 

# HYDROGEN'S POTENTIAL ROLE IN LDCS' TRANSITION TO A LOW-CARBON FUTURE

*Marcia Hook, Drake Hernandez, Duncan Grimm, Heidi Li*[*]

Synopsis: Every day across the United States, local distribution companies (LDCs) deliver natural gas to millions of homes and businesses, allowing people to heat buildings and water, cook, operate cooling equipment, and meet other basic needs. Increasingly, however, LDCs face challenges from regulators, investors, consumers, and other stakeholders pushing for a transition to a lower-carbon future. Many LDCs find themselves grappling with an existential question: how should a business based on natural gas adapt and transition into a low-carbon future? This article explores what role hydrogen can play in an LDC's energy transition strategy. The numerous practical and legal challenges to integrating hydrogen into the LDC system and business model mean that hydrogen will not be a panacea for LDCs seeking to successfully transition into a low-carbon future. However, with appropriate study, planning, and action, LDCs can position hydrogen as a component of their energy transition strategies.



* Marcia Hook is a partner and Duncan Grimm is an associate in the energy regulatory group of Kirkland & Ellis LLP. Drake Hernandez is an associate principal and Heidi Li is an analyst at Charles River Associates. The authors would like to thank everyone who engaged with and provided input on this article. The views expressed in the article are the authors' alone and do not represent the views of any of their firms or respective clients.

## I. INTRODUCTION

There can be no dispute that natural gas is currently indispensable to meeting basic needs of residential and commercial users across the United States. Approximately half the homes in the United States use natural gas for space and hot water heating.[1] Residential and commercial users of natural gas together represented roughly 26% of the United States' natural gas consumption in 2021.[2] In 2018, approximately 90% of this natural gas was delivered by LDCs.[3]

Yet the last few years have seen a historically unprecedented push by regulators, investors and consumers towards decarbonization, which has had direct implications for these LDCs. At the local level, dozens of cities have adopted bans on new natural gas hookups in residential and commercial buildings, including major cities such as Santa Monica and New York City.[4] State legislatures and regulators also have taken significant steps to transition away from the use of natural gas in residential and commercial buildings.[5] These steps include several state regulators initiating "gas transition" proceedings, Washington updating its State Energy Code to require builders to install electric heat pumps for space and water heating in most new commercial buildings and multifamily residences, and the California Air Resources Board voting to end the sale of gas furnaces and gas water heaters in its state by 2030.[6] At the national level, the U.S. Consumer Product Safety Commission announced in early 2023 that it intended to issue a Request for Information seeking the public's input on hazards associated with gas stoves.[7]

Given the concentration of such bans and other proceedings in certain states and the backlash against such initiatives, it might be tempting for some to discount the potential impacts of these legislative and regulatory initiatives on LDCs. After all, twenty states, representing 31% of U.S. residential and commercial gas use, have adopted laws prohibiting the adoption of local gas bans.[8] And, on April 17, 2023, the 9th Circuit struck down the City of Berkeley's gas ban, finding that it was preempted by the Energy Policy and Conservation Act, potentially portending a similar fate for similar measures adopted by other jurisdictions.[9] However, the pressure to decarbonize is not coming just from legislatures and regulators, but

1. *Natural Gas Explained: Use of Natural Gas*, U.S. ENERGY INFO. ADMIN., https://www.eia.gov/energyexplained/natural-gas/use-of-natural-gas.php (last updated Nov. 16, 2022).

2. *Id.*

3. *Today in Energy,* U.S. ENERGY INFO. ADMIN. (Jul. 31, 2020), https://www.eia.gov/todayinenergy/detail.php?id=44577.

4. *See infra* section III.B (discussing "stretch" codes and other state and local government actions).

5. *Id.*

6. CAL. AIR RES. BD., 2022 STATE STRATEGY FOR THE STATE IMPLEMENTATION (2022), https://ww2.arb.ca.gov/sites/default/files/2022-08/2022_State_SIP_Strategy.pdf.

7. *Minutes of Commission Meeting, Decisional Matter: Fiscal Year 2023 Operating Plan*, UNITED STATES CONSUMER PROD. SAFETY COMM'N (Oct. 26, 2022), https://www.cpsc.gov/s3fs-public/Commission-Meeting-Minutes-FY-2023-Operating-Plan_0.pdf?VersionId=wiJw89I902pxZ_6C.Zz08whJ6l6.9fo5.

8. Tom DiChristopher & Anna Duquiatan, *States that outlaw gas bans account for 31% of US residential/commercial gas use,* S&P GLOB. MKT. INTEL. (Jun. 9, 2022), https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/states-that-outlaw-gas-bans-account-for-31-of-us-residential-commercial-gas-use-70749584.

9. California Rest. Ass'n v. City of Berkeley, No. 21-16278, slip op. at 7 (9th Cir. 2023).

also from investors, companies, customers, and other stakeholders.[10] Nearly 40% of all Fortune Global 500 companies have set a net-zero target.[11] These pressures can affect any LDC, even where there is no concerted state legislative or regulatory action.

While a summary of the climate commitments and actions of all public and private actors in the U.S. that could impact LDCs is beyond the scope of this article, the snapshot provided above highlights the multifaceted pressures facing LDCs, leading many LDCs to consider how to transition their business model into a low-carbon future.

Enter hydrogen, which has been touted as one potential option for decarbonizing numerous end uses, including many of those currently served by natural gas via LDCs. Over the last few years, interest in hydrogen has experienced a renaissance, today being referred to as the "Swiss Army knife of decarbonization" because of its broad range of potential applications in the energy transition.[12] A number of these potential applications are relevant to LDCs. For example, the Hydrogen Council has written that "[h]ydrogen in gaseous form can provide a low-carbon alternative to natural gas heating as it can largely utilise the same infrastructure network – from pipelines to the boilers themselves."[13] The same study concluded that of the limited options for decarbonizing this sector, hydrogen solutions are "among the most cost-effective and flexible ways to facilitate . . . transition."[14]

At the same time, it is not difficult to find hydrogen skeptics. Consumers of energy news will remember the joke bordering on adage, "[hydrogen] is the fuel of the future — and always will be."[15] There are historical justifications for this uncertainty: hydrogen was floated during the fossil fuel shortages of the 1970s and 1980s as a potential solution.[16] And during the 1990s, carmakers had costly false

10. Taylor Kuykendall, *Path to net zero: Miners are starting to decarbonize as investor pressure mounts*, S&P GLOB. MKT. INTEL (Jul. 28, 2020), https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/path-to-net-zero-miners-are-starting-to-decarbonize-as-investor-pressure-mounts-59583837.

11. *Fortune Global 500 Climate Commitments*, CLIMATE IMPACT PARTNERS, https://www.climateimpact.com/news-insights/fortune-global-500-climate-commitments/.

12. William G. Bolgiano, *FERC's Authority to Regulate Hydrogen Pipelines Under the Interstate Commerce Act*, 43 ENERGY L.J. 1 (2022). While this article focuses primarily on end uses for hydrogen of relevance to LDCs, William Bolgiano's recent article published in this journal provides a thorough summary of the other potential applications of hydrogen.

13. HYDROGEN COUNCIL, PATH TO HYDROGEN COMPETITIVENESS: A COST PERSPECTIVE 51 (2020), https://hydrogencouncil.com/wp-content/uploads/2020/01/Path-to-Hydrogen-Competitiveness_Full-Study-1.pdf.

14. *Id.*

15. *The future, finally*, THE ECONOMIST (Feb. 15, 2013), https://www.economist.com/schumpeter/2013/02/15/the-future-finally (tracing major carmakers' experimentation with vehicles powered by hydrogen fuel cells).

16. Llewellyn King, *Hydrogen Is Back as the Green Fuel of the Future*, ENERGYCENTRAL (Feb. 1, 2020), https://energycentral.com/c/um/hydrogen-back-green-fuel-future.

starts exploring replacing passenger cars' internal combustion engines with hydrogen fuel-cells.[17] There are also numerous technical and practical challenges associated with hydrogen. These challenges include the lack of certainty surrounding end-use applications and that pure hydrogen cannot be transported on conventional natural gas pipelines without significant risk of embrittlement.[18] Decades on, hydrogen is still being described as the fuel of the future: many of today's hydrogen-hopeful headlines end in a question mark, reinforcing the entrenched uncertainty towards a fuel whose end use and exact role in the clean energy transition remain the subject of ongoing debate.[19] Yet an undeniably new characteristic of today's reinvigorated interest in hydrogen is that there are now real financial incentives for the development of hydrogen projects, resulting in investments in hydrogen projects across the U.S.[20] There also is a wealth of new literature on hydrogen's potential uses in the energy transition, some of which we explore here.

Against this backdrop, this article explores the potential role that hydrogen could play in LDCs' energy transition strategies. Although some LDCs also serve retail electric customers, this article focuses on gas LDCs, as such LDCs face the greatest downside risk from decarbonization trends. This article also focuses primarily on private LDCs rather than municipalities that serve gas retail customers, which are generally subject to a different regulatory regime. It is worth noting, however, that many of the practical considerations discussed herein will still be relevant for such municipalities if they are considering integrating hydrogen into their business model.

The article begins with an overview of the gas LDC business model, which is crucial to understanding what end-uses such LDCs serve and what constraints affect their decision-making. The article then provides a deeper analysis of some of the drivers behind LDCs' decarbonization efforts, as the impetus behind an LDC's decision to decarbonize may impact the goals and strategies an LDC may use. The article then analyzes some of the practical and legal challenges to LDCs integrating hydrogen into an energy transition strategy. Finally, it will attempt to provide a framework for LDCs and stakeholders considering if, and how, LDCs can integrate hydrogen into their business model.

This article does not seek to provide a single, easy answer to the question of how an LDC can best use hydrogen as part of a successful energy transition plan

---

17. Vijay Vaitheeswaran, *Hydrogen hype is rising again--will this time be different?*, THE ECONOMIST (Nov. 14, 2022), https://www.economist.com/the-world-ahead/2022/11/14/hydrogen-hype-is-rising-again-will-this-time-be-different; *The future, finally*, *supra* note 15.

18. UNIV. OF CAL., RIVERSIDE, HYDROGEN BLENDING IMPACTS STUDY (2022), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M493/K760/493760600.PDF.

19. Alan Ohnsman, *Is Green Hydrogen The Fuel Of The Future? This CEO Is Betting On It*, FORBES (Nov. 17, 2022), https://www.forbes.com/sites/alanohnsman/2022/11/17/green-hydrogen-plug-power-andy-marsh; Vaitheeswaran, *supra* note 17; Jim Park, *Is Hydrogen Really Trucking's Fuel of the Future?*, TRUCKINGINFO (Sept. 23, 2022), https://www.truckinginfo.com/10181511/is-hydrogen-really-truckings-fuel-of-the-future (contrasting European versus North American development and deployment of green hydrogen technologies and the trucking industry's role in both transporting hydrogen and running off of it); Miles O'Brien et al., *Could hydrogen be the clean fuel of the future?*, PBS NEWSHOUR (Apr. 20, 2022), https://www.pbs.org/newshour/show/could-hydrogen-be-the-clean-fuel-of-the-future; King, *supra* note 16.

20. *See infra* notes 54, 158-162 and accompanying text (describing, among other federal programs and incentives, the Inflation Reduction Act and the U.S. Department of Energy's Hydrogen Hubs).

because there is none. How could there be when there are over 2,000 LDCs across the U.S.[21] with unique systems and customer profiles, subject to differing regulatory regimes depending on their location and status as a public or private entity? Rather, the goal of this article is to serve as a resource for LDCs and other stakeholders considering what role hydrogen can play in an LDC's transition to a lower-carbon future, identifying key issues and sources to help guide that analysis. Hydrogen will not be a silver bullet for LDCs seeking to successfully transition into a low-carbon future. Nonetheless, with appropriate planning and action by an LDC, hydrogen may be able to serve as a key component of an LDC's energy transition strategy.

## II. THE LDC MODEL

Before exploring the ways in which an LDC may integrate hydrogen into its energy transition strategy, it is essential to have a high-level understanding of the LDC business model and how LDCs fit into the natural gas supply chain, including the types of customers and end-uses served by LDCs.

People have been using gas in their everyday lives long before the LDC delivery model existed. In the nineteenth century, while gas was manufactured from commodities like coal, it was understood that natural gas could be used for similar end uses if it could be harnessed.[22] The challenge was extracting such gas and getting it to market, as the necessary technology did not exist.[23] It was not until more advanced steel compositions and welding techniques developed in the first quarter of the twentieth century, enabling the construction of high-pressure pipelines, that natural gas could be moved over long distances at low costs.[24]

As new pipelines spread, the importance of state regulatory bodies became apparent. Consumers and communities discovered that competition alone offered insufficient protection.[25] Indeed, the ruthless competition that arose in the absence of government regulation had disastrous effects on both rates and the physical environment, with "an initial period of 'wasteful competition' followed by a massive consolidation and the threat of monopolistic pricing."[26] In answer, states began regulating natural gas companies as retail monopolies. After surviving numerous legal challenges on dormant Commerce Clause grounds, states were secure in their authority to regulate "as a matter of local concern, all direct sales of gas to consumers within their borders, absent congressional prohibition of such state regulation."[27]

21. Mike Kopalek, *U.S. homes and businesses receive natural gas mostly from local distribution companies,* U.S. ENERGY INFO. ADMIN. (Jul. 31, 2020), https://www.eia.gov/todayinenergy/detail.php?id=44577.

22. General Motors Corp. v. Tracy, 519 U.S. 278, 288 (1997).

23. *Id.*

24. *Id.*

25. *Id.*

26. *Tracy*, 519 U.S. at 289. The Supreme Court recounts how during this initial period of wasteful competition, citizens "suffered the inconvenience of city streets being constantly torn up and replaced by installation and relocation of duplicate facilities." *Id.* at 289 n.5.

27. *Id*. at 290.

When the federal government began to regulate the natural gas industry, Congress recognized this history of state regulation and preserved a role for state regulators. So while the Natural Gas Act (NGA), signed in 1938, regulated interstate natural gas pipelines, it "explicitly exempted 'local distribution of natural gas' from federal regulation."[28] The NGA's purpose was to "fill the regulatory void created by the Court's earlier decisions prohibiting States from regulating interstate transportation and sales for resale of natural gas, while at the same time leaving undisturbed the recognized power of the States to regulate all in-state gas sales directly to consumers."[29]

Thus, the LDC business model today is primarily regulated at the state level.[30] Generally, state public utility commissions (PUCs)[31] regulate how most LDCs operate their businesses and set limits on the maximum return LDCs can earn in their operations. In many states, the relevant PUC grants the LDC the exclusive right to distribute gas directly to retail customers in a particular region (often in the form of a certificate or franchise), unless the PUC grants an exception permitting another company the right to distribute gas to retail customers in such region.[32] In return, the LDC must provide service to all customers within that region at the prices and terms approved by the PUC.[33]

State-level gas utility planning differs across jurisdictions but often consists of a variety of objective-based processes with varying time horizons.[34] A minority of states, including Oregon, Washington, Rhode Island and New York, have adopted an Integrated Resource Planning (IRP) or similar model for their gas utilities, similar to the planning process required of electric utilities.[35] Whether using a traditional gas supply planning or IRP process, proceedings vary across states. In most states, to develop an LDC's maximum annual revenue, the LDC and PUC agree on an annual revenue requirement. In general, PUCs will try and calculate the revenue requirement in close collaboration with LDCs using a formula that takes into account the LDC's regulated rate of return, the depreciated utility rate base (which is discussed further below), depreciation, and taxes.

The regulated rate of return is a value the regulator allows the LDC to earn on the undepreciated capital it has invested to deliver a regulated commodity—natural gas or, in the future, potentially a natural gas-hydrogen blend[36] or pure

28. *Id*. at 291.

29. *Id*. at 292.

30. *Tracy*, 519 U.S. 278.

31. In many states, the relevant regulatory body is not actually referred to as a PUC. However, for ease of discussion, this article will use the term PUC to refer to the relevant state agency that regulates LDCs.

32. LOWELL E. ALT, JR., ENERGY UTILITY RATE SETTING 18 (Lulu 2007).

33. *Id.*

34. Elaine Prause, *Modernizing Gas Utility Planning: New Approaches for New Challenges* 5, REGUL. ASSISTANCE PROJECT (2022), https://www.raponline.org/wp-content/uploads/2022/09/rap-prause-modernizing-gas-utility-planning-new-approaches-new-challenges-2022-september.pdf. Prause's article provides a helpful graphic for visualizing the time frames and scope of typical gas planning processes, including distribution planning, capacity planning and supply planning.

35. *Id*. at 6.

36. When referring to a "blend" of hydrogen in the LDC's distribution system, we are referring to a blend by volume rather than by mass or energy. This is discussed further in Section IV.B.

hydrogen—to customers within their service territory.[37] A PUC will generally seek to balance the LDC's customers' need for low-cost and reliable service to their homes and businesses and the LDC's need for access to an economic source of capital.[38] It is the balance to which LDCs are accustomed for their natural gas businesses that will be just as relevant for any expansion into hydrogen.

Such balance is an essential component of the conversation between any LDC and its state PUC today, which often come in the form of rate cases. If the regulated rate of return is set too high, the LDC will have access to lower-cost capital, but ratepayers will end up paying more for a given service.[39] In the alternative scenario where the rate of return is unnecessarily low, ratepayers will have access to low-cost service, but the LDC will not be able to access low-cost capital from the public markets.[40] Ideally, LDCs and their PUCs, in open and transparent proceedings, find the middle ground that allows the LDC access to reasonably priced capital while providing ratepayers with affordable service.[41] The ultimate rate the LDC is allowed to recover from its ratepayers considers the LDC's weighted average cost of capital based, in part, on the LDC's debt ratio among many other financial metrics.[42]

Capital investments the LDC makes in infrastructure to deliver natural gas to its customers are summed into a figure called the "rate base." This value is a measure of the LDC's total investment in the system.[43] Each year, the LDC can make more capital investments in the rate base, but the rate base also depreciates.[44] At the end of a given year, the rate base will reflect the capital investment made throughout the year less the depreciation on the existing rate base. The resultant value is the depreciated utility rate base which is multiplied by the regulated rate of return to give the LDC's annual regulated return. The LDC is also authorized to recover the depreciation incurred throughout the year and the taxes incurred from the sale of natural gas to their ratepayers.[45]

Generally, PUCs allow the LDC to pass through the costs associated with procuring natural gas from its suppliers and operating the system to its ratepayers. The LDC is not allowed to recover any margin on those costs. Any margin the LDC earns comes through the LDC's investment in the rate base and the associated return allowed by the regulator. Moreover, each LDC is generally only permitted to invest in the distribution and sale of natural gas within its established service territory.[46]

---

37. *See infra* sections IV and V (discussing the practical and legal challenges an LDC may face in integrating hydrogen to its distribution system).

38. Prause, *supra* note 34, at 18-19.

39. *Id.*

40. *Id.*

41. *Id*. at 8.

42. FERC, COST-OF-SERVICE RATES MANUAL 14 (1999), https://www.ferc.gov/sites/default/files/2020-08/cost-of-service-manual.pdf (specifics regarding the rate of return calculation may vary by PUC, but general discussion of how the rate of return is set for regulated entities is shown here).

43. *Id*. at 8.

44. *Id*.

45. *Id.* at 25-26.

46. COST-OF-SERVICE RATES MANUAL, *supra* note 42.

Historically, LDCs were owned by broader utility holding companies that owned and operated the entire natural gas value chain, including natural gas production.[47] The natural gas value chain is shown in Figure 1 below, for reference.

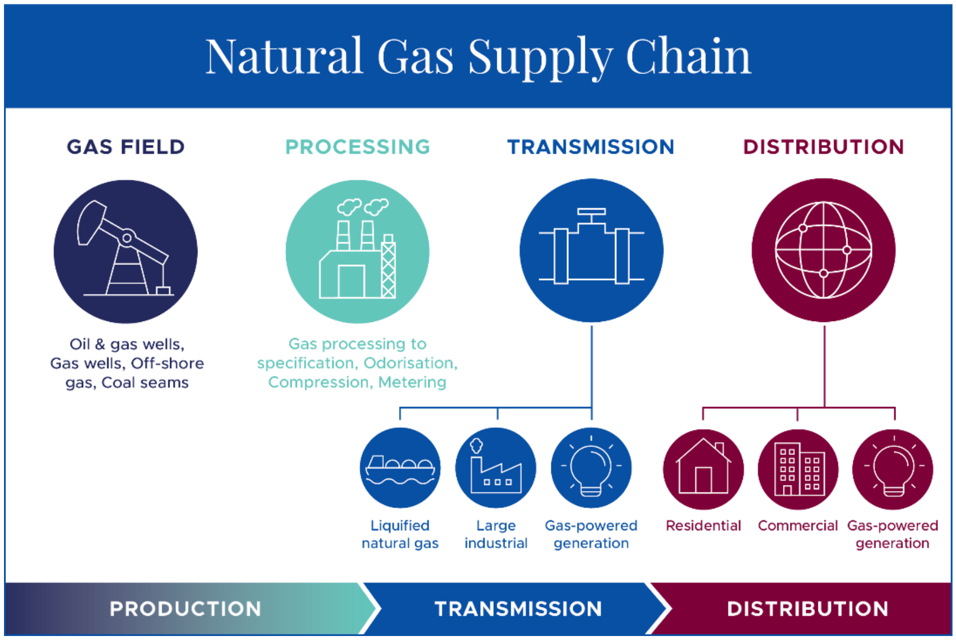


Figure 1. Natural Gas Supply Chain.

Today, LDCs are less likely to be affiliated with upstream producers and transporters of natural gas. Rather, they primarily serve residential and commercial customers, delivering approximately 90% of end-use natural gas to these sectors in 2018.[48] LDCs serve electric power generators, but at a much lower level on average: 75% of natural gas deliveries to electric power sector customers in 2018 were via pipeline companies, while 18% of natural gas deliveries to electric power sector customers in 2018 were via LDCs.[49] Industrial customers, too, are more likely to be served by pipeline companies (51% of deliveries in 2018), but also receive a significant percentage of deliveries from LDCs (34% of deliveries

47. JEFF D. MAKHOLM, THE POLITICAL ECONOMY OF PIPELINES: A CENTURY OF COMPARATIVE INSTITUTIONAL DEVELOPMENT, at 121, (Univ. of Chi. Press 2012). Through the Public Utility Holding Company Act of 1935, 15 U.S.C.A § 79 (repealed in 2005 and replaced with the Public Utility Holding Company Act of 2005), the Securities and Exchange Commission was given the authority to investigate and simply holding company structures. *Id.* The Securities and Exchange Commission'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." *Id.*

48. Kopalek, *supra* note 21.

49. *Id.*

in 2018).[50] It is important to note, however, that these percentages are aggregate numbers for the entire U.S. market—the concentration of any particular customer class varies widely across LDCs.

These residential, commercial, and industrial LDC customers use natural gas for different purposes. Residential customers use natural gas to heat buildings and water, cook, and dry clothes.[51] Commercial customers use natural gas to heat buildings and water, operate refrigeration and cooling equipment, cook, dry clothes, and provide outdoor lighting.[52] Industrial customers use natural gas for process heating, in combined heat and power systems, as feedstock to produce chemicals, fertilizer, and hydrogen, and as plant fuel.[53] These customers could use hydrogen as a fuel replacement for natural gas.[54] To deliver hydrogen to these different demand sectors, LDCs can supply hydrogen to their customers by either developing a new hydrogen-specific pipeline along an existing gas pipeline or blending hydrogen into an existing natural gas pipeline.[55] Blending hydrogen into natural gas pipelines taps into an LDC's ability to leverage the existing infrastructure and, therefore, may be a cost-effective way of introducing hydrogen to new customers.[56] However, there are significant hurdles that must be acknowledged and addressed before an LDC opts to move hydrogen on their system. These challenges are discussed in detail in section IV.

## III. DECARBONIZATION CHALLENGES TO THE LDC MODEL

As noted above, there are numerous developments leading LDCs to consider how to transition into a low-carbon future. However, these developments are not affecting all LDCs equally—some states have not adopted emissions reduction targets, and other states have preempted gas bans with proactive legislation limiting municipalities' ability to adopt such codes and regulations. And yet it is unavoidable that these developments can deeply impact how an LDC's energy transition strategy will develop. As such, this section discusses these three main developments that may shape an LDC's energy transition strategy: state decarbonization targets and energy transition proceedings, gas bans, and private sector and other pressures.

---

50. *Id.*

51. *Natural Gas Explained: Use of Natural Gas*, *supra* note 1.

52. *Id.*

53. *Id.*

54. Currently, the Department of Energy is investing $7 billion on the H2Hubs program to scale up clean hydrogen production and develop ecosystems for hydrogen utilization in a diversity of end-uses such as transportation and power generation. *See* Hannah Murdoch et al., *Pathways to Commercial Liftoff: Clean Hydrogen* 2 (2023), U.S. DEP'T OF ENERGY, https://liftoff.energy.gov/wp-content/uploads/2023/03/20230320-Liftoff-Clean-H2-vPUB.pdf. These projects can demonstrate end-use cases for hydrogen and provide insight on infrastructure needs to develop a network.

55. *Hydrogen Pipelines*, U.S. OFF. OF ENERGY EFFICIENCY & RENEWABLE ENERGY, https://www.energy.gov/eere/fuelcells/hydrogen-pipelines; *see also,* M. W. Melaina et al., *Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues*, NAT'L RENEWABLE ENERGY LAB'Y (2013), https://www.nrel.gov/docs/fy13osti/51995.pdf.

56. Kevin Topolski et al., *Hydrogen Blending into Natural Gas Pipeline Infrastructure: Review of the State of Technology*, NAT'L RENEWABLE ENERGY LAB'Y (2022), https://www.nrel.gov/docs/fy23osti/81704.pdf.

### A. *State decarbonization targets and "transition proceedings"*

Across the U.S., states have adopted ambitious decarbonization goals and targets. For example, in New York, the 2019 Climate Leadership and Community Protection Act (CLCPA) created a standard to achieve net-zero greenhouse gas emissions by 2050 and use emissions-free electric power sources by 2040.[57] In another instance, through the 2020 Global Warming Solutions Act (GWSA), Massachusetts established a legally binding target to reach net-zero greenhouse gas emissions by 2050.[58] The logical next step arising from the adoption of these targets is that instrumentalities of the state begin to take action to achieve the target. Thus, perhaps unsurprisingly, in response to these ambitious state decarbonization targets, several PUCs have opened gas utility planning proceedings.[59] This section looks at one such proceeding—initiated in New York—to analyze how an LDC's decision-making may be affected by such proceedings.[60]

In 2020, the New York Public Service Commission (NYPSC) opened a natural gas planning proceeding to establish new planning and operational practices to support customer needs and emission objectives, while curtailing fossil fuel infrastructure investments.[61] The primary impetus behind the proceeding was the passage of the CLCPA.[62] Another impetus for initiating the proceeding, however, was the moratoria on new service connections adopted by several LDCs.[63] The NYPSC reasoned that the old systems needed to be reformed because LDCs have not "kept pace with recent developments and demands on energy systems."[64]

In the proceeding, the NYPSC emphasized the need for LDCs to provide information so that alternatives to firm gas service and fuel choices are consistent with the state's energy policies.[65] Therefore, the NYPSC ordered the state's largest LDCs to file: (1) a supply and demand analysis with regard to the utility's entire service territory, (2) a supply and demand analysis with regard to areas vulnerable

---

57. *N.Y. State Climate Action Council Draft Scoping Plan*, N.Y. STATE CLIMATE ACTION COUNCIL (Dec. 30, 2021), https://climate.ny.gov/resources/draft-scoping-plan/.

58. MASS. GEN. LAWS. CH. 298, § 3(a) (2020).

59. *State Clean Energy Policy Tracker*, NAT'L REG. RES. INST., https://www.naruc.org/nrri/nrri-activities/clean-energy-tracker/; MD. COMM'N ON CLIMATE CHANGE, BUILDING ENERGY TRANSITION PLAN (2021), https://mde.maryland.gov/programs/air/ClimateChange/MCCC/Documents/2021%20Annual%20Report%20Appendices%20FINAL.pdf.; Tom DiChristopher, *Seeking emission cuts, Colo. regulators propose major gas utility rule changes*, S&P GLOB. MKT. INTEL. (Oct. 7, 2021), https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/seeking-emissions-cuts-colo-regulators-propose-major-gas-utility-rule-changes-66995434.

60. *Proceeding on Motion of the Commission in Regard to Gas Planning Procedures*, N.Y PUB. SERV. COMM., Case No. 20-G-0131, at 1 (Mar. 19, 2020), https://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=20-g-0131#.

61. *Id.* at 3.

62. *Id.*

63. *About the Westchester Natural Gas Moratorium*, CONEDISON, https://www.coned.com/en/our-energy-future/electric-heating-and-cooling-equipment/about-the-westchester-natural-gas-moratorium; *Ongoing scrutiny of NY gas moratorium prompts reform at National Grid*, S&P GLOB MKT. INTEL. (Mar. 30, 2020), https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/ongoing-scrutiny-of-ny-gas-moratorium-prompts-reform-at-national-grid-57822332.

64. *Proceeding on Motion of the Commission in Regard to Gas Planning Procedures*, *supra* note 60, at 2.

65. *Id.* at 12-14.

to supply constraints, (3) a proposal for peaking services and moratorium management issues, and (4) a status report and proposals discussing the extent that the utility currently uses or plans to use demand reducing measures, including fuel supply alternatives and non-pipe solutions, to aid in the management of moratoria.[66] After receiving the requested filings and additional comments, the NYPSC issued a combined order for two different cases that approved a gas planning process.[67]

The order outlining the planning process requires New York's eleven largest LDCs to file proposed long-term plans every three years with the goal of engaging in a stakeholder engagement process.[68] With each filing, the LDC must outline one scenario with a "no infrastructure option" such as non-pipe alternative (NPA) solutions.[69] Additionally, the NYPSC recommended that LDCs quantify the availability of renewable natural gas or biogas as part of the supply forecast in their long-term plans.[70] The NYPSC recognized the potential role of hydrogen in decarbonizing the distribution system and committed to considering its use in future phases of the proceeding.[71] The NYPSC did recognize that while "use of NPAs instead of building new infrastructure is preferable in light of CLCPA targets . . . suggesting all new infrastructure needs or continued maintenance of the gas system could be met with NPAs may not be possible."[72] Therefore, while the NYPSC still required LDCs to provide "no infrastructure" scenarios in their long-term plans, the NYPSC permits an LDC to assert such a scenario is not feasible for either a particular project or a portion of their long-term plan.[73] Should an LDC make this assertion, the LDC is required to submit supporting documentation which would be "vigorously" tested by NYPSC staff.[74]

This proceeding, and particularly the directives issued to the LDCs, is informative because it demonstrates just how an LDC's energy transition strategy, and its ability to incorporate hydrogen, may be impacted by directives from its regulators. If a regulator directs LDCs to lead with "no infrastructure options," opportunities for such LDCs to build new pipeline infrastructure that is capable of handling higher percentages of hydrogen will be limited.

66. *Order Adopting Gas System Planning Process*, N.Y. PUB. SERV. COMM., Case Nos. 20-G-1031, 12-G-0297 (2022), https://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=20-g-0131#.

67. *Id.* at 8-10.

68. *Proceeding on Motion of the Commission to Examine Policies Regarding the Expansion of Natural Gas Service*, N.Y PUB. SERV. COMM., Case 12-G-0297 at 11 (Order Adopting Gas System Planning Process, May 12, 2022).

69. *Id.* A "no infrastructure" component of a filing means, in addition to other options proposed by LDCs, where an LDC includes some combination of demand response and NPAs such as seasonal and peak day rates which close the gap between demand and supply. *Id*. at 35.

70. *Id.* at 54.

71. *Id.* at 63-64.

72. *Proceeding on Motion of the Commission to Examine Policies Regarding the Expansion of Natural Gas Service*, *supra* note 68, at 36.

73. *Id.* at 36-37.

74. *Id*. at 37.

### *B. Gas bans and "stretch" codes*

Transition proceedings are not the only method by which state and local governments are addressing climate change. To curb fossil fuel emissions, many states and municipalities across the United States have taken steps to rewrite state and local energy and housing codes. These revisions include prohibitions on new natural gas hook ups in new buildings, sometimes referred to as "gas bans."[75] These gas bans generally prohibit appliances that use fossil fuels to generate heat, such as gas furnaces, stoves or ovens, with the goal of limiting emissions caused by residential, commercial, and industrial consumers.[76] As discussed further below, these bans, where adopted, have significant implications for an LDC's energy transition strategy, including the ability to blend hydrogen.

Berkeley, California, became the first city in the U.S. to ban natural gas in 2019; as of June 2022, seventy-seven cities in ten states have followed suit.[77] Currently, Washington and California are the only states that have approved of statewide restrictions on the use of fossil fuels, however they may soon be joined by other states.[78] California was the first state to pass a gas ban through a building code that requires new homes and buildings to either be equipped with a highly-efficient heat pump for space and water heating, or face a high energy efficiency requirement.[79] Building on this momentum, the Bay Area Air Quality Management District adopted new zero-emission appliance rules, where only zero-emission water heaters can be sold or installed in the California Bay Area starting in 2027. Such rules would apply only to new furnaces and commercial water heaters in 2029 and 2031 respectively, and would not mandate the replacement of existing appliances. The rule also does not apply to cooking appliances, including gas

---

75. Ella Nilsen, *Cities tried to cut natural gas from new homes. The GOP and gas lobby preemptively quashed their effort,* CNN POLITICS (Feb. 12, 2022) https://www.cnn.com/2022/02/17/politics/natural-gas-ban-preemptive-laws-gop-climate/index.html.

76. *Id*.

77. Jen A. Miller, *Natural gas legislation: What multifamily developers, owners need to know,* UTILITYDIVE (June 2, 2022), https://www.utilitydive.com/news/natural-gas-legislation-what-multifamily-developers-owners-need-to-know/624779/. As with other topics discussed in this article, "gas bans" are evolving policy issues subject to ongoing litigation, which means as a matter of policy such bans and challenges to them are not as of this writing settled issues. In April 2023, a Ninth Circuit panel reversed an earlier California federal court's dismissal of a challenge to Berkeley's ban, finding the city had "waded into a domain preempted by Congress." California Rest. Ass'n v. City of Berkeley, No. 21-16278, slip op. at 7 (9th Cir. 2023); Janie Har, *Court tosses Berkeley gas ban, but wider impact is unclear*, ASSOCIATED PRESS (Apr. 18, 2023), https://apnews.com/article/berkeley-california-natural-gas-ban-overturned-court-3546acbaec5db011c89a 610baa42cebc; *Court throws out Berkeley, California's ban on natural gas*, ASSOCIATED PRESS (Apr. 18, 2023), https://apnews.com/article/berkeley-california-natural-gas-ban-overturned-appeals-court-7dafca58d1996 3f322100d73caf9c31a.

78. David Iaconangelo, *East Coast's first countywide gas ban passed in Md.,* E&E NEWS (Nov. 30, 2022), https://www.eenews.net/articles/east-coasts-first-countywide-gas-ban-passed-in-md/.

79. Caleigh Wells, *California plans to phase out new gas heaters by 2030*, NAT'L PUBLIC RADIO (Sept. 23, 2022), https://www.npr.org/2022/09/23/1124511549/california-plans-to-phase-out-new-gas-heaters-by-2030; *California Passes Nation's First Building Code that Establishes Pollution-free Electric Heat Pumps as Baseline Technology; Leads Transition Off of Fossil Fuels in New Homes*, NAT. RES. DEF. COUNCIL (Aug. 11, 2021), https://www.nrdc.org/media/2021/210811-0.

stoves.[80] Similarly, Washington state enacted its ban through its Clean Buildings Act, which mandates new commercial buildings and large multifamily apartments to install electric heat pumps to warm air and water.[81] Following this legislation, Washington's State Building Code Council approved similar heat pump mandates for newly constructed smaller residential buildings, which as of this writing is currently being challenged by a coalition which includes building industry groups.[82] Separately, State Department of Commerce has begun a rulemaking process for the state's expanded Clean Buildings Performance Standard. The state is required to complete the rulemaking by December 1, 2023.[83]

In the northeast, New York and Massachusetts have either adopted or are exploring similar measures.[84] In 2021, New York City announced it would phase out fossil fuel usage in newly constructed residential and commercial buildings, with certain exemptions (commercial kitchens, laundromats, manufacturing operations, hospitals, crematoriums and emergency power) and two separate effective dates in 2024 and 2027 based on building height.[85] The same law also requires the Mayor's Office to study heat pump technology and electrical grid readiness.[86] As of this writing, New York state lawmakers are pursuing similar efforts, which, if enacted, would make it the first state to enact a full natural gas ban for new buildings, building on the efforts of New York City and other cities and counties.[87]

---

80. *Air District approves phasing out new natural gas furnaces, water heaters*, CBS BAY AREA (Mar. 15, 2023), https://www.cbsnews.com/sanfrancisco/news/natural-gas-furnace-water-heater-phase-out-ban-bay-area-air-district/; Claire Hao, *Bay Area will end sales of gas furnaces and water heaters. Here's what it means for you*, SAN FRANCISCO CHRON. (Mar. 15, 2023), https://www.sfchronicle.com/bayarea/article/bay-area-end-sales-natural-gas-furnaces-water-17841072.php.

81. David Iaconangelo, *Building codes: The new natural gas battlefront?*, ENERGYWIRE (May 3, 2022), https://subscriber.politicopro.com/article/eenews/2022/05/03/building-codes-the-new-natural-gas-battlefront-00027828.

82. Melissa Santos, *State's plan to phase out natural gas in buildings prompts lawsuit*, AXIOS SEATTLE (Mar. 2, 2023), https://www.axios.com/local/seattle/2023/03/02/washington-state-heat-pump-rules-electric.

83. *Owners of buildings over 20,000 sq. ft. invited to participate in state Clean Buildings expansion rulemaking*, NEWSWIRES (Apr. 4, 2023), https://www.einnews.com/pr_news/626114347/owners-of-buildings-over-20-000-sq-ft-invited-to-participate-in-state-clean-buildings-expansion-rulemaking. The rulemaking began with an introductory webinar discussing the basics of the Clean Buildings Program and was the first of several workshops which, according to the state, are "an opportunity for communities, building owners and the industry to help shape how buildings operate, the cost to maintain them, and the role they play in reaching Washington state's energy efficiency and emission reduction goals." *Id*.

84. David Iaconangelo, *Mass. Unveils plans to roll back gas in new buildings,* E&E NEWS (Jan. 1, 2023) https://www.eenews.net/articles/mass-unveils-plans-to-roll-back-gas-in-new-buildings/; *Mayor de Blasio Signs Landmark Bill to Ban Combustion of Fossil Fuels in New Buildings*, CITY OF NEW YORK (Dec. 22, 2021), https://www.nyc.gov/office-of-the-mayor/news/852-21/mayor-de-blasio-signs-landmark-bill-ban-combustion-fossil-fuels-new-buildings.

85. *Mayor de Blasio Signs Landmark Bill to Ban Combustion of Fossil Fuels in New Buildings*, *supra* note 84; Marie French, *Hochul backs eventual bans on gas furnaces and stoves in new buildings*, POLITICO (Jan. 13, 2023), https://www.politico.com/news/2023/01/13/hochul-backs-ban-gas-furnaces-stoves-00077751.

86. *Id.*

87. Maxine Joselow & Vanessa Montalbano, *New York, citing consumer costs, may ease its greenhouse gas accounting rules*, WASH. POST (Apr. 4, 2023), https://www.washingtonpost.com/politics/2023/04/04/new-york-citing-consumer-costs-may-ease-its-greenhouse-gas-accounting-rules/; Marie French, *New York nears deal to ban gas stoves in new homes*, POLITICO (Mar. 23, 2023), https://www.politico.com/news/2023/03/23/new-york-gas-stoves-ban-00088648; Lamar Johnson, *New York state relights the gas stove wars*, POLITICO (Mar. 16,

Separately, the Massachusetts Department of Energy Resources released a draft rule for public comment in December of 2022 where, as part of a demonstration program, up to ten Massachusetts towns and cities can ban fossil fuels in new buildings.[88] As of January 2023, under the program known as the Municipal Fossil Fuel Free Building Construction and Renovation Demonstration Project, new residences must meet certain requirements, such as being "pre-wired" for electrification where owners would be positioned to swap gas appliances for electric equivalents without facing major renovations.[89]

At the city and county level, such codes are known as "reach" or "stretch" codes, because they "reach" or "stretch" beyond the promulgated base building code, enabling a municipality or other body of government to set mandatory or voluntary compliance pathway for its buildings.[90] As described by the New Buildings Institute,

> [w]hen base codes are not keeping up with advances in technology and design practices, stretch codes provide an opportunity to train the building and development communities in advanced practices before the underlying energy code is improved and help accelerate market acceptance and adoption of more stringent energy efficiency codes in the future.[91]

Model code authors, including advocacy organizations and the U.S. Department of Energy's Building Energy Codes Program, play an important role in facilitating such code rewrites.[92] Such codes can align with utility energy efficiency programs, incentivizing LDCs to help municipalities adopt programs.[93]

However, "reach" or "stretch" codes can also facilitate the aforementioned gas bans. Such codes are the means by which local governments can prohibit new natural gas hook ups in new buildings, dissuading use of fossil fuels for heating, cooking or other household appliances and limiting emissions from the same while

---

2023), https://www.politico.com/newsletters/power-switch/2023/03/16/new-york-state-relights-the-gas-stove-wars-00087440.

88. *Municipal Fossil Fuel Free Building Demonstration Program*, MASS. DEP'T OF ENERGY RES. (Dec. 23, 2022), https://www.mass.gov/info-details/municipal-fossil-fuel-free-building-demonstration-program.

89. *Mass. unveils plans to roll back gas in new buildings*, *supra* note 84.

90. *Stretch Codes*, NEW BLDG. INST., https://newbuildings.org/code_policy/utility-programs-stretch-codes/stretch-codes/.

91. *Id*.

92. *Stretch Codes*, U.S. OFF. OF ENERGY EFFICIENCY & RENEWABLE ENERGY, https://www.energycodes.gov/stretch-codes (stating that the U.S. Department of Energy, in collaboration with the Pacific Northwest National Laboratory, is developing technical briefs to aid all levels of government in updating their building codes, and further stating that the department "supports the advancement of building energy codes, including stretch codes that empower states and local governments in achieving their energy and climate goals"); *see* NEW BLDG. INST., *supra* note 90 (describing "stretch" codes and their benefits to LDCs, including how such codes can work in concert with utility energy efficiency programs).

93. *Aligning Utility Programs with Codes*, NEW BLDG. INST., https://newbuildings.org/code_policy/utility-programs-stretch-codes/aligning-utility-programs-codes/. "Reach" or "stretch" codes are not inherently good or bad but represent yet another opportunity for LDCs to be part of the stakeholder process. LDCs are often able to offer expertise to other stakeholders and can take an active role in the drafting of such codes to help a local government achieve its goals while at the same time avoiding any unintentional stifling of innovation. To the extent a local government's goals are opposed to an LDC's objectives, such a stance still represents an opportunity for the LDC—and, by extension, that LDC's regulator—to ensure a local government is making a fully informed decision.

encouraging the replacement of such appliances or functions with electric equivalents.[94] Municipalities institute the bans through local ordinances, resolutions, building codes, or other requirements, while state governments are turning to legislation.[95] Most gas bans restrict the use of natural gas in only new construction, but at least one city has applied its ban to retrofits.[96] Not all stretch codes contain such provisions, but they are an important tool used by local governments in advancing decarbonization policy.

Conversely, as of February 2022, twenty states have passed preemption laws prohibiting local governments from implementing gas bans.[97] This means, generally, that some state legislatures are deploying their authority to overrule the ability of municipal governments to make policy in this area. States that have passed legislation outlawing such bans account for 31% of residential and commercial gas use across the country.[98]

Where so-called gas bans have been adopted, they will deeply shape an LDC's energy transition strategy, including the ability to utilize hydrogen. As discussed in section IV.B, existing natural gas infrastructure can only handle a blend of hydrogen into natural gas, potentially a relatively low percentage blend. An LDC will either face difficult stakeholder pressures or simply not be able to develop new natural gas infrastructure that can handle higher hydrogen blends if there are restrictions installing new natural gas hookups.[99] Where these gas bans exist, LDCs are likely already exploring how to refocus their business efforts. For example, based on the nuances of the specific code, statute or regulation, service to industrial customers, particularly those with few decarbonization alternatives to natural gas, and some commercial customers may still be permitted. Therefore, seeking to expand business to these classes of customers may be the best way to replace lost residential and commercial customers covered by the prohibitions. These customers also may be better situated to use hydrogen in the first place.[100]

94. INST. FOR ENERGY RSCH., AN OVERVIEW OF NATURAL GAS BANS IN THE U.S. (2021), https://www.instituteforenergyresearch.org/wp-content/uploads/2021/08/Natural-Gas-Ban-Report_Updated.pdf; DiChristopher & Duquiatan*, supra* note 8.

95. Tom DiChristopher, *Gas Ban Monitor: Building electrification evolves as 19 states prohibits bans*, S&P GLOB. MKT. INTEL. (July 20, 2021), https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/gas-ban-monitor-building-electrification-evolves-as-19-states-prohibit-bans-65518738.

96*.* *Id.* (noting that with the exception of Denver, Colorado, most ordinances restrict new residential and commercial building, with New York considering statewide mandates for new and existing buildings).

97. Alejandra Mejia Cunningham & Kimi Narita, *Gas Interests Threaten Local Authority*, NAT. RES. DEF. COUNCIL, https://www.nrdc.org/experts/alejandra-mejia/gas-interests-threaten-local-authority-6-states (last updated Feb. 22, 2022). These states are Alabama, Arkansas, Arizona, Florida, Georgia, Indiana, Iowa, Kansas, Kentucky, Louisiana, Mississippi, Missouri, New Hampshire, Ohio, Oklahoma, Tennessee, Texas, Utah, West Virginia and Wyoming. *Id*.

98. DiChristopher & Duquiatan, *supra* note 8.

99*.* *Id.*; *see* Daniel Esposito, *Gas Utilities Are Promoting Hydrogen, But It Could Be a Dead End For Consumers and The Climate*, FORBES (Mar. 29, 2022), https://www.forbes.com/sites/energyinnovation/2022/03/29/gas-utility-hydrogen-proposals-ignore-a-superior-decarbonization-pathway-electrification/?sh=6c6b2176a199.

100*.* *See* Murdoch et al., *supra* note 54, at 2 (articulating three anticipated phases of clean hydrogen expansion in the United States: near-term (2023-2026), where clean-hydrogen replaces unabated, carbon-intensive hydrogen; industrial scaling (2027-2034), where hydrogen costs call driven by economies of scale and continued

### C. *Private sector and other pressures*

In addition to these governmental pressures, LDCs, like other major corporations evaluating and developing environmental, social and governance ("ESG") frameworks and programs, are facing growing private sector pressures to implement such programs, including by decarbonizing the services they deliver. Such pressures come from a variety of sources, including investors or consumers that are pushing towards net-zero targets, as well as decarbonization targets set by LDCs and their parent companies (sometimes in response to investor and consumer pressures). The impetus for these private sector initiatives is a multivariate combination of, among other things, government policy, shifting risk perceptions, and a general increased consciousness regarding potential impacts of climate change.[101] LDCs that are responding to such pressures, including net-zero initiatives, will face a different path than those LDCs that are responding to governmental initiatives.

The last few years have witnessed unprecedented private sector commitments towards achieving significant, measurable reductions in global emissions as companies identify and manage the risks elevated by a combination of ESG-conscious investors and/or such companies' own budding ESG frameworks. In Glasgow, COP26 in 2021 saw the formation of the Glasgow Financial Alliance for Net Zero.[102] The members of the Glasgow Financial Alliance for Net Zero—now totaling over 500 firms globally—have committed to using science-based guidelines to reach net-zero emissions by 2050, set interim targets for 2030, implement action to achieve such targets, stand up monitoring regimes to track such action plans and follow strict guidelines surrounding the use of offsets.[103] In the U.S., McKinsey estimates "400 large US-based companies" have made net-zero pledges, with some setting earlier milestones for incremental emissions reduction targets.[104]

---

research and development, allowing build-out of midstream distribution and storage networks; and long-term growth (2035+), with a self-sustaining commercial market post-PTC expiration driven by at least four factors).

101. Paul Bodnar et al., *Managing the net-zero transition*, BLACKROCK INV. INST. (2022), https://www.blackrock.com/corporate/literature/whitepaper/bii-managing-the-net-zero-transition-february-2022.pdf. Such pressures from consumers and investors will likely increase as jurisdictions move towards mandatory climate risk disclosure standards, or as companies adopt similar reporting as a signal of their climate stewardship. *See* Charles Di Leva et al., *Accelerating Net-zero Pledges with Public-led Climate Financing*, INT'L INST. FOR SUSTAINABLE DEV. SDG KNOWLEDGE HUB (Nov. 9, 2022), https://sdg.iisd.org/commentary/guest-articles/accelerating-net-zero-pledges-with-public-led-climate-financing/ (detailing the efforts of the US, EU and international bodies in moving towards disclosure requirements and arguing such standards are long overdue: "[w]hile the days when a financial company could claim to be net zero, with no credible roadmap to get there, may not be over, these new reporting standards should help to limit greenwashing.").

102. *About us,* GLASGOW FIN. ALL. FOR NET ZERO, https://www.gfanzero.com/about/ (explaining the Glasgow Financial Alliance for Net Zero's goal to accelerate the transition to a net-zero global economy and describing the sector-specific alliances comprising over 500 firms in more than 50 jurisdictions).

103. *Id.*; *see generally* Ross Kerber & Noor Zainab Hussain, *Vanguard quits net zero climate effort, citing need for independence*, REUTERS (Dec. 7, 2022), https://www.reuters.com/business/sustainable-business/vanguard-quits-net-zero-climate-alliance-2022-12-07/ (discussing differences in the approach of certain asset managers).

104. Rory Clune et al., *Navigating America's net-zero frontier: A guide for business leaders*, MCKINSEY & CO. (May 5, 2022), https://www.mckinsey.com/capabilities/sustainability/our-insights/navigating-americas-net-zero-frontier-a-guide-for-business-leaders.

As far as LDCs, in 2018, Xcel Energy Inc., which serves 3.7 million electricity customers and 2.1 million natural gas customers across eight states, became the first major utility to set a net-zero emissions goal.[105] It pledged to cut carbon emissions from its *electric* utility business in Colorado and Minnesota by 86% in 2030 (from 2005 levels) and reach net zero from *both* power and natural gas operations by 2050.[106] Since that time, "virtually all leading U.S. utilities have . . . set[] greenhouse gas emissions reduction targets [or] making net-zero announcements."[107] S&P Global reports that twenty-five of the thirty largest power and natural gas companies (measured by market capitalization) have now set carbon reduction milestones.[108] In addition, three of these companies have included in their climate targets "all emissions connected with natural gas, including hard-to-measure Scope 3 emissions."[109] S&P Global observes that utility support for climate policies and state clean energy laws often overlap, and further provides a detailed breakdown of the climate goals of these top thirty utilities in the United States.[110]

These private sector pressures will affect LDCs in several ways. For an LDC that has itself adopted a net-zero target, any attempt to incorporate hydrogen into an energy transition strategy will have to consider emissions impacts. As discussed in section IV.D below, the emissions profile of hydrogen varies greatly depending on how it is produced. Even LDCs that have not adopted net-zero targets may face significant pressure from customers, particularly corporate customers, to reduce the emissions impact of the natural gas supplied or delivered by LDCs.

## IV. PRACTICAL CHALLENGES TO LDCS INTEGRATING HYDROGEN

The ability to expand new natural gas infrastructure, future-proof that infrastructure for hydrogen, or explore investment in new types of infrastructure unique to hydrogen as a fuel source will vary widely across LDCs.[111] Just as legislation

105. Karin Rives, *Path to net-zero: Utility execs insist 'we can'*, S&P GLOB. MKT. INTEL. (June 9, 2022), https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/path-to-net-zero-utility-execs-insist-we-can-69901885.

106. *Id.*

107. *Id.*

108. *Id*.

109. Rives, *supra* note 105. These three utilities are: CMS Energy, Dominion Energy, and Duke Energy Corp. *Id*.

110. *Id*. (providing net-zero targets for electric utilities, gas utilities and multi-utilities, and listing the five utilities that did not, as of S&P's writing, have net-zero targets).

111. "Future proof is a buzzword that describes a product, service or technological system that will not need to be significantly updated as technology advances." Alexandra Klass, *Future-Proofing Energy Transport Law*, 84 WASH. UNIV. L. Rev. 827, 828 n.1 (2017) (quoting *Future Proof*, TECHOPEDIA, http://www.techopedia.com/definition/2204/future-proof). Part of the goal of this section IV is to help LDCs identify some of the questions they should be asking as they consider how to future-proof their own infrastructure to maximize the likelihood that the assets they build now will retain their use and value as the energy transition advances and avoid the problem of stranded assets. *See* Catherine Morehouse, *Utilities don't see stranded assets as a top risk. Should they?*, UTILITYDIVE (Feb. 14, 2020), https://www.utilitydive.com/news/utilities-dont-see-stranded-assets-as-a-top-risk-should-they/572246/ (describing survey results, interviewing industry representatives and concluding that LDCs, "particularly vertically integrated [LDCs], may feel more confident in regulatory structures

and regulation varies across states and service territories, so too does infrastructure. LDCs seeking to incorporate hydrogen into their energy transition strategy will need to examine their service territories to better understand the practical challenges of integrating hydrogen into their energy transition strategy. For example, some of the opportunities and challenges, such as available end-uses, will not be relevant to all LDCs.

### *A. Limitations of existing infrastructure*

One of the most commonly repeated cautions about the potential utility of hydrogen for LDCs is that the existing U.S. natural gas system cannot tolerate blending hydrogen into natural gas above a certain percentage, as hydrogen can embrittle pipes and have significant adverse impacts on end-use appliances.[112] As noted above, there have been studies indicating LDCs can safely blend anywhere from 5% to 20% hydrogen into the natural gas stream without needing to make significant upgrades to the system.[113] What is less commonly discussed, however, is that across the U.S., the composition of LDCs' systems varies greatly and will impact such LDCs' ability to blend hydrogen.[114] Indeed, the LDC's current asset base will be a significant driver when considering whether hydrogen can play a role in the business's future.

The studies to date indicate that while hydrogen can cause embrittlement in some steel grades, it may be less likely to degrade plastic pipe.[115] This suggests that LDCs with a system comprised of a higher percentage of plastic pipe may be able to blend a higher percentage of hydrogen into their existing systems with less risk of embrittlement.[116] Even amongst steel pipes there is a significant difference in terms of potential risk of embrittlement: the risk of hydrogen embrittlement is greater in high-pressure, high-strength steel typically used for natural gas transmission and lower in low-pressure, low-strength distribution pipes.[117]

Across the U.S., there is a significant range in the percentage of LDC systems that are comprised of plastic versus other materials. For example, in 2021, S&P Global analyzed a subset of LDCs with at least 5,000 miles of distribution mains and service lines.[118] According to S&P Global's analysis, the percentage of the

---

and new financing mechanisms that will allow them to recover those costs, say some observers and stakeholders. Others warn [LDCs] should be cautious in their long-term investments, particularly if they want to stay on their customers' good side" while noting "some argue that building out that [pipeline] infrastructure still makes sense for a lower-carbon gas system, where today's natural gas is replaced by biofuels and hydrogen, which would still need a way to be transported.").

112. Esposito, *supra* note 99.

113. Melaina *et al.*, *supra* note 55.

114. *Id.* at v.

115. *Id.* at 22-23.

116. *Id.*

117. Paul W. Parfomak, *Pipeline Transportation of Hydrogen: Regulation, Research, and Policy*, CONGR. RSCH. SERV. 3 (2021), https://crsreports.congress.gov/product/pdf/R/R46700.

118. Tom DiChristopher & Anna Duquiatan, *Gas utilities make fewer leak repairs in 2020 as monitoring technology improved*, S&P GLOB. MKT. INTEL. (Oct. 28, 2021), https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/gas-utilities-make-fewer-leak-repairs-in-2020-as-monitoring-technology-improved-67225162.

LDCs' systems that were comprised of plastic pipeline varied from 58.20% to 87.10%.[119] A chart excerpted from S&P's analysis is provided below:

| | | | Share of mileage by pipeline material (%) — *higher shares shaded darker* | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Company | State(s) of operation | Main and line length (miles) | Cathodically protected steel (bare) | Cathodically protected steel (coated) | Iron* | Plastic | Unprotected steel (bare) | Unprotected steel (coated) | Others |
| West Texas Gas Inc. | LA, NM, OK, TX | 5,943 | 1.85 | 13.50 | 0.00 | 81.88 | 1.87 | 0.88 | 0.00 |
| Northwest Natural Gas Co. | OR, WA | 24,264 | 0.00 | 37.42 | 0.00 | 62.57 | 0.00 | 0.00 | 0.00 |
| New York State Electric & Gas Corp. | NY | 8,452 | 0.06 | 30.60 | 0.07 | 64.72 | 1.25 | 2.48 | 0.79 |
| Wisconsin Electric Power Co. | MI, WI | 17,297 | 0.00 | 22.48 | 0.00 | 77.52 | 0.00 | 0.00 | 0.00 |
| Rochester Gas and Electric Co. | NY | 9,120 | 0.04 | 38.74 | 0.03 | 58.60 | 0.72 | 0.70 | 1.17 |
| ENSTAR Natural Gas Co. | AK | 6,098 | 0.02 | 8.40 | 0.00 | 87.10 | 0.00 | 0.00 | 4.49 |
| New Mexico Gas Co. Inc. | NM | 15,772 | 0.69 | 41.11 | 0.00 | 58.20 | 0.00 | 0.00 | 0.00 |
| Wisconsin Gas LLC | WI | 20,295 | 0.00 | 26.84 | 0.00 | 72.39 | 0.00 | 0.00 | 0.77 |
| Puget Sound Energy Inc. | WA | 26,307 | 0.00 | 22.78 | 0.00 | 77.22 | 0.00 | 0.00 | 0.00 |
| Middle Tennessee Natural Gas Utility District | TN | 7,032 | 0.00 | 19.70 | 0.00 | 80.30 | 0.00 | 0.00 | 0.00 |

Data compiled Aug. 19, 2021.
* Includes cast and ductile iron.
Analysis is limited to companies with at least 5,000 miles of distribution mains and service lines.
Service line length estimated from count of lines and average length.
Source: S&P Global Market Intelligence

Figure 2: S&P Global Market Intelligence.[120]

While S&P's analysis arose in the context of reporting on leak repairs, this data highlights how LDCs are differently situated in their ability to blend hydrogen in their existing pipeline systems due to the diversity of their systems in age, construction materials, length and other factors. It also points to one of the key variables an LDC will need to analyze when considering whether and to what extent it can incorporate hydrogen into its existing business model.

Another step that LDCs can take to analyze the potential impact of hydrogen blending on their systems is to engage in pilot or demonstration projects. Several LDCs in the U.S. and abroad have already begun engaging in such projects. For example, Southern California Gas Co. (SoCalGas) was reportedly among the first utilities to test hydrogen blending on both natural gas infrastructure and end-use equipment like stoves and home heating systems.[121] SoCalGas's preliminary results showed some household appliances could tolerate up to a 20% hydrogen blend.[122] Additionally, SoCalGas and other large California LDCs have been directed by the California Public Utilities Commission (CPUC) in a recent rulemaking to inaugurate additional pilot projects to study infrastructure limitations and

119. *Id.*

120. *Id.*

121. *SoCalGas Among First in the Nation to Test Hydrogen Blending in Real-World Infrastructure and Appliances in Closed Loop System*, HYDROGEN CENTRAL (Oct. 2, 2021), https://hydrogen-central.com/socalgas-test-hydrogen-blending-infrastructure/.

122. *Id.*

demonstrate the viability of hydrogen blending between 0.1% and 5% and between 5% and 20%.[123]

The results of these initiatives likely will be informative for other LDCs seeking to consider the practical implications of hydrogen blending and how to potentially structure a demonstration or pilot program for their own systems. The International Energy Agency (IEA) maintains a Clean Energy Demonstration Projects Database that maps major demonstration projects globally, which can serve as a valuable resource for LDCs considering how to structure such a project.[124]

### *B. Challenges with blending hydrogen into the LDC system*

When discussing the use of hydrogen as a medium through which the LDC can decarbonize, practitioners generally refer to the concept of "blending" hydrogen into gas delivered to individual customer facilities (*i.e.*, industrial customers who require high heat processes) and separately blending into the natural gas distribution system. However, the LDC and their end-users must consider their own infrastructure and capabilities before leveraging a natural gas-hydrogen blend.

Infrastructure tolerances vary, and due to the case-by-case studies required, there is no definitive rule for blend tolerances. In theory, blending hydrogen into the natural gas distribution system for a utility is a way to replace energy sold to the customer via natural gas with hydrogen, which does not emit carbon dioxide when combusted.[125] Doing so will allow LDCs to move hydrogen without needing to fully replace the LDC's gas delivery system. There have been several studies indicating LDCs can safely blend anywhere from 5% to 20% hydrogen into the natural gas stream without needing to make significant upgrades to the system.[126] However, a recent study out of California suggests the actual blend threshold could be closer to 5% in that state's distribution system.[127] As blend thresholds exceed these limits, operational upgrades are needed in the system to safely deliver gas to customers.[128] Such upgrades will generally include significant upgrades to the

123. *Joint Application of Southern California Gas Company (U 904 G), San Diego Gas & Electric Company (U 902 G), and Southwest Gas Corporation (U 905 G) to Establish Hydrogen Blending Demonstration Projects*, PUB. UTIL. COMM'N OF THE STATE OF CALI., Case A.22-09-XXX (Sept. 8, 2022).

124. *Clean Energy Demonstration Projects Database*, INT'L ENERGY AGENCY, https://www.iea.org/data-and-statistics/data-tools/clean-energy-demonstration-projects-database (last modified Sept. 22, 2022). Notably, it appears that the database has not yet been updated to reflect that several projects are no longer "under construction" and are now in operation. *Id.* For example, Air Liquide's liquid hydrogen production and logistics infrastructure in North Las Vegas, Nevada, which is reported now in operation, provides hydrogen for fuel cell vehicles in California and is fully powered by renewable electricity. Eli Segall, *Energy giant opening $250M plant in North Las Vegas*, LAS VEGAS REVIEW-JOURNAL (May 14, 2022), https://www.reviewjournal.com/business/energy/energy-giant-opening-250m-plant-in-north-las-vegas-2576157/; *Air Liquide inaugurates in the U.S. its largest liquid hydrogen production facility in the world*, AIR LIQUIDE (May 23, 2022), https://usa.airliquide.com/air-liquide-inaugurates-us-its-largest-liquid-hydrogen-production-facility-world.

125. Miroslav Penchev et al., *Hydrogen Blending Impacts Study*, CAL. PUB. UTIL. COMM'N (2022), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M493/K760/493760600.PDF.

126. *See generally id.*; Melaina *et al.*, *supra* note 55, at vii.

127. Penchev et al., *supra* note 125.

128. *CPUC Issues Independent Study on Injecting Hydrogen Into Natural Gas Systems*, CAL. PUB. UTIL. COMM'N (July 21, 2022), https://www.cpuc.ca.gov/news-and-updates/all-news/cpuc-issues-independent-study-on-injecting-hydrogen-into-natural-gas-systems.

LDC's distribution system and each discrete home and business's gas delivery system within each building's walls.[129] There is no formal agreement on maximum blending percentage among utilities, and this variability can be seen across states.[130] Given the level of operational and technical data required to assess the viability of blending for a given pipeline system or large industrial customers, LDCs are among the stakeholders best positioned to lead the required technical and scientific inquiry.[131]

Another challenge is the difference in volumetric delivery requirements between natural gas and hydrogen. When blending percentages are mentioned, the percentage is generally given on a "volume" basis rather than an "energy" basis. In essence, if a customer is receiving 100 cubic feet of natural gas with no blend, the same customer would receive eighty cubic feet of natural gas and 20 cubic feet of hydrogen in a 20% blend scenario. Based on the lower volumetric energy density of hydrogen compared to natural gas, if a customer were to receive a 20% blend of hydrogen for 100 cubic feet of delivered gas, the total embedded energy within the delivery would be lower than if 100 cubic feet of natural gas had been delivered. This is demonstrated below in Figure 3.

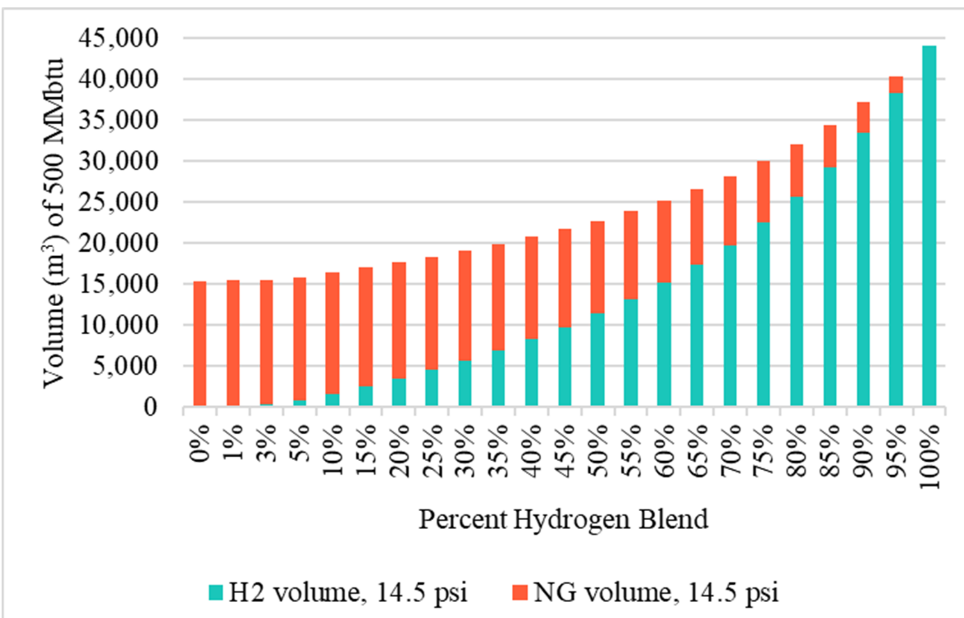


Figure 3. Volumetric Gaseous Requirement to Meet 500 MMBtu of Energy Demand, Source: Hernandez and Li Analysis

129. *Id.*
130. Murdoch et al., *supra* note 54, at 8.
131. *Id.*

Figure 3 shows the volumetric requirement if an LDC were to meet the same monthly energy demand for a given customer – in this illustrative example, the energy demand considered is 500 MMBtu at a pressure of 14.5 pounds per square inch (psi) and 15ºC.[132] As the hydrogen blend percentage increases, the actual volume required to meet the same energy demand grows non-linearly. In a situation where an LDC moves pure hydrogen on its system at 14.5 psi, it would ultimately need to sell approximately three times more physical gas to meet the same energy demand than if it were delivering strictly natural gas. This implies the LDC's customer would need to be prepared to accept three times more physical gas than it currently accepts to meet the same energy demand at that pressure. Further, the volume of hydrogen and natural gas will change based on the pressure of distribution lines because of hydrogen's lower energy density compared to natural gas. Again, it will be important for both the LDC and customer to understand infrastructure availability and tolerances before considering the use of hydrogen. Aside from the volumetric need for the LDC to upgrade its system to move hydrogen, each customer that currently consumes gas within a home or business may also need to reinvest in their gas delivery system and the appliances to accept a fuel with different chemical properties compared to natural gas.

In considering how to overcome some of the potential limitations on hydrogen blending, it is important to note that many of the studies on hydrogen blending presume that hydrogen will be blended into the gas network for delivery for all customers connected to that network. However, as observed in a Connecticut state report investigating the viability of hydrogen blending as an end-use, "[h]ydrogen blending for non-core customers (e.g., industrial or power generation customers) could be done at the facility level due to the large, concentrated demand for natural gas that exists at these facilities."[133] While such blending would still require an assessment of the customers' facility to determine whether hydrogen can be blended directly into their fuel feedstock without affecting operations, because the use case focuses on individual customer facilities it avoids the need to assess the impact of hydrogen blending on the wider distribution network.[134] Thus, the opportunities for hydrogen blending (as a percentage) may be greater for non-core customers.

### *C. Limitations of customers' end-use products*

A significant limitation on the utility of hydrogen to serve customers' needs is the lack of end-use products that can operate on a high volume of hydrogen. Hydrogen is more flammable than natural gas and the risk for embrittlement of

132. At 360 psi and 15 ºC, the volumetric energy density of hydrogen is roughly 296 MJ/m3 and the volumetric energy density of natural gas roughly 907 MJ/m3 on a higher heating value basis. These base values were chosen based on average commercial usage per month and approximate value for backbone trunkline pressures. *See Number of Natural Gas Consumers,* U.S. ENERGY INFO. ADMIN., https://www.eia.gov/dnav/ng/ng_cons_num_a_EPG0_VP5_Mcf_a.htm.

133. CONN. GREEN BANK & STRATEGEN, CONNECTICUT HYDROGEN TASK FORCE STUDY: SUBMITTED TO THE ENERGY & TECHNOLOGY COMMITTEE OF THE CONNECTICUT GENERAL ASSEMBLY PER SPECIAL ACT 22-8 61 (2023), https://www.ctgreenbank.com/wp-content/uploads/2023/01/Connecticut-Hydrogen-Task-Force-Study-FINAL-20230114.pdf.

134. *Id.*

metal is higher.[135] Accordingly, household appliances such as stoves or HVAC systems that currently operate on natural gas cannot run on pure hydrogen and will need to be retrofitted or replaced.[136] Further, the blend threshold for such products will vary by appliance type and age. LDCs must study their own systems and consider how the potential incorporation of hydrogen in their distribution system will affect their customer-base.

There have been some advancements in developing end-use products that can run on higher percentages or pure hydrogen. For example, in 2019 BDR Thermea group installed the world's first hydrogen-powered domestic boiler in the Netherlands, which reportedly is still in "excellent condition, having operated continuously and without any issues or loss of capacity since installation."[137] A number of utilities, both in the U.S. and abroad, also are investigating the potential viability of integrating hydrogen into residential end-uses through the use of demonstration projects. In the UK, Northern Gas Networks has opened a number of hydrogen homes, which are fitted with hydrogen gas appliances, including stoves and boilers.[138] In California, SoCalGas is constructing what it calls the "[H2] Innovation Experience," which will be a modular home with solar panels, a battery system, and electrolyzer to convert solar energy to hydrogen and a fuel cell to supply electricity for the home.[139] SoCalGas also intends to blend hydrogen with natural gas to be used in the home's heat pump HVAC unit, water heater, clothes dryer, and gas stove.[140] Even if these demonstration projects prove fruitful, however, scaling up from a demonstration project to a system-wide blend of hydrogen and natural gas will be a significant undertaking.

### *D. Carbon-intensity of hydrogen production*

While certain hydrogen end-uses do not emit carbon dioxide, combustion of hydrogen does emit nitrogen oxides (NOx). Additionally, emissions associated with producing hydrogen without carbon capture, sequestration, and storage (CCS) or other appropriate control devices are not negligible. In fact, depending on the production mode, the emissions associated with producing hydrogen can be quite significant.[141]

There are two primary modes through which hydrogen is produced in the United States: (i) steam methane reforming (sometimes referred to as a "gray hy-

---

135. *Safe Use of Hydrogen*, U.S. OFF. OF ENERGY EFFICIENCY AND RENEWABLE ENERGY, https://www.energy.gov/eere/fuelcells/safe-use-hydrogen.

136. Esposito, *supra* note 99.

137. *Three Years On, and the World's First 100% Hydrogen Boiler is Still Going Strong*, BDR THERMEA GROUP (Jan. 16, 2023), https://www.bdrthermeagroup.com/en/stories/hydrogen-boiler-is-still-going-strong.

138. *Our Hydrogen Home*, N. GAS NETWORKS, https://www.northerngasnetworks.co.uk/current-business-plan/our-hydrogen-home-welcome-to-green-gas/.

139. [H2] Innovation Experience: The Future of Renewable Energy is Here, SOCALGAS, https://www.socalgas.com/sustainability/h2home.

140. *Id.*

141. *See* Murdoch et al., *supra* note 54, at 51 (describing the health impacts associated with the production and end-use of hydrogen and stating that without emission control devices, steam methane reforming can produce carbon dioxide and other volatile organic compounds emissions and other "comorbidities").

drogen"); and (ii) electrolysis by splitting water into hydrogen and oxygen (sometimes referred to as "green hydrogen").[142] Excluding hydrogen produced as a by-product, industrial participants in the United States produce on the order of 10 million tons (MMT) of hydrogen today, effectively all via steam methane reforming.[143] The production of hydrogen via steam methane reforming emits on the order of nine kilograms (kg) of carbon dioxide per kilogram of hydrogen produced.[144] It is possible to incorporate CCS technologies to capture emissions released from this steam methane reforming process—in the U.S., such steam methane reforming units paired with CCS technologies are actively operating and others have been announced—which could reduce the emissions associated with producing such hydrogen (sometimes referred to as "blue hydrogen").[145] In 2022, such "blue hydrogen" accounted for less than 5% of production.[146] Even hydrogen produced via electrolysis may have potentially significant embedded carbon emissions.[147] If the electrolyzer is directly connected to a local power grid, the carbon intensity of the hydrogen produced will rely directly on the carbon intensity of the power grid within the region.[148]

Revisiting the example in section IV.B, if an LDC wanted to supply a customer with 500 MMBtu of energy at 14.5 psi, the emissions associated with producing hydrogen will be extremely sensitive to both the blend percentage of hydrogen and natural gas as well as the hydrogen production mode and location. Results from this illustrative example are shown below in Figure 4.

---

142. Mohit Joshi et al., HYDROGEN 101: FREQUENTLY ASKED QUESTIONS ABOUT HYDROGEN FOR DECARBONIZATION, GREENING THE GRID 2-3 (2022), https://www.nrel.gov/docs/fy22osti/82554.pdf. There has been movement away from utilizing colors to describe hydrogen based on its production method for a number of reasons, including the limiting nature of using such labels given the increasing number of technologies being used to produce hydrogen. Accordingly, this article endeavors to describe hydrogen based on the process used to create it rather than a color. However, for convenience and ease of understanding in an evolving discourse, this article continues to make use of colors in specific circumstances.

143. Elizabeth Connelly et al., CURRENT HYDROGEN MARKET SIZE: DOMESTIC AND GLOBAL, U.S. DEP'T OF ENERGY (Oct. 1, 2019), https://www.hydrogen.energy.gov/pdfs/19002-hydrogen-market-domestic-global.pdf.

144. Units converted from emissions rate of 0.8091 kg of carbon dioxide per cubic meter of hydrogen produced from steam methane reforming. INT'L ENERGY AGENCY GREENHOUSE GAS R&D PROGRAMME, IEAGHG TECHNICAL REPORT 16 (2017), https://ieaghg.org/exco_docs/2017-02.pdf. This value will vary based on the embedded emissions associated with leaks in the production and delivery of natural gas. Alan Krupnick & Aaron Bergman, INCENTIVES FOR CLEAN HYDROGEN PRODUCTION IN THE INFLATION REDUCTION ACT, RES. FOR THE FUTURE (Nov. 9, 2022), https://www.rff.org/publications/reports/incentives-for-clean-hydrogen-production-in-the-inflation-reduction-act/.

145. Port Arthur Fact Sheet: Carbon Dioxide Capture and Storage Project; Carbon Capture & Sequestration Technologies, MASS. INST. OF TECH. (2016), https://sequestration.mit.edu/tools/projects/port_arthur.html; see generally Louisiana Clean Energy Complex, AIR PRODUCTS, https://www.airproducts.com/campaigns/la-blue-hydrogen-project.

146. *See infra* note 168.

147. Krupnick & Bergman, *supra* note 144.

148. *Id.*

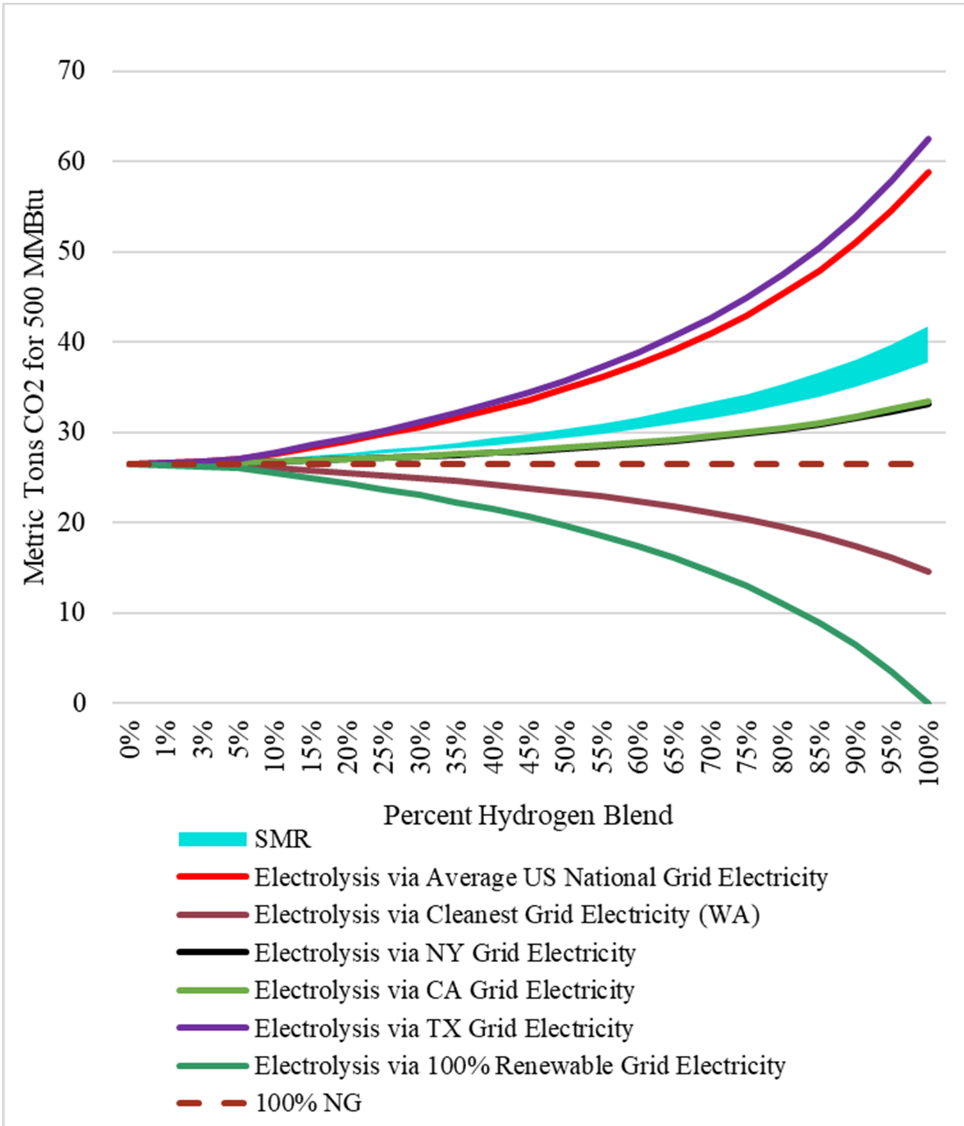


Figure 4. Carbon Intensity of Delivered Energy, Source: Hernandez and Li Analysis

It is worth noting that there are only two scenarios detailed above that ultimately emit less carbon dioxide than that of natural gas: (i) power sourced from the "cleanest" portion of the U.S. grid according to the U.S. Energy Information

Administration, which is in Washington state, where the primary source of electricity is hydroelectric production;[149] and (ii) hydrogen produced via electrolysis powered by 100% renewable energy.[150] For the sake of this analysis, the emissions in Figure 4 only represent emissions from the production of hydrogen.[151]

LDCs will need to be mindful of these varying emission rates when representing the potential benefits of hydrogen blending to both regulators and consumers. For example, it would be difficult for a utility to justify to a regulator the required infrastructure investment to move a blend of hydrogen and natural gas on the grounds of reducing emissions associated with LDCs' operations if there are no real emissions benefits. LDCs also will need to be aware of potential litigation and regulatory action that may arise if they make claims about environmental benefits from hydrogen blending that are not supported by the actual emissions data.

### *E. Cost of producing low-carbon hydrogen*

Because LDCs pass on to ratepayers the costs of the commodities procured to serve such ratepayers, it is important for LDCs to consider the potential costs of hydrogen acquired to serve customers and potential ratepayer impacts.

The commodity cost of delivered gas on a dollar-per-unit energy basis is a function of the blend percentage of the fuel being delivered to customers.[152] Hydrogen is generally discussed on a dollar-per-unit mass ($/kg) basis.[153] Price targets for clean hydrogen are generally set on this basis as well.[154] For example, the U.S. Department of Energy, through its Hydrogen Earthshot Initiative, has a target of producing clean hydrogen at $1/kg by 2031.[155] In order to translate this cost to one easily compared with natural gas, the cost would need to be presented in a dollar-per-unit energy ($/MMBtu) basis.[156] This conversion can be made by multiplying the hydrogen cost by a range of roughly 7 to 9 depending on if a higher or lower heating value of for hydrogen is assumed. Table 1 below shows the price of hydrogen on both a $/kg and $/MMBtu basis, assuming a higher heating value.[157]

---

149. *Washington Electricity Profile 2021*, U.S. ENERGY INFO. ADMIN. (Nov. 10, 2022), https://www.eia.gov/electricity/state/washington/. Emissions from electrolysis are calculated based on the annual emissions intensity of power produced in each respective state. This analysis is meant to be illustrative, as the embedded emissions associated with hydrogen production via electrolysis can vary based on a selected carbon dioxide accounting methodology.

150. *See* Figure 4.

151. *Id.*

152. *Gas Prices Explained*, AM. PETROLEUM INST., https://www.api.org/oil-and-natural-gas/energy-primers/gas-prices-explained.

153. *Hydrogen Shot*, U.S. OFF. OF ENERGY EFFICIENCY & RENEWABLE ENERGY, https://www.energy.gov/eere/fuelcells/hydrogen-shot.

154. *Id.*

155. *Id.*

156. *Explore MMBTU*, ADANI GRP., https://www.adanigas.com/png-commercial/explore-mmbtu.

157. BRITISH PETROLEUM, APPROXIMATE CONVERSION FACTORS 2 (2021), https://www.bp.com/content/dam/bp/business-sites/en/global/corporate/pdfs/energy-economics/statistical-review/bp-stats-review-2022-approximate-conversion-factors.pdf. The higher heating value of hydrogen yields a conversion rate of 7.44; in order to get the cost of hydrogen on a $/MMBtu basis, one must multiply the $/kg figure by 7.44. This figure is calculated by converting the higher heating value of hydrogen to a MMBtu/kg basis.

Table 1. Energy Equivalent Cost of Hydrogen on a $/kg and $/MMBtu Basis

| $/kg | $/MMBtu |
|---|---|
| $ 1.00 | $ 7.44 |
| $ 2.00 | $ 14.87 |
| $ 3.00 | $ 22.31 |
| $ 4.00 | $ 29.75 |
| $ 5.00 | $ 37.18 |

The actual delivered commodity cost, which is passed through directly to the customer, will vary considerably based on a number of variables: (i) the blend percentage; (ii) the price of natural gas; and (iii) the price of hydrogen. As an illustrative example, if we consider the same 500 MMBtu discussed prior delivered to the customer at 14.5 psi, the price of the delivered commodity will vary, as shown in Figure 5.

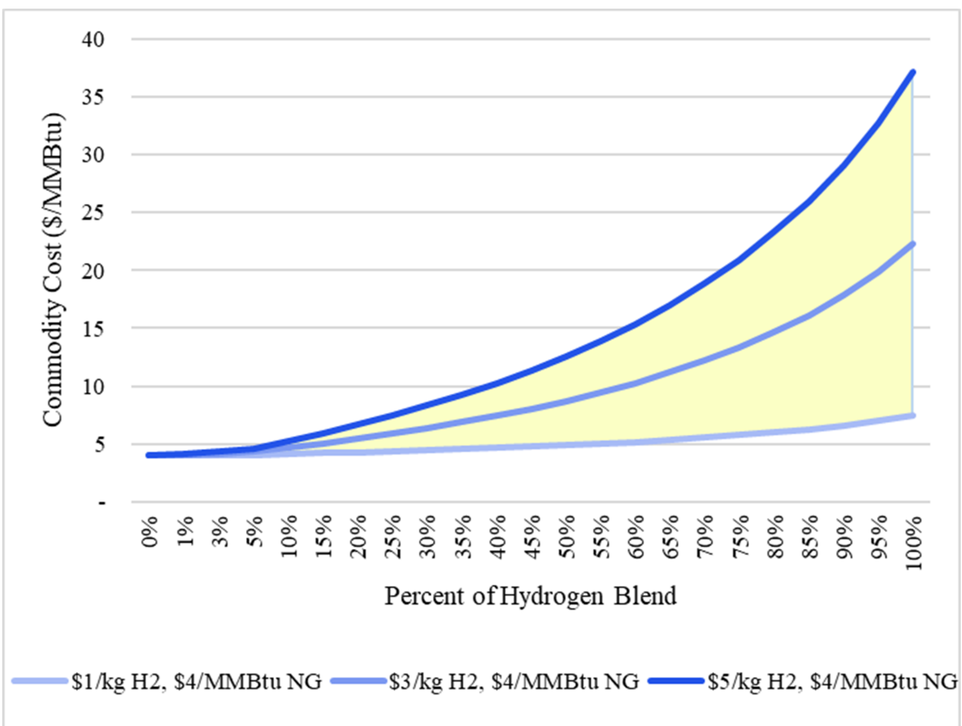


Figure 5. Commodity Cost of Gas Delivered to Customer, Source: Hernandez and Li Calculations

If one assumes a base natural gas price of $4/MMBtu and adjusts the hydrogen price between $1/kg and $5/kg, the commodity cost for the delivered gas can vary from $4/MMBtu in a 0% hydrogen blend scenario to $37.18/MMBtu in a 100% hydrogen blend, high-cost scenario. In other words, in the lowest cost hydrogen scenario, the commodity price for the delivered energy in a 100% hydrogen blend would be 1.85 times more expensive than directly delivering natural gas. In the worst case, the commodity cost would almost be ten times more expensive.

Note that this is only the commodity cost component of the ratepayer's bill. To safely move 100% hydrogen on the LDC's system, LDCs will need to make significant capital expenditures in their systems. These expenses would then be recovered by the utility with a return through the cost-of-service ratemaking process that was discussed in section II. In short, the cost of delivered gas to meet the same energy demand could be significantly more expensive in a world where the LDC is moving hydrogen versus a world where the LDC moves natural gas.

There are federal tax incentives that could drive down hydrogen commodity costs and increase project economic feasibility.[158] Producers of hydrogen with lifecycle greenhouse gas emissions less than 4 kg CO2/kg H2 can qualify for the production tax credit (PTC) set forth in section 45V of the Internal Revenue Code.[159] The ultimate tax credit value varies depending on the lifecycle greenhouse gas emissions associated with the hydrogen and can range from $0.6/kg to $3/kg of hydrogen.[160] Another tax credit is available under section 45Q of the Internal Revenue Code for CCS projects, though there may be certain limitations on claiming the 45V and 45Q credits on the same projects.[161] This credit may help decrease costs of hydrogen produced via steam methane reforming combined with CCS.[162] In addition to these federal incentives, state level incentives or regulations might decrease hydrogen production costs. For instance, California is pushing hydrogen demand as a transportation fuel through its Low Carbon Fuel Standard (LCFS) program.[163]

These incentives do not represent the entirety of funding and programs aimed at commercializing multiple segments of the hydrogen value chain; rather, these examples are meant to highlight just some of the federal and state-level government policy and programs available to hydrogen projects. Such federal and state incentives may be able to reduce the cost of hydrogen as a commodity and, therefore, the final delivered commodity cost of hydrogen for the end-use customer, ultimately determining if hydrogen is cost-competitive for gas blending. In states where there are no existing incentives, LDCs may consider advocating for the creation of such incentives.

---

158. *Financial Incentives for Hydrogen and Fuel Cell Projects*, U.S. OFF. OF ENERGY EFFICIENCY & RENEWABLE ENERGY, https://www.energy.gov/eere/fuelcells/financial-incentives-hydrogen-and-fuel-cell-projects.

159. BIPARTISAN POL'Y CTR., INFLATION REDUCTION ACT SUMMARY 3, https://www.energy.gov/sites/default/files/2022-10/IRA-Energy-Summary_web.pdf.

160. *Id*.

161. *Id*.

162. Krupnick & Bergman, *supra* note 144, at 15, 17, 26.

163. *Alternative Fuels Data Center: Hydrogen Laws and Incentives in California*, U.S. DEP'T OF ENERGY, https://afdc.energy.gov/fuels/laws/HY?state=CA.

### *F. Need for scale-up of domestic low-carbon hydrogen production*

Another challenge to successfully integrating hydrogen into a decarbonization strategy is the need to scale up domestic production of low-carbon hydrogen.

Some estimates put the per annum requirements of a net-zero emissions steel industry alone—not including the hydrogen needed to decarbonize existing hydrogen demand or deploy as an energy storage vector—at over 50 MMT of green hydrogen globally.[164] However, in 2021, there was less than 1 MMT of low-emission hydrogen produced globally, most of which was produced from plants using fossil fuels fitted with CCS technologies.[165] The Department of Energy estimates that the U.S. produces 10 MMT per year of hydrogen, over 95% of which comes from steam-methane reformation, which is not considered to be a source of low-carbon hydrogen.[166] Globally, hydrogen "demand . . . is met almost entirely [with] hydrogen" produced from fossil fuels.[167] This is also true of hydrogen produced in the U.S., where reformation-based production without CCS accounted for roughly 95% of hydrogen production in 2022, and hydrogen produced with electrolysis powered by grid electricity accounted for less than 1%, with reformation paired with CCS making up the difference.[168]

The long road to scaling green hydrogen is especially apparent when viewed in the context of blending hydrogen into natural gas consumed by the residential, commercial, and industrial sectors in the United States. In 2022, these sectors consumed a combined 17 trillion cubic feet (Tcf) of natural gas.[169] Even a 5% volumetric blend of hydrogen into the natural gas demand within the sectors would require roughly 2 MMT of hydrogen to serve the same energy demand.[170] This is notable since, as discussed above, annually the entire U.S. market for intentionally produced hydrogen is 10 MMT, the overwhelming majority of which is produced through steam methane reforming rather than by electrolysis.[171]

This has significant implications for LDCs seeking to procure low-carbon hydrogen to serve customers. First, there will need to be a significant increase in low-carbon hydrogen production capacity to meet the needs of U.S. LDCs. Second, because there is no existing liquid market for low-carbon hydrogen in the

---

164. *Decarbonising global iron ore and steel industry by 2050 necessitates urgent action and US$1.4 trillion of investment*, WOOD MACKENZIE (Sept. 15, 2022), https://www.woodmac.com/press-releases/decarbonising-global-iron-ore-and-steel-industry-by-2050-necessitates-urgent-action-and-us$1.4-trillion-of-investment/.

165. Julien Armijo et al., *Global Hydrogen Review*, INT'L ENERGY AGENCY 5 (2022), https://iea.blob.core.windows.net/assets/c5bc75b1-9e4d-460d-9056-6e8e626a11c4/GlobalHydrogen-Review2022.pdf.

166. *See* Parfomak*, supra* note 117, at 4.

167. *See* Armijo et al.*, supra* note 165, at 71.

168. Murdoch et al., *supra* note 54, at 10.

169. *Natural Gas Consumption by End Use,* U.S. ENERGY INFO. ADMIN. , https://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm.

170. This calculation makes the following simplifying assumptions: (1) the amount of hydrogen needed in a 5% blend by volume scenario is roughly 0.85 Tcf of hydrogen; and (2) the assumed density of hydrogen is roughly 0.09 kg/m$^3$. Based on these assumptions, the amount of hydrogen required to meet a 5% blend of annual natural gas consumption in the United States is roughly 2 MMT.

171. U.S. DEP'T OF ENERGY., DEPARTMENT OF ENERGY HYDROGEN PROGRAM PLAN (2020), https://www.hydrogen.energy.gov/pdfs/hydrogen-program-plan-2020.pdf.

U.S., LDCs likely will need to contract directly with producers of low-carbon hydrogen.

### *G. Competing, conventional technologies remain cheaper*

Hydrogen, natural gas, oil, and propane leverage the combustion of the fuel to produce heat used to warm the environment. For electric power, heat can be produced either via a resistance heater, which converts electric power directly to heat, or a heat pump, which leverages electric power to move latent heat from a heat source (in the case of an air-source heat pump, the outdoor environment) to the indoor environment.[172] Heat pumps have the ability to heat and cool while using up to 70% less energy than compared to other technologies.[173] Based on the technology present in a heat pump, it is possible that the conversion from electric power to heat is more than 100% efficient.[174] These competing technologies will provide a challenge to using hydrogen as a heating fuel from both an operational and economic perspective.

As discussed previously, there are ample operational challenges associated with an LDC moving either a blend of hydrogen and natural gas, or pure hydrogen, on its existing gas distribution system.[175] Beyond the operational challenges associated with moving hydrogen, significant investment needs to be made beyond each individual customer's meter to ensure the customer's internal gas distribution system can move hydrogen. Moreover, the commodity cost for hydrogen will be much higher than that of natural gas.

Numerous academic and industry studies have evaluated the potential use of hydrogen for heating purposes. An assessment of over 30 studies focused on the issue of using hydrogen as a fuel for space and water heating came to the following key conclusions:

1. "Hydrogen for heating is associated with higher energy system costs when compared [against] alternatives";

---

172. *Air-Source Heat Pumps*, U.S. DEP'T OF ENERGY, https://www.energy.gov/energysaver/air-source-heat-pumps.

173. Rachel Golden & Cara Bottorff, *New Analysis: Heat Pumps Slow Climate Change in Every Corner of the Country*, SIERRA CLUB (Apr. 23, 2020), https://www.sierraclub.org/articles/2020/04/new-analysis-heat-pumps-slow-climate-change-every-corner-country.

174. *How a Heat Pump Works*, INT'L ENERGY AGENCY, https://www.iea.org/reports/the-future-of-heat-pumps/how-a-heat-pump-works (explaining a heat pump is a tool that moves heat from a "source" to a "sink." In the context of an air-source heat pump, the technology pulls heat present in the outside environment and moves it to the inside environment (the sink)). However, there are numerous types of heat pumps, including ground-source, water-source, and heat pumps that leverage waste heat from nearby industrial processes. *Heat Pump Systems*, U.S. DEP'T OF ENERGY, https://www.energy.gov/energysaver/heat-pump-systems#:~:text=There%20are%20three%20main%20types,%2C%20water%20source%2C%20and%20geothermal. The efficiency of this process, while it can exceed 100%, will vary based on the latent heat available in the source. *Heat Pumps in Cold* Climate, BLOCPOWER, (Jan. 9, 2023), https://www.blocpower.io/posts/cold-climate-heat-pumps. For reference, the efficiency of an air-source heat pump degrades considerably as the outdoor temperature drops below freezing. *Id.* Heat pumps can also work in reverse, where latent heat in the "sink" is moved to the "source." *How a Heat Pump Works*, *supra* note 174. This operating mode leads to cooling of the "sink" by reducing heat within it. *Id.*

175. As of this writing, in the United States there are 1,600 miles of dedicated hydrogen pipelines while over 3 million miles of operational natural gas pipelines. Murdoch et al., *supra* note 54, at 14; Penchev et al., *supra* note 130, at 15.

2. "Hydrogen for heating results in higher costs [to the consumer]"; and

3. Using "hydrogen for heating" generally yields "more negative environmental impacts"[176]

Of course, the ultimate cost to an LDC's customer to meet a given heat load will vary depending on actual capital costs associated with installing the technology and the commodity cost associated with fueling the technology. However, LDCs must be aware of potential costs to their consumers as they pursue potential strategies within their system, and that the decarbonization of their system may lead their customers to defect to other sources of water and space heating if the costs of incorporating hydrogen are too high. At the same time, using hydrogen may be the only option for decarbonizing service for some large commercial customers where electrification is not practical to serve their end uses.

## V. LEGAL CHALLENGES TO LDCS INTEGRATING HYDROGEN

One of the key challenges that will face many LDCs, as least initially, is the lack of legal and regulatory certainty with respect to whether LDCs may purchase, transport, and charge customers for the purchase of hydrogen. In many states, the relevant statutes and regulations specifically tie the definition of gas utility (or other applicable titles) to natural gas and are silent on the role of hydrogen, which may have significant implications for LDCs.[177]

Other authors have addressed the arguments regarding potential regulation of hydrogen transportation on the federal level and it is not an objective of this paper to replicate such analyses.[178] A similar comprehensive analysis and drawing generalized conclusions at the state level is more difficult because each state has its own unique regulatory regime.

At a high level, however, each state defines key terms such as "natural gas" and "utility" differently. In many states, the relevant statutes and regulations do not explicitly address hydrogen at all.[179] The lack of hydrogen's inclusion—or its implicit exclusion by being defined elsewhere—may create regulatory uncertainty for an LDC as to what extent such LDC will be able to rate base for hydrogen-related initiatives as it would with natural gas. If not affirmatively addressed and resolved, this ambiguity can give rise to litigation. This is playing out in one proceeding in California. In response to an application from SoCalGas to the CPUC for a memorandum account for its proposed hydrogen Angeles Link Project, one

---

176. Jan Rosenow, *Is heating homes with hydrogen all but a pipe dream? An evidence review*, REGUL. ASSISTANCE PROJECT (Sep. 27, 2022), https://www.cell.com/joule/fulltext/S2542-4351(22)00416-0.

177. In his article from last spring's edition of this journal, Will Bolgiano comprehensively addresses the arguments regarding federal regulation of transportation of hydrogen by interstate pipeline. *See* Bolgiano, *supra* note 12. Since that article was published, there have been two proposed amendments to major legislation that would have amended the NGA to incorporate hydrogen into the definition of natural gas. This would have unavoidable follow-on consequences for LDCs.

178. Bolgiano, *supra* note 12.

179. *Hydrogen Law, Regulations & Strategy in the US*, CMS, https://cms.law/en/int/expert-guides/cms-expert-guide-to-hydrogen/united-states-of-america.

party filed a protest arguing that such an account would be improper and the production or transmission of hydrogen should not be regulated as a public utility.[180] Notably, the blending of hydrogen into existing natural gas distribution is not an objective of the Angeles Link Project, which is instead being developed to deliver green hydrogen to end-users.[181]

This proceeding highlights the fact that LDCs will always need to thoroughly review the state statutes and regulations governing their service territory to identify potential ambiguities. Once such ambiguities have been identified, LDCs should consider beginning a dialogue with their regulators about adopting necessary changes. Given that LDCs must operate daily under such statutes and regulations administered by their regulators, LDCs are often among the stakeholders best positioned to help regulators identify and overcome potential regulatory hurdles.

In considering how to approach such a dialogue, it can be valuable to look at other states that are currently tackling such issues. Several jurisdictions are pushing forward efforts on both natural gas and hydrogen, all at different stages of regulatory study or implementation and all with nuanced policy goals. While these proceedings have varying policy goals, one common theme is how to define clean or green hydrogen in order to better demarcate the sector itself. California is fairly advanced in this process and has adopted an interim definition.[182] Other states are continuing to study their potential paths forward.[183]

LDCs and other interested stakeholders should therefore aim to track state regulatory developments as relevant to their particular service territory or region. These proceedings also offer an opportunity for LDCs and interested stakeholders to advocate for changes that will support utilization of hydrogen by LDCs. Further, as more proceedings run their course, increasing regulatory certainty will help crystalize the hydrogen value chain and solidify a framework for integrating hydrogen in an LDC's system.

---

180. So. Cal. Gas Co., Protest of Air Products and Chemicals, Inc., Application No. 22-02-007, PUB. UTILS. COMM. OF THE STATE OF CAL. (filed Feb. 17, 2022), at 6, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M460/K301/460301926.PDF (providing grounds for protest and arguing "[h]ydrogen has not traditionally been considered a 'gas' subject to regulation under the [California] Public Utilities Code"). This same party further argues: "California has led the nation in pursuing clean and renewable alternative fuels. As SoCalGas accurately observes hydrogen will play a significant role in decarbonization and combating climate change. The [CPUC] should not stifle innovation, competition, and private investment in this developing industry by subjecting it to regulation envisioned by one company, particularly where, as here, there are no captive customers in need of protection." *Id*. at 14-15.

181. *Id*. at 3, 5, 9.

182. *Clean Hydrogen Program*, CAL. ENERGY COMM., https://www.energy.ca.gov/programs-and-topics/programs/clean-hydrogen-program.

183. Connecticut Hydrogen Task Force Study: Submitted to the Energy & Technology Committee of the Connecticut General Assembly per Special Act, *supra* note 133, at 68-71 (exploring through a stakeholder process and examination of other jurisdictions how to define clean hydrogen, first summarizing the new federal rules before exploring similar definitions in Montana, Washington, Oregon and international jurisdictions for a total of 14 separate definitions of clean, renewable, or green hydrogen; many commenters expressed that any definition that Connecticut adopts should be consistent with federal definitions while others called for a higher standard, such as capturing only hydrogen produced with zero-carbon renewable energy).

## VI. CONCLUSION

Just as there are no two identical LDCs, service territories, regulators, or customer bases, there is no single blueprint for how an LDC can best leverage hydrogen as part of a successful energy transition plan. Nonetheless, there are certain key steps that an LDC can take when considering how to integrate hydrogen into an energy transition strategy.

First, what is driving the LDC to develop a decarbonization strategy or consider incorporating hydrogen into its business model? If the initiative is in response to a specific regulatory directive, such as the gas transition and other proceedings described above, then the strategy must be designed to meet the objectives of that directive, which may leave less room for creativity in how to comply with any future emissions limits through planning processes even if the LDC is not legally bound to do so. On the other hand, if the initiative is driven by a commitment by the LDC itself, its parent company or investors, there may be more room for the company to think broadly in the formulation of its goals and the strategies it adopts to achieve those goals. Such drivers are not mutually exclusive.

Second, the LDC must analyze potential legal hurdles to incorporating hydrogen into its business model. It is unclear in some jurisdictions whether an LDC may purchase hydrogen or pass on the cost of hydrogen or infrastructure improvements associated with it to ratepayers. LDCs should work with their trade associations, legislators and regulators to revise the appropriate laws, rules, regulations, codes and standards simultaneously and at multiple levels of government to specifically address hydrogen in a coherent fashion.

Third, the LDC must analyze potential practical challenges to and limits on incorporating hydrogen into its system. This will require considering the composition of the LDC's existing system, as the system's age and existing materials may affect the level of hydrogen that can be blended. The composition of the LDC's existing customer base also may affect the degree to which hydrogen can be blended into the system. Moreover, until there is a significant scale-up of domestic, low-cost, low-carbon hydrogen production, the ability to access a consistent supply of low-carbon hydrogen also may be a challenge, especially in certain markets.

Finally, the LDC must do what LDCs have done for over a hundred years to serve their customers: they must plan, and they must act to implement such plans. This planning process will vary depending on the state. And while hydrogen will not be the right solution for all customers or all LDCs' systems generally, having reasons backed by principled analysis as to why an LDC does or does not pursue a particular plan to provide clean, reliable service will be important to regulators and, by extension, the public.

Once the LDC has developed its plan, hydrogen projects will need to be integrated into rate base, to the extent possible. Pilot projects also may be a valuable first step to demonstrate scalability. When an LDC pursues any decarbonization strategy, whether or not that strategy includes hydrogen, incorporating learnings from pilot projects can be a key ingredient in stakeholder advocacy.

Along the way, LDCs should leverage existing federal and state incentives. While LDCs may initially not be in the business of generating hydrogen, as required to qualify for the production tax credit for clean hydrogen under the Inflation Reduction Act, they can potentially benefit from these incentives by virtue of lower offtake costs.[184] In states where there are no incentives, LDCs can engage with legislators on a state level to adopt incentives to promote hydrogen deployment.

The default, however, cannot be inaction. LDCs risk diminishing customers and load as more states and customers explore transitioning away from widespread use of natural gas. This means that as LDCs simultaneously continue investing in their existing systems for safety and reliability reasons, they may also be recovering such costs from an ever-smaller customer base, leading to a combination of rising rates, increasing burden for ratepayers, and leading to potential under-recovery for LDCs.[185] And while hydrogen will not be a complete solution or fit into the decarbonization strategies of all LDCs, with appropriate planning LDCs can incorporate hydrogen into a larger strategy to successfully transition into a low-carbon future.

184. *See supra* notes 54, 158-162 and accompanying text (discussing these and other federal programs promoting clean hydrogen).

185. *Affordability and credit quality in the gas utility industry*, CHARLES RIVER ASSOCS. (Dec. 8, 2022), https://www.crai.com/insights-events/publications/affordability-and-credit-quality-in-the-gas-utility-industry.