A Framework for Long-Term Gas Utility Planning in Colorado

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1. EXECUTIVE SUMMARY

In many places today, there is a lack of shared vision about the path forward for building decarbonization. While almost all analyses show electrification as a key component of that pathway, the timing and extent of electrification, the future of gas pipeline infrastructure, and the role of low-carbon combustion fuels remain open. In the face of this lack of consensus and the simple uncertainty of core information about technologies and strategies, policymakers have been reluctant to make decisions and implement actions that are commensurate with the problem. This lack of early actions has meant that the challenges facing the sector have only grown, because the pace of necessary change under any approach has become more difficult to implement.

Colorado is at a critical point in accelerating its actions to decarbonize the building sector. Laws enacted in the 2021 legislative session will transform utilities' approaches to energy efficiency, beneficial electrification, and gas supply planning. These actions, in turn, will drive changes in gas utility infrastructure planning and finance. In order to meet Colorado's greenhouse gas (GHG) reduction requirements, utilities and state agencies will need to act quickly and decisively, even in areas where they lack complete information about the state's long-term direction.

We propose a model based on the *observe-orient-decide-act* (OODA) loop approach, developed in the military context, where continuous iteration enables actors to make decisions based on available information and then adjust their actions during the next cycle. In the policy-making context, roadmaps deliver observation and orientation, while strategic frameworks are the core of the orientation phase. Colorado's recent actions to develop the Greenhouse Gas Pollution Reduction Roadmap and evaluate building electrification form part of the "observe" and "orient" phases, which will continue through the Public Utilities Commission's recently-opened rulemaking regarding Clean Heat requirements and gas utility planning, and the strategic issues proceedings that follow in 2022. Utility action plans for demand-side management (DSM), beneficial electrification (BE), and clean heat set forth "decisions" regarding the specific steps to be taken, and their implementation moves the cycle into "action." We recommend integration of a regular (e.g., three-year) cycle across all aspects of gas and electric utility building decarbonization planning, with each loop consisting of strategy development followed by program decisions and action.

Change management for decarbonization across the building sector will require more than just actions by regulated utilities, although they have a central role to play. Change is required across the areas of people, processes, and technology. Managing change with people requires understanding how building owners make decisions, how to address barriers to equitable action for disproportionally impacted communities, and how to work with the building trades and utility employees to help them find successful careers in a changing sector. Most process change will be addressed in the regulatory context, and address utility business models, rates and rate design, and utility program designs and regulation. Deployment of technologies is what reduces emissions, and actions here include demonstrations and pilots to bring new technologies to greater maturity and learn how they can be deployed more equitably and effectively. We place the numerous existing and potential processes and programs related to building decarbonization in Colorado in the context of these considerations and potential solutions to identified challenges.

In addition to the structural planning recommendations for an iterative cycle of strategic planning and action, we recommend a set of low-regrets and no-regrets actions to reform processes, evaluate options for the near- and longer-term future of gas utility business models, and take initial steps to drive carbon-reducing actions, such as building shell improvements, heat pump market development, and pilots for low-carbon fuels.

1. Introduction

Colorado has embarked upon a considered and timely process to advance gas utility planning in the context of deep decarbonization of the building sector. Multiple relevant bills were enacted in the 2021 session, including legislation to begin beneficial electrification programs, require gas utilities to meet increased requirements for clean heat, reform and expand gas efficiency programs, and advance energy justice. The Colorado Public Utilities Commission (PUC) has opened an expanded rulemaking to create a coherent and comprehensive regulatory structure for this multi-faceted challenge. This white paper is intended to (1) provide a framing structure for these multiple facets, (2) identify key considerations, and (3) help the Colorado Energy Office (CEO), regulators, utilities, and stakeholders establish a shared understanding and processes to develop strategies and drive actions toward the state's goals.

The white paper begins with an introduction to a change management paradigm in Section 2, including a framework for considering changes in the areas of people, processes, and technology. We also introduce the observe-orient-decide-act (OODA) approach, which is an iterative decision-making approach designed for situations in which decisions must be made with incomplete information. In Section 3, we propose principles to guide these decisions.

In Section 4, the white paper then applies these concepts to the specifics of building decarbonization. For each area of *people*, *processes*, and *technology*, we identify specific considerations for building emission reduction, then map the space of potential solutions to make progress in light of those considerations. In Section 5, we map these considerations onto Colorado's ongoing and required processes, with particular focus on the laws enacted in the state's 2021 legislative session and the resulting rulemaking processes and other dockets. Based on this analysis, Section 6 presents specific near-term recommendations regarding the relationships between different processes, information requirements to inform future iterations of the OODA loop, and specific low-regrets programmatic actions to consider (both inside and outside of the regulatory arena). Section 7 ends the report with short concluding remarks.

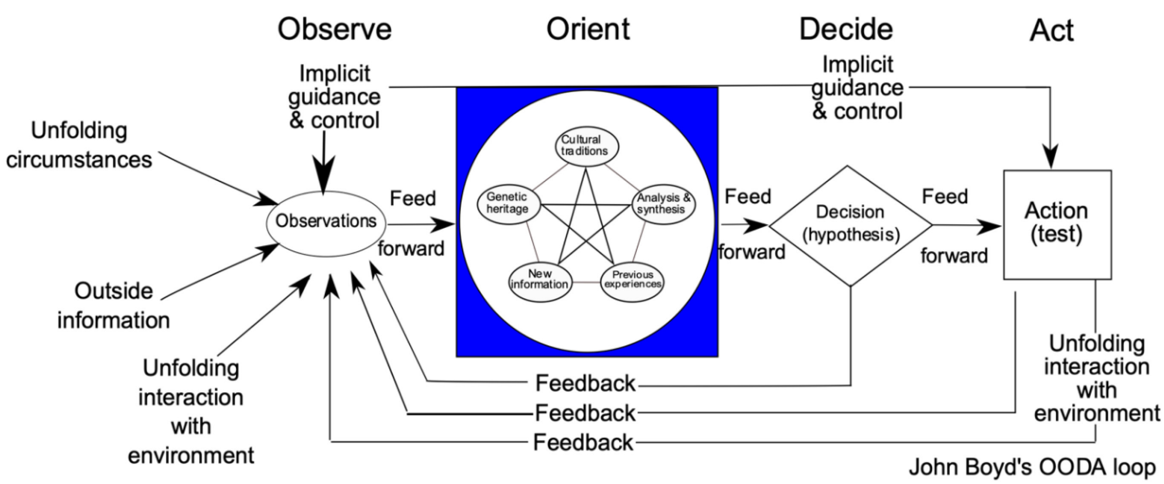
2. A Change Management Paradigm

This white paper approaches the challenge of building decarbonization from a change management standpoint. The first step of change management is determining what change we desire to implement. In the case of building decarbonization, we know the outcome we want (zero or near-zero GHG emissions from energy use in buildings), but the actual changes to get to that point remain a matter of contention. Thus, the first challenge is one of **direction**. The choice of direction determines the shape of the change, and the potential shape of the change impacts what direction we want to pursue. We evaluate the potential changes against **principles** and seek a path that is most consistent with those principles. The changes themselves will occur in three broad areas: **people**, **processes**, and **technologies**. In each area, we evaluate:

- What are the concerns or issues that need to be resolved?
- Do we have the information necessary to resolve the concern?
- Are there no-regrets first steps of action?
- When must we hit certain milestones to resolve the concern in line with deployment timescales?

Given time to prepare and gather a complete set of data (including clarity about the future), we could use a plan-do-check-adjust (PDCA) approach. However, we are forced by time constraints to act on building decarbonization before we have complete information. (Some of our actions can be related to gaining more information, of course.) This puts us more in the world of "OODA" loops—observe, orient, decide, act. In this approach, developed in the military context, the need to act before full information is available changes the paradigm to one of continuous iteration and learning. Some actions will be fully informed (these can be "no regrets" actions), while others must be taken without full knowledge. In any case, iteration provides a framework to avoid locking in long-term decisions before it is necessary to do so. The iterative process looks like this:

1) Observe the situation
2) Orient the choice to be made: evaluate, analyze, synthesize
3) Decide on actions to take
4) Act on those decisions



Source: "John Boyd's OODA loop" by Patrick Edwin Moran - Own work, CC BY 3.0. (Full diagram originally drawn by John Boyd for his briefings on military strategy, fighter pilot strategies, etc. 19 April 2008)

Let us now map the stages of the OODA loop onto decarbonization planning actions. Planning processes serve three functions: roadmaps, strategic frameworks, and action plans. Specific processes can combine these functions, but it is useful to track distinct purposes.

- **Roadmaps** provide the lay of the land and describe the implications of pursuing different pathways toward the end goal. They primarily provide the "observe" step in the OODA process, although more analytical roadmaps, such as Colorado's Greenhouse Gas Pollution Reduction Roadmap,[1] may also "orient."

- **Strategic frameworks** are primarily analytical in nature and draw on available information to provide a high-level synthesis of the general steps and processes to be pursued. They primarily "orient" the state or utility, allowing comparison of the expected results of different actions, identifying uncertainty, and providing a structure in which decisions can be made.

- **Action plans** lay out specific decisions—the "decide" step in the OODA process—and describe the resulting expected actions, leading into the "act" step. In general, action plans should specify who, what, and when.

The scale and scope of roadmaps and strategic frameworks is generally larger than for action plans. For example, statewide planning at the roadmap and strategic framework level makes sense, but action plans are better scaled to the different entities (utilities, state agencies, etc.) that will implement the actions. Utilities, which have many different potential levers for action, may benefit from developing an organization-wide strategic framework, which is compatible with the statewide framework, to guide the action plans for specific components of their work (such as rate design, demand side programs, and infrastructure investments).

Returning to the flexibility and the need to act in the face of uncertainty that brought us to the OODA approach, we see that, in this context, "decisions" are only made with respect to actions to be taken by particular entities within the current iteration of the loop. Future decisions are left for future iterations of the loop and the range of available decisions is shaped by the outcomes of the current set of decisions. The roadmap and strategic framework evolve as the results of actions become clear, and as uncertainties are resolved. This approach maintains flexibility by not fixing decisions for the long-term, while also lowering barriers to acting in the immediate term.

3. DIRECTION AND PRINCIPLES

In many places today, there is a lack of shared vision about the path forward for building decarbonization. While almost all analyses show electrification as a key component of that pathway, the timing and extent of electrification, the future of gas pipeline infrastructure, and the role of low-carbon combustion fuels remain open. In the face of this lack of consensus and the simple uncertainty of core information about technologies and strategies, policymakers have been reluctant to make decisions and implement actions that are commensurate with the problem. This lack of early actions has meant that

[1] Colorado Energy Office. 2021. "GHG Pollution Reduction Roadmap." *Climate and Energy*. Available at: https://energyoffice.colorado.gov/climate-energy/ghg-pollution-reduction-roadmap.

the challenges facing the sector have only grown, because the pace of necessary change under any approach has become more difficult to implement.

What is standing in the way of creating a shared understanding of a path forward, and associated certainty for businesses, building owners, utilities, and other stakeholders?

- Lack of complete information to determine that a given path will be optimal
- Inadequate understanding of the impact on economically disadvantaged and historically impacted communities
- Fear of picking a path that will be more costly or not work
- Desire to retain optionality to choose a better path if it becomes available
- Concern about losses to incumbent-industry firms
- Desire to support workers whose careers are tied to the existing industry structure

The flexibility of the OODA approach can help resolve some of these concerns by avoiding lock-in, while simultaneously recognizing path dependence. The observation step, part of the roadmap phase, identifies path dependence. For example, it is not possible for market share of a product to be at some high level (e.g., 90 percent) without first passing through steps with smaller market share. The roadmap can identify the time necessary to develop that market, and the strategic framework can lay out approaches to growing the market. But specific actionable decisions need only be made regarding the initial steps of that market transformation—actions to take market share from one to ten percent, for example. The decision as to whether the correct final share is 85 or 95 percent (or even only 40 percent) can be left for a future iteration of the loop. Similarly, for potential but uncertain new technologies, initial actions such as pilots or demonstrations appropriate to the technology's scale and maturity can preserve the option, without locking in or committing to using it at scale. No-regrets or low-regrets actions that make some progress can help to build a foundation for more ambitious actions later.

Explicitly leaving some decisions for later can increase flexibility, maintain optionality, and make it possible to proceed with decisions that need to be made today, without knowing the final state in detail. So, what decisions need to be made now, and what can be left for later?

The primary constraint on this choice comes from timescales. Timescales, in turn, are driven by the need to achieve GHG reductions. The roadmap identifies the necessary timescales for transformation in different end uses (such as space and water heating) or supply chains (such as low carbon fuels), while the strategic framework lays out the strategies and milestones. Decisions, and resulting actions, must have commensurate scale and speed to plausibly achieve the required GHG reductions.

One of the key things learned through recent decarbonization observation and orientation efforts (including the state's *Greenhouse Gas Pollution Reduction Roadmap* and CEO's building electrification studies[2]) is that the available time for transformation is short compared with the characteristic

[2] Hasselman, R., et al. 2020. *Beneficial Electrification in Colorado: Market Potential 2021-2030*. Prepared by GDS Associates, Inc., for Colorado Energy Office. Available at: https://drive.google.com/file/d/17bMnJv-5YgIeW3y6NERyqYBRhtYm7BR6/view. Hasselman, R., and Duckwall, J. 2020. *Beneficial Electrification in Colorado: Market Barriers and Policy Recommendations*. Prepared by GDS Associates, Inc., for Colorado Energy Office. Available at: https://drive.google.com/file/d/1d_O7u2SUgt4ASvJ0LLry16h5dffNF19l/view.

timescales of change in the building sector. The things that will take the longest to change or develop are therefore among the ones that need action now. Examples of recommended changes include:

- Increase market adoption of essential technologies (like building envelope improvements and heat pumps) with slow stock-turnover times that currently have small market share.
- Avoid creating the need for retrofits by encouraging forward-looking new construction practices.
- Develop the associated workforce and business models for deployment.

These examples will be further elaborated later in the white paper.

Recent experience in the observation and orientation stages, in Colorado and elsewhere, also yields another critical insight: all pathways depend on technologies with uncertain future cost, performance, and availability. The range of uncertainty varies by technology. Maintaining optionality to find the best pathway, however, requires actions to narrow the range of uncertainty for diverse technologies on both the end-use and supply sides. Decisions today can help gather useful information through technology-specific actions along the spectrum of research, development, demonstration, and deployment. When considered in concert with the limited timeframe, discussed above, and the potential need to scale some set of technologies once uncertainties have been reduced, learning by doing and other pilot- and demonstration-based approaches appear the most promising, because they are key precedents for scaling.

3.1. Principles/Objectives

One foundation of the roadmap is to lay out the core principles to preserve or enhance through decarbonization actions, and the strategic framework includes how decisions can be evaluated against them.

- **Affordability**: the ability of customers to pay for energy services. This may consider energy as one among several necessary expenses, to be balanced against customers' income and assets. It may also consider how costs change over time.

- **Economic vitality and employment**: how different transition pathways will affect economic development for Coloradans in general and for specific groups of people (e.g., natural gas distribution system workers or the building trades).

- **Equity and justice**: how customers and communities who have historically been left out of energy decision making—including low-income and moderate-income customers, captive customers, and historically and disproportionately impacted communities—will be affected by building decarbonization and gas transition efforts. It also involves the distribution of energy-related benefits and burdens over time and between different groups of people. For example, it requires consideration of economic and health costs to both current and future populations.

- **Reliability and access**: the ability of the energy system to provide uninterrupted supply of sufficient quality and quantity to end-use customers, and the extent to which people have access to energy services. The fuel types used to provide energy services might change over time.

- **Safety and human health**: the extent to which utility workers and the public are protected from danger, risk, injury, or disease associated with the energy system.
- **Resilience**: the ability to remain operational in the face of large-scale events and to quickly resume service after a disruption.
- **Risk minimization**: how changes and both physical and economic dangers in the energy system can be anticipated and accounted for, thereby avoiding surprises that could harm the public interest. This includes managing the risk of changes in utility financial viability and ability to serve customers.

4. Key Considerations: People, Processes, and Technology

Parallel and consistent change in the buildings sector will be required across the three aspects of people, processes, and technology. In each section that follows, we first identify the primary considerations for that aspect. These considerations are informed by roadmaps and strategic frameworks (the observation and orientation stages) developed in Colorado and elsewhere, and grounded in the principles introduced in the preceding section. We then introduce the space of solutions or actions to address the need for action while mitigating the challenges presented by the considerations. Our objective is not to provide a comprehensive review of all potential actions, but instead to introduce a range of potential actions and actors so that Colorado stakeholders can see how they fit into the different processes developing in the state. Mapping these actions and considerations to the Colorado context is the subject of Section 5.

4.1. People

Considerations

People are at the core of the energy transition in buildings because those buildings are their homes and workplaces (both as the locations of businesses and their employees, and also as the venues for the work done by the building trades). People's choices, attitudes, careers, and participation will shape and determine how buildings are decarbonized.

The principles of equity and justice are central to any approach to the human choices and impacts of decarbonization. Communities that have borne a disproportionate burden from the current energy system have an opportunity to relieve that burden, and obtain a measure of justice, if the approaches to decarbonizing their homes and workplaces are developed appropriately. Success here also requires understanding from these communities and authentic engagement with them in developing and implementing solutions. Equitable approaches to building decarbonization must also account for the unique challenges faced by renters, who lack decision-making authority and the responsibility for capital investments. Several critical pieces of Colorado's recent energy legislation, including HB21-1266, SB21-272, SB21-264, HB21-1238, and SB 21-246, discussed in detail below, are motivated and shaped by concerns for environmental justice.

One challenge facing building decarbonization is that customers are not homogeneous—they have access to different resources and have different needs, priorities, and motivations. To convince people to act, they must see alignment between the potential actions and their preferences. In the buildings sector, there are multiple aspects to this challenge. Many people do not know a great deal about how their buildings use energy and drive GHG emissions and some, like renters, may not be able to act even if they have information and interest. And when building owners make choices about their buildings they are generally motivated by factors beyond climate change, such as cost, comfort, health, and convenience. This lack of knowledge and prioritization also manifests itself in a low market value for energy- and GHG-related components of a building, relative to other factors (such as high-end appliances or granite countertops).

Actions to decarbonize buildings must be just and offer opportunity not only for building residents (renters, homeowners, or businesses) but also for the people who gain their livelihoods from building and energy systems. This includes tradespeople who install and maintain building systems (such as HVAC, plumbing, and electrical contractors) as well as utility employees who maintain the systems that bring gas and electricity to buildings.

The markets for appliances and building equipment will change more quickly than the energy supply side, because energy supply is shaped by the composition of the stock of installed systems, which changes more slowly than the sales share for new technologies. For example, a heat-pump based pathway might show a rapid transformation in the sales share of heat pumps—with immediate implications for HVAC installers and technicians—while the demand for fossil fuels (and associated pipeline jobs) would fall much more slowly because it relates to the total installed stock of heating systems. Adopting a heat-pump based pathway suggests that near-term priorities should focus on training, business models, and market dynamics within the HVAC and water heating markets.

One aspect of these markets that challenges solutions and business models, and is driven by human behavior, is the fact that the overwhelming majority of space and water heating systems are replaced under time pressure because of the failure of existing equipment without a plan in place to install lower-carbon alternatives. In this circumstance, replacement in kind is the easiest and most common path, and yet that choice would commonly lock in fossil fuel use, and associated emissions, for an additional decade or more. A combination of people-based (education and business models) and process-based (regulatory and funding) approaches are required to address this challenge.

Longer-term transition plans and approaches for the supply-side workforce will also be necessary. The timescale for career change in the gas utility supply sector is driven by changes in capital infrastructure investment, as well as changes in the physical extent of the gas system (which drives operations and maintenance work). The timeframe for changes in these two aspects remains uncertain but will become clearer as the strategic direction is established in the next few years. The extent of gas utility capital investment could change relatively quickly, relative to operations and maintenance work.

Solution space

Addressing people-based challenges requires careful and human-centered approaches. There is no single action to take to address equity and justice concerns. Instead, they must be woven throughout the design and implementation of each of the approaches discussed here and in the following sections. In general, this will mean a greater amount of engagement than has been typical in program development, which should have the co-benefit of greater buy-in and understanding of the approaches that emerge.

While building decarbonization is not a priority for many building owners or decision-makers, education about the alignment between decarbonization actions and associated benefits could increase motivation and action. For example, building shell improvements and more advanced (multi-speed) HVAC equipment (which can be heat-pump-based) improve building comfort. Likewise, removing combustion from buildings can increase health and safety.

Each GHG-relevant building system in a given building will be replaced between one and three times between now and 2050. Simple and clear messaging regarding the importance of the choices available to customers and their respective benefits can help customers make more informed decisions. Policymakers and others who shape the choices facing customers, including the PUC and utility planners, need to make sure that clearly defined choices are in fact available and affordable (aligned with support from programs and processes, discussed below).

When making these choices, building owners will be in consultation with another key group of people: the building trades (particularly HVAC, electrical, and plumbing contractors). Fostering new business models and approaches for selling low-carbon technologies such as heat pumps would enable the contractor to be a primary influence on the building owner’s choices. These business models and approaches will need to be tailored to different actors (e.g., landlords, low-income households, homeowners, and property managers) and building types (e.g., multi-family, single-family, and commercial buildings). The process, programs, and regulations discussed in the following section should take account of their impacts on the business model and sales process for tradespeople. Training for the building trades should focus not just on the technical details of new technologies to develop trust and familiarity with new technologies, but also on business model approaches and ways of selling these products and integrated solutions to building owners. Changes in standard practice among the building trades will be essential to address the challenge of default “in-kind” emergency replacements: the support and business models must be developed for these trusted tradespeople to quickly guide a building owner through a more complex and decarbonized replacement process without sacrificing health or comfort.

Gas utility workforce transition options will be shaped by the physical form of the future energy infrastructure. It is therefore essential to coordinate analysis of training and workforce needs with the gas utility business model and investment paths addressed in the sections that follow. Analysis of the paths forward within each of the trades (pipefitting, laborers, electrical, etc.) will provide increasing clarity for these workers, including both those already in the trades and those entering the trades and planning for a career that could extend to 2050.

4.2. Processes

Utility business model

Under traditional cost of service regulation, utilities earn allowed profits based on their invested capital. In addition, they can have an incentive to increase sales between rate cases, unless a decoupling structure has been put in place. Utilities invest in long-lived assets and plan to recover and earn a return on their capital over the lifetime of the assets. Sustained declines in sales, such as may result for gas utilities from electrification, can challenge all these fundamentals of the utility business model. Sustained declines could result in increasing rates (to recover the capital invested, now over fewer unit sales), if the sales decline faster than the utility's asset base depreciates and faster than operations and maintenance costs can be decreased.

Even without a well-managed approach to decarbonization, increasing gas rates (and projected continued increases) could increase customer interest in electrification. Those who can afford the higher upfront costs to switch fuels will be the first to defect from the gas system. In this case, without changes to regulatory practices, the remaining customers (who will tend to be lower income) would be required to shoulder the cost for the remaining gas system. Rate escalation would hit these groups the hardest. If the utility cannot raise rates sufficiently, or assets are retired before the end of their useful life, it may face a problem of "stranded" assets: assets with undepreciated value but for which the utility cannot recover revenue (either because it cannot further raise rates or because the assets are no longer used and useful).

Continued investment in new assets would exacerbate this challenge by slowing the rate of cumulative depreciation. This poses a particular challenge for gas utilities with aging, leak-prone pipes (such as cast iron or bare steel main or service lines). Safety concerns and emissions reduction would favor investment to replace these pipes, but new assets are at higher risk of becoming stranded at some point during their lives.

The question of whether stranded costs will be recovered (and if so, how) will need to be addressed. This is a question to be addressed at the level of the strategic framework, informed by the roadmap-level processes that gather and synthesize information across the energy sector. Gas ratepayers, electric ratepayers, taxpayers, utility shareholders, or some combination of these entities could bear the expense or loss. Taking steps now to optimize gas system investments and to direct new investments toward the best and highest use of fossil gas, as determined using a full accounting of lifetime costs and benefits (including the costs of carbon and methane emissions), is an important tool for mitigating stranded asset risk and cost burden in the future.

Solution space

New business models. Gas utilities may be allowed to propose new business models. These could include provision of new services, such as geothermal or district heating networks. When evaluating a proposal for a new line of business, care should be taken to consider a wide range of potential impacts. Natural monopolies such as gas utilities do not face competitive pressures to reduce costs. Rather, regulation seeks to keep these firms' pricing and other practices in check. If a monopoly firm is allowed to expand into a new line of business, which may or may not have a natural monopoly structure, there is the potential for unintended consequences, and regulators may be challenged to appropriately monitor the firm's behavior in a less familiar setting. Also, launching a new gas utility model could undermine the development of competitive markets or impede firms that are already operating in this space on a smaller scale.

New business models would allow the gas utilities to augment revenues in the face of declining sales. One potential business model involves reconfiguring and repurposing the existing pipe system as a geothermal network. This model is being considered in Massachusetts.[3] In New York, National Grid is exploring providing shared ground-source heat pump infrastructure.[4] Another approach could be to focus on payment for performance of services delivered, rather than capital investments.

In another business model, similar to the existing utility model, gas companies could sell lower carbon gaseous fuels, such as biomethane, green hydrogen, and/or synthetic natural gas (produced from hydrogen and captured carbon), delivered via the existing pipes or through another means. However, as discussed in Section 4.3, supplies of non-fossil gas have not materialized at a price anywhere near the cost of fossil gas. A business model centered on these alternative fuels would thus pose considerable risks of customer defection among customers that do have the option of electrifying or otherwise switching fuels. Gas utilities may therefore shift their asset base to primarily serve as the distributors of non-fossil gas to customers with end-uses for which economically viable low-carbon alternatives do not currently exist, including some industrial processes and combined heat and power.

The characteristics of individual gas utilities may influence the business model(s) they choose to pursue. Utilities with greater capacity to coordinate on fuel-switching actions, such as joint gas and electric utilities, may follow a different strategy than standalone gas companies will. Joint gas and electric utilities can also potentially coordinate better on paired infrastructure investment between the electric side and corresponding gas line retirement. Whatever the utility characteristics, regulators and other stakeholders must be prepared to consider a wide range of options, explore their implications, and establish the structure to ensure policy goals (e.g., consumer protection, emissions reduction, affordability) are attained.

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[3] Gerdes, J. 2020. "Massachusetts Pilot Project Offers Gas Utilities a Possible Path to Survival." *GreenTech Media*. Available at: https://www.greentechmedia.com/articles/read/can-gas-companies-evolve-to-protect-the-climate-and-save-their-workers.

[4] New York State Energy Research and Development Authority (NYSERDA). October 19, 2017. "National Grid and NYSERDA Announce Clean Heating and Cooling Demonstration Projects for Long Island Residents." https://www.3blmedia.com/news/national-grid-and-nyserda-announce-clean-heating-and-cooling-demonstration-projects-long-island.

Coordinated regulatory oversight of utility competition/coordination. Individual regulated utilities that sell different fuels for the same end-uses often compete. In some cases, different arms of the same regulated company (e.g., an electric and gas utility have the same owner) may even vie for the same end uses. Such competition is not sufficient to ensure that prices are reasonable. Regulators will need to prioritize the public interest, rather than what is necessarily in the interest of either utility. This likely means addressing the incentives to compete (and conversely to collaborate), by providing clear guidance and expectations for utility conduct regarding pricing, customer acquisition, marketing, and other aspects of business during the transition. For standalone gas companies entering new markets, regulators may seek to foster competitive forces in the new business area to ensure that these companies are not able to exert market power by virtue of their name recognition and access to capital. Where the electric and gas companies are part of the same parent company, the focus may be on maintaining customer protections and appropriate barriers between these business areas, even as decarbonization policy increases the demand for electricity, as well as exploring new collaborative approaches to address price risks to remaining low-income gas customers.

Reduce stranded cost risks. Society benefits from having a gas utility that retains the financial health to invest in the safety of the gas system. As a result, ratepayers or taxpayers benefit from minimizing the extent of stranded costs (which could otherwise prove damaging to the utility's operations and may prove burdensome to those who remain on the gas system). Shareholders, of course, share an interest in minimizing stranded costs. The two main methods for minimizing these costs are to (1) plan to recover the capital invested in existing assets and (2) minimize the risk of new asset investments.

Regarding recovery of capital invested in existing assets, there are several potential approaches. The most straightforward would be to shorten the expected remaining lifetime of existing assets through accelerated depreciation. This could be as simple as changing depreciation lifetimes so that all assets are fully depreciated by a certain date. Alternatively, utilities could use even faster depreciation approaches that depreciate the assets such that each year's depreciation is in proportion to that year's share of the expected total remaining gas that will flow through the assets during their lifetime. This faster approach would more equitably assign costs to the current generation of system users, rather than shift costs to the last users of the system. There is substantial overlap between depreciation timeframes and potential changes in the utility business model (discussed above). A utility without a rate base (or a steadily shrinking one) would by necessity require a different approach to investment and profit, such as a service-based rather than investment-based approach, to maintain a safe system that delivers the services that customers demand.

Other options for recovering the capital invested in existing assets are to shift the assets off the utility's books. This could be accomplished through securitization, wherein the state coordinates the buy-out of the assets and taxpayers take responsibility for paying back the bond used to pay for the assets. Where enabled by statute,[5] securitization may allow shifting costs of gas infrastructure from gas ratepayers to

[5] While Colorado's enacted Senate Bill 19-236 provides a means of securitizing electric utility fossil fuel assets, separate legislation may be needed for securitization of gas system assets. See Colorado General Assembly, "SB 19-236 Sunset Public Utilities Commission," at https://leg.colorado.gov/bills/sb19-236.

taxpayers. Securitization is an alternative form of financing that can enhance the certainty of utility cost recovery. Legislative underwriting of debt may lower the cost of capital (based on state bond rates instead of the utility's cost of debt and equity), and thus reduce the burden on gas system ratepayers. Securitization may be structured to provide utilities full recovery of the value of the assets but can also exclude some portion such as profit. Securitization could also decouple the timeframe for repayment from the lifetime of the asset.

It may be appropriate to recover some gas system costs from electric ratepayers, who might benefit from spreading fixed electric infrastructure costs over a larger number of kilowatt hours as gas customers electrify end uses. If such cost shifting is allowed, it will be important to encourage customers to manage electricity use to mitigate overall electric system costs—which will likely be increased to address increased demands during peak periods.

Regarding new assets, mitigating stranded cost risk requires optimizing and carefully planning for any new investment. Threshold requirements for approval of conventional gas investments should be raised. Gas utilities should be required to demonstrate that they considered non-pipeline alternatives such as demand side management (DSM) or electrification—ideally through a competitive solicitation—and should provide well-documented analysis of the alternatives to conventional investment. Any proposal for conventional gas investments should also include quantitative analysis of the risks associated with the proposed investment and demonstrate that it is compatible with state climate policy. Utility regulators should provide guidance (e.g., through rulemaking) on the types of circumstances in which investment in traditional gas assets might be a reasonable approach and on standardized assumptions that utilities should use to demonstrate compatibility with climate goals.

Just as new gas main infrastructure should be subject to a higher threshold for approval, new gas services should be subject to similar rigorous review. In many cases, new gas service is no longer needed, given the accessibility and cost-effectiveness of electric heating and appliances and that new or gut renovated buildings already have or will have connections to the electric system. Despite this, gas utilities may be providing new services at little or greatly reduced cost to new customers. For example, the PUC has ordered Public Service of Colorado to provide service laterals for residential gas service at no cost up to a fixed length (with that length calculated to be revenue neutral from pre-existing practice), and at a standardized cost per foot over that length.[6] However, the new customer's total upfront contribution will remain less than the cost to construct the lateral. The expectation is that the utility will recover these costs through bills if the customer requesting service buys gas in sufficient quantities and over a long enough period of time. In order to meet Colorado's decarbonization targets, connection costs that are incurred now may not be fully recovered before the systems need to be retired. This practice shifts gas costs and risks away from new customers and onto existing customers. To address this, all gas utilities should report data on the costs and numbers of interconnections.

[6] Colorado Public Utilities Commission. July 2019. Decision No. C19-0634 in Proceeding No. 18AL-0852E and Proceeding No. 18AL-0862G.

Further, the costs of new gas connections that are paid by the gas company—and thus its ratepayers—should be minimized.

If a utility does make new investments, depreciation lifetimes should be set to be consistent with the time frame over which the asset is likely to be in service given the need to achieve emission reduction targets instead of reflecting the engineering lifetime of the asset. A gas utility that intends to serve a smaller number of customers in the future, such as only industrial and combined heat and power customers, would develop depreciation and investment plans that wind down the portions of the gas network that will no longer be used, while targeting investment to the portions of the system that will be used for a longer period. This could include working with the electric utility to electrify neighborhoods or streets over a short period of time, then retiring the associated main line. Buildings in the targeted area that are not ready to electrify could use delivered fuels (e.g. propane) for a transition period, with support for electrifying when they next make changes in their building systems.

Rates and rate design

The primary point at which building owners make energy decisions that substantially impact total energy cost and emissions is when selecting the hardware systems that drive energy use in their buildings, such as HVAC and water heating. These decisions are made every decade or two. However, customers primarily see the consequences of these energy choices each month on their energy bills. This disconnect between upfront investment and operating costs is one source of market failures, because customers either do not or cannot take energy operating costs into account when selecting building equipment to the extent they should under standard economic theories. Landlords and tenants, for example, commonly each see only one side of this choice, and the resulting mismatched incentives stymie energy efficiency.

Even without changes in building equipment, variation in energy use has consequences in terms of costs and emissions. Energy use at times of high demand drives the need for capacity in electric generation and for investments in electricity and natural gas transmission and distribution systems. Emissions can also vary substantially between different times on the electric grid. Flat, non-time-differentiated electric and gas rates fail to pass on information to customers regarding the costs that their choices cause. This includes both environmental costs (including the social cost of emissions and the indirect cost that increased emissions place on all other residents to reduce emissions to compensate) and direct energy system costs.

Flat (non-time-varying) electric rates are designed assuming a particular load shape, used to allocate energy and peak demand costs to customers. Customers who adopt electric space and water heating will have load shapes that are quite different from the typical load shape used today in rate design. In particular, these customers are likely to have a higher load factor (that is, a lower ratio of peak to average consumption). As a result, flat electric rates can have the effect of overcharging these customers. This can mask the economic impact of customers choosing electric heating equipment on the electric system as a whole, further exacerbating market failures. This effect is even more magnified when a utility has inclining-block rate structures, which increase the per-unit cost of electricity once a threshold is passed in a given month, even if this additional consumption is occurring off-peak. Low natural gas rates, combined with flat or especially inclining-block electric rates, can make it harder for electrification to be cost-effective from an individual customer perspective, even when some amount of electrification is necessary from a statewide perspective to meet emissions requirements. Demand charges (which charge customers for their peak demand regardless of when it occurs) can also lead to overcharging for electrified customers, unless their customer-level peak demands occur at the times when system-level peaks are also occurring. This coincidence is unlikely to occur until enough customers electrify that new peaks emerge in the winter months.

Solution space

In an economically ideal world, the rate for an increment of consumption should reflect the long-run marginal cost caused by that consumption. While perfectly varying rates that reflect variations in costs by location and over time are unwieldy and not generally feasible, time-varying rates are straightforward to implement and can better express the marginal cost of consumption. Where policymakers have established a social cost of carbon emissions and emissions vary between on- and off-peak periods, that cost differential can be made visible to customers through incorporation in time varying rates, even if the utility does not collect a net carbon revenue (that is, without a carbon tax or other pricing mechanism).

Time varying rates open up the possibility of tapping into the inherent energy storage capabilities of some electrification technologies. These rates can be designed to encourage customers to use their newly electrified end uses as electric grid resources. Heat pump water heaters, for example, can be programmed to primarily heat during off-peak periods, to store heat for use during peak periods. Time-varying rates allow customers to see some benefit for this operational choice that lowers grid costs.

Programs for end-use energy choices

States implement or oversee a variety of DSM programs, including ratepayer-funded energy efficiency programs by the state's electric and gas utilities, appliance standards, building energy codes, and local and state building performance standards. These DSM policies and programs have been very cost-effective in reducing energy consumption and emissions from buildings. These initiatives are vital for achieving GHG emissions targets for the building sector. However, they are not currently optimized to reduce emissions to required levels.

The main objective of traditional energy efficiency policy is to improve efficiency and reduce energy use within one fuel type (e.g., electricity or natural gas). However, just improving efficiency in fuel use will not get the state to the 90 percent statewide emissions reduction target by 2050. To meet its GHG targets, Colorado needs to reduce the use of fossil fuels by more than the incremental amounts available through traditional efficiency improvements in gas equipment and building shells. This means that end-use policies and programs need to find ways to switch away from fossil fuels like fossil gas and propane and to increasingly low- and zero-carbon electricity (alongside potential use of low or zero carbon fuels such as hydrogen or synthetic methane, discussed in the Technology section below).

For example, building codes need to be re-designed to achieve emissions reductions, which may require promoting electrification or zero emission fuels instead of simply prescribing efficiency levels of certain equipment. Electrification or net zero energy (NZE) codes are an emerging approach in new construction in some states. Colorado appears to have a bigger challenge in adopting such codes than other states because it is a home-rule state which allows local governments to adopt their own building codes. This rule has led local governments to adopt various and often-outdated codes.[7] HB19-1260, adopted in 2019, partly addressed this issue by requiring local governments to adopt a code with energy provisions at least as strong as one of the three most recent versions of the international energy conservation code, while maintaining a significant amount of local control by allowing local jurisdictions to adopt stronger codes. This legislation was possible because building energy codes are a matter of mixed local and state interest; in matters of mixed interest the courts have ruled that state law preempts local ordinances and codes. New legislation could be considered to set stronger minimum requirements for local energy codes that align with state climate goals and move new construction towards NZE. However, implementing NZE codes across the state will still be a significant challenge, and it would likely require technical assistance to help local governments to adopt and implement such codes.

Another important policy is a building performance standard. Colorado has recently adopted HB21-1286 to implement building performance standards across the state. This law sets emission reduction requirements for large commercial buildings at or above 50,000 square feet for 2025 (7 percent below 2021 levels) and 2030 (20 percent). One critical issue is that the law does not directly set emissions reduction requirements for the period after 2030; rather, it requires the state Air Quality Control Commission to consider this issue as part of a rulemaking that will take place in 2023 and set long term requirements that align with the state's climate goals. The lack of a long-term set of emission requirements means that building owners with replacement cycles past 2030 do not yet know what level they will need to aim for, depending on the actions taken by the Air Quality Control Commission this may be clarified in 2023. Besides this long-term target issue, near-term elements that must be designed before implementing this policy include penalties, compliance methods, incentives, building exemptions, use of offsets, and coordination with existing building performance standards already implemented by a few local governments. Buildings smaller than 50,000 square feet are also not initially addressed by this law, although it allows the Air Quality Control Commission to lower this threshold after 2029.

In other jurisdictions, ratepayer-funded DSM programs may face greater challenges in shifting focus to reducing GHG emissions than other policies. First and foremost, traditionally DSM programs discourage or prevent fuel switching including electrification, even if it is cost-effective and reduces emissions. There is a common practice of requiring electric ratepayer funds to go to electric DSM, and the same for gas. This is based on the paradigm that efficiency is "least cost supply" of a given fuel. Colorado's new laws SB21-246 (Beneficial Electrification Plans), HB 21-1238(Modernize Gas DSM), and SB21-264 (Clean Heat Plans) have created new avenues for electric and gas utilities to fund beneficial electrification

[7] The Southwest Energy Efficiency Alliance (SWEEP) noted that "more than 150 jurisdictions have an energy code from 2009 or earlier, and another 50 jurisdictions have no building codes whatsoever." SWEEP. 2019. "A New Model for Energy Codes in Home Rule States." Available at: https://www.swenergy.org/a-new-model-for-energy-codes-in-home-rule-states.

measures or any other measures to reduce GHG emissions from pipeline gas use and direct the Public Utilities Commission to remove this fuel switching prohibition, thus mitigating this concern for Colorado.

Another consideration for DSM programs is that key metrics used to set DSM program targets are typically set in terms of electricity and pipeline gas savings, not emission reductions. Because fuel switching with electrification will increase kWh consumption, it goes against achieving the electric utility's DSM targets. Colorado has not yet completed its process for updating how performance will be measured, and how DSM, clean heat, and BE plans will intersect and overlap, although SB21-264 made a first step in establishing a revised framework by setting emission reduction targets for gas utilities.

In addition, the current cost-effectiveness framework does not fully value benefits and costs of consumers' choices, including fuel switching electrification measures. Colorado utilities use the Modified Total Resource Cost (mTRC) test as the primary test and three other tests including the Utility Cost Test as secondary tests to evaluate the cost-effectiveness of DSM programs. The mTRC includes avoided costs of carbon and non-energy benefits. Xcel Energy used $46 per ton of CO2 based on Senate Bill 19-236 in its 2021/2022 DSM plan. SB21-246, HB 21-1238 and SB21-264, adopted this year, increased this value to $68 per ton of CO2, based on the federal government's social cost of carbon estimate at a 2.5 discount rate, and requires inclusion of the social cost of methane at a discount rate of no more than 2.5 percent. This is a vital step to correct the undervaluation of the social cost of carbon. However, it is highly likely that actual social costs of carbon are considerably higher than the latest value established in the recent laws given the higher social cost of carbon estimates in many studies. For example, the social cost of carbon developed by New York State's Department of Environmental Conservation ranges from $121 in 2020 to $172 in 2050.[8] These are also the values recommended by the Avoided Energy Supply Component (AESC) study from which the states in New England select avoided costs to evaluate their DSM programs. Under the new laws, Colorado's value will automatically reset to a higher value if the federal government updates the social costs of carbon to a higher level.

There is also uncertainty about the magnitude of non-energy benefits. Energy efficiency and electrification offer numerous non-energy benefits including improved comfort, indoor and outdoor air quality improvement, safety improvement, and various low-income customer benefits (including risk reduction regarding future gas rates). It is likely that that the current non-energy benefit adder is underestimating the real benefits for beneficial electrification measures. Recent studies found significant negative health impacts (e.g., increased respiratory symptoms and asthma attacks) from burning gas in buildings (in particular, from NO_x emissions from indoor gas appliances).[9] Further, improved safety associated with electrification measures could provide significant benefits, as the state is now facing greater wildfire and associated gas explosion risk. The current non-energy benefit adder is not likely sufficient to reflect these additional benefits.

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[8] New York Department of Environmental Conservation. "Climate Change Guidance Documents." Accessed at https://www.dec.ny.gov/regulations/56552.html in October 2021.

[9] See, for example, Seals, B., Krasner, A. 2020. *Health Effects from Gas Stove Pollution*. Rocky Mountain Institute, Physicians for Social Responsibility, Mothers Out Front, and Sierra Club. Available at: https://rmi.org/insight/gas-stoves-pollution-health/.

Even assuming full benefits are accounted for in the cost-effectiveness screening practice, one needs to examine whether measure lifetimes for gas equipment are appropriate. For example, when evaluating benefits and costs of an electrification measure (e.g., heat pump) and an efficient gas heating system, assuming any benefit of the gas heating system beyond 2050 is not consistent with the state's climate targets.

Some DSM program designs could also prevent or slow the adoption of electrification. One notable example is the downstream, rebate-based program design. This typical DSM program incentive approach makes the process of purchasing a new piece of equipment complicated and time-consuming for both customers and contractors. A customer needs to cover the full cost of the upgrade up front, which places a burden on capital-constrained customers, then fill out a rebate form and wait for a long time to receive the rebate. A contractor also needs to spend extra time for the administrative work while their profit may be the same. This process may slow down the adoption of electrification measures. In addition, the downstream rebate approach does not address one of the major barriers to electrification. In emergency situations, when the existing heating systems suddenly fails to operate and needs immediate replacement, customers and contractors tend to replace the system in kind. Rebate programs do not change what products are readily available from distributors.

Finally, utility DSM programs provide important signals to the marketplace. Promoting pipeline gas consuming equipment, even if it is more efficient than "baseline" or standard efficiency gas equipment, through gas DSM programs continues to send the signal that this equipment is part of an approved and planned path to meeting state policy objectives. While it is not the intention, this type of program is slowing the shift toward beneficial electric options.

Solution space

<u>Codes and standards</u>

Building codes and performance standards are key parts of the policy toolbox, and Colorado is using them. However, they can be further optimized for GHG emissions reduction. For building codes, further statewide authority to set a performance floor for the codes adopted by local governments may be warranted. In addition, there are various considerations for developing new codes. Such considerations include (a) whether or not to ban new gas connections; (b) whether to provide some kind of incentives for electrification through codes, disincentives to gas connections, or both; (c) whether to provide incentives or set requirements for net zero energy construction; and (d) whether to develop and implement such codes incrementally or all at once. Incremental approaches could range from adopting electrification ready codes first (which requires new buildings to have sufficient electrical capacity for future electrification) to adopting aggressive codes that address a certain set of end-uses first (e.g., space heating and water heater) and leaving out some end-uses (e.g., cooking). A thorough and open stakeholder process is necessary to develop optimal code designs.

Building performance standards are well suited to align landlord and tenant incentives for cost-effective changes in building systems, especially if they lay out long-term and predictable paths that enable owners to plan ahead. Performance standards also support the development of new business models for contractors and engineers, who know they can develop service and hardware offerings with a predictable market. Similarly, building energy codes can encourage homebuilders and trades to develop the skills and practices for advanced building construction. These skills and workforce are then also useful in many retrofit and renovation applications. Next steps for Colorado's nascent building performance standards could be to provide a longer-term performance trajectory as part of the 2023 rulemaking, to enable long-term planning by building owners, and to gradually expand coverage to smaller buildings over time.

Utility DSM programs

Justice and equity. Utility programs can directly address the barriers resulting from lack of access to capital, by facilitating support from the aggregate customer base to those most in need. In the context of electrification, those without easy access to capital, along with renters without the ability to make changes in their buildings, are the most at risk of bearing a disproportionate share of the cost of the gas utility system. Programs that focus on assisting these customers are therefore likely to produce the greatest risk reduction while simultaneously helping these customers manage the system change happening around them. Building shell improvements implemented ahead of or associated with electrification can also deliver outsized non-energy returns in comfort and health benefits for residents of lower quality housing stock.

Cost-effectiveness test. Cost-effectiveness screening reflects a particular policy perspective. To the extent that the test used in a given jurisdiction does not reflect the guidance provided by policymakers through their enactment of laws and other regulations, the test will produce outcomes that appear to be counter to policy objectives. The *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources* lays out a revised approach to developing a cost-effectiveness test to reflect state policy priorities through a test that reflects the "regulatory perspective." [10] In states where GHG reductions are mandatory, the question of whether a given action is cost-effective relative to a non-GHG-compliant baseline is no longer the best question. Instead, cost-effectiveness screening can be used to evaluate whether a given measure or portfolio is the most cost-effective way to meet the stated policy goal.

Program targets and performance incentives. Utilities are compensated for the performance of their programs in achieving stated objectives. Where the objectives change, the metrics for performance should also change. States can consider fuel-neutral performance targets for energy efficiency programs, or explicit targets for fuel switching aligned with the state's strategic direction. It is important to avoid creating incentives for unnecessary load building on the part of electric utilities. This can be achieved by setting parameters for what electrification is "beneficial," maintaining robust support for traditional efficiency objectives, and providing a framework for separating the savings from efficiency programs from the increased load from BE programs.

[10] Woolf, T., et al. 2020. *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources*. National Energy Screening Project - a project of E4TheFuture. Available at: https://www.nationalenergyscreeningproject.org/national-standard-practice-manual/.

Decoupling utility revenues from the amount of fuel sold can help to align electrification incentives for both the electric and gas utilities. For electric utilities, decoupling can reduce incentives for load building, while on the gas side it can reduce resistance to DSM and electrification. Decoupling based on a fixed average revenue per customer, however, can create an unhelpful incentive for gas utilities because it encourages them to expand to serve additional customers, and to resist customers disconnecting from the gas system.

It is likely that a suite of performance metrics, each offering tailored performance incentives, is better suited to meeting multi-faceted transformation objectives than any single metric.

Program design. Three aspects of program design can be particularly effective at changing the processes of these programs to align with accelerating building sector change:

- First, gas utility DSM programs should be carefully designed to minimize the risk of supporting new gas equipment that ends up costing customers more later. This implies a need to strictly limit standard incentives for more efficient gas equipment. Instead, gas DSM programs can focus on building shells, alongside supporting electrification to hit GHG reduction targets.
- Second, midstream program designs (which work with distributors rather than customers) for electric HVAC and water heating equipment can change what is stocked and available for emergency replacements and avoid the delays and hassles of a rebate-based approach.
- Third, programs should develop new ways to support customers moving beyond "in-kind" replacement on failure. In addition to encouraging distributors to stock relevant equipment so it is available quickly, as discussed above, programs can try new approaches like providing "bridge" equipment (e.g., temporary solutions like space heaters) to reduce the need to install new hardware immediately. This would allow time for bringing in an electrician, for example, to run a new circuit or even upgrade an electric panel. Utilities should consider ways to support both proactive and as-needed electric panel upgrades for beneficial electrification as part of their portfolios.

Financing

Financing solutions spread the initial cost of decarbonizing out over time, making actions more affordable. This is particularly valuable for low- and moderate-income customers who generally have less ready access to capital, but solutions developed for these groups are likely to be more broadly applicable as well. Customer comfort with financing solutions can depend on whether it takes the form of debt (to them as an individual or business) or is tied to the property. Where an installed solution is cost-effective (meaning it is lower cost than the alternatives, on a lifecycle basis), it can be fair to tie the repayment to the energy bill for the property, since whoever lives or works there will benefit more than they pay. Electric panel upgrades could also be a promising option for meter-tied financing, since the occupant of the house will benefit from the greater capacity throughout its lifetime, while benefiting from lowered barriers to electric heating and transportation.

The source of capital for the decarbonization investment can be a bank or the utility and could be supported by a state green bank or other program that can increase program access or lower capital costs through supports such as loan loss reserves or interest rate buydowns. Generally, utilities have higher costs of capital than banks would be able to offer, but regulators and utilities should consider different approaches to these programs in the context of utility business models and risk or benefit to other customers.

4.3. Technology

Considerations

Low-carbon combustion fuels

SB 21-264 defines eligible low-carbon fuel resources to use as part of meeting the requirements to reduce emissions. These are biomethane, recovered methane, and hydrogen, improved end-use efficiency, and reduction in leaks beyond state and federal requirements.[11]

Biomethane and recovered methane. SB21-264 defines "biomethane" as a mixture of carbon dioxide and hydrocarbons released from the biological decomposition of organic materials that is primarily methane and provides a net reduction in GHG emissions. It also defines "recovered methane," which generally includes methane recovered from coal mines or from gas distribution system leaks, biomethane, and methane derived from municipal solid waste and wastewater treatment.

The availability of biomethane and recovered methane may change over time, however their supply is currently very limited and faces market challenges. In addition, these fuels require processing to get them up to pipeline quality, raising questions about the cost of processing, associated energy use, and the need for processing facilities. Collecting these fuels from their sources and transporting them to end uses can be expensive. Processing for pipeline use must compete with the option to combust the unprocessed (or less processed) fuels at their site of production to generate electricity and transport the resulting low-carbon energy to customers that way.

There are also concerns about leakage of biomethane and recovered methane. Fugitive emissions can be high in certain production processes, including digestate storage and biogas upgrading.[12] In addition to having a high global warming potential, leaked methane poses safety concerns, and losses due to leakage represent a substantial cost to the utility or facility operator.

Hydrogen. Hydrogen is often characterized as gray, blue, or green. Currently, the vast majority of hydrogen is produced from fossil fuels using steam methane reforming (SMR) of fossil gas, which results

[11] Colorado General Assembly. 2021. *SB21-264 Adopt Programs Reduce Greenhouse Gas Emissions Utilities*. Available at: https://leg.colorado.gov/bills/sb21-264.

[12] Liebetrau, J., Reinelt, T., Agostini, A., Linke, B. 2017. *Methane emissions from biogas plants*. IEA Bioenergy. Available at https://www.ieabioenergy.com/wp-content/uploads/2018/01/Methane-Emission_web_end_small.pdf.

in high emissions of CO_2.[13,14] The hydrogen produced from this process is called gray hydrogen. Some have called for using carbon capture and storage to reduce these emissions, producing so-called blue hydrogen.[15] As defined in SB21-264, green hydrogen is derived from a clean energy resource that uses water as the source of the hydrogen.

SB21-264 allows gas distribution utilities to propose investments in green or blue hydrogen projects that will reduce GHG emissions. While blue hydrogen is sometimes described as having zero or low GHG emissions, its potential for reducing GHG emissions is unclear. Because blue hydrogen uses natural gas as a feedstock, there are emissions associated with the extraction, processing, and use of natural gas in the SMR process, even though the carbon dioxide from the final hydrogen production step is captured and sequestered.[16] How low-carbon blue hydrogen is also depends on the efficiency of the carbon capture and how permanently the carbon is sequestered. Given these challenges, and the fact that the answers could vary for each project, careful accounting protocols will be required to ensure that blue hydrogen projects meet SB21-264's requirement that such projects show they will reduce GHG emissions.

While green hydrogen does not have the emissions associated with using natural gas as a feedstock, there are significant uncertainties associated with its development. Green hydrogen is not currently cost competitive with gray hydrogen. While the decreasing cost of renewables and improvements in electrolyzers may improve their economics, the cost trajectory and future supplies of green hydrogen are uncertain.[17]

In addition to supply issues, hydrogen presents several other challenges. Much of the existing stock of customer owned natural gas end-use equipment will not be able to use hydrogen.[18] Some technologies that use hydrogen, such as hydrogen boilers, are nascent. These technologies have uncertain performance, availability, and cost. Hydrogen also presents safety concerns, as it can ignite more easily than natural gas. As with conventional natural gas, there will be costs of losses due to leakage, or conversely costs associated with fixing leaks or replacing leak-prone pipes. However, existing natural gas pipelines may not be suitable for hydrogen. For example, some metals become brittle when exposed to

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[13] Hydrogen can also be produced using coal gasification (brown hydrogen), but this method is much less commonly used than SMR in North America. (See Howarth, R., Jacobson, M. 2021. "How green is blue hydrogen?" *Energy Science & Engineering:* 12. August. Available at https://onlinelibrary.wiley.com/doi/full/10.1002/ese3.956.)

[14] Howarth and Jacobson 2021.

[15] While "blue hydrogen" is mentioned in SB21-264, it is not specifically defined therein.

[16] Howarth and Jacobson 2021.

[17] Ibid.

[18] U.S. Department of Energy. "Safe Use of Hydrogen." Available at https://www.energy.gov/eere/fuelcells/safe-use-hydrogen.

hydrogen.[19] The volumetric heat content of hydrogen is also lower than methane,[20] so larger pipes may be required to carry the same amount of energy to customers.

One approach for hydrogen is to blend it with methane in the pipeline network. Up to 20 percent hydrogen by volume (or 7 percent by energy content) can be blended without changing the characteristics of the blended gas beyond the limits of what pipes and appliances are designed to burn.[21] With enough green hydrogen supply, a utility could thereby reduce the system's GHG emissions by about 7 percent by blending. While the GHG emission reduction is limited, it could provide a temporary bridge to deeper reductions using other approaches. Blending at higher ratios would require the same scale of pipe and appliance change-outs as for pure hydrogen, so it would face a much higher barrier.

Synthetic Methane. Methane can be created using hydrogen obtained from an electrolysis process, combined with carbon dioxide captured from the atmosphere or that would otherwise be emitted. As with hydrogen, the source of the energy for processing (including electrolysis) has a substantial impact on the fuel's carbon footprint.[22] Leakage of the newly produced methane could counter some of the GHG benefit of this fuel.

Gas end-use technologies

There are some potential new technologies that could reduce emissions from direct use of natural gas or low-carbon gases. These include gas heat pumps and micro-fuel cell combined heat and power systems. While these technologies could reduce emissions when using fossil natural gas, they cannot eliminate emissions unless powered by zero-carbon fuels. To contribute to meeting state GHG reduction objectives, these technologies would have to mature quickly and be able to outcompete other options to meet the same end use needs.

Electric end-use technologies

While fossil gas has recently been considered a low-cost fuel, electric heat pumps are now cheaper options to provide space heating for new construction in many parts of the country when heat pumps and gas options are properly compared against each other. That is, since heat pumps offer both space heating and cooling services, a proper comparison requires adding the cost of a new air conditioning to a natural gas furnace system. Using this approach, a 2018 study by the Southwest Energy Efficiency

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[19] U.S. Department of Energy. "Safe Use of Hydrogen."

[20] College of the Desert. 2001 *Module 1: Hydrogen Properties*. Available at: https://www1.eere.energy.gov/hydrogenandfuelcells/tech_validation/pdfs/fcm01r0.pdf.

[21] Melaina, M., Antonia, O., Penev, M. 2013. *Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues*. National Renewable Energy Laboratory Technical Report NREL/TP-5600-51995. Available at: https://www.nrel.gov/docs/fy13osti/51995.pdf.

[22] Timmerberg, S., Kaltschmitt, M., Finkbeiner, M. "Hydrogen and hydrogen-derived fuels through methane decomposition of natural gas – GHG emissions and costs." Energy Conversion and Management: X. Vol. 7, Sept. 2020, 100043. Available at https://www.sciencedirect.com/science/article/pii/S2590174520300155.

Project (SWEEP) found that heat pumps are substantially cheaper to install for new construction homes and also cheaper on a lifecycle basis (including operating costs) in the Southwest region including Denver (although the study found the winter operating cost of a heat pump in Denver was slightly more than that of a gas furnace).[23] It is important to note that this finding did not include the avoided cost of the new gas connection service for new all-electric homes, which further improves the economics of electric options. For example, a 2016 study by TRC estimated the cost of adding a gas service connection to be about $6,400 for a single-family home.[24]

On the other hand, heat pumps are often more expensive for existing buildings because initial installed costs and operating costs for heat pumps tend to be higher than gas furnace options (although they are often cheaper than propane or oil heating systems on a lifecycle basis). For example, the 2018 SWEEP study mentioned above found that retrofit heat pump options are currently cost-effective in only one of five studied cities in the Southwest.[25]

One main factor for the relatively high cost of retrofit heat pumps is that installing new heat pumps in existing buildings will not avoid any gas infrastructure related costs. In addition, heat pump options in existing buildings may require replacing or fixing existing heating distribution systems such as ducts and radiators, which incur additional costs. Finally, while homes with air conditioning or new homes are not likely to need to upgrade their electrical panels, some old homes with limited electrical capacity may need to spend extra money to upgrade their panels.

For a building with an existing forced-air system (e.g., gas furnace) with ducts, the lowest cost option is installing a new ducted air-source heat pump (ASHP) and using the existing ductwork. This could be a less expensive option than replacing pipeline gas in some cases.[26] However, this system could be more expensive when the existing ducts are not well suited to heat pump systems (e.g., the ducts may not be sized for heat pump air flow requirements) or need to be repaired.[27] Other ASHPs such as ductless mini split heat pumps and variable refrigerant flow (VRF) systems are more efficient than ducted heat pump models partly because they do not have any issue of duct leaks, but their installation costs are typically higher than ducted heat pumps, and multiple units may be required to serve buildings with numerous rooms.

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[23] Kolwey, N., Geller, H. 2018. *Benefits of Heat Pumps for Homes in the Southwest.* Southwest Energy Efficiency Project (SWEEP). Table 5a on Page 17 and Appendix A on page 33. Available at: http://www.swenergy.org/Data/Sites/1/media/documents/heat-pump-study-2018-06-11-final.pdf.

[24] TRC. 2016. *Palo Alto Electrification Final Report*. Prepared for the City of Palo Alto. Available at: https://www.cityofpaloalto.org/files/assets/public/development-services/advisory-groups/electrification-task-force/palo-alto-electrification-study-11162016.pdf.

[25] Ibid.

[26] The 2018 SWEEP study found that total installed costs of ducted heat pumps are slightly less expensive than the cost of installing a new gas furnace and a new central AC.

[27] ICF Canada. 2019. *Heat Pump Best Practices Installation Guide for Existing Homes*. In partnership with FRESCo. Page 47. Available at: http://www.homeperformance.ca/wp-content/uploads/2019/12/ASHP_QI_Best_Practice_Guide_20191209.pdf.

Ductless mini-split heat pumps are suitable for residential and small commercial buildings and can be an alternative heating system to many of the residential and small commercial buildings with existing gas boiler systems. VRF systems are suitable for medium-to-large commercial buildings and offer the capability of providing heating and cooling simultaneously in different rooms. VRF requires less space than ducted systems or central heating and cooling plants.[28] However, VRF uses a lot of refrigerant, which could pose a risk of negative climate impacts from leaks.[29] Cost is still a major issue for replacing natural gas heating systems with either mini-splits and VRFs because the cost of switching to ductless or VRF heat pumps is likely to be higher than the cost of simply replacing existing gas furnaces and boilers in kind. However, if building owners need to replace their existing heat distribution system (e.g., radiators), both mini-splits and VRF can be lower cost options.

One important consideration for all types of ASHPs is that their efficiency and capacity drop in very cold air temperatures. Thus, conventional ASHPs may require backup electric resistance heating elements in cold climate areas, depending on the system sizing and building shell. However, cold climate ASHPs (or ccASHPs) have become widely available in the market. Such ASHPs can deliver comfortable heat even at temperatures well below freezing. For example, one field study in Vermont observed that ccASHPs operated at 5° F with a coefficient of performance (COP) of 1.6 (or 160 percent efficient) and they operated even under -20° F at above 1 COP (albeit with reduced capacity).[30] In some climates, ccASHPs can help to mitigate winter peak concerns on the electric grid. Since ccASHPs are slightly more expensive than regular ASHPs, one needs to examine whether ccASHPs are necessary for the climate in which they operate.

Ground-source heat pumps (GSHPs) are another type of heat pump. GSHPs can provide superb performance and work efficiently even in very cold temperatures because they take advantage of heat from underground rock or groundwater as the heat reservoir instead of ambient air. Because the ground has more stable temperatures throughout the year than air, GSHPs are more efficient than ASHPs. However, GSHPs are considerably more expensive than ASHPs because drilling underground to install a heat exchanging ground loop is very expensive. One source estimates that GSHPs are two to nearly three times more expensive than ASHPs.[31]

Air-to-water heat pumps (AWHP), or "hydronic" heat pumps, heat water instead of air, using ambient air as the heat source. Heat pump water heaters (HPWHs) are the most widely available AWHPs in the United States. Several companies make AWHPs that produce enough hot water for space heating for

[28] ProudGreenBuilding.com. 2017. "VRF solution provides efficiency for luxury residential retrofit." Available at: https://www.proudgreenbuilding.com/articles/vrf-solution-provides-efficiency-for-luxury-residential-retrofit/.

[29] Propane is a possible non-GHG refrigerant for VRF systems but the volumes and pressures of propane required would pose flammability concerns.

[30] Walczyk, J. 2017. *Evaluation of Cold Climate Heat Pumps in Vermont*. Prepared by The Cadmus Group, LLC for the Vermont Public Service Department. Available at: https://publicservice.vermont.gov/sites/dps/files/documents/Energy_Efficiency/Reports/Evaluation%20of%20Cold%20Climate%20Heat%20Pumps%20in%20Vermont.pdf.

[31] NYSERDA. 2017. *Renewable Heating and Cooling Policy Framework. Options to Advance Industry Growth and Markets in New York*. Page 86. Available at: https://www.synapse-energy.com/sites/default/files/RHC-Framework-NYSERDA-16-093.pdf.

both residential and commercial buildings. However, applications of such systems are limited in the United States, especially in cold climate regions. AWHPs can be advantageous for some large buildings that have heat sources within the building (e.g., waste heat from spas, restaurant kitchen or wastewater treatment facilities, below grade garages, mechanical rooms, or laundry exhaust). These heat reservoirs enable AWHPs to perform very efficiently in cold climates throughout the year. Further, AWHPs can dehumidify rooms, which can be beneficial for certain areas such as laundry rooms.[32] Shared central AWHP systems for multiple tenants and uses within a building can enable increased performance and reduced unit costs.[33]

Electrification of various end-uses (e.g., space heating, water heating, cooking) and transportation are expected to increase electric consumption and peak load in the long-term. New loads create additional costs—to produce the electricity, and particularly to generate additional electricity at peak times and transport it to customers. Among building electrification measures, water heating and cooking electrification will add additional loads during summer peak hours. Heat pumps for space heating can be very efficient for cooling, so they can reduce summer peak loads for homes and buildings that currently have air conditioners (especially centrally ducted systems). However, to the extent that heat pumps are installed in buildings without air conditioners, they will increase electric peak loads during the summer.

Electrification will also increase electric consumption and peak loads during the winter. As more households and buildings switch to heat pumps for space heating, winter peak loads are expected to exceed summer peak loads at some point in the future. Depending on the performance of the heat pump systems, and the extent to which electric resistance or combustion systems are used as backup, the extent of this winter peak could vary considerably. There is uncertainty regarding the composition and cost of low-carbon electric supply to meet a substantially different load profile, especially during the winter. Impacts on the transmission and distribution system are also uncertain.

Building shell improvements and weatherization (e.g., adding insulation and air sealing, installing double- or triple-pane windows) are important for making low-carbon space heating more affordable because such improvements will reduce space heating loads and the size and cost of heating systems required. Further, building shell improvements will ensure that space heating is more comfortable (e.g., no drifts, cold air from walls and windows). However, building shell improvements require additional costs for building owners, and can create substantial disruption for residents.

Transitioning a building or neighborhood off pipeline gas can incur early retirement costs for some equipment. It is very unlikely, for example, that all the gas-powered appliances within a given home will be due for replacement at the same time. If the homeowner opts to electrify some of their systems will be retired early and the owner will incur additional costs to replace them. This effect will be magnified

[32] Hopkins, A., Takahashi, K., Glick, D., Whited, M. 2018. *Decarbonization of Heating Energy Use in California Buildings - Technology, Markets, Impacts, and Policy Solutions*. Synapse Energy Economics for the Natural Resources Defense Council (NRDC). Page 22. Available at: https://www.synapse-energy.com/sites/default/files/Decarbonization-Heating-CA-Buildings-17-092-1.pdf.

[33] RMI and Redwood Energy. 2020. *Heat Pumps for Hot Water: Installed Costs in New Homes*.

when multiple buildings transition at once. Each investment in a new gas appliance today creates a risk of early retirement later.

Solution space

Adopting new technologies and fuels at the scale required to meet Colorado's GHG targets will require new types of action and planning to address the critical questions of availability, cost, and performance.

Gather information. Research and development and utility pilots can be used to learn about cost, performance, and availability of new technologies, techniques, or processes. Pilots can be an effective way to test new approaches and technologies before implementing at a large scale, thus reducing risk.

Pilot proposals should provide a complete study design that clearly describes the knowledge gaps that the proposed research is intended to address, considers whether an alternative pilot study design could achieve the same objectives, and describes how the proposed methodology is the best way to achieve the stated goals. In addition, the study design should indicate use cases for the technique, process, or technology and relate these to the pilot design. Study designs should describe how success is defined and include a description of what will be reported, to whom, and how often.

Pilots need not be limited to novel technologies: they also make sense when seeking breakthroughs in underserved markets or overcoming historically intractable barriers. For example, pilots for program designs and approaches aimed at hard-to-reach market segments may be particularly valuable, given the importance of equity concerns to the state's goals and priorities, and inform understanding of the barrier and costs to decarbonization in these communities. The lessons learned from these pilots could also see broader application in easier-to-reach market segments. Pilots could also make sense as a way to test approaches to overcoming the "in-kind" emergency replacement challenges. At the neighborhood scale, pilots could be used to learn about the challenges of using targeted electrification as an approach to retire segments of the gas system. While the technologies in this case may be well known, the coordination challenges among building owners, gas and electric utilities, and municipalities could be substantial.

Detailed modeling of relevant portions of the energy system can also provide important information. For example, the Massachusetts Clean Energy Center is working with the state's major utilities to model the effect of high degrees of electrification on the electric distribution system. This modeling will lead to pilots for new approaches to manage the resulting impacts. Pilots and demonstrations of load management technologies, including those enabled by electrification such as managed HPWH operations, can also inform grid assessments.

Clearly document planning assumptions. To the extent that utilities propose projects for highly uncertain technologies, such as for green or blue hydrogen, such proposals should account for all costs, including for electricity supply and for infrastructure and equipment to process, store, and use the gas. Also, the proposing utility should be required to provide a full accounting of emissions and leakage associated with all parts of the process, including emissions during gas extraction, processing, transport, storage, and use. In addition, proposals should clearly indicate and, where possible, monetize risks associated with performance, availability, and cost of equipment to use hydrogen.

Learning by doing. Some technologies for building decarbonization are generally mature but still incur additional costs due to their complexity and because contractors are not yet familiar with how to best use them in their customers' buildings. In these cases, programs to support scaling market adoption of these technologies will also enable installers to "learn by doing" and develop approaches that reduce customer cost and/or improve system performance. Sharing lessons learned, while also enabling firms that successfully innovate to capture the value of their innovation through market growth, will be a key part of market development. Market intelligence, driven by policy direction, will also impact manufacturers. Market stakeholders in California identified the need for a "retrofit ready" heat pump water heater that could be installed with lower barriers (e.g., by not requiring a new electric circuit), and worked with manufacturers to develop new products for which they expect a substantial market.

5. Alignment with Colorado Context

The Colorado legislature, administration, regulators, local governments, and utilities are taking or planning significant actions related to decarbonizing the building sector. Recent analysis and planning processes include the development of the state's *Greenhouse Gas Pollution Reduction Roadmap* as well as CEO's statewide studies of beneficial electrification. Denver has set out a pathway for net zero, all-electric buildings under its building code,[34] and the City of Boulder and Boulder County have paired residents with advisors to guide them through plans to electrify their homes.[35] Together, these studies, reports, and initial actions provide a solid foundation for observation and orientation on which the state can build further decisions and actions. This means the state is presently in the orientation period, where strategic frameworks should be developed, and will shortly proceed toward decisions and actions implemented as part of utility beneficial electrification, clean heat, and DSM plans. The next section describes the planning processes and other changes that have resulted from new legislation, were spurred by the analyses completed to date, or are otherwise expected in the next few years. We then place the considerations developed in the previous section into this context to illustrate the potential alignment and remaining gaps.

[34] Denver Office of Climate Action, Sustainability, and Resiliency. 2021. *Denver's Net Zero Energy New Buildings & Homes Implementation Plan*. Available at: https://denvergov.org/files/assets/public/climate-action/documents/denver-nze-implementation-plan_final_v1.pdf.

[35] WePowr. "Comfort365 Renewable Cooling and Heating." Available at: http://wepowr.com/bouldercomfort365.

5.1. New Colorado laws and processes

Demand side management changes and plans

HB21-1238 establishes a DSM framework for gas utilities that parallels that for electric utilities.[36] The law requires the PUC to establish demand-side gas savings targets that are consistent with achieving the state's GHG reduction requirements and the maximum amount of achievable cost-effective savings, and the budgets associated with programs to meet these targets. It also sets the social cost of carbon dioxide and methane emissions to be used in cost-effectiveness screening, while allowing those values to be updated in the future.

In keeping with the revised and more ambitious structure that HB21-1238 establishes for gas DSM, the new law requires that each investor-owned gas utility file an application to open a "strategic issues proceeding" before the PUC in 2022. This strategic proceeding will establish the framework for gas DSM programs, including the targets to be achieved and the estimated budgets required to achieve them. Each utility's gas DSM plan, developed within this framework, would be the action plan that lays out the specific actions required to meet the targets. These strategic issues proceedings must be conducted every four years.

The new law also allows gas utilities to file for a "rate adjustment mechanism" to decouple their revenues from sales. This mechanism would ensure that the utility's revenue per customer is recovered independent of the quantity of gas they sell, thereby removing a disincentive for the utility to support DSM.

HB21-1238 requires that gas utilities set aside a portion of program spending for income-qualified households. The portion is 25 percent for large utilities and 15 percent for small ones.

HB21-1238 requires that utilities use a list of certified contractors for projects that receive financial support under their DSM Plans. These contractors are those which participate in registered apprenticeship programs and meet specific graduation standards.

Beneficial Electrification (BE) Plans

SB21-246 requires Colorado's investor-owned electric utilities to develop and implement BE Plans using a similar structure to that used for electric DSM planning.[37] The utilities must file BE plans every three years and can coordinate or combine their filing with DSM plans. BE plans are action plans: they are required to include specific programs, budgets, and outreach activities. The first BE plans are due to be

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[36] Colorado General Assembly. 2021. *HB21-1238 Public Utilities Commission Modernize Gas Utility Demand-side Management Standards*. Available at: https://leg.colorado.gov/bills/hb21-1238.

[37] Colorado General Assembly. 2021. *SB21-246 Electric Utility Promote Beneficial Electrification*. Available at: https://leg.colorado.gov/bills/sb21-246.

filed by July 1, 2022. These first plans will take their strategic framework from existing analysis, such as CEO's beneficial electrification potential study.

SB21-246 also establishes a required recurring "strategic issues filing," to be completed every six years (starting in 2024) that sets a pace for returning to the observation and orientation steps to revise the strategic framework for the next two three-year BE action plans.

SB21-246 adopts a similar structure for labor standards in BE programs as required in DSM programs (described above).

Clean Heat Plans

SB21-264 requires Colorado's gas utilities to plan to reduce their GHG emissions 4 percent by 2025 and 22 percent by 2030, with reduction requirements for 2035 and future years to be set by the PUC.[38] SB21-264 requires that the PUC open a rulemaking to define the scope and process for utility Clean Heat Plans (CHPs) by October 1, 2021 and complete it by December 1, 2022. Each utility's first CHP is due to be filed by August 1, 2023 (for Xcel Energy) or January 1, 2024 (for others).

The structure established by SB21-264 created two separate steps, which play distinct roles in the overall change management approach: the rulemaking step, and the utility planning step. The rulemaking step plays the role of a strategic framework (primarily the "orient" step of the OODA loop). The rule sets out the strategic approach to be taken by the utilities when developing their CHPs, which are action plans ("decide," then "act").

Gas infrastructure planning and investments (for both load growth and leak mitigation) and utility business models are implicated by the need to steadily reduce GHG emissions from the building sector, as required by SB21-264. The PUC has recognized the strategic role of the Clean Heat Rulemaking step by expanding the scope of the rulemaking to include broader questions of short- and long-term gas system planning. As the PUC stated in its Notice of Proposed Rulemaking, "[w]e attach an initial version of these new rules for gas planning to this Decision because they are intended to work in conjunction with the new rules for CHPs during the coming decades when the gas utilities transition their businesses and the services they provide to their customers to achieve the substantial reductions in statewide greenhouse gas emissions required by" Colorado law.[39]

The utilities' Clean Heat planning comes after the Beneficial Electrification and DSM planning described above. The utilities' next BE and DSM plans will be filed while the PUC's Clean Heat rulemaking process is still ongoing. This allows the PUC to take the strategic and action items from those plans and use them as part of the context to inform the strategic framework for Clean Heat and gas planning that it creates in the rule. SB21-264 also establishes a cost cap (equal to 2.5 percent of utility revenues) for CHP

[38] Colorado General Assembly. 2021. *SB21-264 Adopt Programs Reduce Greenhouse Gas Emissions Utilities*. Available at: https://leg.colorado.gov/bills/sb21-264.

[39] Public Utilities Commission of the State of Colorado. 2021. Decision No. C21-0610: Notice of Proposed Rulemaking in Proceeding No. 21R-0449G. Para. 33 on p. 16.

actions. By establishing DSM and BE action plans first, these separate sets of actions and their associated costs can be accounted for, so that it is clear that only incremental additional actions required to reach the Clean Heat GHG reduction targets count toward the Clean Heat cost cap.

SB21-264 requires that any actions as part of a CHP that could otherwise be part of a DSM or BE plan have the same labor standards are required for those processes and further requires disclosure of the use of Colorado vs. out of state labor for large projects and requires the PUC to give additional weight to proposals that incorporate training programs, in-state labor, and support long-term careers and good wages.

Other new laws from the 2021 legislative session

Building performance standards

HB21-1286 requires the state to develop building benchmarking and performance standards for existing buildings.[40] The law requires certain large buildings to track and report their building energy use to CEO. The goal is to ensure that these standards achieve a measurable sector-wide reduction in GHG emissions: a 7 percent reduction by 2025 and a 20 percent reduction by 2030 from a 2021 baseline.

On or before October 1, 2021, CEO is required to convene a stakeholder task force to develop and recommend performance standards, which will be executed as rules by the Air Quality Control Commission. The task force will discuss, among other topics, rules regarding the issuance of waivers and extensions of time for compliance.

The law requires CEO to develop and manage a benchmarking database, as well as coordination between CEO and local governments to streamline reporting and coordinate benchmarking and performance requirements.

Environmental justice

HB21-1266 concerns efforts to redress the effects of environmental injustice on disproportionately impacted communities.[41] The legislation requires improved air pollution monitoring and the creation of a task force with robust community representation to better address equity in decision-making. It also explicitly places equity in the center of CEO's mission.

SB21-272 makes various changes to the statutory framework for the Colorado PUC.[42] Of particular relevance here is that it explicitly defines disproportionately impacted communities and requires the

[40] Colorado General Assembly. 2021. *HB21-1286 Energy Performance For Buildings*. Available at: https://leg.colorado.gov/bills/hb21-1286.

[41] Colorado General Assembly. 2021. *HB21-1266 Environmental Justice Disproportionate Impacted Community*. Available at: https://leg.colorado.gov/bills/hb21-1266.

[42] Colorado General Assembly. 2021. *SB21-272 Measures To Modernize The Public Utilities Commission*. Available at: https://leg.colorado.gov/bills/sb21-272.

PUC to develop rules that embed consideration of equity, impacts, and benefits for disproportionately impacted communities throughout all of its actions.

5.2. Aligning Colorado processes with key considerations

Colorado's recent legislative activity will primarily drive program-based approaches, although it also establishes frameworks for strategic planning to orient those actions. There will also be opportunities to establish actions outside of utility programs, which may be better suited to address some of the challenges and considerations identified in Section 4.

Clean Heat rulemaking and strategic issues dockets

Each of the three major pieces of 2021 legislation establishes a strategic planning step, although each is on a different timeframe:

- HB21-1238 requires a gas DSM strategic issues process in 2022, repeating on a four-year (or faster) cycle.
- SB21-246 requires a BE strategic issues process in or before 2024, repeating every six years (or sooner). It also requires a BE plan every three years (or faster).
- SB21-264 requires a Clean Heat rulemaking beginning in 2021, with no set schedule for revisiting strategic questions. The PUC has also expanded the scope of the proceeding around this rulemaking to encompass a broader range of planning questions.

The laws allow utilities to combine their filings for these different types of programs, although the timeframes do not obviously align. We address a potential timeline for alignment in Section 6.1 below.

These strategic processes provide a critical opportunity to orient the utility plans and programs that translate strategy into action. They also provide a venue to examine and resolve questions regarding the appropriate scale and scope for utility programs and the best roles for different actors (such as utilities, state agencies, and the unregulated marketplace) in delivering solutions to the state's building decarbonization challenges.

The just-launched Clean Heat rulemaking, with its scope broadened by the PUC to include gas planning, is well placed in both time and scope to address overarching planning and scoping questions related to the allocation of different kinds of actions to different programs, plans, and review cycles. For example, which potential actions are "DSM" programs, which are "BE programs", and which are "Clean Heat" programs? This allocation is important because the law requires budgets and tracking of costs for each class of programs, and each has their own treatment of shareholder incentives and cost controls. This allocation also serves to allocate costs and responsibilities between electric and gas utilities—and can reflect the different situations for combined electric-gas companies and single fuel utilities.

One critical role for the Clean Heat rulemaking, which is enabled by the PUC's decision to broaden the scope to short- and long-term gas planning, is to establish a strategic direction regarding non-programmatic issues, primarily those related to the utility business model and rates and rate design. As discussed above, the question of if and how stranded costs are recovered is a strategic-level question, to be informed by both the statewide roadmap and equity considerations. A PUC rulemaking process is the right venue to map the state's overall roadmap onto the requirements for utility filings and decision-making. The rule would lay out the process and expectations for strategic issues filings to address these questions. These strategic issues proceedings would require analysis and information from the utilities, CEO, and others regarding the impact of different approaches on both (1) the amount of assets at risk of stranding and (2) how investments might be recovered in the event assets become stranded. Once the strategic direction is established in the strategic issues dockets, the utility-specific implementation would take place through both rate cases and other utility plans and programs. Specifically, the rulemaking should address and set strategic direction regarding

- data that utilities need to provide to inform planning processes (such as projections of need for future pipeline safety programs), including geographic (map-based) data regarding the age and condition of utility assets;
- tailored engagement by utilities with disproportionately impacted communities, their own workforces, and the building trades to assess how to manage the carbon transition;
- depreciation schedules and other financial methods to limit stranded cost risks;
- decision-making processes and requirements regarding building new gas infrastructure, including pipe replacement and leak mitigation investments as well as ways to serve areas of growing demand for heating service; and
- processes to investigate solutions to longer-term challenges such as how to deal with any stranded costs that do arise, and potential new utility business models.

Once the overall strategic framework is established in the PUC's current rulemaking, and specific strategies are set for DSM, BE, and Clean Heat programs, then programs and regulatory processes can effectuate those strategies through decisions and actions.

One key aspect of the strategic phase, beginning with the present rule making, is to identify what information is not available, and to lay out potential approaches to acquire the information. There are two benefits to being explicit about information needs. The first benefit is transparency: being explicit about the information used, and also the information not available, to inform stakeholders and the public about the strategic-level decision-making process and to increase understanding and acceptance of the path forward. The second benefit is that it provides guidance to those developing action plans that those actions should include actions that will produce the necessary information.

Each of the strategic processes that Colorado has established should conclude by identifying the key questions to be settled by specific subsequent processes. In some cases, those questions will be resolved later because more information will be available.

Utility-specific DSM, BE, and Clean Heat programs

Utility programs can be well suited to address the challenges and solutions on the demand and supply sides. On the demand side, utilities can use funding and financing to support customer adoption of low-carbon end use technologies, such as heat pumps for space and water heating. Utility end-use programs address two related but distinct challenges for building decarbonization: (1) transforming markets to increase deployment of cost-effective mature technologies and (2) helping less mature and/or more costly technologies develop and scale through learning by doing and economies of scale. This second purpose creates virtuous cycles with strategic planning by providing otherwise-unavailable information on cost, availability, and performance of new technologies that can be used in the next iteration of strategic updates.

Depending on the state of the market for a given technology, the form and structure of utility market intervention needs to be tailored, and this kind of specificity is well suited to the action plans required for DSM, BE, and Clean Heat. For example, utility incentives to change the relative cost of different appliances can encourage customers to adopt low-carbon options. Utilities can also educate and market to customers, and train contractors and distributors, regarding how to best and most easily adopt and install low-carbon options. Utilities can also develop programs to proactively address hidden barriers to electrification, such as the potential need for electric panel upgrades and the availability of electric options on short notice from suppliers.

HB21-1238 and SB21-246 require that the utilities' DSM and BE plans, which address customer buildings and systems, be cost-effective. The determination of cost-effectiveness includes a cost of carbon dioxide and methane emissions, but there may still be some promising technologies that are likely the best long-term solution for some end uses or building types but which are not strictly cost-effective today. The regulatory process can address these in two ways. First, the PUC can evaluate the DSM and BE plans of a portfolio basis for cost-effectiveness, rather than on a project or program basis. This allows some programs that are necessary but not cost-effective against the traditional test to nonetheless be part of the overall portfolio. Second, the utilities and PUC can place programs that support these technologies in the Clean Heat Plans instead of the DSM or BE plans. The CHPs do not have the same cost-effectiveness structure as DSM and BE, in that they are focused on finding the most cost-effective way to meet fixed emission reduction targets rather than on being less expensive than a hypothetical alternative. This structure is necessary for CHPs because they can also support supply-side actions, which cannot be easily evaluated on the same cost-effectiveness footing as demand-side actions.

Supply-side actions in CHPs are another example of a place where utility actions can change the trajectory of cost and performance for needed technologies. Demonstrations and pilots for supply-side low-carbon actions, such as methane recovery or producing biomethane and green hydrogen, can help answer open questions regarding these resources while simultaneously providing the opportunity to discover or develop ways of producing these fuels at lower cost. Pilots and demonstrations should abide by strategic guidance and best practices. For example, pilots should have clearly defined objectives and questions they are designed to answer. They should also take account of the likely end uses for the fuels produced. For example, it is higher value to integrate a hydrogen production with industrial end uses that can simultaneously research ways to use the fuel in next generation production (especially where electrification of production is likely to be infeasible) than to simply generate hydrogen and blend it in with the utility's supply of natural gas (where blend fraction limits will ultimately limit its ability to reduce emissions to about 7 percent).

Gas utility regulatory processes

Rate cases are the primary regulatory venue for implementation of changes to utility regulatory processes and practices. These cases address the particulars of depreciation for different classes of assets, cost recovery and risk allocation for new utility business models, and the prudence of utility expenditures on assets and programs. They are also where rate designs are established, once the total revenue requirement is established and costs are allocated to rate classes. If cost sharing or shifting between gas and electric utilities, or securitization of gas utility assets, are required to produce a just and reasonable outcome, the details of such shifts or other changes in cost recovery would also be worked out in rate cases or spun out from rate cases.

The gas planning rulemaking could also establish thresholds for increased review and screening of gas system infrastructure investments, in order to limit stranded cost risk. These reviews, like other evaluations for certificates of public convenience and necessity (CPCNs), would evaluate whether the investment provides sufficient benefit over its expected lifetime to warrant its cost to ratepayers. Because the number and distribution of ratepayers (both in terms of class and geography) served by the asset might change substantially over its lifetime, and the lifetime might be different depending on how it will be used, the parameters will be particular to evaluate a given investment. CPCN evaluation should also include a process for consideration of non-pipeline alternatives. For large investments, a market sounding to solicit third party proposals to defer or avoid the investment would be warranted, while for smaller investments, a standardized set of typical non-pipes alternative parameters could be developed to compare with the proposed investment. Where possible, the value of optionality and flexibility (or the cost to irreversibility) should be reflected in the infrastructure investment analysis.

A similar process could also be used to establish screening or planning parameters for classes of investments, rather than individual larger investments that warrant specific analysis. For example, such a process could establish screening parameters for the standard replacement of a length of leak-prone pipe, to determine whether any given segment should be replaced with modern pipe, any investment be deferred, if the pipe should be retired and the customers transitioned to electricity, or if some other action may be warranted. Line extensions and new gas services are also prime candidates for an updated and standardized screening treatment.

Other processes

Other new processes outside the utility and regulatory spheres can also address key considerations for building decarbonization, as part of a coherent and "all of government" approach. These include Colorado's new building performance benchmarking and performance requirements, which support new contractor business models while also driving market interest in utility programs and increasing assurance that emission targets will be met in large commercial buildings.

Colorado also has several existing programs and processes that align with considerations for change management. These include training and technical assistance for high-performance building practice in the context of building energy codes,[43] as well as customer engagement and education programs for home electrification coordinated by the Beneficial Electrification League of Colorado.[44] The PUC has established distribution system planning processes, which will be utilized as electric utilities begin to plan for local impacts of electrification on their grids.[45] Both the PUC's and CEO's programs and approaches across the energy sector will be shaped by the new statutory requirements to consider equity throughout their work.

6. Colorado-Specific Recommendations

6.1. Integration of planning processes

Managing the decarbonization transition across the building sector, including its impacts on gas and electric utilities, is a complex and multi-faceted problem. Colorado has established multiple processes, each focused on a specific facet. However, given the tight interrelationships between these issues, having one venue to address them all at the strategic level would be valuable. The utilities could file unified DSM, BE, and Clean Heat plans within this strategic framework, or separate plans—either way should work as long as they are sharing this common foundation.

While the legal requirements for filing timelines for DSM, BE, and Clean Heat do not immediately and obviously line up, it would be possible within the legally allowed schedules to align the strategic planning cycles by speeding each cycle up to catch up to the fastest legally required cycle. SB21-246 requires that utilities file BE plans every three years or sooner. To maintain a structure wherein strategic issues are addressed before the implementation plans are filed, it would be necessary to put all planning on a three-year cycle.

Specifically, the PUC should require a combined strategic cycle for DSM and BE in 2022, aligned with the later stages of the Clean Heat and gas planning rulemaking. If it anticipates this schedule, the PUC should inform the utilities promptly so that they can begin to prepare a combined filing. The focus on this initial cycle would be on establishing the strategic framework and identifying strategies to use to

[43] Colorado Energy Office. "Building Energy Codes." *Energy Policy.* Available at: https://energyoffice.colorado.gov/climate-energy/energy-policy/building-energy-codes

[44] See, for example, *Love Electric* at https://loveelectric.org.

[45] See the "Distribution System Planning" section on Public Utilities Commission, "2019 Legislative Implementation." Available at: https://puc.colorado.gov/2019-puc-legislative-implementation.

meet the states' 2025 goals. (This is the only planning cycle that would happen in time to appreciably change how the state meets those near-term goals.)

The initial strategic cycle could also serve as an initial venue to address long-term questions, such as business model and investment/asset planning, grounded in the GHG Roadmap. At this stage, the key task is to identify which of those questions need to be answered (permanently or on an interim basis) now, even without full information, and which can be deferred while more information is gathered. The process would identify the missing information and task utilities, CEO, or others with developing ways to gather it before the next cycle.

Filings for the next strategic cycle would be due in 2025, although in order for action plans to also be filed in 2025, it may make sense to begin the strategic work in 2024. This iteration would look past 2025, and focus on how to meet 2030 goals, while developing actions that can scale throughout the 2030s to be on track for longer-term goals. By the 2027-28 cycle, meeting objectives for 2030 should be well in hand, and planning for 2040 coming into view.

Over time it could evolve that major strategic issues are addressed on a six-year cycle, with revisions every three years, but during the first few cycles when the foundation is being established for how these processes will work and the rate of programmatic change is greatest, we expect major issues would need to be addressed every cycle.

6.2. Clean Heat rules

With the integrated planning cycle and approach just described, the PUC's new Clean Heat and gas planning rules have a clear and important role to play in establishing the structure and expectations for integrated, holistic analysis to support the state's strategic framework for building decarbonization.

Decision-making

The PUC's Clean Heat rules establish the framework and requirements for the utilities' Clean Heat plans. As previously discussed, the Clean Heat and gas planning rulemaking itself is playing an important role as the strategic step in the initial Clean Heat planning process, in parallel with the strategic issues proceedings for DSM and BE which can take place over the next year. The utilities' DSM, BE, and Clean Heat plans (whether formally separate or integrated) take on the key role of the Decide step of the OODA loop: they should lay out clear plans for action. While the plans may contain specific analysis where additional observation and orientation are required for program design or other practical considerations, the utilities' plans must contain actions that are aligned with the strategic framework and commensurate with the identified gap between the status quo and the path toward Colorado's long-term objectives. The execution of the utilities' programs, as well as actions by non-regulated actors such as CEO and municipalities, are the "Act" portion of the OODA loop, and set up the next cycle.

Data generation and gathering

Data and analysis are required for two primary purposes in each iteration of the planning cycle: to inform the strategic framework, and to inform the selection and implementation of actions. The Clean Heat and gas planning rulemaking provides an appropriate venue to establish what information is collected in each cycle. Information that would be required includes the following:

- Customer and energy consumption data (anonymized/aggregated as necessary), along with the utility's forecasts of how loads and customers will change (with details on the method used to develop the forecasts).

- Maps and other data regarding the state of the pipeline system. This should include both physical information (How many miles of pipe are made of each material, and what is the age distribution of each material?) and financial information (the undepreciated balance for each type and age of pipe, its depreciation lifetime, etc.). In order to evaluate equity impacts of changes in the gas system, it would also be important to gather information about the distribution of physical and financial characteristics of the pipe serving different customer types, including low-income customers.

- Market and program data regarding customer uptake of different technologies (or actions, such as building envelope improvements). This should also include the cost (to utility and to customers) of technologies or actions and the programs promoting them. Where possible, breakdowns of customer participation by geography and income will help evaluate equity impacts and gaps. (Note that it is more important to use effective program designs than to sacrifice program effectiveness in exchange for better market or customer data.)

- Analysis and performance data on research, pilots and demonstration activities. These activities should be designed to provide useful information for strategic or program planning, and that information should be disclosed in detail.

Specific to the development of the strategic framework, the utilities should also present data and analysis relevant to assessment of their present and future business model and related activities. This analysis is less relevant for the details of program implementation under the DSM, BE, or Clean Heat plans, (although it would be shaped by the customer-level results of those plans' implementation) and instead would be implemented through rate cases or other tailored regulatory proceedings. Among the information required should be the following:

- Details about assets at risk of becoming stranded, and assessment of options for (1) how the utility could mitigate that risk, and (2) how the value of the assets would be treated if they become stranded.

- Analysis of any new lines or business proposed, and how they would (or would not) be regulated.

- Analysis of options for the evolution of the utility's existing business model.

Investment screening rules and processes

Gas planning rules should address the screening processes and assumptions to be used when evaluating whether a new investment in the gas system is necessary. The rules should identify the information that must be filed regarding the proposed facility and why it is needed, but should also go beyond simply listing information to lay out the standard or principles to be used to determine whether a proposed facility is, in fact, needed. This should include whether an appropriate planning and/or solicitation process has been used to evaluate non-infrastructure solutions (such as DSM and electrification). Given the risk and cost associated with new gas infrastructure in Colorado's new policy environment, the proposing utility must pass a high bar to prove that the proposed investment is both necessary and consistent with state policy. For the benefit of the proposing utility, and other parties, the PUC should strongly consider laying the details of this evaluation out in the rule.

In addition, this rule would be the appropriate place to reinforce these investment screening processes with a bright line regarding ratepayer and investor responsibilities for new investments. By establishing that investors, not ratepayers, will be responsible if new investments become stranded, the utility's incentives are aligned with the regulator's: to carefully scrutinize any new investment.

6.3. No-regrets and low-regrets actions

While assessing the strategic framework and developing processes to implement Colorado's new laws, utilities and other actors in the state can also begin to take no-regrets and low-regrets actions that are necessary to continue to reduce GHG pollution from Colorado's buildings sector. These actions fall into two categories: process and implementation.

Process

These are actions to take now or in the near term that would evolve Colorado's processes to align with the structure and needs of transforming the building sector. The first two of these can be addressed in the DSM strategic issues proceeding to come in 2022, while the third may require a separate venue.

- Cost-effectiveness screening: The PUC can update the cost-effectiveness test for DSM, BE, and Clean Heat programs to reflect the state's new policy reality. This includes the legislatively required updates to the cost of carbon and methane emissions. It also includes potential updates to recognize that when emission reductions are required, the value of emission reductions is not just societal: it is internalized because emission reductions from one action reduce the need to reduce emissions elsewhere.

- DSM targets and incentives: The PUC should develop metrics for performance in DSM and electrification, for both electric and gas utilities, which measure progress in ways that are consistent with the state's policy principles. This includes GHG reductions, as well as affordability, equity, and risk mitigation. A portfolio approach to utility performance incentives for achieving these targets should encourage the utilities to perform in all areas.

- HB21-1238 allows gas utilities to file adjustment mechanisms so that their delivery revenue per customer is not affected by implementation of energy efficiency measures. In the long term, this approach would be counter to efforts to limit stranded cost risk, because it would encourage the gas utility to maintain or even expand the full gas system even with low levels of utilization. While it is not essential that decoupling be aligned with the state's long-term strategies immediately, evaluating other options at this time of strategic planning and transition could be timely and avoid creating unnecessary business model transitions.

Implementation

Given the short timeline to produce substantial GHG emission reductions in the building sector, increased implementation of emissions-reducing actions is necessary. Many actions are consistent with a wide range of potential futures, and can be pursued today without regrets:

- Increased insulation and air tightness in building envelopes, in both new and existing buildings, produces energy and emissions reductions while increasing comfort and health. This is an area of particular importance for low- and moderate-income households and renters, who face additional barriers and risks associated with some pathways to decarbonization. Both state-run low-income weatherization programs and utility programs have substantial roles to play here.

- Increased adoption of heat pumps for both space and water heating is required in all deep decarbonization pathways. Incentives, financing, and new program designs can increase adoption and help customers, contractors and distributors develop comfort and familiarity with these technologies. Programs that support the development of new business models and scaling approaches in the HVAC market are likely warranted here, including training (not just on how to best select and install heat pump systems, but also on sales and marketing). Where possible, CEO and utilities should facilitate sharing of lessons learned both within Colorado and from other states.

- A wide range of pilots, demonstrations, and research projects could gather essential information for later stages of the decarbonization transition. In each case, it is important to learn from similar efforts being pursued elsewhere, to share the insights learned in Colorado in order to reduce societal cost and accelerate societal learning, and to track the workforce needs and training required for successful scaling.

    - Emergency replacement: Test program designs that help customers take the time to electrify when their existing equipment fails, such as by providing temporary equipment and facilitating financing to ease the upfront cost.

    - Targeted electrification: Identify a small portion of the gas system due for replacement and work with the residents and building owners to coordinate a targeted electrification wave, to learn about costs, savings, barriers, and customer acceptance. This could be particularly beneficial if it also addressed equity concerns by including disproportionately impacted communities.

    - New utility business models: Analyze and research new potential lines of business for gas utilities along with new approaches to their existing business that may be more compatible with or ease the transition to a decarbonized future. Where promising options are found, consider pilots to test implementation.

    - Low-carbon fuel technologies: Research and pilot opportunities here range from identifying and studying the potential biomethane resources in Colorado to testing hydrogen production technologies and demonstrating the production of synthetic methane. Pilots and demonstrations in this area should be particularly cognizant of efforts elsewhere to pursue similar objectives, and designed to produce data about how these technologies will scale in cost and availability for application in Colorado.
    - Electric grid impacts: Detailed examination of electric loads in highly electrified homes and neighborhoods can illuminate what issues electric utilities may face on the distribution system when a larger fraction of building energy use depends on their systems. This includes testing the ability of different electrified end uses to provide grid services and shift loads, as well as the coincidence and diversity of different kinds of loads in diverse weather conditions.

- Expand rate design reform. Xcel's new time varying rates could be very beneficial for customers choosing heat pumps for space and water heating. Under current rates, with an inclining block rate structure that charges more as consumption increases, customers choosing a heat pump would expect to pay almost 10 cents for each incremental kWh of consumption. In contrast, under the new time of use rate, most incremental winter heating energy, for example, would be charged at just over 5 cents per kWh. Colorado should build from the example of Xcel's approved time varying rates to
    - develop time varying rates for other utilities;
    - consider including the cost of carbon and methane emissions in rate design estimates of marginal cost; and
    - further evaluate Xcel's rates and consider alternate rates that reflect the load shapes and cost structures of heat pumps for space and water heating.
- State agency and municipal building regulations can also set floors for building performance and increase knowledge about building energy use. These include
    - further advancing adoption of building codes, including evaluation of net zero energy building codes, and harnessing utility programs to increase compliance with high-aspiration codes;
    - extending the state's commercial building performance standard past 2030 to provide a known GHG reduction trajectory for building owners, and considering expansion to smaller buildings over time; and
    - encouraging the use of building labeling and certification systems to increase market understanding of building performance and allow building owners to better value higher-performing buildings.

7. CONCLUDING REMARKS

This white paper presents an approach tailored to the current status of Colorado's decarbonization approach, as utilities, regulators, CEO, and other stakeholders begin to address the need for a more detailed strategic framework and action plans to accelerate change in the building sector. In keeping with the OODA approach proposed here, future observations could re-orient the appropriate approach and change the context for decisions and actions. However, by maintaining an iterative and adaptive structure, the state can manage change through engagement and development of its people, through reform and expansion of its processes, and by taking advantage of the promise of new and maturing technologies. Each iteration through the cycle will bring new information and insights, reduce uncertainty, drive change, and further clarify the view of the road ahead.