural Gas Act of 1938

The next piece of legislation that served to dramatically change the natural gas industry was the Natural Gas Act of 1938 (NGA). In short, the NGA extended the regulatory authority of the Federal Power Commission (FPC) – the precursor to

FERC – to include interstate transportation or sale of natural gas. [13] Pulling directly from the NGA, the first section states "the business of transporting and selling natural gas for ultimate distribution to the public is affected with a public interest, and that Federal regulation in matters relating to the transportation of natural gas and the sale thereof in interstate and foreign commerce is necessary in the public interest." [20] While the act had many moving pieces, the most consequential section to the development of the natural gas markets as we know them today is section 7.

Section 7 of the NGA lays the framework for natural gas infrastructure development in the United States. Section 7 gave the FPC the right to hold hearings and determine whether a proposed natural gas infrastructure project is in the public interest. If the project is found to be in the public interest the FPC will issue a certificate of public convenience and necessity (CPCN) and construction of the facility can commence. Notably, such a framework does not exist for oil pipelines. [20]

Also, in contrast to oil pipelines, section 7 of the NGA rejects the notion of common carriage on a natural gas pipeline. Specifically, section 7 states the FPC has no authority to "compel such natural-gas company to establish physical connection or sell natural gas when do to so would impair its ability to render adequate service to its customers." [20] [60]

A key difference between the development of oil and natural gas pipeline markets in the United States is that of regulatory accounting. Namely, whereas Congress struggled, and continues to struggle, valuing oil pipelines, the process by which natural gas pipelines in the US are valued is detailed in Section 8 of the NGA. Section 8 explicitly states "[e]very natural-gas company shall make, keep, and preserve for such periods, such accounts, records of cost-accounting procedures, correspondence, memoranda, papers, books, and other records as the Commission may by rules and regulations prescribe as necessary or appropriate for purposes of the administration of this Act." [20] This structured accounting process allows for the execution of a cost-of-service ratemaking scheme, similar to the ratemaking process for an electric or gas utility. This regulatory accounting mechanism does not exist for oil pipelines within the US. Ultimately, a lack of a regulatory accounting mechanism and a corresponding tariff base for oil pipelines impeded the development of a transparent market for oil within the US. [60]

The regulatory accounting method used to calculate the tariff base of natural gas companies was affirmed by the 1944 case *Federal Power Commission v. Hope Natural Gas* (*Hope*). Prior to Hope, the FPC had the authority to set "just and reasonable" tariff rates for natural gas companies operating interstate natural gas transmission systems without clearly establishing the tariff base of the natural gas company. In *Hope*, the Supreme Court make the clear distinction that the tariff base of a natural gas company must be based on "actual legitimate costs" less applicable depreciation rather than "reproduction cost" or "trended original costs" which were typically relied on by the gas company when setting their rate base. [23]

The clear accounting practices laid out in section 8 of the NGA and clarification from the Supreme Court as to what costs should be included in a natural gas company's rate base allowed the FPC to clearly set rates for the natural gas company's shippers on mature cost-of-service ratemaking practices.

Ronald Coase and an Open-Access Gas Transmission Market

One of the central tenants of the modern interstate natural gas market is that of Coasian bargaining. Nobel laureate Ronald Coase was the first to make popular the notion that a "private enterprise system cannot function unless property rights are created in resources, and when this is done, someone wishing to use the resource has to pay the owner to obtain it." [14] Makholm makes the argument that pipelines are not simply a steel tube, but they are, instead, the "physical means for providing an intangible property right to transport fuel from one point to another at a highly predictable payment to the pipeline owner." [60] The marriage of these two ideas form the market for capacity on interstate natural gas transmission lines – a market which has led to some of the lowest natural gas prices in the world.

By the mid-1980s, the natural gas pipeline industry was on the precipice of ruin. As Congress attempted to deregulate the natural gas industry in the 1970s, the natural gas pipeline companies, attempting to maximize revenues through the movement of natural gas on their system found themselves with ample excess supply which was valued on the order of $11.7 billion. In dire need of a bailout, the Congress offered the following deal to the sector: bail the sector out in exchange for the acceptance of "open-access" status in which the gas pipeline purely served as a transportation company moving "independently owned gas on a first-come first-served, nondiscriminatory basis under a pre-approved, standard license and existing transport contracts." [60].

FERC Order 636

In April 1992, FERC Order 636 was released. This order was written to foster competition in the natural gas industry. Order 636 restructured the natural gas markets through the "unbundling" of natural gas company services. To this point, natural gas companies bought natural gas supplies and sold them to customers, primarily natural gas utilities, through bundled rates which included the cost of the commodity along with a bundled fee which included transportation, storage, and peak shaving. After Order 636, pipelines were no longer permitted to sell natural gas through these bundled packages. Rather, the natural gas pipeline companies were obligated to separate sales services from transportation services. This opened up the possibility for pipelines to offer new services to their customers such as "no-notice" firm transportation service, unbundled storage services, and uninterruptible transportation services. [7] [18]

3.1.3 Interstate Electric Power Transmission Development

Unlike either oil or natural gas, there is currently no commercially viable technology to store large quantities of electric power for a long duration. As a point of contrast, the natural gas transmission system has ample storage sites throughout the United States [1] – see figure 3-3 below.

[1]One may argue that storage on the natural gas transmission system is, by proxy, electric power storage. However, there are no commercial technologies which can store large quantities of electric power once said power has been generated.

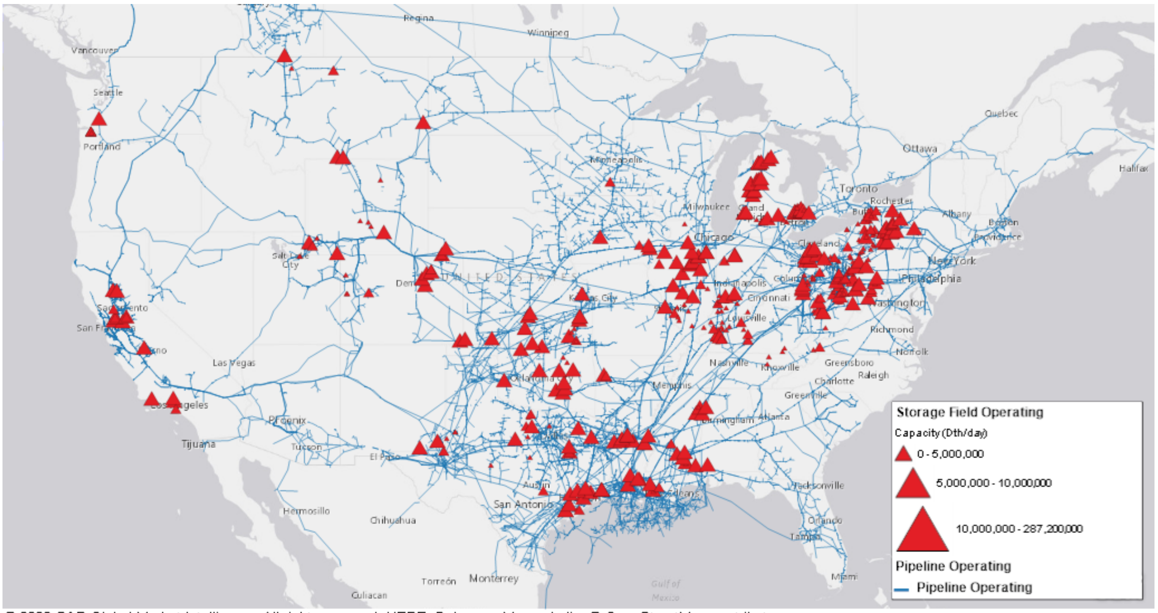

Figure 3-3: Map of United States' Natural Gas Transmission Pipeline and Storage System; Source: SNL

These storage sites are used to store excess natural gas, generally during the Summer months, and provide an extra supply of natural gas during the Winter peak months as homes in the Northern United States turn to natural gas to heat their homes.

This lack of large-scale energy storage infrastructure for the electric power sector has led to the development of an electric power market with an inelastic demand curve. This inelastic demand curve opened the possibility of a market with power prices based on the locational marginal price (LMP) of electric power produced in a given area. In essence, the LMP at a given point on the power grid reflects the actual cost of electric power produced at that point and any constraints on the transmission system used to move the electric power from the producer to the consumer.

Coasian Property Rights and Financial Transmission Rights (FTR)

A sophisticated system trading financial transmission rights (FTR) has developed around the existing electric power system. An FTR is not a physical right to move electric power on the system. Rather, an FTR is a financial hedge against congestion on the system. Put simply, the owner of an FTR is either paid or must pay depending on the local congestion at two points on the system. [2] Coase's definition of market efficiency through clear delineation of property rights is well met through the establishment of markets for FTRs in various independent system operators (ISOs) in the United States.

From the section above on the development of the midstream natural gas markets, clear delineation of ownership rights for physical transportation of natural gas on a company's system has led to the most liquid natural gas market in the world. While electric power markets in the United States have crossed this threshold, there are more institutional barriers that are impeding the development of more variable renewable energy (VRE) within the United States. Namely, the process through which electric power transmission infrastructure is sited and constructed differs significantly from that of natural gas infrastructure.

The Federal Power Act and FERC's Role

The Federal Power Act (FPA) is the seminal piece of legislation that establishes the rules under which electric power was produced and sold in the United States. Enacted in 1920, originally as the Federal Water Power Act renamed to the Federal Power Act in 1935, laid the groundwork for the today's electric power markets. While this act had multiple parts, of particular importance is Part II, which focuses on the regulation of electric utilities. Part II of the FPA gave the Federal Power Commission (FPC), and ultimately FERC, the right to regulate the "the transmission of electric energy in interstate commerce and to the sale of electric energy at wholesale in interstate commerce." Notably, while the FPA gave the FPC the authority to regulate interstate wholesale electric power transactions, the FPA stands in stark contrast to the Natural Gas Act in that these same federal agencies do not have the authority to site interstate electric power transmission infrastructure. The siting of said infrastructure is generally left to the states themselves. [100] [97]

The States vs. Electric Power Transmission Development

Leaving the siting of interstate electric power transmission infrastructure to the states has led to many issues as companies have looked to construct new transmission lines to connect the most "high quality" VRE – generally produced in remote areas of the country with either high sustained winds or high solar irradiance – to demand regions in highly dense metropolitan areas. This concern is amplified as the developers of these projects work secure the right to construct this infrastructure on land when the landowners are receiving none of the economic benefit from the project. The book *Superpower: One Man's Quest to Transform American Energy*, written by Russell Gold, details the struggles Michael Skelly faced as he looked to connect a major wind farm in the Oklahoma panhandle to a demand region in Tennessee. The project at hand was the Plains & Eastern Clean Line, developed by Clean Line Energy Partners. The Plains & Eastern Clean Line was a high-voltage direct current (HVDC) transmission line, proposed in connecting the windy plains of Oklahoma to the Memphis, Tennessee region. A map showing the project's path is shown below in figure 3-4.

Reviewing the map in figure 3-4, one can see clear winners and losers from the proposed development. Those who owned the wind farm in Oklahoma were given a more lucrative market in which to sell their renewable power. [2] However, if the Plains & Eastern Clean Line were built, this wind farm would have the opportunity to sell their electric power, presumably at a higher price, to a region with higher demand for electric power. On the other side of the transmission line, utilities in Tennessee – the Tennessee Valley Authority in this case – would have more ready access to low-cost renewable energy from these windy plains of Oklahoma.

Given the Plains & Eastern Clean Line was meant to be a HVDC transmission line, the project did not leave much benefit for the state of Arkansas. While the project would have created jobs for local Arkansans during the construction process, the state would not have seen long-term benefits associated with a greater supply of

[2]The real-time price of electric power is set based on the supply of and demand for electric power at a given moment, if this wind farm was producing power in remote Oklahoma and had no outlet to sell this power beyond the local region, the price for that would likely be very low as supply far outpaces demand.

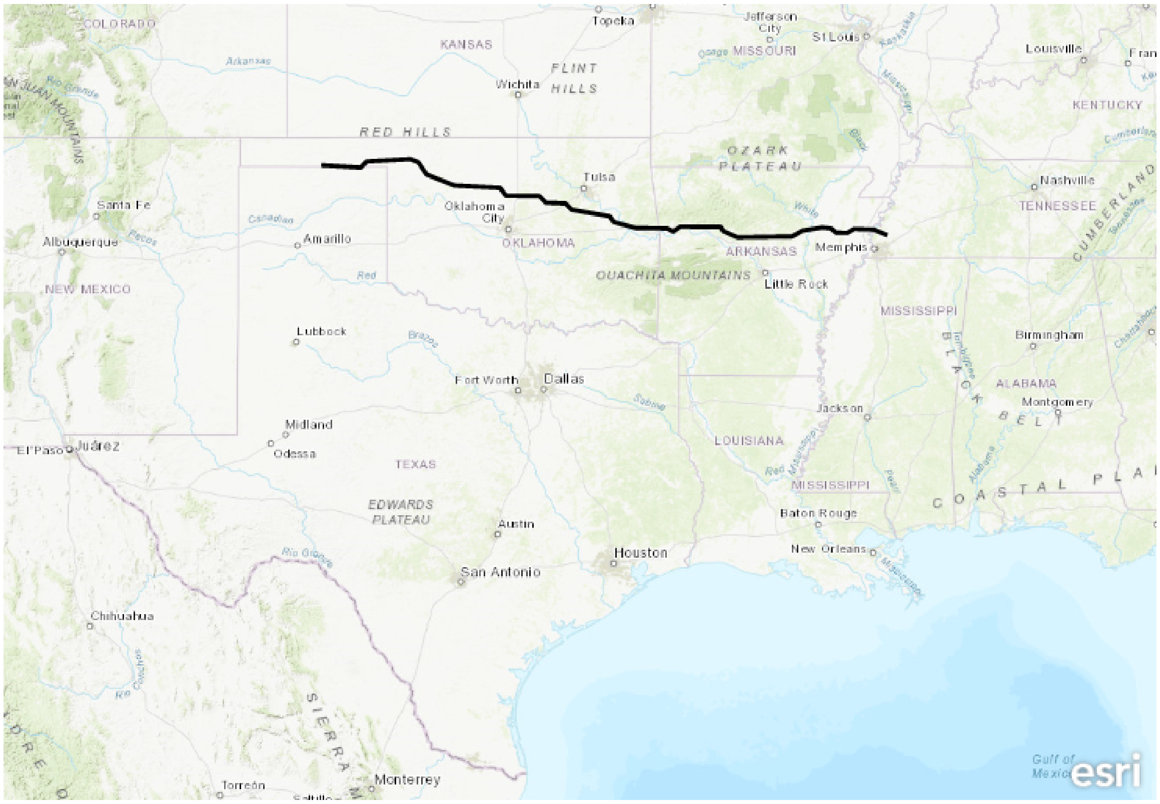

Figure 3-4: Plains & Eastern Clean Line; Source: SNL

low-cost renewable energy.

This discrepancy set the stage for a decade-long battle for the future of the Plains & Eastern Clean Line. Ultimately, the Plains & Eastern Clean Line project was terminated, though a portion of the line within Oklahoma was sold to NextEra, in 2018 [39].

Arkansas representatives claimed victory for state's rights after the Plains & Eastern Clean Line project was terminated. According to an article written in POWER-Grid International, Arkansas lawmakers stated: "This is a victory for states' rights and a victory for Arkansas. We are pleased that the Department of Energy responded favorably to our request to terminate this agreement. We support policies that put our nation on the path to energy independence, but they should not cost Arkansas landowners a voice in the approval process." [48]

The situation faced by Clean Line Energy Partners is not unique; similar court battles have played out across the United States. The story is generally the same: as a power line crosses state lines there will be winners and losers. While the winners are generally fighting for more access to low-cost renewable electric power, the losers are fighting to either keep the renewable resources for use within the state, as seen in Southern California Edison Company, Case No. 130, Decision No. 69638, or to maintain the natural beauty of their state, as seen in Northern Pass decision in New Hampshire to reject the project's permitting. [15] [79]

3.2 Key Takeaways from Energy Commodity Market Development in the United States

Given the physical characteristics of hydrogen – namely, hydrogen is a gas at standard temperature and pressure and it can be liquefied at very low temperatures – it would be easy to default to the framework which regulates the natural gas sector in the United States as a reasonable proxy for hydrogen market development. However, there are important lessons to be gleaned from the development of the oil and electric power markets as well.

Oil The development of the oil market in the United States can be summarized as a fight against market consolidation and monopoly. The key takeaways from an analysis of the historical development of the oil sector are:

- Reject the notion of common carriage as it leads to economically sub-optimal outcome and breeds market consolidation through moving favored shippers' quantities ahead of other customers.

- Implement the commodities clause to ensure the separation of pipeline owners and resource owners. Building off the prior point, if the pipeline owner also owns the resource it is moving there is a tendency to favor one's own capacity over another customer.

Electric Power It is more difficult to draw similarities between hydrogen and electric power given the lack of bulk storage options for electric power on the grid.[3] Regardless, the development of the electric power markets in the United States does offer one critical insight for a future hydrogen infrastructure and market development.

- Critically, siting authority of bulk interstate transmission projects should be in the hands of the federal government rather than the States.

Natural Gas Natural gas is the most physically similar to hydrogen. Hydrogen, if demand materializes, will most likely prove a zero-carbon substitute for natural gas in many cases. Unsurprisingly, the development of the natural gas regulatory framework and market is the most applicable to that of hydrogen. There are many lessons that can be gleaned from the development of the natural gas markets and should be considered when evaluating the future of hydrogen in the United States.

- From the Public Holding Company Act of 1935, keep the end-use shippers from owning interstate hydrogen pipelines. Historically, this materialized as keeping local natural gas distribution companies from owning interstate pipeline companies.

- Either revise the NGA or write legislation specifically delineating a regulatory construct for hydrogen within the United States to make clear the sale of hydrogen is *necessary and in the public interest*.

- Enact an order similar to Section 7 of the NGA to give the federal government, likely through FERC, the authority to issue CPCNs for hydrogen transmission projects in the United States.

- Enact an order similar to Section 8 of the NGA ordering hydrogen pipeline companies to follow structured regulatory accounting practices.

[3] Coincidentally, hydrogen is a molecule that could enable bulk seasonal storage of electric power.

- Firmly establish property rights associated with capacity ownership on a hydrogen pipeline a la Ronald Coase. Similar to natural gas, this should materialize through the establishment of a market for capacity on the pipeline.

- Unbundle hydrogen company services before these companies have the opportunity to bundle them. From the historical analysis of the natural gas market development, it is clear companies which own interstate pipeline should only be in the business of moving the commodity through the pipeline and storing the commodity.

3.3 Cross-Sectional Analysis of International Hydrogen Strategies

Previous sections have provided historical context as to how and why rules developed concerning the siting and construction of midstream oil, natural gas, and electric power infrastructure in the United States. The takeaways from each of these sections will prove useful in assessing rules under which hydrogen infrastructure might be built out. It will also be useful to review how other countries who are more seriously considering hydrogen as an energy vector to decarbonize their societies are planning to build out their hydrogen infrastructure. The rest of this section analyzes the hydrogen strategies of the European Union, Japan, and Australia, respectively, in an effort to identify key strategic items the United States should consider when writing regulation focused on a future hydrogen sector.

3.3.1 The European Union

As quoted at the beginning of this chapter, the European Commission released their hydrogen strategy in July 2020. This high-level strategy lays out a road map for hydrogen technology development and consumption by sector. In particular, this strategy calls for the consumption of hydrogen for heating industrial processes, for balancing the bulk power system, for fueling transportation, and for heating the residential and commercial sectors by 2030 in certain regions. This excess demand far outstrips the existing demand for crude oil refining and ammonia manufacturing and the applications. If this were the United States, one could argue the consumption of hydrogen in this time frame is clothed in the *public interest*. While the European Commission's hydrogen strategy clearly lays out the commission's goals as far as hydrogen sector investment targets, electrolyzer installed capacity targets, and target costs for hydrogen, details concerning the regulation of new hydrogen infrastructure are lacking. The quote at the outset of this chapter makes it clear that the Commission understands the necessity of midstream hydrogen infrastructure. While the regulatory details are not discussed in the strategy, the Commission recognizes the need to a jointly develop this hydrogen infrastructure along with the commercial realities associated with developing this hydrogen market [16].

Unlike the United States, the European Commission does not have an agency which has the authority to site new energy infrastructure within the Commission's constituent countries – similar to that of FERC in the United States. This leaves each individual member state to establish their own hydrogen road map and come to their own conclusions concerning the construction of new energy infrastructure within their borders. The sections below detail individual country's prerogative and written hydrogen strategy.

The Netherlands

The Netherlands, and more specifically the port of Rotterdam, is generally considered the energy gateway to Europe. As Europe has looked toward liquefied natural gas (LNG) as a substitute for Russian natural gas the Port of Rotterdam and the country's natural gas trading hub, the Title Transfer Facility (TTF), have become critical to Europe's energy sector.

Conscious of the Netherlands' critical role in Europe's energy sector, the Dutch government has made the decision to pursue an aggressive hydrogen strategy in an effort to stimulate further hydrogen demand throughout Europe.

The Dutch hydrogen strategy is focused on being a first mover in the hydrogen space and establishing the Port of Rotterdam as a hub for international hydrogen flows. There is an overarching assumption that the hydrogen supply chain will develop similar to that of natural gas and electric power.

While the government is driving the development of the country's hydrogen strategy, there is a particular emphasis on having individual gas companies operate a future hydrogen network and establish their own hydrogen transport tariffs. The government is taking the lead, en concert with the two major gas network companies in the Netherlands, to determine under which conditions the existing gas network can be used to transport and distribute hydrogen.

This emphasis on the developing hydrogen's midstream infrastructure is driven by anticipated supply and demand within the country and the continent more broadly. In order to stimulate demand for hydrogen in the short-term, the government is considering mandates to blend hydrogen into the existing natural gas system. With this blend target, the government is striving to incentivize investment in hydrogen production capacity by ensuring a demand for the gas as an energy vector exists.

The Dutch strategy is written conscious of the country's position within the broader continent. Specifically, it is understood that if the Netherlands pursues this hydrogen future alone, economies of scale will be lost and the cost of a potential hydrogen future would be even more expensive than originally anticipated. The Dutch government sees the development of a liquid hydrogen market as a necessary compliment to the build out of hydrogen infrastructure within the country and Northwestern Europe. The strategy gives particular attention to the development of a Northwestern European hydrogen network when considering the future of their own infrastructure development.

The government is aware hydrogen exists uniquely at the nexus of traditional electric power and natural gas infrastructure. To this end, the two gas network operators have identified the development of the power grid and the hydrogen grid should be effectively coordinated. The strategy lays out the establishment of the Main Energy Infrastructure Programme which aims to jointly develop these networks. Given the footprint of the Netherlands is relatively small, offshore wind farms are likely to make up the bulk of new power generation assets. Addressing this fact, the strategy states: "In the case of offshore conversion of electricity to hydrogen, the costs of landing renewable energy and congestion on the electricity grid can potentially be reduced. After all, the transport of hydrogen is considerably cheaper than transporting electricity."

The strategy does not lay out any specific regulatory language. However, as it is written, it is clear the government is acutely aware of the importance that regulation plays in this sector. This study sets a review process for the regulation of a future hydrogen market, which includes the operation of the future network. In the short-term, this review will focus on more temporary roles aimed at helping to kick-start the hydrogen market and developing more structural roles as the market reaches maturity. The purpose of this review is to ensure the security of supply of hydrogen and to keep the total cost of a hydrogen future as low as possible.

The strategy concludes by stating the country is pursuing relevant laws and regulation to ensure the development of hydrogen infrastructure and the simultaneously established market for hydrogen are optimally developed to see the growth of hydrogen demand within the Netherlands and Northwestern Europe more generally. [49]

Germany

Germany has long been a leader in the environmental movement. This movement has been codified through the government's pursuit of *Energiewende* – Germany's plan to reduce annual greenhouse gas (GHG) emissions from 80% to 95% relative to 1990 emissions by 2050. [81]

The Energiewende recognizes the need for power-to-gas technologies in order to deeply decarbonize their energy sector and extract the most value out of the power grid with a large supply of VRE. To this end, Germany has been particularly bullish on hydrogen playing a central role in their energy system moving forward. Germany released their National Hydrogen Strategy in June 2020. This document offers a wide breath of topics concerning the future of hydrogen in Germany: it offers particular plans around hydrogen production technologies, the utilization of hydrogen in the transportation sector, the industrial sector, heating, hydrogen transportation infrastructure, research plans, the need for a broader European focus on hydrogen, and international collaborations aiding in the development of the hydrogen sector. [40] For the sake of this thesis, the focus will be on Germany's strategy concerning the development of hydrogen transportation (midstream) infrastructure.

Germany currently has a ubiquitous natural gas transmission system with bulk gas storage units connected to it. In order to stimulate a hydrogen future within Germany, the government is planning to build and expand the dedicated hydrogen network within the country. As a first step, the government is planning to develop a regulatory framework and technical requirements for gas infrastructure to move hydrogen. The government will also assess whether obsolete natural gas pipelines could be retrofitted to move hydrogen rather than natural gas.

Aside from infrastructure development, the government is planning to make an effort to better align electric power, heat, and gas infrastructure within the country. This will materialize as a reshaping of the planning, financing, and regulatory framework such that it is possible to coordinate across these different infrastructure classes and develop them "in line with the needs of the energy transition." [40]

Moreover, the German government sees hydrogen playing a substantial role in the transportation sector. The development of German hydrogen infrastructure will pay particular attention to the needs of road transport, railway, and waterways in an effort to make hydrogen widely available to this sector.

3.3.2 Japan

Japan has arguably the most developed hydrogen strategy in the world. Driven by a desire to decarbonize their economy and wean their country off of imported fossil fuels Japan has made substantial strides in establishing a hydrogen market and broader hydrogen economy. The 2020 Summer Olympics, now the 2021 Summer Olympics, are going to be held in Tokyo. These games have been dubbed the "hydrogen Olympics." These games will feature the following: an Olympic torch fueled with hydrogen produced via solar power from the Fukushima Prefecture (an homage to the country's move toward renewable energy and away from nuclear power), a hydrogen Olympic village which consumes power produced from local fuel cells, and hydrogen transportation via buses and fuel cell electric vehicles (FCEV) throughout the games. [30]

This commitment to hydrogen at the Olympic games is a result of the country's concerted effort to enable hydrogen as an energy vector within the country. Japan's first hydrogen strategy, the "Basic Hydrogen Strategy," was released in 2017 and was the first to be released by a government worldwide. [22] This strategy consisted of three main parts: (i) realizing low-cost hydrogen, (ii) developing international hydrogen supply chains, and (iii) expanding renewable energy in Japan. [62]

Realizing Low-Cost Hydrogen The objective of this part was to procure massive amounts of hydrogen such that supply could always meet demand as Japan ramped up its hydrogen economy. Japan proposed procuring this large quantity of hydrogen through the combination of cheap, unused, energy from overseas, as well as carbon capture and sequestration (CCS). Overall, the target hydrogen cost laid out by Japan was 30 yen per cubic meter of hydrogen (roughly $3 per kilogram of hydrogen).

Developing International Hydrogen Supply Chains This tenant of the strategy focused primarily on the development of international liquefied hydrogen supply chains. Similar to the first part of the strategy, the objective is to ensure enough supply is available to meet demand for hydrogen in the short-term. This part also outlined a couple technological goals. Namely, Japan aimed to establish technologies for an organic hydride supply chain to be commercialized in 2025, and to develop technologies which minimize nitrogen oxide emissions from combustion of hydrogen.

Expanding Renewable Energy in Japan This section of the strategy focused primarily on developing power to gas technologies to store renewable energy in the country.

Japan more recently released their 5th Strategic Energy Plan. While this strategy is more general than the Basic Hydrogen Strategy, hydrogen plays a central role within the plan. Quoting the plan: "Since technology innovation has proceeded, now is the time to advance comprehensive initiatives for a 'hydrogen society,' which uses hydrogen as an energy." To this end, the government promotes a strategic arrangement of systems and infrastructure to ensure hydrogen becomes a key energy vector for mid-to-long-term energy security. In order to see this vision become a reality, the government plans to rely on the Ministerial Council on Renewable Energy, Hydrogen, and Related Issues for policy coordination and promotion the "divine trinity" of (i) regulatory reform, (ii) technology development and cooperation with the private sector, and (iii) strategy development of hydrogen stations.

3.3.3 China

China has not published a formal "hydrogen strategy" in the way many countries around the world have. China has, however, pushed for the creation of a "hydrogen society." China is paying particular attention to the consumption of hydrogen in their transportation sector in an effort to both decrease emissions within the country and reduce the country's dependence on foreign oil imports in the sector. [11]

As is the story with many technological developments, China is driving significant cost reductions in electrolyzer technologies. Bloomberg New Energy Finance (BNEF) estimates China is already producing Alkaline electrolyzers at a cost on the order of $200/kW. This is roughly a fifth of Alkaline electrolyzers in the West – see Chapter 4. [55]

While a formal document has not been released, it is clear the Chinese government is actively investing in hydrogen technologies and taking steps to integrate low-carbon hydrogen into their future energy system.

3.3.4 Russia

As a country, Russia arguably has the most to lose from a global shift to hydrogen. Russia is a key supplier of natural gas both directly to Europe through the

European natural gas transmission pipeline network and to the global LNG markets through their Yamal LNG liquefaction and exportation facility. Figure 3-5 shows the international natural gas trade.

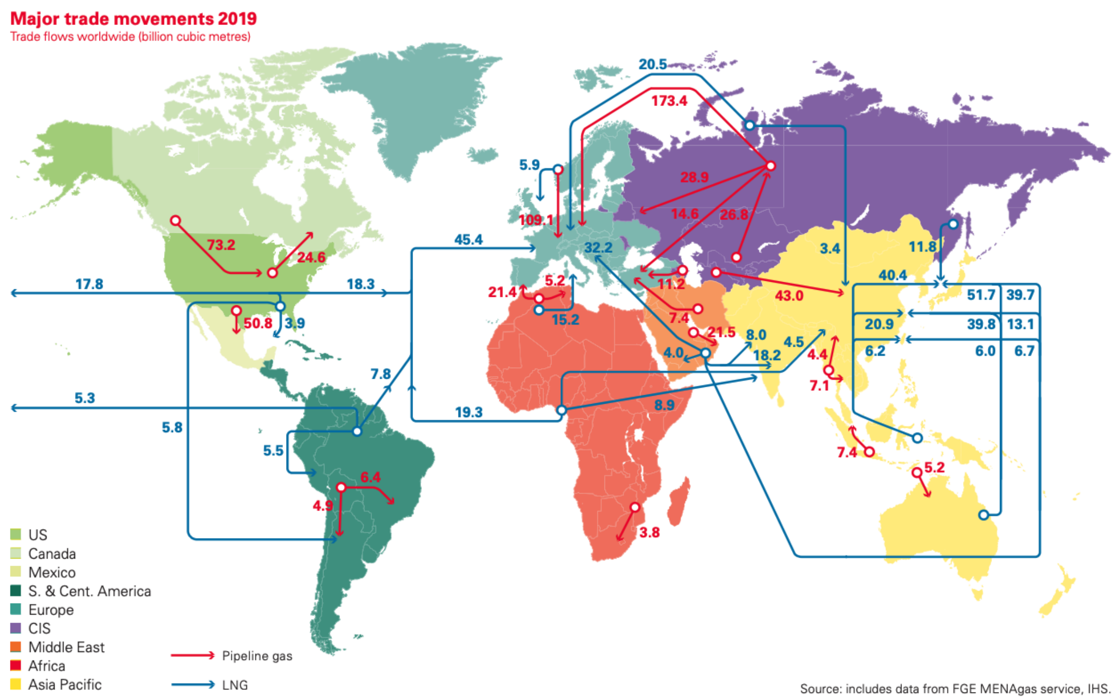

Figure 3-5: 2019 Global Natural Gas Trade [10]

Similar to China, Russia has not released a formal hydrogen strategy. However, Argus has reported Russia's deputy prime minister, Alexander Novak, has stated "Russia aims to utilise its vast fossil fuel resources, nuclear technologies and scientific expertise to become 'one of the world's leaders in production and exports of hydrogen' by 2035." [50]

Russia is conscious of hydrogen's potential role in a future energy sector, and in order to maintain its position as a key energy exporter it is making moves to decrease local production cost of hydrogen in order to enable arbitrage opportunities between Russia and destination markets.

The same physical location that has made Russia a key supplier of energy commodities in the past affords opportunity as a hydrogen supplier. Namely, Russia is physically close to both Europe and East Asian demand centers.

3.3.5 Australia

Australia is another country that has taken the lead on developing a hydrogen strategy. Australia proves to be an interesting case study for two reasons. First, the Commonwealth of Australia is made up of six constituent states. Australia cedes certain regulatory authority to relevant agencies within each of these states, similar to that of the United States. Second, Australia is an energy exportation power house. In 2019, Australia was the largest coal exporter in the world and the second largest LNG exporter. [10] [37]

This history as an energy exporter feeds into their countrywide hydrogen strategy. Stimulated by the demand in East Asia, Australia has introduced a detailed hydrogen strategy aimed at producing and exporting hydrogen to international destinations.

Australia's National Hydrogen Strategy focuses broadly on the government's role in regulating the burgeoning hydrogen market and necessary infrastructure. Notably, the strategy highlights the need for responsive regulation. The Australian government understands it plays a critical role in ensuring the regulatory environment for hydrogen is consistent and predictable in order to support industry investment and innovation. Moreover, the government understands its role in setting regulation that is also efficient and secures opportunities for jobs and economic development within Australia.

The government has taken initial steps to preparing a legal framework for the large-scale production and use of hydrogen as an energy carrier within the country. Currently, it's unclear whether the definition of "natural gas" in the National Gas Law captures a hydrogen and natural gas blend as well. The extent to which the existing regulatory framework applies to blended gas and the implications of this blending are uncertain under the existing legal framework within Australia. At the time of publication, the government had identified 730 pieces of legislation and 119 standards potentially relevant to a nascent hydrogen industry. The government plans to continue reviewing existing legislation, regulations, and standards to address whether their respective legal frameworks can support hydrogen industry development.

Aside from the Australian National Government, each of Australia's constituent states have also released their own hydrogen strategies. As mentioned previously, Australia cedes particular regulatory authority to local state governments, similar to that of the United States. The national government's strategy specifically calls out the need for a coordinated approach to planning and regulatory approvals for hydrogen infrastructure projects. Groups within each of these state and territory governments have been established to develop "competency" and awareness of hydrogen across the country. These groups are meant to address the regulatory gaps and provide advice to proponents of hydrogen projects within each of the states to ensure compliance with state laws. To encourage private investment in hydrogen projects, these state governments are to develop and incorporate "hydrogen-ready" capabilities into planning and regulatory approval schemes. [24]

3.4 Key Takeaways from International Experience

Each of the strategies detailed above focus on the development of a hydrogen market, but for dramatically different purposes beyond simply looking to decarbonize.

- The Netherlands is looking to use its strategic geographic position to enable a hydrogen revolution in the European Union.

- Germany is looking to further its investment in a clean energy future through the utilization of green hydrogen across end use sectors.

- Japan is taking the opportunity to invest in new technologies to wean their economy off fossil fuels.

- Australia and Russia are looking to maintain their positions as a major energy exporters within the market. The Australian government is effectively using hydrogen market development as a hedge against potential lost demand for coal and natural gas.

One thing is abundantly clear: while these countries have seemingly determined hydrogen has a role as an energy vector in their respective energy sectors, there are specifics concerning what changes must be made to existing regulatory and legal frameworks to enable the grow of hydrogen infrastructure.

Regardless of the relatively weak regulatory and legal analysis, applicable take-aways can be gleaned from each of these hydrogen strategies and applied to the United States case.

- In each strategy, the government has committed to working with the owners of existing natural gas infrastructure within each country. This is of particular importance in the increasingly polarized political environment within the United States. Rather than demonizing the companies which own existing fossil fuel infrastructure, the United States' government must be conscious that these companies can, and arguably should, play a critical role in the growth of the hydrogen sector in the United States. Rather than defaulting to constructing new infrastructure to move and store hydrogen, the United States should look to the existing infrastructure system.

- If the United States makes the decision to actively pursue a hydrogen future, the market will evolve gradually. However supply will not stimulate demand. In the context of a hydrogen future, the construction of a robust hydrogen transport network will not stimulate production and consumption of hydrogen within the country. The bulk of the cost savings associated with learning-by-doing and economies of scale occur in the upstream element of the value chain. As more green hydrogen is produced and more electrolysis units are demanded, the cost of produced hydrogen will reduce, and the gas may begin to become an economically substitute for natural gas. Therefore, as in the case of the Dutch and Australian hydrogen strategies demand for hydrogen should first be stimulated through blending requirements in the natural gas system before significant investments in transmission infrastructure can be justified.

- As stated in all three of the aforementioned strategies, hydrogen transmission network planning cannot happen in a vacuum. Hydrogen uniquely allows for the "electrification" of many end uses through the production of hydrogen in an electrolyzer. This interplay implies it is critical to jointly plan the electric power networks and future hydrogen networks. As the United States has begun to rely more on natural gas as a fuel for the electric power sector, the disjointed network planning of the two systems has raised several unanticipated issues. [45] The development of a hydrogen network from scratch allows for optimal coordination with the electric power system.

- The Australian Government has taken a concerted effort to parse through a substantial amount of legislation and standards that may be relevant to a future hydrogen industry. If hydrogen is to be a central energy vector in the future of the United States' energy sector, it is critical a similar review occurs at both the federal and state levels. Unlike the advent of renewable energy which produced electric power – a commodity which was already sold in a liquid market – the hydrogen industry and market are being built from the ground up. There is no widespread, public facing, hydrogen market. This is a novel technology and merits a full legal analysis to ensure there are no impediments facing the future of the industry.

Chapter 4

Justification for Midstream Hydrogen Infrastructure Development in the United States

To justify the evaluation of a regulatory framework for midstream hydrogen infrastructure in the United States, one must first evaluate whether such a transmission network has any place in the United States' energy future.

This chapter introduces a novel midstream hydrogen infrastructure expansion model which identifies optimal hydrogen infrastructure build-out under different market development conditions. The results from this model – in conjunction with the historical commodity market development analysis and cross-sectional international experience from Chapter 2 – can be used to assess different regulatory frameworks for midstream hydrogen infrastructure development in the United States.

4.1 Methodology to Assess Midstream Hydrogen Infrastructure Build-out and Cost Impacts

To understand the midstream infrastructure requirements for the hydrogen sector in the United States, it's important to understand potential hydrogen demand scenarios across different regions and the supply constraints associated with meeting this demand. Given a view of the United States' hydrogen supply and demand balance, its possible to estimate the required midstream infrastructure needed to enable affordable trade of hydrogen between regions. An optimal network of hydrogen transmission infrastructure would enable arbitrage opportunities between states and yield minimized cost for hydrogen across the country. The following model, created by the author of this paper, assesses this infrastructure requirement based on the following elements:

1. Model 2050 hydrogen production costs via electrolysis in each region listed in figure 4-1

2. Estimate different 2050 demand scenarios for hydrogen in the United States and allocate demand to regions

3. Model transmission costs associated with moving hydrogen between regions via inter-regional pipeline

4. Optimize hydrogen network to minimize delivered cost of hydrogen in each region

The output of this model is an estimate of the necessary connections between regions in the United States on a capacity basis to minimize total hydrogen expenditure. If the optimal results show connections between regions, this implies that the construction of a network could serve to lower total expenditures on hydrogen throughout the country rather than having each region rely on its own hydrogen supply.

The following sections discuss each element of the model listed above in more detail.

Table 4.1 shows the abbreviations used throughout this section when formulating the model used to minimize delivered hydrogen costs.

Abbreviation	**Variable**
r	Region
i	Index
j	Index
t	Year
S	Supply
Q	Demand
α	Share of Demand
P	Price
OCapEx	Overnight Capital Expenditure
O&M	Operations and Maintenance Expenditure
C	Cost
CRF	Capital Recovery Factor
PC	Production Cost
Cap	Capacity
SC	Soft Costs
η	Efficiency
HF	Hydrogen Flow
n	Project Lifetime
d	Discount Rate
FOM	Fixed Operations and Maintenance Expenditure
PP	Price of Power
H2	Hydrogen Produced
CF	Capacity Factor
WP	Price of Water
WC	Rate of Water Consumption
β	Rate of Return on Rate Base
L	Length of Pipeline
ν	Compressor Ratio of Power Demand to Length
D	Depreciation

Table 4.1: Mapping of Abbreviations to Variables in Model

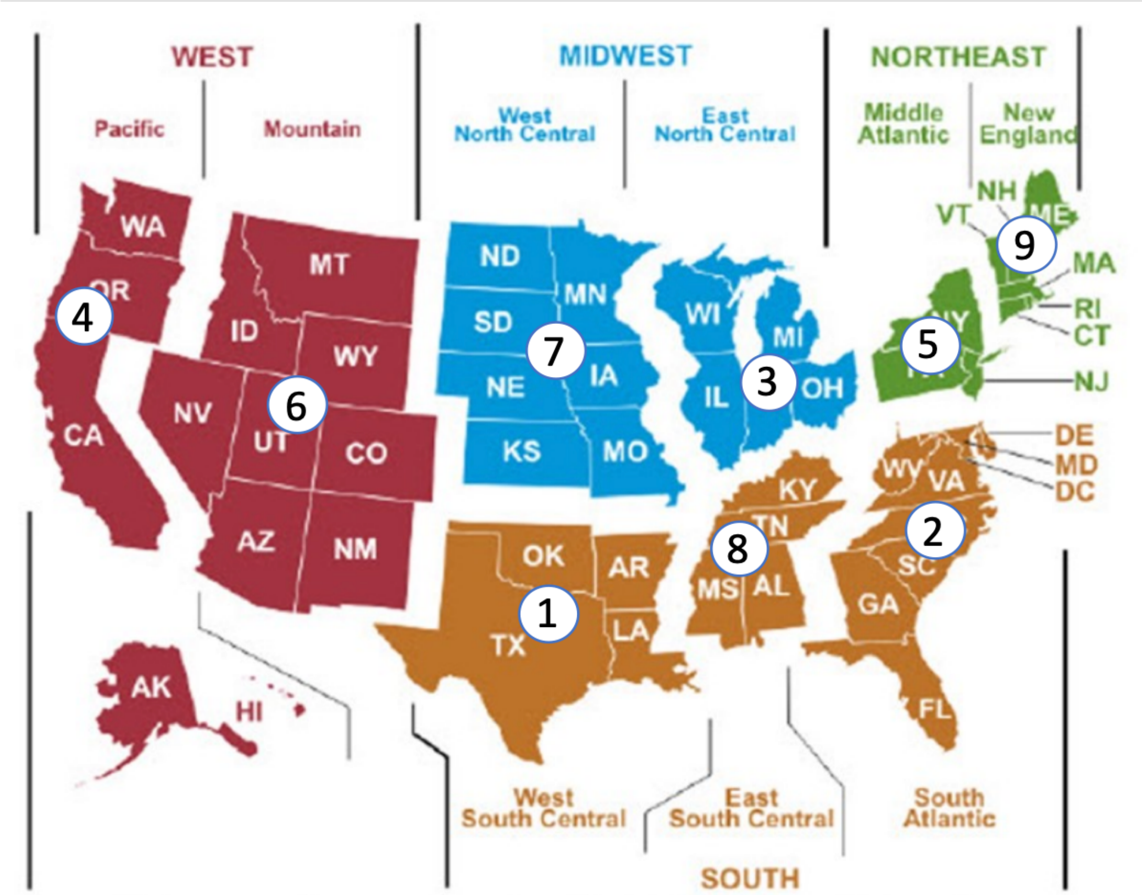

Figure 4-1: Demand Regions based on 2020 EIA AEO with Author's Labels Enumerating Regions [63]

4.1.1 Upstream: Modeling the Cost of Producing Hydrogen Across Each Region

To estimate the hydrogen production cost via electrolysis, the model assesses annual costs associated with operating an electrolyzer and divides said costs by the total quantity of hydrogen produced in the year. The annual costs are broken down into the following sub-costs: (i) capital costs, (ii) operation and maintenance costs, and (iii) feed stock costs – each of which is described in more detail below.

Electrolyzer Capital and Operating Costs:

Estimates for electrolyzer capital and operating costs are based on a review of academic literature and commercial releases. Forecasted capital costs reductions for Alkaline and Proton Exchange Membrane (PEM) electrolysis units are seen below in 4-2.

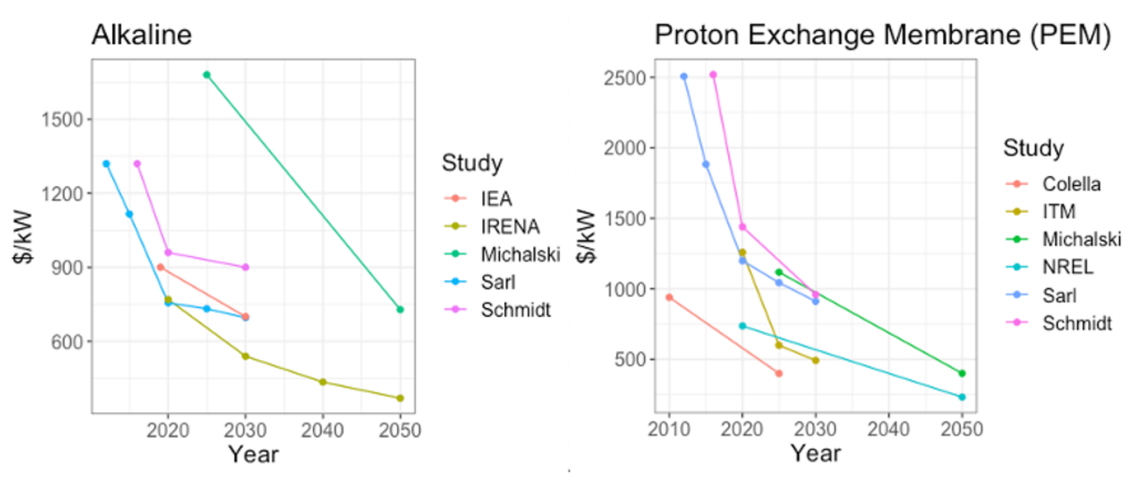

Figure 4-2: Forecasted Capital Cost Estimates for Alkaline and PEM Electrolyzers (Assumed currency exchange rate of 1 Euro = 1.20 USD)

Given the rapid cost decreases forecasted for PEM electrolyzers, this model focuses on the production of hydrogen via a PEM rather than an Alkaline electrolyzer. Based on these forecasts, the model assumes the current (2020) capital cost of a PEM electrolyzer stack is 1,240 USD per kilowatt consumed in the production process ($/kW). Given the forecasted cost reductions for the PEM electrolyzer, the model assumes the capital cost for a PEM electrolyzer in 2050 is $480/kW.

To translate these capital costs to overnight costs, the model assumes a "soft cost" factor of 30%. This factor – based on NREL's H2A model – considers the total cost associated with procuring the land, obtaining the permits, and constructing the facility [66]. This model assumes the 30% soft cost factor holds through 2050. The model assumes annual fixed operation and maintenance costs are equal to 75.20 USD per kilowatt-year ($/kW-year) for PEM electrolyzers [41]. It's assumed the fixed operation and maintenance costs for the electrolyzer scale with the capital cost of the unit. Therefore, in a 2050 case, the fixed operations and maintenance costs are equal to \$20.40/kW-yr. The model solves for the variable costs for electrolysis (electric power and water) endogenously based on demand for hydrogen within the region.

Power Cost

The cost of produced hydrogen is a function of the cost of power and water in a region. This model relies on the EIA AEO for 2050 power prices across each region. This model utilizes the industrial power prices within each region from the EIA AEO when assessing the hydrogen production cost in each region [26].

This forecast is only one estimate. The power costs presented in the AEO are quite high, especially as the share of zero-marginal cost variable renewable energy technologies grows across the nation. To address these high prices, the model uses the power prices from the AEO in a high price case. The cost of power in the East North Central region of the United States is thereby equal to \$0.01/kWh in a low price case and \$0.05/kWh in a mid-price case. The model also adjusts power prices in other regions based on the relative costs in each region based on the AEO's estimates.

For example, the AEO estimates a 2050 power price of \$0.12/kWh in the East North Central region and \$0.17/kWh in the Middle Atlantic region – i.e. 40% higher. The model takes a set price for power in the East North Central region and adjust prices in other regions based on the relative price differences seen in the AEO. This is visualized in figure 4-3 below.

The model does not assume these 2050 power prices are stagnant, rather it's assumed the power price in each region is a function of the total power consumed in the region based on the price elasticity demand for electric power within each region. While price elasticities for each region are not published, they can be estimated based on annual power prices and electricity consumption within each region over time. The formula for the price elasticity of demand for electric power is shown in the equation below:

$$\epsilon = \frac{\%Q}{\%P} \tag{4.1}$$

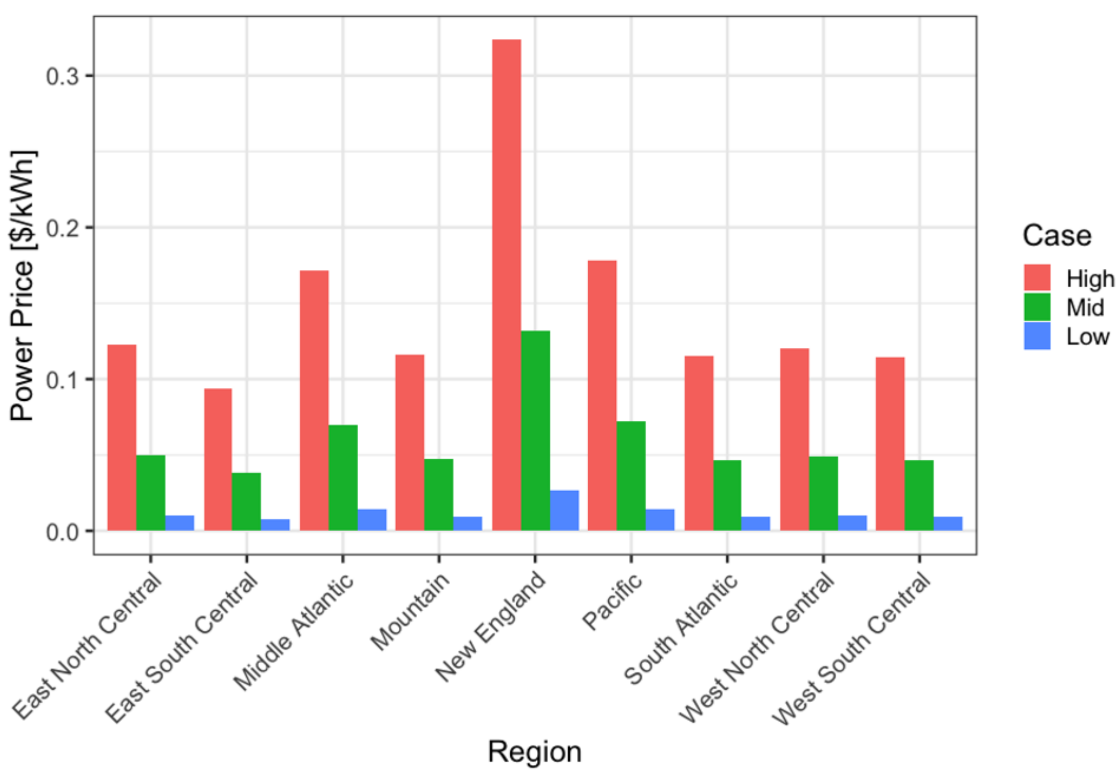

Figure 4-3: Estimated 2050 Power Prices by Region in Each Case

This relationship gives a relative percentage change in quantity of a good demanded based on a percentage change in the price for the good. In the case of electric power, the model solves for this value in each region using the forecasted demand for electric power in the industrial sector and the price paid for electric power in the industrial sector from the AEO [26]. Table 4.2 shows the price elasticity of demand by region.

Region	Price Elasticity (ϵ)
West South Central	0.981
South Atlantic	0.979
East North Central	0.981
Pacific	0.984
Middle Atlantic	0.966
Mountain	0.989
West North Central	0.983
East South Central	0.980
New England	0.971

Table 4.2: Price Elasticity of Demand for Industrial Customers Based on AEO [26]

In this model, the excess demand used to estimate new power prices within the region via the price elasticity of demand are based on the electric power consumed in the hydrogen production process and the electric power consumed to power compressors which move the hydrogen on the pipelines. [1]

Water Cost

Rather than estimate water prices across each of these regions, the model assumes the water cost is the same across the United States.

Electrolyzer Technical Specifications

While electrolyzers are technologically complex, this study characterizes electrolyzers based on three main technical specifications: (i) hydrogen flow, (ii) water consumption, and (iii) efficiency.

Hydrogen flow is an electrolyzer's rate of hydrogen production – this figure is generally measured in cubic meters per hour (m^3/hr). This model assumes the electrolyzer used to produce hydrogen from excess power has a hydrogen flow rate of 300

[1] All power used to compress hydrogen and move it on the pipeline is allocated to the supply region.

m^3/hr. This figure is estimated based on Hydrogenics' technical specifications for their existing line of PEM electrolyzers [46].

Water consumption is a measure of how much water the electrolyzer consumes during operation. This figure varies by electrolyzer technology, but it's assumed a PEM electrolyzer consumes 1.4 liters of water to produce a cubic meter of hydrogen [46].

Efficiency is a measure of power input to effective power output through the production of hydrogen. This figure is typically measured in kilowatt-hours per cubic meter of hydrogen produced (kWh/m^3). The model assumes this figure is equal to 5.2 kWh/m^3, the average of the lower and higher ranges of PEM electroylzer efficiencies as stated in Hydrogenics' technical specifications for their line of PEM electrolyzers [46]. [2]

Summary of Techno-Economic Specifications for the Hydrogen Value Chain

Each of the specifications mentioned in the sections prior, along with their respective sources, are summarized in 4.3.

Abbreviation	Variable	Value	Unit	Citation
CapEx	Capital Cost	480	\$/kW	[88] [21] [9] [83]
FOM	Fixed Operation and Maintenance	20	\$kW-yr	[41]
WC	Rate of Water Consumption	1.4	liter/m^3	[46]
SC	Soft Costs	30%	%	[66]
$\eta_{Electrolyzer}$	Efficiency of Electrolyzer	5.2	kWh/m^3	[46]

Table 4.3: Techno-Economic Assumptions for Hydrogen Production Cost Modeling

Production Cost Model

The production cost of hydrogen is modeled using bottom-up estimates of operational costs and technical characteristics of an electrolyzer constructed in each of the model's regions.

[2] Solving for an energy-equivalent efficiency, 5.2 kWh/m^3 $\sim$ 58%

The production cost of hydrogen is found by summing the annual costs associated with operating an electrolyzer and dividing that by the total quantity of hydrogen produced in a year. Annual costs include capital cost, operation and maintenance costs, and the cost of electric power and water consumed during the hydrogen production process.

$$PC_{r_i} = \frac{OCapEx_{r_i} * CRF + O\&M_{Elyzr_{r_i}} + C_{Power_{r_i}} + C_{Water_{r_i}}}{S_{H2_{r_i}}} \tag{4.2}$$

The overnight capital cost for an electrolyzer is equal to the capital cost of an electrolyzer multiplied by the capacity of the electrolyzer divided by the soft costs associated with constructing the asset.

$$OCapEx_{r_i} = \frac{Cap_{Elyzr_{r_i}} * CapEx}{(1 - SC)} \tag{4.3}$$

The capacity of electric power consumed in the hydrogen production process by the electrolyzer is found by multiplying the efficiency of the electrolyzer by a set hydrogen production rate. The hydrogen production rate within each region (HF_{r_i}) is one of the model's free variables. This variable is adjusted to ensure total hydrogen supply across all regions is equal to the total hydrogen demand. This is detailed further in later sections.

$$Cap_{Elyzr_{r_i}} = \eta_{Elyzr} * HF_{r_i} \tag{4.4}$$

The capital recovery factor is used to annualize the total capital cost of an asset based on a set lifetime and discount rate for the asset.

$$CRF = \frac{d * (1 + d)^n}{(1 + d)^n - 1} \tag{4.5}$$

The operation and maintenance expense for the electrolyzer is based on the fixed annual operation and maintenance rate for the electrolyzer multiplied by the capacity of electric power consumed by the asset.

$$O\&M_{Elyzr_{r_i}} = Cap_{Elyzr_{r_i}} * FOM \tag{4.6}$$

The total cost of power associated with producing hydrogen from this asset is equal to the quantity of power consumed in the process multiplied by the price of the power within a region. This price varies by region, as mentioned above.

$$C_{Power_{r_i}} = PP_{r_i} * Q_{Power_{r_i}} \tag{4.7}$$

The quantity of power consumed in the hydrogen production process depends on the total quantity of hydrogen produced. The efficiency of the electrolyzer gives a relationship between the power consumed in the process and the hydrogen produced in the process.

$$Q_{Power_{r_i}} = S_{H2_{r_i}} * \eta_{Elyzr} \tag{4.8}$$

The total hydrogen produced in a year within a given region is based on the hydrogen flow rate and the capacity factor at which the electrolyzer operates. The hydrogen flow rate is given in units of hydrogen produced per hour of operation of the electrolyzer.

$$S_{H2_{r_i}} = HF_t * CF_{r_i} * 8760 \tag{4.9}$$

The total cost of water associated with producing hydrogen depends on the price of water within a region and the total quantity of water consumed in the hydrogen production process. The relationship between water consumption and hydrogen production is dependent on the electrolyzer technology.

$$C_{Water_{r_i}} = WP_{r_i} * WC_{r_i} * S_{H2_{r_i}} \tag{4.10}$$

4.1.2 Downstream: Hydrogen Demand by Region

It is impossible to accurately forecast how demand for hydrogen might materialize across each region within the Energy Information Agency's (EIA) Annual Energy Outlook (AEO) [26]. To minimize the complexity of the model, the model sets three cases for 2050 hydrogen demand in the United States.

Current demand for hydrogen across all sectors in the United States is on the order of 10 million tons of hydrogen per year (1.1 quadrillion British thermal units (Quads)). This study considers three 2050 hydrogen demand cases: (i) 1.6 quads (Low), (ii) 4.1 quads (Mid), (iii) 9.1 quads (High). The low case represents only modest demand growth outside of current demand (0.5 quads). The mid case represents ambitious hydrogen demand growth based on the United States Department of Energy's hydrogen strategy from November 2020 [75]. The high case represents an overly ambitious case wherein hydrogen represents 10% of the total energy consumed in 2050.

To determine the hydrogen demand within each region, the model assesses the share of 2050 energy demanded in each region relative to the total energy demanded in the country. This share is then multiplied by the total estimated demand for hydrogen across all regions.

Today's demand for hydrogen is not ubiquitous in the United States. Rather, demand is limited primarily to regions with crude oil refining and ammonia production capacity. This demand is already considered in the current 1.1 quads of hydrogen demanded today [75]. This model allocates this 1.1 quads of demand for hydrogen across the West South Central (70%), Pacific (20%), and East North Central (10%) regions in order to ensure new demand does not cannibalize current demand. New demand for hydrogen is split as detailed above and added to current demand.

Assessing total demand for energy in 2050 based on the AEO, the model finds the share of energy demand by region shown in Figure 4-4.

In each scenario, the new hydrogen demand will be multiplied by each region's share of total 2050 energy demand, shown in 4-4. This yields 2050 demand estimates

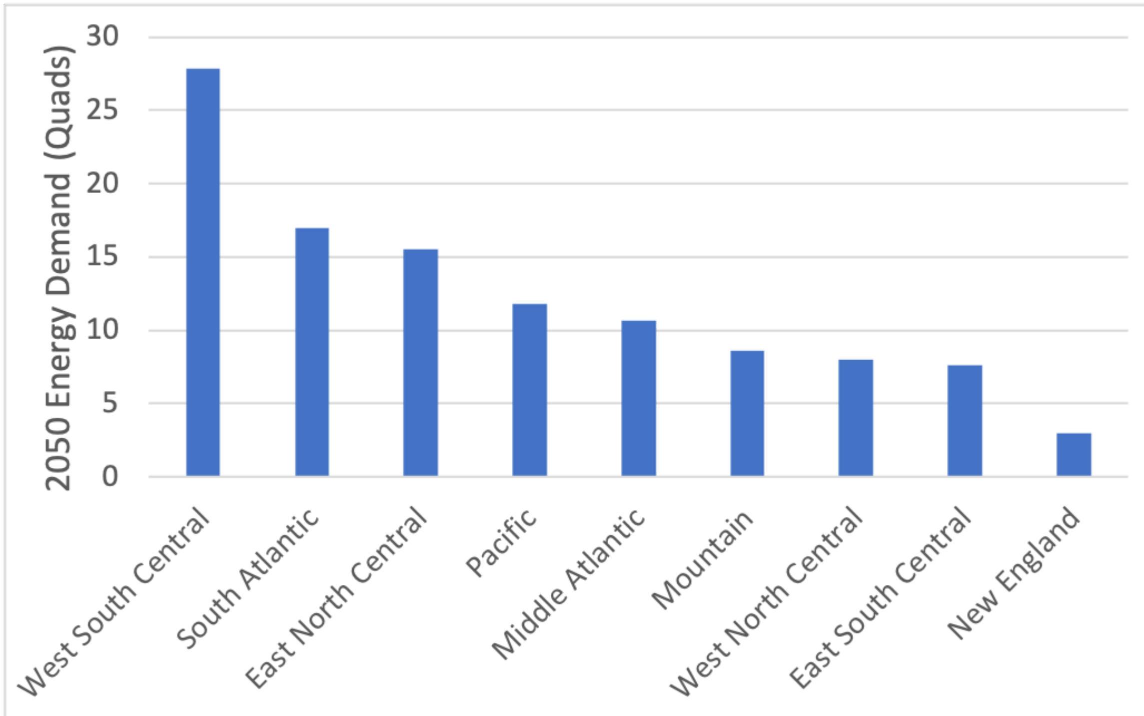

Figure 4-4: 2050 Energy Demand Across Study Regions [26]

curves out to 2050 for each region under different demand cases.

This relationship is formalized and shown mathematically in Equation 4.11.

$$Q_{H2_{r_i}} = \alpha_{r_i} * Q_{H2} \tag{4.11}$$

Where α_{r_i} is equal to the region's share of total energy demand in 2050 from the EIA AEO [26].

4.1.3 Transmission Network Modeling

This model is structured such that a given pipeline is measured by the total capacity of hydrogen it can move in power terms. While the power capacity for a pipeline is generally a function of the diameter of the pipeline and the pressure at which the gas is moving on the pipeline (indicated in equation 4.12), this study assumes a hydrogen pipeline has an equivalent power capacity of 13 gigawatts (GW) based on the European Hydrogen Backbone [42].

$$Capacity_{Pipeline} \sim f(Diameter_{Pipeline}, Pressure) \tag{4.12}$$

Similarly, the effective capital expenditure for a hydrogen pipeline would generally follow the relationship laid out in Equation 4.13.

$$CapEx_{Pipeline}[\$/mile] \sim f(Diameter_{Pipeline}, Pressure) \tag{4.13}$$

This study assumes the cost of constructing a new hydrogen pipeline is on the order of three million USD per kilometer of pipeline constructed ($M/km) or $4.8M/mile [42]. Dividing this rate by the stated capacity of the pipeline, the model finds the CapEx of a pipeline is $369/MW-mile. [3]

There are also capital costs associated with constructing the compression system required to move hydrogen along the pipeline. This cost relies on the total distance hydrogen must be moved on the system. As stated in the European Hydrogen Backbone, a hydrogen pipeline system requires 0.53 megawatts of electric power per mile moved [42]. The cost of installing compression on the system is $4M/MW.

This model assumes the total cost of transporting hydrogen between regions is based on a cost-of-service rate-making scheme. Assuming a single entity owns the hydrogen transmission capacity, that entity would roll all investment in their system into a rate base. The entity would earn a rate of return on the capital they invest and structure their rates such that this value – along with annual operation and maintenance expenses – is covered by the rates they charge their customers for using their service.

The annual cost associated with operating the pipeline divided by the anticipated hydrogen shipped on the pipeline yields the rate a transmission company would be allowed to charge a customer looking to use their asset under a regulated rate-making scheme. This formula is shown in equation 4.14.

[3] Given the capacity of the pipeline is 13 GW, one could theoretically calculate a cost per length-capacity via the division of the cost per length by the stated capacity $\frac{\$4.8\text{M}}{mile}/13,000\text{MW} =$ $369/MW-mile

$$T_{(r_i,r_j)} = \frac{\beta * (OCapEx_{Pipe_{(r_i,r_j)}} + OCapEx_{Comp_{ri}} - D) + O\&M_{Pipe} + PP_{ri} * Q_{Power_{ri}}}{Q_{Moved(r_i,r_j)}} \tag{4.14}$$

This formula is based on a cost-of-service rate-making scheme and will yield a total cost per kilogram of hydrogen moved between different regions based on an allowed rate of return on capital spent by the entity (β). This value will differ as pipelines are built to connect different regions. For example, a pipeline constructed to connect the Pacific region to New England will be considerably longer than a pipeline constructed to connect the East North Central region to New England. This difference in length will drive a difference in total installed cost of the pipeline and this will be reflected in the total transmission cost. The model limits pipeline construction only to adjacent regions. Therefore, it is not possible to construct a pipeline directly from the West South Central region to New England. Rather, gas must be moved incrementally on the pipeline to adjacent regions. To estimate the distances between each of these regions, this model leverages Google Maps to measure the distance between the centroid of each region. A figure indicating each region's label is shown in figure 4-1 below and the corresponding distances between each region is shown in table 4.4.

	1	2	3	4	5	6	7	8	9
1						1180	737	499	
2			700		627			586	
3		700			579		650	551	
4						980			
5		627	579				800		
6	1180			980			800		
7	737		650			800		864	
8	499	586	551				864		
9					286				

Table 4.4: Distances (Miles) between regions based on Author's Estimates

The total hydrogen moved on the network yields an energy figure. For example, if one million tons of hydrogen are moved between region 1 (r_1) and region 2 (r_2) that is the equivalent of 333,600,000 megawatt-hours (MWh) moved between the two regions. Given the pipelines are rated on a power basis, if it's assumed that an equivalent amount of hydrogen is moved per day on the pipeline, then the pipeline would need to be at least $\frac{333{,}600{,}000\text{MWh}}{8760\text{hours}} = 38,000\text{MW} \sim 38\text{GW}$. The capacity connecting regions must be at least as great as the energy moved between the regions if said energy were moved in every hour of the year. This is formalized in Equation 4.15.

$$Q_{Pipe_{(r_i,r_j)}} \geq \frac{Q_{Moved(r_i,r_j)}}{8760} \tag{4.15}$$

The overnight capital cost associated with constructing a new hydrogen pipeline is equal to the rated hydrogen transmission capacity (in terms of power, not energy) multiplied by a set capital cost for the hydrogen pipeline (given in USD per megawatt-mile).

$$OCapEx_{Pipe_{(r_i,r_j)}} = \frac{Q_{Pipe(r_i,r_j)}}{8760} * CapEx_{Pipe} * L_{(r_i,r_j)} \tag{4.16}$$

The overnight capital cost associated with the compression system to move the hydrogen on the pipeline is equal to the power required to move hydrogen, which is a function of the length of the pipeline, multiplied by the capital cost for the compressor – which is given in terms of dollars per megawatt ($/MW).

$$OCapEx_{Comp_{(r_i,r_j)}} = CapEx_{Comp} * L_{(r_i,r_j)} * \nu \tag{4.17}$$

The depreciation for new pipeline system built in each year is assumed to be at a 40-year fixed depreciation rate based on the total capital expenditure associated with constructing new length of pipe.

$$D = \frac{OCapEx_{Pipe} + OCapEx_{Comp}}{40} \tag{4.18}$$

The annual operation and maintenance cost associated with operating the pipeline system, which include the compression system, is assumed to equal 1.7% of the system's ratebase [42].

$$O\&M_{Pipe_{(r_i,r_j)}} = (OCapEx_{Pipe} + OCapEx_{Comp} - D) * FOM \tag{4.19}$$

The power cost, used in compression, associated with moving hydrogen from region to region is equal to the effective utilization of the pipeline multiplied by the power capacity of the compression system.

$$PP_{ri} * Q_{Power_{ri}} = \frac{Q_{Moved(r_i,r_j)} * L_{(r_i,r_j)} * \nu}{Q_{Pipe(r_i,r_j)}} \tag{4.20}$$

The unit cost of moving a quantity of hydrogen on the built system will then be added to the production cost of hydrogen in the origin region. The total delivered hydrogen cost is equal to the production cost of hydrogen in the origin plus the transmission cost associated with moving the hydrogen from the origin to the destination. This is shown in Equation 4.21 below.

$$P_{r_i,r_j} = PC_{r_i} + T_{(r_i,r_j)} \tag{4.21}$$

4.2 Objective Function and Model Formulation

The objective of the model is to solve for a transmission network such that the total cost paid for hydrogen across all regions and years is minimized. This is quantified through a sumproduct of each region's price of delivered hydrogen and quantity of hydrogen demanded. This is codified in Equation 4.22.

$$\text{minimize} \sum_{(r_i,r_j)} P_{(r_i,r_j)} * Q_{H2_{r_j}} \tag{4.22}$$

The results of this model will yield the total cost paid for hydrogen across all regions and the optimal hydrogen transmission network associated with producing such costs. This model can be used to determine whether a federal regulatory framework is actually necessary, or the issue of hydrogen infrastructure siting might be best suited for the state-level.

Formalizing the model, and leveraging the equations introduced in prior sections, the following equation must be solved::

$$\begin{array}{ll} \text{minimize} & \sum_{(r_i,r_j)} P_{(r_i,r_j)} * Q_{H2_{r_j}} \\ \text{subject to} & \sum_{r_i} S_{H2} = \sum_{r_i} Q_{H2}, \ \forall i, j \end{array}$$

4.3 Presentation of Results from Model for Each Case

The output of this model is a hydrogen transmission network which minimizes total hydrogen expenditure across all regions in 2050. In a case which yields network connections, there are arbitrage opportunities to produce hydrogen in a different region and move that hydrogen into the demand region. More specifically, the sum of hydrogen production cost and transmission cost is lower than the cost of producing hydrogen in within the demand region.

This section presents the results of three cases considered based on different hydrogen demand and power price scenarios. Table 4.5 summarizes each of the cases and its constituent scenarios. While many other cases have been run, these results are presented to show the change in optimal hydrogen transmission network based under different hydrogen demand cases.

Scenario	Power Price	Hydrogen Demand
1	Mid	Low
2	Mid	Mid
3	Mid	High

Table 4.5: Case Study Scenarios

4.3.1 Scenario 1 – Low Hydrogen Demand

Scenario 1 evaluates a 2050 future with low hydrogen demand (1.1 quads) and mid-case electric power costs (\$0.05/kWh in the North East Central region). The mid-case power prices offer potential arbitrage opportunities between regions, but the total delivered cost of hydrogen within a region depends on the trade between regions. If trade between regions is low, the unit cost associated with transporting hydrogen between regions increases.

Based on these two facts, the lowest cost inter-regional hydrogen transmission system is no system at all. The optimal transmission network based on this case is shown in figure 4-5 below.

Figure 4-6 shows the total installed capacity within each region dedicated solely to hydrogen production in this scenario 1.

The total expenditure on hydrogen in scenario 1 is 67 Billion USD.

4.3.2 Scenario 2 – Mid Hydrogen Demand

Scenario 2 evaluates a 2050 future with mid-case hydrogen demand (4.1 quads) and mid-case electric power costs (\$0.05/kWh in the North East Central region).

In this scenario, the model finds the total expenditure on hydrogen is lower in the case with an installed hydrogen transmission network than the case without such a network. The optimal transmission network is shown in figure 4-7 below.

Figure 4-8 shows the total installed capacity within each region dedicated solely

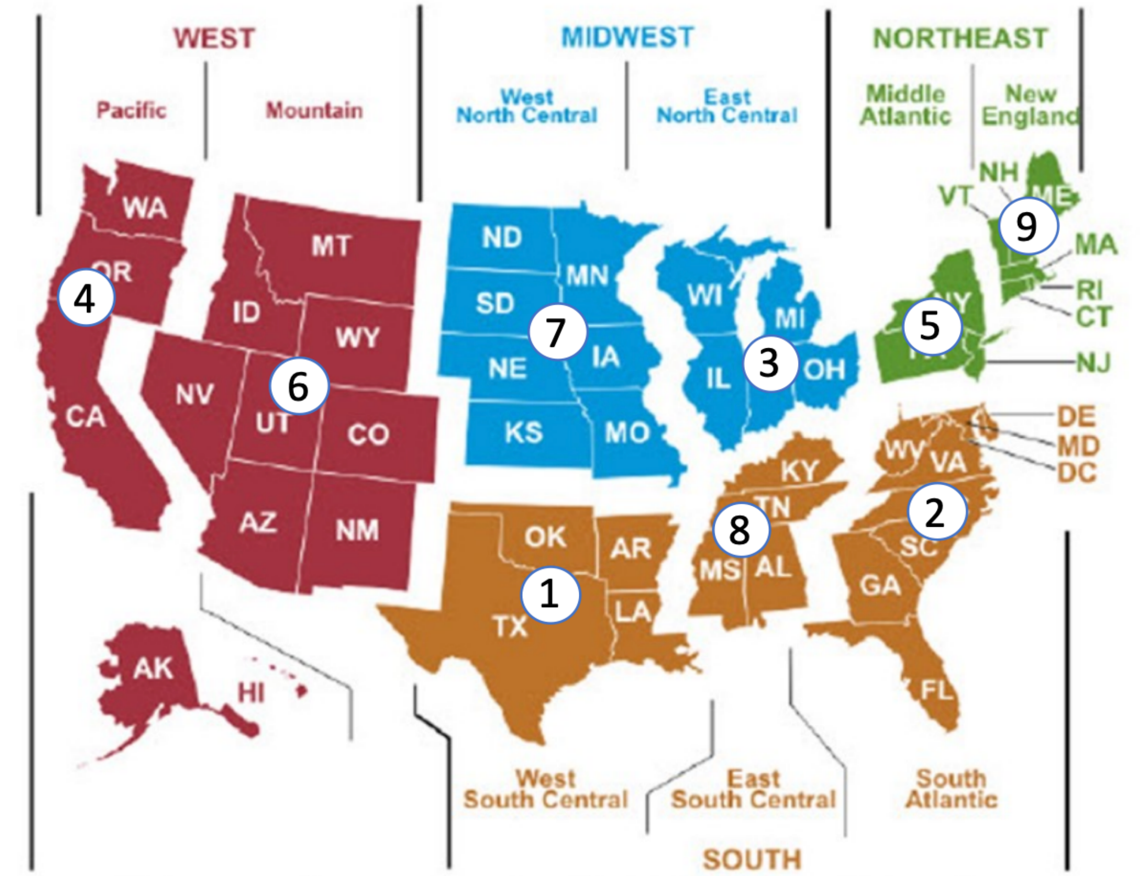

Figure 4-5: Optimal Network Based on Mid Case Power Prices and Low Case Hydrogen Demand – Optimal Network is No Network, Each Region Satisfies its own Demand

to hydrogen production in this scenario 2.

The total expenditure on hydrogen in scenario 2 without a network is 177 Billion USD. If a transmission network is constructed, the total expenditure is 175 Billion USD. Moreover, the total expenditure on hydrogen transmission infrastructure, which includes both the cost associated with constructing the pipelines and the compressors, is 60 Billion USD.

4.3.3 Scenario 3 – High Hydrogen Demand

Scenario 3 evaluates a 2050 future with high-case hydrogen demand (9.1 quads) and mid-case electric power costs ($0.05/kWh in the North East Central region).

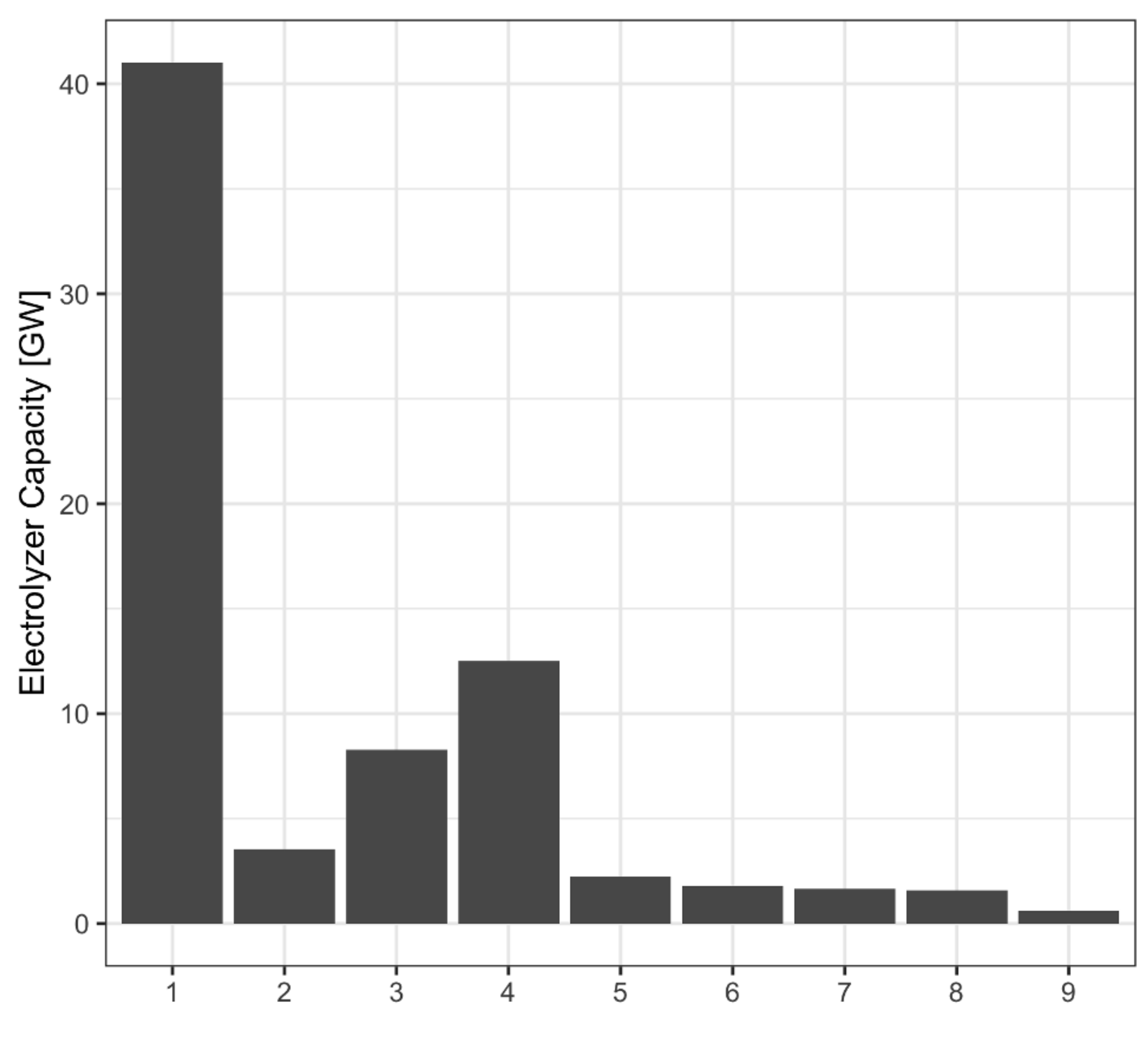

Figure 4-6: Scenario 1 Required Installed Capacity for Hydrogen Production by Region

In this scenario, the model finds the total expenditure on hydrogen is much lower in the case with an installed hydrogen transmission network than the case without such a network. The optimal transmission network is shown in figure 4-9 below.

Figure 4-10 shows the total installed capacity within each region dedicated solely to hydrogen production in this scenario 3.

The total expenditure on hydrogen in scenario 3 without a network is 408 Billion USD. If a transmission network is constructed, the total expenditure is 361 Billion USD. Moreover, the total expenditure on hydrogen transmission infrastructure, which

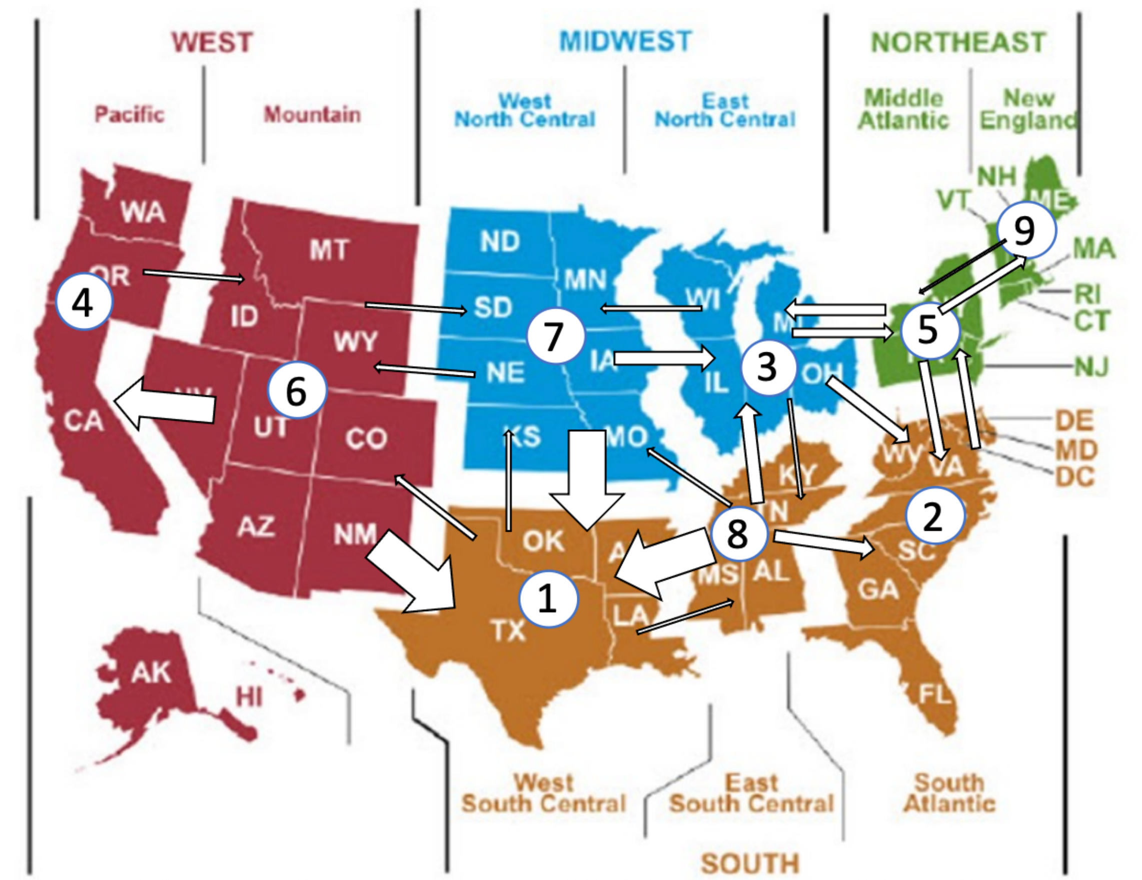

Figure 4-7: Optimal Network Based on Mid Case Power Prices and Mid Case Hydrogen Demand – Widths of Arrows Reflect Connection Capacities between Regions

includes both the cost associated with constructing the pipelines and the compressors, is \$75 Billion.

4.4 Discussion of Results

The key metric to measure the relative economic efficiency of a future with or without a hydrogen transmission network is the ratio of total expenditure on hydrogen in each power and hydrogen demand case with the network to the total expenditure without the network. For example, revisiting the results from scenario 3 above, the ratio of total expenditures on hydrogen with a transmission network to total expenditures without a transmission network is equal to $\frac{\$361B}{\$408B} = 0.88$. In scenario 1, the scenario

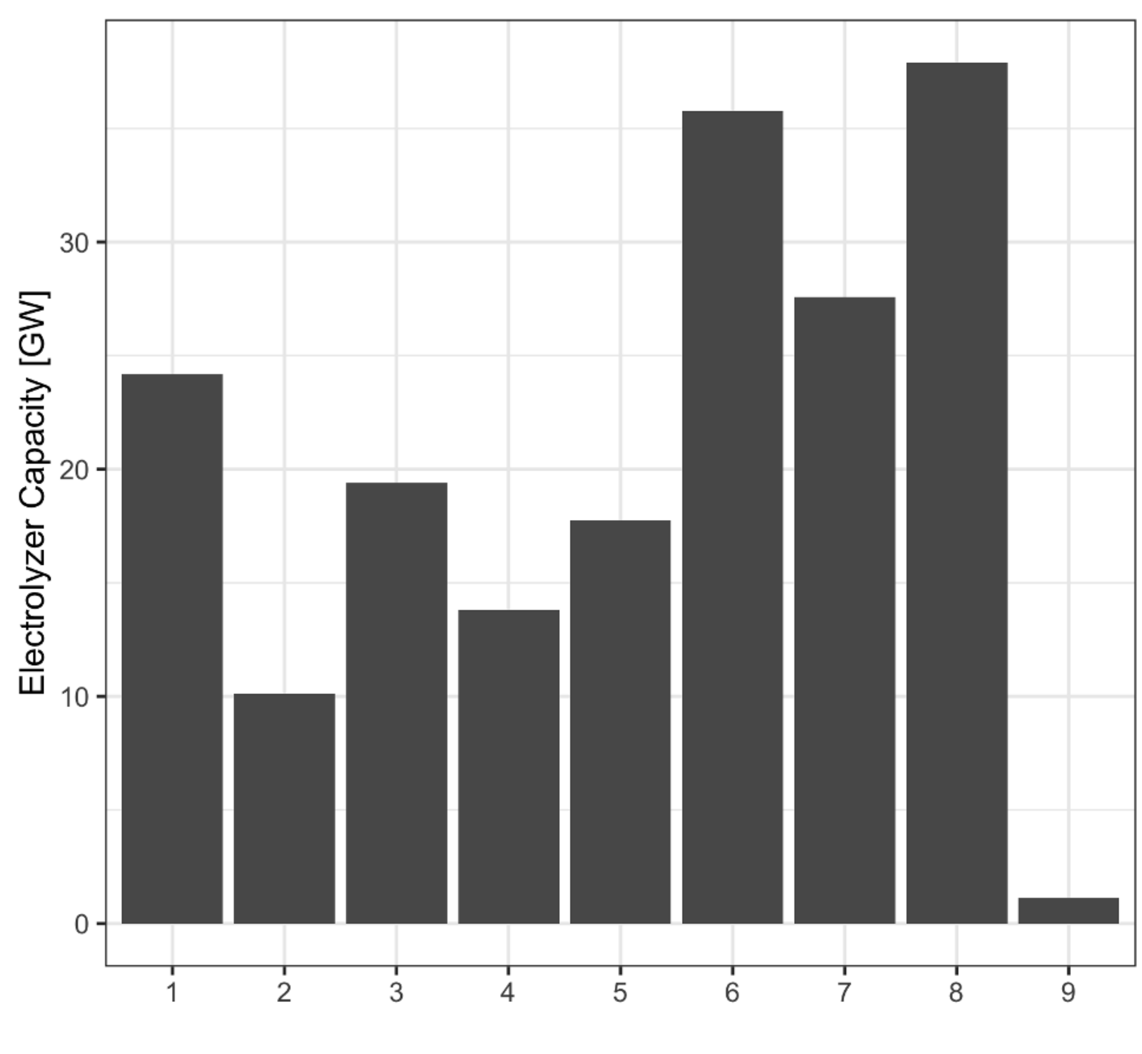

Figure 4-8: Scenario 2 Required Installed Capacity for Hydrogen Production with Network by Region

in which the optimal hydrogen transmission network was no network at all, this ratio is equal to one. Table 4.6 summarizes these ratios across all power and demand cases.

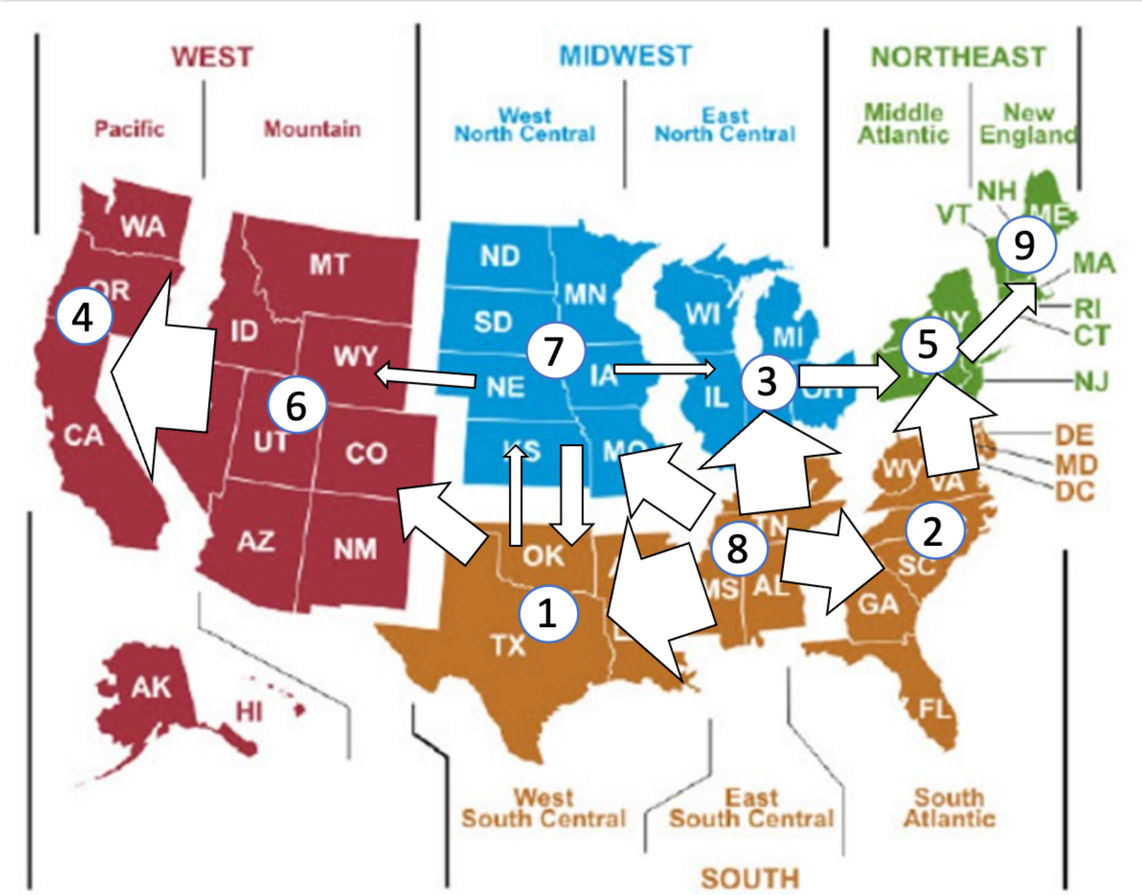

Figure 4-9: Optimal Network Based on Mid Case Power Prices and High Case Hydrogen Demand – Widths of Arrows Reflect Connection Capacities between Regions

	1.1 Quads	4.1 Quads	9.1 Quads
\$0.01/kWh	1	1	1
\$0.05	1	0.99	0.88
\$0.12 (AEO Base)	0.99	0.96	0.91

Table 4.6: Ratio of Total Expenditures with and without Hydrogen Transmission Across Each Power and Hydrogen Demand Case

In each case with a ratio less than one, hydrogen consumers are saving billions of USD on total hydrogen expenditures. This lower cost for hydrogen yields lower unit costs across the board for products and services which use hydrogen as a feed-stock for their processes. Based on these results, an evaluation of a regulatory framework

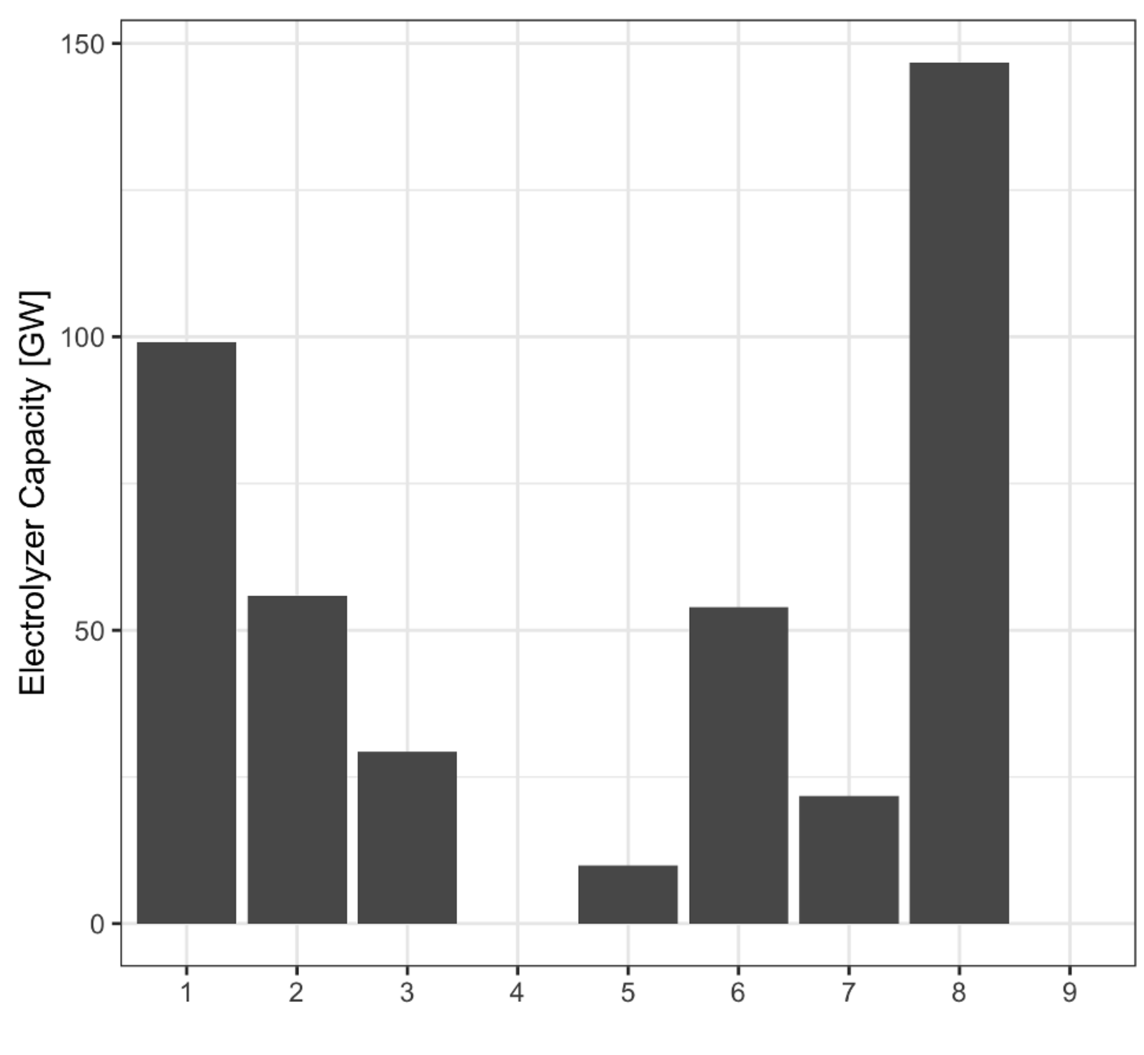

Figure 4-10: Scenario 3 Required Installed Capacity for Hydrogen Production with Network by Region

for hydrogen infrastructure in the United States is rightly justified.

Chapter 5

Assessing Regulatory Frameworks for the Development of Interstate Hydrogen Transmission Infrastructure in the United States

To say the future of hydrogen in the United States' energy sector is uncertain would be an understatement. However, there is a relatively low opportunity cost associated with ensuring impediments are cleared to allow for hydrogen to play a central role in a future of the United States' energy sector. These "no-to-low regrets" solutions should be pursued in the short-term to ensure hydrogen is a viable alternative to other energy vectors in the future. This chapter begins with a discussion of each different country's aspirations concerning a hydrogen future and cross references each country's motives with those of the United States. After which, three regulatory frameworks for the United States are introduced to aid in the evaluation of hydrogen in the energy sector. Each of these frameworks are qualitatively assessed on the solution's effectiveness and political reality. Furthermore, discussion of each solution includes potential pitfalls to address prior to introduction.

5.1 Why Hydrogen Might be Considered in the United States

Each country has a different prerogative regarding the future of hydrogen within their respective energy sectors. While not entirely driven by geopolitics, demand for hydrogen within the majority of the country's surveyed is driven by geopolitical motives.

Revisiting the hydrogen strategies of the Netherlands, Japan, and Australia, from Chapter 3, there are clear geopolitical underpinnings. The Netherlands aims to leverage their physical location within Europe to drive the creation of a liquid hydrogen market pricing point, similar to the Title Transfer Facility (TTF) for natural gas. Japan aspires to wean itself off of foreign imports for energy commodities through the production of hydrogen via renewable electric power. Australia aims to maintain its strong position as a world-scale energy exporter, primarily serving demand for hydrogen in East Asia.

The United States faces more of an uphill battle as it relates to the uptake of hydrogen within its energy sector. The United States has only recently come into its own as an energy exporter through the export of oil and natural gas to foreign nations – thus, its historical position as an energy exporter is nascent, unlike Australia. Moreover, a key destination of United States liquefied natural gas (LNG) is Europe and East Asia. When demand for natural gas does not materialize in East Asia, the liquid natural gas markets and ample storage in Western Europe offer a ready destination to balance United States LNG supply. However, the demand for hydrogen within these regions is not large enough to justify investment in large-scale hydrogen exportation infrastructure in the United States. As this demand does grow, hydrogen from the Middle East is likely to meet this demand since the total delivered cost to a European port of hydrogen is likely lower if the shipment is from the Middle East as opposed to the United States.

However, this does not mean there will be no play for hydrogen exportation from the United States. Markets would need to materialize and off-takers must be in place in order to justify such a capital-intensive investment – not unlike the development of large-scale natural gas liquefaction facilities within the Gulf of Mexico region in the 2010s.

Another factor driving demand for hydrogen in a given region is the need to decarbonize the energy sector, and economy more generally. This message is clear in the European Union's stated hydrogen strategy. European countries have historically been first-movers when it comes to climate related issues, and the issue of hydrogen is no different. When the author first began writing this piece in 2020 while the United States was led by President Donald Trump and his administration, there was little hope that demand for hydrogen would be driven by the federal government as "climate" was not particularly high on the docket. A a point of reference, the Paris Climate Agreement, originally signed in December 2015, set voluntary targets for carbon dioxide reductions from different county's economies. [93] President Trump removed the United States from the Paris Climate Agreement, stating "I was elected to represent the citizens of Pittsburgh, not Paris." [6] [43]

As of January 20th, 2021, the political leadership in Washington, D.C. shifted to the Democratic party and Joe Biden stepped in as the President of the United States. On President Biden's first day in office, he signed an executive order re-joining the Paris Climate Agreement. With the President Biden in the Whitehouse, there is a renewed interest in climate issues from Washington, D.C. This renewed interest could potentially drive industry in the United States towards lower-carbon alternatives faster than they would naturally through the use of a carbon tax or another federal carbon pricing scheme.

Realistically, future demand for hydrogen in the United States will depend on a number of different factors. The combination of a desire to compete within a global market for hydrogen and an effort to decarbonize the economy may be the key levers driving hydrogen demand in the United States. As shown in Chapter 4, an increase in demand for hydrogen will drive the necessity of an interstate hydrogen transmission network and a regulatory scheme to drive the development of said infrastructure.

5.2 Today's Hydrogen Regulatory Paradigm in the United States

The development of hydrogen pipelines and large-scale underground storage is not new in the United States. On the Gulf Coast, industrial gas companies own and operate over 500 miles of interstate, dedicated, hydrogen pipelines. Maps of these systems, released by industrial gas companies are shown below in figure 5-1 [102].

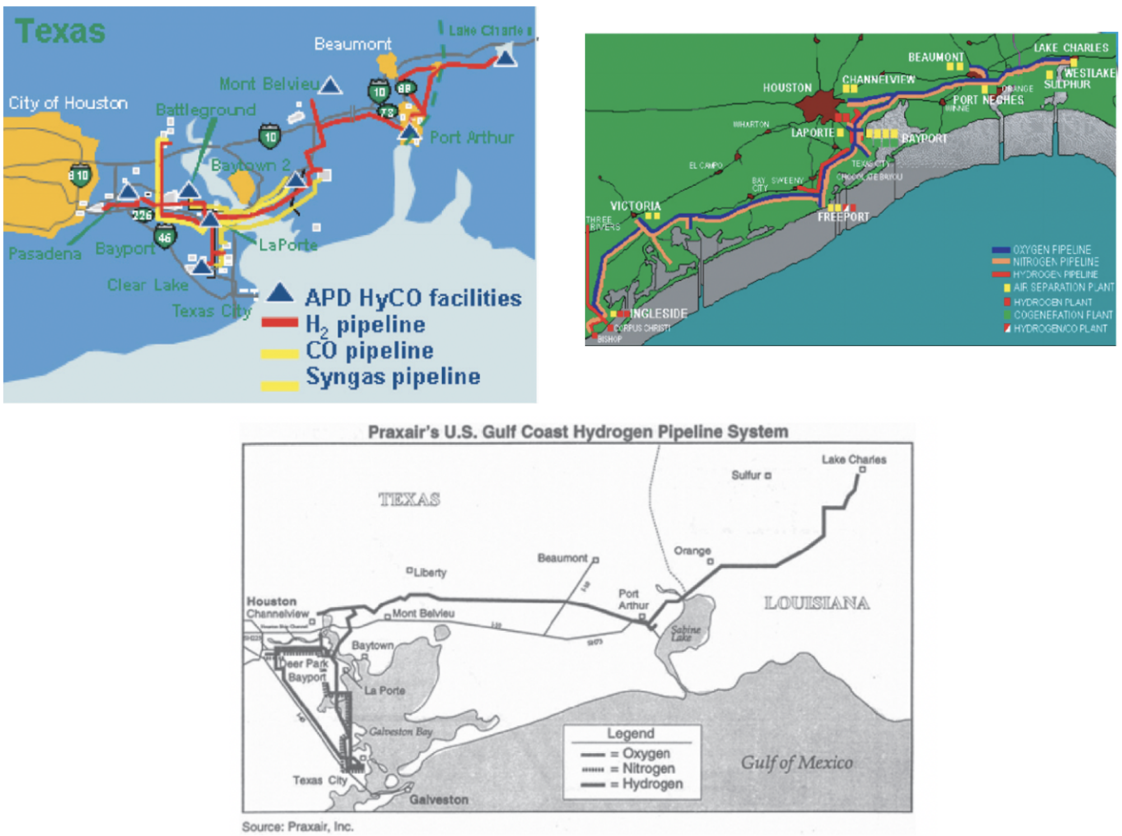

Figure 5-1: Industrial Gas Networks in Gulf Coast Region, Top left: Air Products, Top Right: Air Liquide, Bottom: Praxair (now Linde); Aggregated by [102]

The Gulf Coast region is home to over 45% of the crude oil refining capacity in the United States and ample chemicals manufacturing capacity is co-located with these refineries. In many cases, these steam methane reforming (SMR) units are actually located within these facilities and provide power and heat along with hydrogen. [29] Given hydrogen is a key input to the crude oil refining process and many chemical manufacturing processes, it makes economic sense for these industrial gas companies to invest in infrastructure to minimize the variable cost of transporting hydrogen between production facilities and customers.

While the operation of these pipelines and storage systems has proven commercially viable and worthy of investment, it is worth noting these pipelines operate as private carriers. As private carriers, they exclusively move gases produced by the industrial gas companies directly to customers and balance the industrial gas companies' supply and demand for hydrogen.

As the United States turns to hydrogen as an energy vector to enable deep decarbonization of its economy, the gas will necessarily become clothed in the *public interest* similar to other energy commodities such as electric power and natural gas. This designation implies the construction of hydrogen production and transmission infrastructure would need to be regulated similar to these commodities. Namely, the United States should consider if a particular government agency should be authorized to site of this infrastructure and create a market to enable the construction of this infrastructure.

As detailed in Chapter 3, FERC has full jurisdiction over the siting of interstate natural gas pipelines and no jurisdiction over siting electric power transmission lines, except in limited cases. [98] [96] The Federal government has yet to make an official determination as to how they will regulate the construction of hydrogen infrastructure. There were many reports released in the early-to-mid 2000s concerning the future of hydrogen infrastructure in the United States as the country looked to hydrogen as an alternative to oil for the transportation sector. Yet no specific rules concerning economic regulation of hydrogen infrastructure were written into law. [12] The closest FERC has come to declaring a position concerning hydrogen infrastructure comes from a 2006 report, published by FERC, which delineated FERC's responsibility under the Energy Policy Act of 2005. This report claims that FERC will "[w]ork jointly with other resource agencies to designate corridors for oil, gas, and hydrogen pipelines... and incorporate the designated corridors into the relevant agency land use and resource management plans." [34] From the author's reading of existing national statutes, national regulation of hydrogen infrastructure is still to be written.

This is not to imply there have been no regulations written regarding hydrogen infrastructure in the United States at all. After all, as mentioned, such infrastructure currently exists and operates within the United States. The Pipeline and Hazardous Materials Safety Administration (PHMSA), which operates within the Department of Transportation (DOT), has regulated hydrogen pipelines in the United States since 1970 "via 49 CFR Part 192." [1] [77] [85]. PHMSA's domain in regards to the pipeline sector is safety. The administration's charter, according to CFR Part 192.1, is to "prescribe[] minimum safety requirements for pipeline facilities and the transportation of gas." [77]

The economic regulation of hydrogen infrastructure has not been written because hydrogen has not historically been clothed in the *public interest*. To design a robust regulatory framework for hydrogen infrastructure development in the United States, its important to understand how different regulatory schemes fare in the regulatory sandbox. Results from Chapter 4 imply it is worth pursuing economic regulation similar to electric power, natural gas, or oil in the United States.

Electric power, natural gas, and oil markets all developed en concert with one another in the early 20th century. While technological advances have changed the nature of production and consumption of these commodities, the fact remains that the markets themselves are mature. As mentioned in Chapter 1, hydrogen is a fundamentally different energy commodity than electric power, natural gas, or oil. Contrary to the aforementioned energy commodities, regulatory frameworks for the development of infrastructure to move these commodities were developed after large-scale transportation infrastructure had been developed. Hydrogen is unique in that regulatory frameworks for the development of transmission infrastructure will be written alongside the transmission infrastructure development. To this end, if the United States is to seriously consider hydrogen as an essential energy vector within the energy sector,

[1] 49 CFR Part 192.3 defines "Gas" as "natural gas, flammable gas, or gas which is toxic or corrosive"

the public facing market for hydrogen will have to be implemented from scratch.

5.3 Options for Economic Regulation of Hydrogen Infrastructure in the United States

The following sections detail three regulatory frameworks the United States might consider in pursuit of a liquid hydrogen market and the construction of the necessary infrastructure to enable said market. The three frameworks considered are:

1. No Regulatory Framework
2. Work Within Existing Framework for Natural Gas
3. Fully Integrate Power and Gas Networks

These three frameworks are structured from most simple – and by proxy most politically palatable – to most complex. The following sections detail each of these frameworks in more detail and discuss the pros and cons of each path.

5.3.1 Option 1: No Regulatory Framework

As mentioned prior, the market for hydrogen, while not particularly liquid, exists today. Moreover, infrastructure currently exists to move hydrogen from production to demand centers. As the United States eyes a potential future in which hydrogen plays a considerable role in its energy sector, one option the federal government could pursue is simply maintaining the status quo and letting the market, and associated infrastructure for hydrogen, evolve and grow organically.

One may argue this option is the simplest and most politically palatable given no measures would need to be taken at the federal level. Given the standards have already been written for hydrogen pipeline safety, each company who saw opportunity in investing in hydrogen infrastructure would invest in projects and bear the full risk associated with pursing these opportunities.

Under this scenario, hydrogen infrastructure might still be built to enable the development of a hydrogen market. However, this situation is similar to the situation faced by John D. Rockefeller and natural gas utility executives in the early 19th and 20th century; they built their empires in the oil and natural gas markets prior to the passing of the Hepburn Act in 1906 and the Public Utility Holding Company Act in 1935. If the historical development of oil or natural gas pipeline infrastructure in the United States is any indication of how hydrogen pipeline infrastructure might organically be developed, the Federal government may need to address similar antitrust issues as certain players act to vertically integrate their supply chains to contain the production, transportation, and ultimate sale of hydrogen to their customers. So, by proxy, if the Federal government opts to not pursue proactive regulation of the transmission of this energy vector they may ultimately need to reactively regulate the sector.

Moreover, by not proactively regulating this sector, the Federal government is ceding authority to the states to drive the development of infrastructure regulation at the state-level. Without Federal guidance, regulation of the hydrogen sector could fall into a balkanized trap, similar to the electric power sector in the United States. This would effectively impede the development of interstate infrastructure and drive higher hydrogen costs for end-use customers as each state looks to supply its own hydrogen to meet internal demand instead of taking advantage of arbitrage opportunities which may exist between states.

5.3.2 Option 2: Work Within Existing Framework for Natural Gas

As detailed in Chapter 3, interstate natural gas transmission infrastructure falls under the purview of FERC based on the Natural Gas Act. In short, FERC has the authority to site interstate natural gas pipeline systems through a well detailed Certificate of Public Convenience and Necessity (CPCN) process. A project developer must prove to FERC the project is necessary, primarily through signed off-take agreements between the developers and shippers on the pipeline. Once approval has been granted by FERC, the developer can begin to construct the project based on the schedule set out in the CPCN application. This regulatory framework authorizes FERC to use eminent domain to secure the land necessary to construct the project should the developer not be able secure a negotiated agreement with the owners of the land on which the pipeline is proposed to be constructed.

If the United States creates a similar regulatory framework for the construction of hydrogen transmission infrastructure, it may be accomplished through an expansion of the Natural Gas Act. Currently, the section 717a of Chapter 15B of the U.S. Code (15 U.S. Code § 717a), which defines the terms used in legal codification of the Natural Gas Act, does not define "gas" similar to the code which delineate PHMSA's purview over hydrogen. Rather, 15 U.S. Code § 717a defines "natural gas" as "either natural gas unmixed, or any mixture of natural and artificial gas." [95] This section of the code does not explicitly define "gas" as methane or otherwise. 49 CFR Part 192.3, which gives regulatory authority to define safety standards on pipelines to PHMSA, defines gas as "natural gas, flammable gas, or gas which is toxic or corrosive." [77]

Depending on the interpretation of 15 U.S. Code § 717a, the siting of hydrogen infrastructure could potentially already fall under the authority of FERC. [95] However, this has not been tested in a court of law. If its interpreted that hydrogen does not currently fall under the Natural Gas Act, there are two potential actions the Federal government could take to regulate hydrogen infrastructure similar to that of natural gas.

The first option would be to expand the definition of "natural gas" in 15 U.S. Code § 717a to "gas," similar to PHMSA. This change could ensure hydrogen falls under the definition. This could either be done by changing the definition of "natural gas" directly or adding a definition for "gas" similar to 49 CFR Part 192.3. [77] However, this change to the US Code would require an act of Congress. [89] From the author's reading, the act of introducing hydrogen into the regulatory scheme is fundamentally different than FERC's orders delineating the Commission's recent rule changes for commodities which FERC currently has under its purview. As an example, FERC already has certain authority over the electric power sector under the Federal Power Act. Therefore, FERC can release an Order stating they are changing particular rules as they relate to this sector without going through Congress. Given FERC does not have clear authority over hydrogen in the United States, it is not possible for FERC to release an Order stating the Commission has authority over hydrogen infrastructure under the Natural Gas Act because hydrogen is not currently under the purview of FERC. [76]

The Federal government could also grant FERC the authority to economically regulate the development of hydrogen infrastructure and market development. As has been stated, the safety of hydrogen infrastructure is currently regulated by PHMSA under 49 CFR Part 192.3. If FERC has authority, they can formulate a regulatory framework for the development of infrastructure and market development, similar to the framework in place for interstate natural gas transmission infrastructure development in the United States.

PHMSA and FERC already cooperate in the development of other energy infrastructure. As an example, natural gas pipeline operators submit applications for a CPCN from FERC (DOE) for an interstate pipeline project. This same entity must submit annual reports to PHMSA based on 49 CFR Parts 191 through 195. [78] [86]

While rolling hydrogen into the broader natural gas regulatory framework is a relatively straightforward way to develop a regulatory framework for hydrogen infrastructure development, this path minimizes critical differentiating factors between natural gas and hydrogen. Namely, the production of hydrogen relies on either natural gas or electric power and the production of hydrogen is not necessarily restricted based on geological attributes of a specific location. In many ways, hydrogen exists at the nexus of the electric power and natural gas markets in the United States.

5.3.3 Option 3: Fully Integrate Power and Gas Networks

The shale revolution in the United States has led to deeper integration of the electric power and natural gas markets. In the major ISOs, natural gas is generally the fuel which sets the real-time price of electric power as cheap natural gas has served to push coal-fired generators further up the bid stack in the power markets. This has been recognized in the literature and the interplay between the electric power and natural gas will only grow into the future. [1]

The advent of large-scale hydrogen production may drive further integration of these two networks. As mentioned in Chapter 1, hydrogen can be used throughout the energy sector across a multitude of end-uses. One topic increasingly being discussed is the utilization of hydrogen production, via electrolysis, and the consumption of hydrogen to produce electric power to balance the bulk power system on a seasonal basis the power production from VRE waxes and wanes. While the current electric power system depends on the natural gas system the natural gas system does not rely on the electric power system to the same degree. A future hydrogen system would rely on the electric power system to produce electric power, but the power system would also rely on hydrogen to produce electric power during periods of scarcity.

The Oxford Institute for Energy Studies recently released a report which highlights opportunities associated with integrating the electric power system, natural gas system, and hydrogen system into a broader energy system. Specifically, the creation of an Energy System Operator (ESO) "would allow an 'energy system' approach to combine and optimize existing (and new) gas and electricity networks, thus leveraging the advantages of both systems." [36] Similar pieces have been written by researchers at the Florence School of Regulation. [80] The push towards an ESO is especially prevalent in Europe where there is a concerted effort to decarbonize, led by the European Union.

While there are clear benefits associated with integrating and co-planning these energy systems, there are legal, commercial, and political hurdles that must be crossed in the United States before an ESO model could be adopted.

First, as mentioned in the prior section, hydrogen infrastructure construction and operation does not operate under the purview of the Federal government. If hydrogen is to be a piece of the ESO, hydrogen must first be introduced to the broader energy regulatory scheme at the Federal level. After appropriate regulatory authorities are in place, the Federal government can move to pursue an ESO model. The ESO model will serve to completely upend the status quo of energy system operating models and integrate the entities responsible for the management of interstate electric power systems and gas networks.

While these two systems operate en concert with one another today, the regulatory frameworks under which they operate are fundamentally different. While there are many facets to these systems to compare and contrast, the siting of transmission infrastructure should be considered specifically. If a region is served by an ISO, the ISO is the entity responsible for identifying transmission needs on the system and soliciting requests for proposal (RFP) from engineering, procurement, and construction (EPC) firms to submit bids to construct the power line. For the natural gas system, the owner of a pipeline network identifies potential opportunities for investment on its system instead of a system operator. This is due to the fact that the natural gas transmission pipeline system operators are the pipeline owners themselves. There is no equivalent to an ISO or RTO for the natural gas system. Once the natural gas pipeline identifies potential opportunities, they then begin to reach out to shippers who might want to move gas on the new pipeline. [2] Once these agreements are signed (generally referred to as "precedent agreements") the entity proposing the project files an application for a CPCN with FERC. Once this CPCN is authorized, construction of the pipeline commences.

An ESO system would be more centrally planned, akin to an ISO or RTO. The entity would be responsible for identifying opportunities to optimize across two energy delivery networks to enable the most cost-effective use of infrastructure capital. However, this would mean the pipeline companies would lose access to their right to identify specific opportunities on their system. The competitive siting model used to connect natural gas customers to their suppliers would need to be completely uprooted. There are also potentially enormous consequences concerning the pipeline network's regulatory accounting system.

This move to an ESO model requires natural gas transmission system owners

[2] A "shipper" is defined as either a natural gas producer looking to push their gas onto the network or a natural gas consumer who's looking to purchase gas off of the system.

forego their right to a competitive process to continue building their networks. It's unclear how natural gas transmission system owners would react to this sort of framework. Trade organizations representing the owners of these pipeline systems may push back against such dramatic changes to the natural gas transmission business model without fighting the changes in court. However, there have been a handful of instances in recent history wherein a pipeline system's expansion projects have been stonewalled by state governments in an effort to minimize investment in fossil fuel infrastructure which would decrease future demand of fossil fuels. [84] [101] In these cases, it may have boded well for a third-party system operator to identify these specific projects for reliability purposes rather than have the pipeline owner alone try to justify construction of the new pipeline.

While Congressional action is likely needed to move the regulation of hydrogen transmission infrastructure under the purview of FERC, it is less clear if Congress' involvement is required in the development of an ESO model. The creation of the ISO was driven by FERC in an effort "to remove impediments to competition in the wholesale bulk power marketplace and to bring more efficient, lower cost power to the Nation's electricity consumers." [33]

FERC Order 636 structurally changed the natural gas markets in the United States. This order mandated open-access information on all interstate natural gas transmission lines be publicly available as the industry moved from a low-competition environment to a market with liberalized price mechanisms at the wellhead where the pipeline simply provided transmission services. [32] This order did not require an intervention by Congress. FERC has full jurisdiction over interstate commerce of natural gas, so they are able to revise rules currently in place.

FERC's legal authority comes from the Federal Power Act and the Natural Gas Act. Congress has ceded authority for interstate electric power and natural gas sales to FERC. In doing so, they have also given FERC the authority to write rules for these sectors how they see fit. By proxy, Congress has theoretically given FERC the authority to establish the ESO model that's been discussed.

Chapter 6

Conclusion

Two quotes have been cited in this thesis which, the author believes, are inseparably intertwined:

"Hydrogen economy is an economy that relies on hydrogen as the commercial fuel that would deliver a substantial fraction of a nation's energy and services."
- Nehrir and Wang, 2016 [64]

"A condition for a widespread use of hydrogen as an energy carrier in the EU is the availability of energy infrastructure for connecting supply and demand."
- European Commission, July 2020 [16]

This is to say, a hydrogen economy is not possible without significant investment in large-scale hydrogen transmission infrastructure connecting different regions and allowing for arbitrage opportunities between them. While hydrogen has the benefit of not being geologically locked in a particular region, large-scale infrastructure can still serve to minimize delivered cost to particular regions. Moreover, a ubiquitous hydrogen network can also serve as the backbone to a liquid hydrogen market in which producers and consumers can compete for the lowest cost hydrogen. This infrastructure could enable a decarbonized future.

6.1 Key Takeaways

This thesis stepped through a number of key topics relevant to the future of interstate hydrogen transmission infrastructure in the United States. This section highlights key sections of the thesis and associated takeaways:

6.1.1 The Hydrogen Value Chain

1. The hydrogen value chain is structured similarly to oil and natural gas: (i) Upstream, (ii) Midstream, and (iii) Downstream.

2. If hydrogen is produced via an electrolyzer powered via renewable power there are no carbon dioxide emissions associated with the molecule.

3. Hydrogen can be moved on pipelines and stored in underground caverns, similar to both oil and natural gas

4. End-uses for hydrogen are numerous. However, hydrogen is not necessarily the most economical option.

6.1.2 The Hydrogen Market

1. Current annual demand for hydrogen is not inconsequential.

2. Hydrogen production assets are financed via bilateral contracts signed with off-takers using hydrogen for dedicated purposes

3. Diversity in the types of customers demanding hydrogen will necessarily require a shift in the industrial gas business.

6.1.3 Energy Commodity Market Development in the United States

1. Reject the notion of common carriage on a potential future hydrogen pipeline system.

2. Implement a "commodities clause" to ensure separation of pipeline owners and resource owners.

3. Ensure siting authority for interstate hydrogen transmission infrastructure is in the hand of the Federal government, not the States to mitigate risk of future "balkanization."

4. Do not allow end-use shippers to own interstate hydrogen pipelines.

5. Give FERC authority to issue CPCN's for hydrogen transportation projects.

6. Ensure company operating interstate hydrogen pipeline is exclusively in the business of moving hydrogen.

6.1.4 Cross-Sectional Analysis of Country's Hydrogen Strategies

1. Ensure Federal government is committed to working with the owners of existing natural gas infrastructure.

2. Stimulate demand for green hydrogen through blending requirements within the natural gas system to stimulate production cost declines.

3. Developing a hydrogen network from scratch allows for optimal coordination with the electric power and natural gas systems.

4. The novelty of hydrogen as an energy vector merits a full legal analysis at both the Federal and State level to ensure there are no impediments facing the future of the industry.

6.1.5 Assessing Optimal Midstream Hydrogen Infrastructure Build-out

1. The scale of optimal hydrogen transmission network infrastructure varies widely based on power price and hydrogen demand assumptions.

2. While there are potential futures in which the optimal hydrogen network is no network at all, there are cases which yield interstate hydrogen networks when optimizing for minimal expenditure on hydrogen in 2050. These cases justify an evaluation of regulatory frameworks for hydrogen transmission infrastructure.

6.1.6 Regulatory Frameworks for Midstream Hydrogen Infrastructure in the United States

1. Hydrogen pipelines are currently in operation within the United States.

2. If hydrogen is to move from an industrial gas used in an industrial capacity to a more broadly used gas, a regulatory framework for hydrogen transmission infrastructure must be evaluated and implemented.

3. Hydrogen pipeline safety is currently regulated by the PHMSA.

4. Without proactive Federal regulation of the midstream hydrogen sector, the Federal government might end up fighting antitrust cases.

5. Hydrogen could potentially fall under purview of FERC today, even without changing any codes, but this has yet to be tested in court.

6. Based on the author's reading of Federal statutes, the introduction of hydrogen to FERC's purview would take an act of Congress.

7. Hydrogen could serve as an accelerant which drives the further integration of electron and molecule-based energy systems.

8. While perhaps wildly unpopular, the most optimal solution might be to challenge the status quo and create an ESO which operates both electron and molecule energy systems.

6.2 Areas of Future Study, Research, and Discussion

Generally speaking, hydrogen is a "hot" topic right now throughout the world. Entities from Wall Street to Major International Think Tanks have made statements that the "hydrogen hype" will materialize. There are, of course, detractors. While climate change is a major, and growing, challenge, economics still tends to win in the short-term. One potential easy-win for green hydrogen is to directly replace grey and brown hydrogen currently consumed throughout the world. However, the industries which currently consume hydrogen can generally be categorized as "commodity businesses" wherein an increased feed-stock cost will increase the unit cost of the produced commodity. In these highly competitive commodity markets, any impact to the unit cost of the produced commodity may push the producer out of the market. Therefore, unless each producer is using a similarly priced feed-stock, it is unlikely demand for a "cleaner" feed-stock will materialize. From the author's conversations with practitioners in the hydrogen sector, this question is of particular importance to those looking to finance hydrogen export projects throughout the world.

Supply does not stir demand and demand will not materialize if there is no supply. This is the "chicken and egg" situation faced by hydrogen as the energy commodity is looked to as a potential solution to help decarbonize the economy. In order for the market to materialize in the United States, consumers need a certain supply of low-cost hydrogen. Other energy commodities in the United States benefit from bulk transmission on systems that have been developed over the past century and a half. The United States has the opportunity to lower barriers to entry and ensure similar transmission infrastructure for hydrogen is developed. The development of this infrastructure will drive a more certain supply of low-carbon hydrogen and enable the diffusion of hydrogen throughout the United States' energy system.

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