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Deploying Advanced Metering Infrastructure on the Natural Gas System: Regulatory Challenges and Opportunities

Romany M. Webb
Columbia University, Sabin Center for Climate Change Law, rwebb@law.columbia.edu

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By Romany Webb

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Sabin Center for Climate Change Law
Columbia Law School
435 West 116th Street
New York, NY 10027
Tel: +1 (212) 854-3287
Email: columbiaclimate@gmail.com
Web: http://www.ColumbiaClimateLaw.com
Twitter: @ColumbiaClimate
Blog: http://blogs.law.columbia.edu/climatechange

About the author: Romany Webb is an Associate Research Scholar at Columbia Law School and a Climate Law Fellow at the Sabin Center for Climate Change Law.

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EXECUTIVE SUMMARY

Recent increases in domestic natural gas use have been widely heralded as a vital step in the fight against climate change. Proponents often characterize natural gas as a "clean" fossil fuel, emphasizing that its combustion produces fewer greenhouse gas emissions than coal and oil (per unit of energy produced). Natural gas combustion still emits large amounts of carbon dioxide, however. Natural gas production and transportation also result in emissions, primarily in the form of methane, which is a highly potent greenhouse gas, with approximately eight-four times the climate impacts of carbon dioxide (on a pound-for-pound basis, over a twenty-year time horizon). Methane emissions during production may, therefore, offset any reduction in combustion-related carbon dioxide emissions from substituting natural gas for other fossil fuels.

Recognizing this, a number of analysts have expressed concern that continued use of natural gas will hamper efforts to address climate change, and called for reductions in gas use. This will require major changes in energy consumption patterns, particularly in the residential and commercial sectors, which currently use over one-quarter of all natural gas consumed in the U.S., primarily for heating and cooking.

This paper considers whether and how new technologies can be used to promote more efficient natural gas use in the residential and commercial sectors. The focus is on advanced metering infrastructure (AMI), consisting of state-of-the-art meters capable of recording natural gas usage daily or hourly, and transmitting the data to customers in real-time via a wireless network. This enables customers to better understand their natural gas usage, leading to increased conservation and reduced greenhouse gas emissions. It may also result in improved natural gas system management, including because the wireless communication networks deployed with AMI can be used to collect and transmit data from methane and other pipeline sensors, enabling faster leak repair and further reducing emissions.

Despite these benefits, to date, AMI has not been widely deployed on the natural gas distribution system in the U.S. While interest in AMI is growing, particularly in California, only a handful of distribution system operators (local distribution companies or LDCs) have undertaken deployment. The reasons for this are poorly understood; previous research has focused exclusively on market barriers to deploying AMI and failed to consider other possible explanations for the

slow rate of deployment. Notably, to the author's knowledge, there has been no comprehensive assessment of the impact of regulation on AMI deployment. This paper is intended to fill that gap.

This paper draws on recent experience with AMI deployment in California, Maryland, and New York to assess how the regulation of LDC rates affects incentives to invest in AMI. The assessment reveals that, in the past, LDCs may have been discouraged from investing in AMI by uncertainty as to whether and how they will be permitted to recover their costs. It appears that many LDCs will only invest if confident that cost recovery will be permitted through a tracking mechanism, rather than in their general rate case, because the latter approach can lead to delays in recovery and thus adversely affect the LDC's financial position. LDCs also require assurance that investment will not reduce their overall (regulated) earnings. Such reductions could occur under traditional regulatory approaches, including because earnings are tied to sales, which may decline as a result of AMI deployment (i.e., due to increased conservation). Moreover, AMI deployment could lead to a reduction in natural gas losses (i.e., due to faster leak detection and repair), which may also contribute to lower earnings.

Given the above, regulatory reforms may be needed to encourage investment in AMI, particularly in the following areas:

- *Cost recovery*: State regulators should consider ways to promote regulatory certainty with respect to cost recovery for AMI. One option is for regulators to issue policy statements in support of AMI, which may increase confidence that AMI investment costs will be recoverable. Regulators should consider allowing cost recovery through a tracking mechanism, which would reduce delays and associated problems that can discourage investment.
- *Decoupling*: States that have not already done so should consider adopting decoupling policies that break the link between LDC revenues and sales. This would remove the incentive, arising under traditional regulatory approaches, for LDCs to maximize pipeline throughput. Where traditional approaches are used, LDCs are unlikely to invest in AMI and other technologies that promote natural gas conservation, because doing so would reduce their revenues.
- *Lost and unaccounted-for gas*: Regulators should also consider changing the way in which LDCs recover the cost of natural gas that is lost during transportation due to leakage and/or other factors. Under current cost recovery frameworks, reduced natural gas losses often translate into

lower revenues for LDCs, discouraging them from investing in AMI and other technologies that reduce gas leaks.

The above reforms would remove disincentives for investment in AMI, but would not necessarily incentivize LDCs to invest. To maximize investment, state regulators may need to adopt other policies, such as performance incentive schemes that reward LDCs for deploying AMI. However, because those policies and other reforms may present risks, each should be the subject of careful assessment, taking into account local conditions.

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1. INTRODUCTION

Natural gas use has grown significantly in the United States (U.S.) in recent years, rising by approximately sixty-seven percent over the last three decades.[1] This trend is expected to continue in the future, with the U.S. Energy Information Administration forecasting that natural gas use could rise by up to fifty-three percent between 2016 and 2050, driven primarily by increased gas demand from industry.[2] Strong demand is also expected in the residential and commercial sectors, which already use large amounts of natural gas in heating, cooking, and other applications. According to the Energy Information Administration, the residential and commercial sectors used in excess of 7.5 trillion cubic feet of natural gas in 2017, accounting for over twenty-eight percent of total gas consumption in the U.S.[3]

Increasing use of natural gas in residential, commercial, and other applications will have major implications for efforts to address climate change. Proponents often assert that substituting natural gas for other fossil fuels will have climate benefits as gas combustion results in fewer greenhouse gas emissions than both coal and oil.[4] However, the combustion of natural gas is still a major source of emissions, releasing approximately 116 pounds of carbon dioxide per million

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[1] U.S. Energy Information Administration, *U.S. Natural Gas Total Consumption*, NATURAL GAS, http://perma.cc/Z42J-X6Q7 (last updated May 31, 2018) (estimating that total natural gas consumption in the U.S. increased from approximately 16,221 billion cubic feet (bcf) in 1986 to 27,090 bcf in 2017).

[2] U.S. Energy Information Administration, *Natural Gas: Use by Sector*, ANNUAL ENERGY OUTLOOK 2018, https://perma.cc/BNV7-QWY9?type=image (last visited June 25, 2018) (indicating that total natural gas consumption was 27.50 trillion cubic feet (tcf) in 2016 and forecasting that consumption could reach 42.21 tcf in 2050 under a "High Oil and Gas Resource and Technology Case"). U.S. ENERGY INFORMATION ADMINISTRATION, ANNUAL ENERGY OUTLOOK 2018 10 (2018), http://perma.cc/K6RF-HUJQ [hereinafter Annual Energy Outlook] (indicating that, "[i]n the High Oil and Gas Resource and Technology Case, lower costs and higher resource availability than in the Reference case allow for higher production at lower prices").

[3] U.S. Energy Information Administration, *Natural Gas Consumption by End Use*, NATURAL GAS, http://perma.cc/U6ZV-GZQ3 (last updated May 31, 2018).

[4] *See e.g.*, International Gas Union, *Natural Gas is the Cleanest Fossil Fuel*, https://perma.cc/VA4J-A5TN (last visited June 25, 2018). The combustion of natural gas emits approximately fifty percent less carbon dioxide than coal combustion. *See* Energy Information Administration, *How much carbon dioxide is produced when different fuels are burned?*, FREQUENTLY ASKED QUESTIONS, https://perma.cc/EAJ7-9Q2F (last updated June 8, 2018).

British thermal units of energy.[5] Carbon dioxide is also emitted throughout the natural gas production process, primarily due to gas flaring, while gas leaks and venting during production result in methane emissions.[6] Those emissions make a significant contribution to climate change as methane is a highly potent greenhouse gas, trapping eighty-four times more heat in the earth's atmosphere than carbon dioxide (on a pound for pound basis) in the first twenty years after it is released.[7] Recent studies suggest that, with current methane emission rates, switching from coal to natural gas may have no climate change benefits.[8]

Recognizing the natural gas sector's contribution to climate change, independent bodies and some governments have called for reductions in gas use.[9] Many analysts see this as necessary to achieve the 2015 Paris Agreement's goal of "[h]olding the increase in the average global temperature to well below 2°C above pre-industrial levels."[10] Remaining within the 2°C threshold will require a dramatic cut in greenhouse gas emissions, on the order of eighty percent by 2050, which will likely necessitate the phasing out of natural gas (and other fossil fuel) use in a range of

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5 *Id*.

6 EPA, INVENTORY OF U.S. GREENHOUSE GAS EMISSIONS AND SINKS: 1990 – 2016 3-77 – 3-79 (2018), http://perma.cc/5CV8-ZH4B. *See also* Ramón A. Alvarez et al., *Assessment of Methane Emissions from the U.S. Oil and Gas Supply Chain*, SCIENCE (June 21, 2018), https://perma.cc/EM3H-PS2C.

7 Rajendra K. Pachauri et al., *Climate Change 2014: Synthesis Report*, *in* FIFTH ASSESSMENT REPORT OF THE INTERGOVERNMENTAL PANEL ON CLIMATE CHANGE 87 (Core Writing Team et al. eds., IPCC 2014), https://perma.cc/DK4M-FBRLhttps://perma.cc/DK4M-FBRL.

8 STEFFEN JENNER & ALBERTO J. LAMADRID, SHALE GAS VS. COAL 7 (2012), https://perma.cc/NBG3-X2JY (indicating that, if upstream methane emission rates exceed two to three percent, switching from coal to natural gas will have no climate benefits). Several recent lifecycle analyses suggest that emission rates may exceed the two to three percent threshold. *See e.g.,* Alvarez et al., supra note 6, at 1 (June 21, 2018) (estimating that methane emissions were "equivalent to 2.3% of gross U.S. gas production" in 2015); Robert W. Howarth et al., *Methane and the Greenhouse Gas Footprint of Natural Gas From Shale Formations*, 106 CLIMATE CHANGE 679, 683 (2011) (finding that, "[c]ompared to coal, the footprint of shale gas is at least 20% greater and perhaps more than twice as great on the 20-year time horizon"); Mohan Jiang et al., *Lifecycle Greenhouse Gas Emissions from Marcellus Shale Gas*, 6 ENVIRON. RES. LETT. 0.4014 (2011) (finding that, on a lifecycle basis, greenhouse gas emissions from electricity generation using shale gas are twenty to fifty percent higher than those from electricity generation using coal). *But compare* Ian J. Laurenzi & Gilbert R. Jersey, *Life Cycle Greenhouse Gas Emissions and Freshwater Consumption of Marcellus Shale Gas*, 49 ENVIRON. SCI. TECHNOL. 4896 (2013) (estimating that lifecycle emissions associated with shale gas are fifty-three percent lower than those associated with coal).

9 *See e.g.*, See U.S. Mid-Century Strategy for Deep Decarbonization (2016), https://perma.cc/6ZZR-PXJE; JAMES H. WILLIAMS ET AL., PATHWAYS TO DEEP DECARBONIZATION IN THE UNITED STATES (2015), https://perma.cc/DHH8-5DBE.

10 UNFCCC, Conference of the Parties on its Twenty-First Session, Adoption of the Paris Agreement, Decision 1/CP.21, U.N. Doc. FCCC/CP/2015/L.9/Rev.1 (Dec. 12, 2015) [hereinafter Paris Agreement].

power, residential, commercial, and other applications, at least unless carbon capture and sequestration technology accompanies these uses.[11]

This paper explores opportunities to promote more efficient natural gas use in the residential and commercial sectors, through deployment of advanced metering infrastructure (AMI), consisting of state-of-the-art gas meters connected to a wireless network that supports two-way communication. Such systems enable hourly or daily natural gas usage figures to be collected and transmitted to customers in real-time, thereby encouraging greater conservation,[12] leading to a reduction in natural gas use and associated greenhouse gas emissions.[13] Additional emissions reductions may also occur due to improved management of the natural gas pipeline system. For example, the wireless communication networks deployed with AMI can be used to collect data from methane and other sensors on the pipeline system, enabling natural gas leaks to be detected and repaired more quickly than if sensor data must be collected manually.[14]

Despite its many benefits, AMI has yet to be widely deployed on the natural gas distribution system in the U.S. Past research suggests that this may be partly due to market factors discouraging investment in AMI by distribution system operators (local distribution companies or LDCs).[15] There has not, however, been any comprehensive assessment of the impact of regulation on AMI investment. This paper is intended to fill that gap, exploring whether and how the regulation of LDC rates affects incentives to invest in AMI. The paper begins with an introduction to the natural gas distribution system and the metering technologies used in it in Part 2. Part 3 then discusses the benefits and drawbacks of deploying AMI on the natural gas distribution system. Based on recent experience with AMI deployment, Part 4 analyzes the impact of rate regulation on LDC incentives, and Part 5 identifies possible reforms to address disincentives for investment in AMI. Part 6 concludes.

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[11] *See* Williams et al., *supra* note 9, at 14 & 20.

[12] In this paper, the term "conservation" is used to refer to reductions in natural gas use, resulting from changes in customer behavior.

[13] *See infra* Part 3.1.

[14] *See infra* Part 3.1.

[15] *See e.g.*, NEIL STROTHER & CAROL STIMMEL, PIKE RESEARCH, ADVANCED METERING INFRASTRUCTURE AND AUTOMATIC METER READING DEPLOYMENTS FOR GAS UTILITIES: GLOBAL MARKET ANALYSIS AND FORECASTS (2012), *available at* https://perma.cc/3UZF-6PB5.

2. NATURAL GAS DISTRIBUTION

2.1 Natural Gas Distribution 101

Consistent with industry parlance, in this paper, the term "distribution" is used to refer to the third and final step in the process of delivering natural gas to residential and commercial customers. Natural gas is delivered via a network of pipelines, extending approximately 2.5 million miles across the U.S.[16] The pipeline network is generally divided into three parts as follows:

1. *the gathering system*, which consists of small diameter, low pressure pipelines that transport natural gas from the site at which it is produced to centralized processing and storage facilities;
2. *the transmission system*, which consists of large, high capacity pipelines used to transport natural gas from processing and storage facilities to large volume customers and LDCs; and
3. *the distribution system,* which consists of smaller pipelines used by LDCs to transport natural gas to residential, commercial, and some industrial customers.[17]

At the time of writing, there were approximately 1,350 LDCs in the U.S., each of which operates its own distribution pipeline system.[18] Due to the high cost of developing pipeline infrastructure, and in order to avoid unnecessary duplication thereof, states historically granted LDCs exclusive rights to distribute natural gas within their service territories.[19] Distribution was initially bundled with the sale of natural gas, meaning that customers had to purchase gas from their LDC, and were charged a single price for both the commodity and the distribution service.[20] Recently, however, LDCs in some areas have been required to unbundle their services, such that

[16] Pipeline and Hazardous Materials and Safety Administration (PHMSA), *Pipeline Miles and Facilities 2010+*, PIPELINE MILEAGE AND FACILITIES, https://perma.cc/HN3U-SSCD (select "2010+ Pipeline Miles and Facilities" hyperlink) (last updated Oct. 31, 2017) (indicating that there were 2,235,727 miles of distribution pipelines, 300,644 miles of transmission pipelines, and 18,357 miles of gathering pipelines in the contiguous U.S. in 2017).

[17] Pipeline and Hazardous Materials Safety Administration (PHSMA), *Gathering Line*, PIPELINE GLOSSARY, https://perma.cc/HPA9-VSC3 (last visited May 15, 2018); PHMSA, *Transmission Line*, PIPELINE GLOSSARY, https://perma.cc/HPA9-VSC3 (last visited May 15, 2018); PHMSA, *Distribution Line*, PIPELINE GLOSSARY, https://perma.cc/HPA9-VSC3 (last visited May 15, 2018).

[18] *Id*. (indicating that 1,352 LDCs were operating in the U.S. in 2017). Most LDCs are investor owned utilities regulated by state authorities. See *infra* Part 4.2.

[19] FRED BOSSELMAN ET AL., ENERGY, ECONOMICS AND THE ENVIRONMENT: CASES AND MATERIALS 504 – 506 (2000).

[20] Energy Information Administration, *Natural Gas Customer Choice Programs*, NATURAL GAS EXPLAINED, https://perma.cc/62HH-4NBP (last updated Jan. 3, 2018).

customers can purchase gas from a third party and have it delivered by the LDC.[21] Thus, in areas where unbundling has occurred, LDCs are no longer the sole (monopoly) supplier of natural gas, but continue to have a monopoly in gas distribution.

All LDCs use basically the same system to distribute natural gas, relying on a network of large distribution mains,[22] which transport gas to smaller service lines connected to individual customers' premises.[23] In 2017, there were 1,308,715 miles of distribution mains, and 927,012 miles of service lines in operation in the U.S.[24] Each distribution main and service line is equipped with several pumping and regulating stations that control the flow of natural gas in the pipeline system. At the point where the system connects to customers' piping, meters are installed to measure the amount of natural gas supplied to individual premises.

2.2 Distribution and Metering

Throughout the distribution system, meters are used to measure natural gas usage at individual premises, and bill customers. Most LDCs historically used diaphragm meters, which consist of two chambers that alternate between filling and expelling natural gas, driving an odometer-like counter.[25] LDC technicians were dispatched on a regular basis – usually monthly or quarterly – to read the odometer and determine the amount of natural gas used during the period.[26] This process was highly resource intensive, requiring LDCs to employ dozens of meter reading technicians, and maintain a large vehicle fleet for use in visiting customers' premises. Visits often failed to yield reliable natural gas usage figures, either because meters could not be

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[21] *Id*.
[22] *See* PHMSA, *Main*, PIPELINE GLOSSARY, https://perma.cc/4BH4-L78K (last visited July 2, 2018) ("A main is a natural gas distribution line that serves as a common source of supply for more than one service line").
[23] *See* PHMSA, *Service Line*, PIPELINE GLOSSARY, https://perma.cc/3J7K-SDQP (last visited July 2, 2018) ("A service line is a distribution line that transports gas from a common source of supply to (1) a customer meter or the connection to a customer's piping, whichever is farther downstream, or (2) the connection to a customer's piping if there is no customer meter").
[24] PHMSA, *Pipeline Mileage and Facilities*, DATA AND STATISTICS, https://perma.cc/JS2H-5U84 (follow "2010+ Pipeline Miles and Facilities" hyperlink) (last visited July 2, 2018).
[25] RYAN KERR & MEREDITH TONDRO, RESIDENTIAL FEEDBACK DEVICES AND PROGRAMS: OPPORTUNITIES FOR NATURAL GAS 16 (2012), *available at* https://perma.cc/LZC7-MPBP. *See also* JAMES THOMSON, FUNDAMENTALS AND PRINCIPLES OF DIAPHRAGM METERS (2004), https://perma.cc/5T8Y-E4X4.
[26] Diaphragm meters record cumulative gas usage over time. Thus, to determine gas usage during a specific period, the technician would subtract the last meter reading from the current reading. *See* Kerr & Tondro, *supra* note 25, at 16.

read manually, or due to human error in the meter reading process. As a result, LDC bills were routinely based on estimated natural gas use, which often led to under- or over-charging of customers.

To address these problems, in the 1980s, LDCs began to deploy automatic meter reading (AMR) technologies that enable metering data to be collected remotely.[27] Most AMR technologies use short-range radio signals to transmit metering data, which is collected by technicians walking or driving past with a receiver.[28] This eliminates the need for manual meter reads, reducing the potential for human error in the meter reading process, and enabling LDCs to reduce costs (e.g., by employing fewer technicians to read meters).

Seeking to further reduce metering costs, LDCs in some areas have recently deployed AMI, incorporating more advanced data collection and transmission systems. AMI uses so-called "smart meters" to collect time-synchronized interval meter data – i.e., reflecting natural gas use during a specified time period (typically one hour or day) – and automatically transmits it to the LDC via a wireless network.[29] Most networks use long-range radio signals which enable two-way communication, meaning that data can be sent both from and to the meter.[30] The data is transmitted via a series of fixed receivers, similar to cell phone towers, that connect the meter directly with the LDC, eliminating the need for "in-the-field" collection (i.e., using handheld or vehicle mounted devices).[31] This offers a number of benefits, reducing the costs incurred by LDCs in collecting metering data, and improving the accuracy of the data collected. These, and other benefits of AMI, are discussed in Part 3.1 below.

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[27] *Id*. *See also* Jim Roche, *AMR vs AMI*, ELECTRIC LIGHT & POWER (Oct. 1, 2008), https://perma.cc/N6K2-CMXZ.
[28] *Id*.
[29] Consolidated Edison Company of New York, Inc. (Con Edison), Advanced Metering Infrastructure Business Plan 67 (2015), https://perma.cc/8HCT-E454 ("Advanced Metering Infrastructure (AMI) is the term denoting electricity and gas meters that measure and record usage data at a minimum in hourly intervals, and provide usage data to both consumers and energy companies at increased frequencies. AMI meters are "smart" and have additional interoperability features, such as 2-way metering, communications enablement with customer equipment, and other capabilities").
[30] Kerr & Tondro, *supra* note 25, at 16.
[31] *Id*.

3. USING AMI IN NATURAL GAS DISTRIBUTION

3.1 Why Use AMI? Technical Capability and Associated Benefits

Deploying AMI on the natural gas distribution system has the potential to deliver widespread benefits to LDCs, their customers, and society as a whole. The extent to which those benefits are realized will depend on, among other things, the precise AMI technology deployed and where and how it is used. In most situations, however, AMI deployment is likely to yield the following benefits:

Enhanced gas usage data: As explained in Part 2.2 above, AMI systems typically use smart-meters to collect time synchronized interval usage data, which is more granular than that collected by traditional meters.[32] Whereas traditional meters use a revolving counter to record natural gas use cumulatively, smart meters are equipped with digital systems that record usage during a specified time period (e.g., hourly or daily).[33] The data can be made available to customers in real-time through a web portal or in-home display and used to generate email or phone alerts when natural gas usage exceeds a pre-determined level.[34] This is likely to encourage customers to conserve natural gas because, as the California Public Utilities Commission ("CPUC") recently observed, "when a largely invisible process (gas or electricity usage) is made more visible, there is a measurable conservation response."[35] Indeed, in the electricity sector, the provision of real-time

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[32] Con Edison, *supra* note 29, at 67.
[33] *Id*.
[34] *See generally* Kerr & Tondro, *supra* note 25, at 25. Alerts could be delivered in both therms and dollars – e.g., "Your December natural gas use is over 200 therms (about $85)" – and be accompanied by recommendations for reducing usage. See *id*.
[35] CPUC, Decision on Application of Southern California Gas Company for Approval of Advanced Metering Infrastructure, Decision 10-04-027 (April 8, 2010). *See also*, Kerr & Tondro, *supra* note 25, at 4-6 & 16 (arguing that providing customers with real-time usage data enables them "to make more informed short and long-term decisions about their energy use"); ITRON, GAS AMI: A MARKET PRIMED FOR INNOVATION 2 (2014), *available at* https://perma.cc/WMV3-794G ("Empowering utility customers with up-to-the-minute gas usage information actively engages them in their consumption decisions and subsequently lowers their gas bills, in turn helping the utility to manage overall demand"); ORACLE UTILITIES, SMART METERING FOR ELECTRIC AND GAS UTILITIES 2 (2011), available at https://perma.cc/5HFD-BSDL ("Smart Metering [i.e., using AMI systems] gives customers real-time consumption information . . . [This] help[s] consumers change their consumption, should they wish to do so, without having to wait for the end of month or end of the quarter to view the results from conservation initiatives. Displays tailored to the specific needs of the user, such as those comparing current use with neighborhood averages or with consumption in previous months, may help consumers further focus on conservation").

data has been shown to reduce usage by five to fifteen percent in some areas.[36] While reductions in natural gas use are likely to be smaller because there are fewer opportunities for behavioral change – i.e., because gas is used in fewer applications – recent studies suggest that savings on the order of one to four percent are possible.[37] Those savings will translate into lower natural gas bills for customers. As less natural gas must be delivered to customers, there will be reduced pressure on the pipeline system, minimizing the risk of supply constraints (i.e., where the pipeline is operating at full capacity). Supply constraints can also be avoided by establishing demand response programs that encourage customers to shift natural gas use away from peak periods.[38] Deploying AMI has been shown to facilitate the use of such programs, including by enabling LDCs to implement time-of-use based rates that vary throughout the day, in line with total natural gas demand.[39] Such rates are likely to encourage customers to reduce their natural gas use during high demand periods. This, combined with reductions in total natural gas usage (see above) and improvements in system management (see below), may enable LDCs to defer or avoid investment in new pipelines, reducing costs and improving environmental quality. Other environmental benefits may also be achieved, for example, through a reduction in greenhouse gas emissions associated with the transportation and use of natural gas.

Remote meter reading and shut-off: As noted in Part 2.2 above, whereas traditional meters must be read manually by technicians, AMI automatically transfers meter data to the LDC using wireless communication systems. Those systems generally allow for two-way communication, enabling the LDC to check the status of meters and shut-off service remotely, without having to

[36] Kerr & Tondro, *supra* note 25, at ix.
[37] *Id*. at 17. *See also* CPUC, Decision on Application of Southern California Gas Company for Approval of Advanced Metering Infrastructure, D10-04-027 (Apr. 8, 2010) (upholding Southern California Gas Company's finding that deploying an AMI system would result gas savings of approximately one percent over the life of the system and concluding that this "do[es] not represent the upper bound of what is achievable in the way of gas conservation . . . but rather a moderate middle ground"). Some overseas studies have found even higher conservation rates, on the order of seven to fourteen percent. *See e.g.,* Matteo Di Castelnuovo & Elena Fumagalli, *An Assessment of the Italian Smart Gas Metering Program*, 60 ENERGY POLICY 714, 715 (2013).
[38] For a discussion of demand response in the natural gas sector, *see* JURGEN WEISS ET AL., DEMAND RESPONSE FOR NATURAL GAS DISTRIBUTION: OPPORTUNITIES AND CHALLENGES (2018), https://perma.cc/QN3C-MF9H.
[39] Matteo Di Castelnuovo & Elena Furmagalli, *An Assessment of the Italian Smart Gas Metering Program*, 60 ENERGY POLICY 714, 715-716 (2013). *See also* U. S. DEPARTMENT OF ENERGY, CUSTOMER ACCEPTANCE, RETENTION, AND RESPONSE TO TIME-BASED RATES FROM THE CONSUMER BEHAVIOR STUDIES (2016), https://perma.cc/834H-46LN.

send a technician into the field.[40] This is likely to generate significant cost savings for LDCs, enabling them to reduce the number of technicians employed, as well as the size of their vehicle fleet.[41] For example, the Consolidated Edison Company of New York ("Con Edison") has estimated that replacing its existing metering system with AMI would enable an eighty percent reduction in the size of its vehicle fleet, taking approximately 100 vehicles off the road.[42] This would have environmental benefits, with Con Edison estimating that it would save over 56,000 gallons of gasoline annually, avoiding the emission of approximately 506 metric tons of carbon dioxide equivalent.[43]

Increased meter accuracy: As AMI automatically transfers meter data to the LDC, inaccuracies due to misreads and transcription errors are significantly reduced, compared to systems involving manual meter reading. Additionally, compared to traditional (manual-read) meters, AMI systems are less prone to mechanical problems that can impair accuracy. Most traditional meters consist of diaphragms that expand and contract in response to the flow of natural gas, moving levers connected to a crank shaft which drives an odometer-like counter.[44] These counters often under-record natural gas flows because the repetitive movement of parts causes wearing and friction.[45] However, that is not an issue with smart meters, which do not have moving parts.

Reduced gas losses: Rates for natural gas distribution currently include an allowance for so-called "lost and unaccounted-for gas," reflecting the difference between the amount of gas metered into a pipeline system and the amount metered out of the system.[46] This difference may be caused by a variety of factors, including meter inaccuracies,[47] which (as discussed above) can be reduced

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[40] Itron, *supra* note 35, at 2.
[41] DAVID ANGLIN, ATMOS ENERGY CORPORATION, AMI FOR GAS UTILITIES (2012), https://perma.cc/YB7K-HMTC (estimating that, by replacing traditional (manual-read) meters with AMI technologies, an LDC with one million customers could realize annual cost savings of over $10.8 million). *See also* Oracle Utilities, *supra* note 35, at 10 (Switching to AMI systems enables utilities to employ "[f]ewer meter readers, which means lower total costs for salary, benefits, and workers compensation").
[42] Con Edison, *supra* note 29, at 12 - 13.
[43] *Id*.
[44] Kerr & Tondro, *supra* note 25, 16.
[45] ROBERT BENNETT, FUNDAMENTAL PRINCIPLES OF DIAPHRAGM METERS 4 (2004), https://perma.cc/MV5K-XK2J.
[46] *See* ROMANY WEBB, LOST BUT NOT FORGOTTEN: THE HIDDEN ENVIRONMENTAL COSTS OF COMPENSATING PIPELINES FOR NATURAL GAS LOSSES 7 (2015), *available at* https://perma.cc/HPC6-L8ZP. Note that an allowance for lost and unaccounted-for gas is also currently included in natural gas transmission rates.
[47] *Id*.

by deploying AMI. AMI may also prove useful in addressing other causes of lost and unaccounted-for gas, including leaks and pressure and temperature changes along the pipeline system.[48] For example, the communication networks deployed with AMI can be used to collect pressure and temperature readings and trigger alerts if they fall outside pre-defined thresholds, enabling the LDC to take remedial action.[49] Thus, the use of AMI may avoid adverse pressure- and temperature-related events that contribute to lost and unaccounted-for gas, leading to lower rates for customers.

Avoided pipeline corrosion: AMI systems can also collect data from voltage sensors which are used as part of cathodic protection[50] monitoring systems to identify natural gas pipelines at risk of corrosion. Sensor readings are currently collected manually by LDC technicians one to two times per year.[51] In the future, however, the communication networks deployed with AMI could collect and transmit sensor data to the LDC in real-time.[52] This would enable remedial action to be taken quickly, avoiding widespread corrosion which can lead to pipeline ruptures, and thereby resulting in cost savings for the LDC. Avoiding corrosion also has environmental benefits, reducing the potential for pipeline leaks, which contribute to methane emissions and thereby accelerate climate change.

Improved leak detection: Deploying AMI on natural gas pipeline systems can also result in faster and more accurate leak detection. Currently, most leaks are detected through periodic surveys, whereby LDC technicians walk or drive along the pipeline route while carrying a methane sensor and/or collect data from sensors installed throughout the pipeline system. Surveys are often conducted just once per year, or even less frequently,[53] leading to delays in leak

[48] *Id*.
[49] Itron, *supra* note 35, at 2.
[50] Cathodic protection is a technique used to prevent the corrosion of underground metal pipelines. See PHMSA, *Fact Sheet: Cathodic Protection*, https://perma.cc/5B8S-TLGQ (last updated Oct. 24, 2017).
[51] Philip Holdbrooks, *Effective Integrity Management with Advanced Communication Technologies*, PIPELINE & GAS JOURNAL (April 2012), https://perma.cc/Z8RH-FEAH.
[52] *Id*. *See also* Anglin, *supra* note 41, at 4.
[53] Federal regulations currently only require distribution pipelines in business districts to be surveyed for leaks annually and allow other pipelines to be surveyed every three to five years. 49 C.F.R. §§ 192.721(b) & 192.723(b).

detection.[54] Those delays could be avoided by using AMI to monitor natural gas flows throughout the pipeline system. By analyzing flow data, LDCs can identify possible leaks (e.g., where natural gas flows suddenly and inexplicably decline), and send technicians into the field to investigate. In more advanced systems, the location of leaks can be determined remotely, by using the communication networks deployed with AMI to collect and transmit data from methane sensors in real-time. The network could be configured such that, if a sensor detects methane in the air, an alarm is triggered indicating the sensor reading and location, enabling the LDC to investigate and take any necessary remedial action quickly. Again, this would have significant environmental benefits, reducing methane emissions that contribute to climate change.[55]

3.2 AMI as a Non-Pipes Alternative

As the foregoing discussion suggests, deploying AMI on the natural gas distribution system is likely to contribute to a reduction in both total and peak gas demand (i.e., by encouraging greater conservation and demand response), as well as an increase in supply (i.e., due to lower rates of gas leakage). Thus, AMI deployment may offer a way of managing the anticipated growth in natural gas consumption,[56] without the need for new pipeline construction. Of course, whether new construction can be avoided by deploying AMI will depend on local conditions, including current and anticipated future levels of pipeline throughput. As a general rule, AMI deployment is likely to prove most useful in areas where pipelines are at or approaching maximum throughput, and only modest demand growth is expected in the near future. In such cases, even the relatively small reductions in natural gas use associated with AMI deployment (i.e., one to four percent) may enable new pipeline construction to be avoided, at least in the short-term. This would provide additional time for LDCs to pursue other measures that further reduce natural gas use and thereby avoid the need for new pipelines in the long-term.

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[54] ROMANY WEBB. SAFETY FIRST, ENVIRONMENT LAST: IMPROVING REGULATION OF GAS PIPELINE LEAKS 9-10 (2015), *available at* https://perma.cc/3YSQ-WHSZ.

[55] The author is not aware of any studies quantifying the potential for reduced natural gas leakage and associated methane emissions. However, given the prevalence of pipeline leaks, the reductions could be significant. For a discussion of the extent of leaks, *see* Environmental Defense Fund, *Local Leaks Impact Global Climate*, OIL AND GAS, https://perma.cc/593Z-FCJS (last visited July 9, 2018).

[56] Annual Energy Outlook, *supra* note 2.

Avoiding new pipeline construction will be important to achieve climate change goals, including the under 2°C target set in the Paris Agreement.[57] A number of analysts have recognized that, to limit warming to 2°C or less, greenhouse gas emissions must be reduced by at least eighty percent by 2050, which will likely necessitate the phasing out of natural gas and other fossil fuel use (at least without CCS).[58] As natural gas pipelines are long-lived assets, typically operating for fifty years or more, new construction threatens to "lock-in" use beyond mid-century. As one recent study noted:

> Investors in [new] facilities will want to maximize their investment return by sustaining natural gas markets as long as possible . . . As more people and institutions invest in natural gas, political pressure to sustain its use grows. It will become more and more difficult to achieve long-range greenhouse gas reduction goals.[59]

Moreover, constructing new natural gas pipelines risks creating stranded assets that will not be needed in the future, imposing substantial costs on LDCs and their customers. Recognizing this, some LDCs have begun exploring so-called "non-pipeline alternatives" that would enable natural gas demand to be met in the short-term, without locking in long-term use. One example is Con Edison, which operates the natural gas distribution pipeline system in New York City and Westchester County. In December 2017, Con Edison issued a request for proposal for "innovative and substantial non-pipeline projects that can reduce . . . gas load or [augment] gas supplies."[60] AMI could, as discussed above, fulfil this role.

3.3 Issues Associated with AMI Deployment

As with any new technology, deploying AMI presents various challenges and risks, which may somewhat offset the above benefits. The most significant risks are arguably economic as AMI deployment requires a large upfront investment to purchase and install smart meters that can cost

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[57] Paris Agreement, *supra* note 10, Art. 2(1)(a).

[58] *See e.g.*, U.S. Mid-Century Strategy for Deep Decarbonization, *supra* note 9; Williams et al., *supra* note 9.

[59] STEVE WEISSMAN, CENTER FOR SUSTAINABLE ENERGY, NATURAL GAS AS A BRIDGE FUEL: MEASURING THE BRIDGE 10 (2016), *available at* https://perma.cc/PC9E-WQJ4.

[60] *See* Con Edison, *Non-Pipeline Solutions*, BUSINESS OPPORTUNITIES, https://www.coned.com/en/business-partners/business-opportunities/non-pipeline-solutions (last visited Dec. 19, 2017).

over $100 per unit.[61] Thus, for a medium-sized LDC serving one million customers, an investment in excess of $100 million may be required.[62] That does not include the cost of establishing a communication network to relay data to and from the meter, nor the cost of information technology (IT) platforms needed to manage metering data, both of which can be significant.[63] As an example, Con Edison has estimated that deploying AMI on its system would require a $375 million investment in communication and IT systems, on top of the $777 million invested in smart metering devices.[64] According to Con Edison, in total, deploying AMI would cost $1.66 billion over twenty years (on a net present value (NPV) basis).[65] Those costs would be outweighed by the benefits of AMI deployment, which Con Edison estimated at $2.81 billion over twenty years (on a NPV basis).[66] The payback period would be at least ten years, however.[67]

Even if AMI deployment is economically viable, LDCs may encounter other difficulties. For example, AMI deployment can be technically challenging, in part because it involves a switch to electronic meters, which require a power source.[68] Most electronic natural gas meters are powered by batteries,[69] which often results in utilization constraints because power use must be minimized to increase battery life.[70] Under optimal conditions, batteries can last for fifteen to

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[61] Con Edison, *supra* note 29, at 57 (indicating that smart gas meters would cost $60 to purchase and at least $40 to install). Other studies have reported higher per-unit costs. *See e.g.*, Kerr & Tondro, *supra* note 25, at 16 (indicating that smart meters "can range in price from about $100 to over $400 depending on design").

[62] LDCs range in size, with some serving over five million customers, and others less than 500,000. See American Gas Association, Ranking of Companies by Total Sales Customers (2016), https://perma.cc/M99R-M8QQ.

[63] Costs are likely to vary depending on, among other things, the design of the communication network. For a discussion of possible communication network designs, *see* Anglin, *supra* note 41, at 2.

[64] Con Edison, *supra* note 29, at 53. The quoted figures reflect the cost of deploying AMI for both electricity and gas customers. Con Edison did not provide an estimate of the costs of deploying AMI for gas customers only.

[65] *Id*. at 39.

[66] *Id*.

[67] *Id*.

[68] Oracle Utilities, *supra* note 35, at 6.

[69] Electricity is typically not available in the locations where gas meters are installed and cannot be provisioned for safety and/or other reasons. *See* Joseph Turgeon, *AMI Trends and Developments in Gas and Water Utilities*, METERING AND SMART ENERGY INTERNATIONAL (Aug. 2, 2013), https://perma.cc/5CAP-P2DS.

[70] Ramyar Rashed Mohassel et al., *A Survey on Advanced Metering Infrastructure*, 63 ELECTRICAL POWER & ENERGY SYSTEMS 473, 475 (2014)

twenty years, but may sometimes have to be replaced sooner, which can be challenging and significantly add to total AMI system costs.[71]

Technical and other challenges also arise from the large amount of data collected by AMI systems. Whereas natural gas meters were historically read once per month or less frequently, AMI meter readings may be collected every day or hour. Thus, for each customer, twelve annual data sets (i.e., reflecting monthly natural gas use) may be replaced by up to 8,760 (i.e., reflecting hourly use).[72] To manage and store the additional data, LDCs must invest in new hardware and software systems, and develop new procedures to ensure data processing occurs smoothly.[73]

The collection of additional data through AMI systems may also raise privacy concerns, though this is less of an issue in the natural gas sector than the electricity sector. Privacy experts have warned that metering data revealing hourly electricity use can enable "customer profiling," for example, to determine whether a given property is occupied, the number of occupants, their travel and work habits, and even food consumption patterns.[74] Fewer conclusions can be drawn from natural gas metering data, primarily because most use occurs in "background" appliances (e.g., central heating systems) that remain on for long periods and thus do not reveal customer behavior as clearly as electrical appliances, which are switched on and off frequently.[75] Nevertheless, natural gas metering data may still prove valuable to third parties and thus ideally should be encrypted or otherwise protected, which adds to the cost and complexity of AMI systems.[76] Even if data is adequately protected, the risk (or the perception of risk) of misuse may cause some customers to reject AMI systems, reducing the benefits of deployment.[77]

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[71] *Id*. at 483. *See also* Turgeon, *supra* note 69.
[72] Oracle Utilities, *supra* note 35, at 8.
[73] *Id*.
[74] *See e.g.*, Mohassel et al., supra note 70, at 478; Mark P. McHenry, *Technical and Governance Considerations for Advanced Metering Infrastructure / Smart Meters: Technology, Security, Uncertainty, Costs, Benefits, and Risks*, 59 ENERGY POLICY 834, 839 (2013).
[75] This is also why AMI deployment is expected to lead to lower levels of conservation in the natural gas sector than the electricity sector. *See supra* Part 3.1.
[76] *See generally* Geert Deconinck, *Metering, Intelligent Enough for Smart Grids*? *in* Securing Electricity Supply in the Cyber Age 143, 1453 (Zofia Lukszo et al. eds., 2010).
[77] For example, if some customers refuse to allow installation of AMI, the LDC may be forced to continue reading their meters manually, reducing the cost savings from switching to remove-read meters.

4. EXPERIENCE WITH AMI IN NATURAL GAS DISTRIBUTION

4.1 Current Deployment of AMI

Despite its many benefits, AMI is yet to be widely deployed on natural gas distribution systems in the U.S., though interest in the technology is growing in some areas. In California, for example, AMI deployment is being pursued as a means of furthering the state's energy conservation goals.[78] California's 2003 State Energy Plan called for the adoption of "strategies for increasing conservation . . . to minimize increases in electricity and natural gas demand."[79] Efforts initially focused on conserving electricity, with the CPUC and other state agencies calling for "[a]ll [electric] customers [to] be provided with an advanced metering system," which will enable them to better manage usage.[80] As several of the state's electric utilities also serve as LDCs, advanced metering systems were simultaneously deployed on the electricity and natural gas networks in some areas, prompting more widespread interest in gas-side opportunities. In 2010, the CPUC issued a statement expressing support for AMI deployment by LDCs, arguing that this will "expand[] the information and tools available to consumers in order to empower them to manage their [natural gas] usage."[81] California's largest LDC – Southern California Gas Company ("SoCalGas") – subsequently began deploying AMI throughout its natural gas distribution system.[82] AMI has also been deployed on the natural gas distribution systems of two other Californian LDCs – Pacific Gas and Electric Company ("PG&E")[83] and San Diego Gas and Electric Company ("SDG&E").[84]

[78] State of California, Energy Action Plan (May 8, 2003), https://perma.cc/RQ36-SH4N.
[79] *Id*. at 4.
[80] California Energy Commission, CPUC, and Consumer Power and Conservation Financing Authority, California Demand Response: A Vision for the Future 3 (June 5, 2003), https://perma.cc/FUZ9-FZ6F. See also *See* CPUC, Decision on Application of Southern California Gas Company for Approval of Advanced Metering Infrastructure 24 (Apr. 8, 2010) (noting that past policy "statements about the desirability of AMI systems have focused on their usefulness as a tool for managing electric usage").
[81] *Id*. at 25.
[82] SoCalGas, *Advanced Meter*, https://perma.cc/U3BA-CG2K (last visited July 3, 2018).
[83] PG&E, *SmartMeter™ network*, https://perma.cc/CAU9-3BXX (last visited July 3, 2018).
[84] SDG&E, *About Smart Meters*, https://perma.cc/5B77-E95B (last visited July 3, 2018).

Table 1: Recent Examples of AMI Deployment in the Natural Gas Sector

Company	Scope of Operations	AMI Coverage	Key Features
SoCalGas	Provides natural gas services in central and southern California	Natural gas only	• AMI made available to 6 million natural gas customers: o 2.4 million new smart meters, capable of two-way communication, deployed; and o 3.6 million existing meters upgraded to allow two-way communication.[85] • Natural gas meters collect hourly usage data, which will be made available to customers daily via a web portal.[86] • Customers can elect to receive weekly natural gas usage alerts via email or phone.[87]
PG&E	Provides natural gas and electricity services in central and northern California	Natural gas and electricity	• AMI made available to 9.3 million electricity and natural gas customers: o 5.1 million new smart electricity meters deployed; and o 4.2 million existing gas meters upgraded.[88] • Natural gas meters collect daily usage data, which will be made available to customers via a web portal.[89] • Customers can elect to receive alerts, via email or phone, when natural gas usage exceeds a specified level.[90]
SDG&E	Provides natural gas and electricity services in San Diego and southern Orange County	Natural gas and electricity	• AMI made available to 2.3 million electricity and natural gas customers: o 1.4 million new smart electricity meters deployed; and o 900,000 new smart gas meters deployed.[91]

[85] *See* CPUC, Decision on Application of Southern California Gas Company for Approval of Advanced Metering Infrastructure 8 (Apr. 8, 2010)
[86] *Id*. at 12-13. *See also* SoCalGas, Application for Approval of Advanced Metering Infrastructure, Chapter VI: SoCalGas AMI Conservation Impacts and Benefits VI-2 (Sep. 29, 2008).
[87] SoCalGas, *Bill Tracker Alerts*, ADVANCED METER, https://perma.cc/J3NW-TZQM (last visited May 14, 2018).
[88] CPUC, Final Opinion Authorizing Pacific Gas and Electric Company to Deploy Advanced Metering Infrastructure 2 (July 20, 2006).
[89] PG&E, *SmartMeter™ Network*, LEARN ABOUT SMARTMETER™, https://perma.cc/98BX-ZJK6 (last visited May 14, 2018). *See also* PG&E, *Understanding the SmartMeter™*, SMARTMETER™ BENEFITS, https://perma.cc/492V-JMJH (last visited May 14, 2018).
[90] PG&E, *Energy Alerts*, https://perma.cc/Q6AG-BJHK (last visited May 14, 2018).

Company	Scope of Operations	AMI Coverage	Key Features
			• Natural gas meters collect daily usage data, which will be made available to customers via a web portal.[92] • Customers can elect to receive alerts, via email or phone, when natural gas usage exceeds a specified level.[93]
Con Edison	Provides natural gas, electricity, and steam services in New York City and Westchester County	Natural gas and electricity	• AMI made available to 4.7 million electricity and natural gas customers: o 3.5 new smart electricity meters deployed; and o 1.2 million new smart gas meters deployed.[94] • Natural gas meters collect hourly usage data, which will be made available to customers daily via a web portal.[95] • Customers can elect to receive alerts, via email or phone, when natural gas usage exceeds a specified level.[96]
Baltimore Gas & Electric (BG&E)	Provides natural gas and electricity services in Baltimore City and ten surrounding central Maryland Counties	Natural gas and electricity	• AMI made available to 2 million electricity and natural gas customers: o 1.36 million new smart electricity meters deployed; and o 730,000 existing gas meters upgraded.[97] • Natural gas meters collect hourly usage data, which will be made available to customers via a web portal.[98] • Customers can elect to receive weekly natural usage alerts and/or alerts when usage exceeds a specified level.[99]

[91] CPUC, Opinion Approving Settlement on San Diego Gas and Electric Company's Advanced Metering Infrastructure Project 2 (Apr. 12, 2007).
[92] SDG&E, *Energy Management Tool*, https://perma.cc/4DQ2-8BNK (last visited May 14, 2018).
[93] SDG&E, *Energy Use Alerts*, https://perma.cc/8322-3QKF (last visited May 14, 2018).
[94] New York Public Service Commission, Order Approving Advanced Metering Infrastructure Business Plan Subject to Conditions 5 (Mar. 17, 2016).
[95] CON EDISON, ADVANCED METERING INFRASTRUCTURE BUSINESS PLAN 65 (2015), https://perma.cc/9DQ5-V6HP. Con Edison, *Start Using Your Smart Meter*, SMART METERS, https://perma.cc/BH4E-W23R (last visited May 14, 2018).
[96] *Id.*
[97] BG&E, Application for Authorization to Deploy a Smart Grid Initiative and to Establish a Tracker Mechanism for the Recovery of Costs 8 (July 13, 2009).
[98] *Id.*

Outside of California, AMI deployment has proceeded more slowly, with only a handful of LDCs investing in the technology. To the author's knowledge, investment has so far been limited to companies that provide both natural gas and electricity services (dual service utilities), likely because cost savings can be realized from deploying AMI in the two sectors simultaneously.[100] Dual service utilities can, for example, reduce costs by using the same communication network to transmit data from both natural gas and electricity meters. Additionally, the same back-office IT systems can be used to manage both sets of metering data, further reducing costs.

Notwithstanding the above benefits, several dual service utilities have elected to only deploy AMI on their electricity systems,[101] perhaps due to the challenges associated with natural gas system deployment.[102] Many of those challenges do not arise in the electricity system,[103] or are outweighed by the benefits of deploying AMI therein, which tend to be larger than in the natural gas sector. For example, as discussed in Part 3.1 above, the potential for conservation as a result of AMI deployment is higher in the electricity sector than the natural gas sector.[104] Moreover, electricity conservation can generate large cost savings by reducing demand at peak times, when the price of electricity is especially high.[105] In comparison, fewer cost savings are generated by

[99] BG&E Alerts & Notifications, *My Account*, https://perma.cc/6Y29-4CMU (last visited June 21, 2018).

[100] This should not be taken to suggest that AMI deployment is only cost effective when undertaken on the electricity and natural gas systems simultaneously. The experience of SoCalGas, which deployed AMI on its natural gas system only, indicates that this is not the case. According to SoCalGas, natural gas system deployment would generate net benefits of $1,756 million over twenty-five years, making it cost effective. *See* SoCalGas, Application for Approval of Advanced Metering Infrastructure, Chapter II: Summary of AMI Business Case II-17 (Sep. 29, 2008).

[101] One example is CenterPoint Energy, which has deployed AMI throughout its electricity system, but not its natural gas system. CenterPoint continues to manual-read meters or AMR systems (i.e., enabling "drive by meter reading") on the gas system. *See* CenterPoint Energy, *Smart Meters*, ELECTRIC TECHNOLOGY, https://perma.cc/VM4D-VVN7 (last visited June 21, 2018). *See also* CenterPoint Energy, *Reading Your Meter*, CUSTOMER SERVICE, https://perma.cc/2B7W-36D2 (last visited June 21, 2018).

[102] See *supra* Part 3.3.

[103] For example, whereas deployment in the natural gas sector is complicated by the need to power smart gas meters using batteries, smart electricity meters can be powered by the same electric feed they are monitoring. *See* Mohassel et al., *supra* note 70, at 475.

[104] Reductions of up to 15% in electricity use are possible, compared to reductions of 1 to 4% in natural gas use. *See supra* Part 3.1.

[105] *See* Oracle Utilities, *supra* note 35, at 2.

natural gas conservation, including because prices tend to be lower and subject to less time-based variation.[106]

Given the above, there are fewer market drivers for AMI deployment in the natural gas sector than the electricity sector.[107] Deployment in the electricity sector has also been driven by government programs, such as the Smart Grid Investment Grant Program, which provided financial assistance to electric utilities to invest in AMI.[108] In operation from 2009 to 2015, the program helped to "kick-start" AMI deployment in the electricity sector,[109] funding the roll-out of over sixteen million smart electricity meters and associated communication networks, at a total cost of approximately $4.4 billion.[110] The program did not, however, provide funding for AMI deployment in the natural gas sector. To the author's knowledge, funding has not been made available through any other federal or state government programs, meaning that the cost of AMI deployment falls entirely on LDCs (and their customers). The regulatory framework for cost recovery may have affected incentives for LDCs to deploy AMI.

4.2 Regulatory Framework for Recovery of AMI Costs

Due to their status as monopoly distributors of natural gas,[111] LDCs are strictly regulated to prevent any abuse of customers.[112] Regulatory authority is exercised by state entities – typically called Public Service Commissions or Public Utility Commissions (PSC/PUCs)[113] – which are responsible for ensuring that LDCs do not exercise their monopoly power in a way that harms customers, for example by charging unduly high rates.[114] While regulation varies between states, a

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106 Strother & Stimmel, *supra* note 15, at 1.
107 *Id*.
108 U.S. Department of Energy (DOE), *Smart Grid Investment Grant Program*, SMARTGRID.GOV, https://perma.cc/WPM8-MHZN (last visited May 15, 2018).
109 Strother & Stimmel, *supra* note 15, at 2.
110 DOE, *Advanced Metering Infrastructure and Customer Systems*, SMARTGRID.GOV, https://perma.cc/TA43-ARHX (last visited May 15, 2018).
111 See *supra* Part 2.1.
112 Bosselman et al., *supra* note 19, at 155.
113 PSC/PUCs are known by other names, such as "corporation commissions" and "railroad commissions," in some states. *See id*. at 505.
114 As LDCs do not face any competition, they have both the opportunity and incentive to raise prices. *See* STEPHEN BREYER, REGULATION AND ITS REFORM 15-16 (1982) ("In a perfectively competitive market, firms expand output to the point where price equals incremental cost—the cost of producing an additional unit of

basic goal of all PSC/PUCs is to ensure "just and reasonable" rates, which approximate those that would exist in a competitive market.[115] To that end, PSC/PUCs set rates so as to enable LDCs to recover their prudently incurred costs, and earn a reasonable return on investment.[116] Rates are set in periodic regulatory proceedings (rate cases), during which the PSC/PUC determines the revenue required by the LDC to cover its costs, and sets rates so as to enable recovery of that amount.[117] Rates generally remain fixed until the next rate case, meaning that the LDC incurs the cost of any under-recovery and enjoys the benefit of any over-recovery, if actual costs are higher or lower than approved by the PSC/PUC.

The above "rate case" approach is used in all states, but is sometimes combined with "cost tracking," which may result in more frequent adjustment of rates.[118] In simple terms, cost tracking allows an LDC to recover the costs associated with a specific activity on a periodic basis, outside of its rate case.[119] The LDC is typically allowed to recover its full activity costs, regardless of whether they are higher or lower than forecast.[120] To that end, LDC tracks cost changes and passes them on to customers through periodic rate adjustments, without filing a new rate case.

Cost tracking is often used to accelerate the recovery of substantial, variable, and uncontrollable costs that could threaten the LDC's financial viability if not addressed outside the rate case.[121] One example is the cost of purchasing natural gas which, due to its variability, is almost always recovered by LDCs through tracking mechanisms.[122] Some LDCs have also been permitted to use tracking mechanisms in other circumstances, for example, to recover substantial

their product. A monopolist, if unregulated, curtails production in order to raise prices. Higher prices mean less demand, but the monopolist willingly foregoes sales—to the extent that he can more than compensate for the lost revenue (from fewer sales) by gaining revenue through increased price on the units that are still sold").

115 Bosselman et al., *supra* note 19, at 506 – 507.

116 *Id*. at 507.

117 Bosselman et al., *supra* note 19, at 156.

118 *See generally* KEN COSTELLO, NATIONAL REGULATORY RESEARCH INSTITUTE, THE TWO SIDES OF COST TRACKERS: WHY REGULATORS MUST CONSIDER BOTH (2009), https://perma.cc/255P-MJEA.

119 *Id*. at 2.

120 *Id*.

121 *Id*. at 7-8.

122 MARK NEWTON LOWRY ET AL., INNOVATIVE REGULATION: A SURVEY OF REMEDIES FOR REGULATORY LAG 5 (2011), https://perma.cc/25ED-ABQY [hereinafter 2011 Innovative Regulation Study].

capital expenditures made between rate cases.[123] This is intended to prevent so-called "regulatory lag," wherein LDCs are required to carry the cost of their expenditure until a future rate case.

Under traditional rate regulation, before LDCs can begin earning a return on their capital expenditures, the PSC/PUC must conduct a review to determine whether the expenditure was "prudent," and resulted in an asset that is "used and useful."[124] This gives rise to a regulatory lag or gap between when expenditures are incurred and when they can be recovered. While this should provide an incentive for LDCs to minimize costs – i.e., to reduce any losses during the period of the lag – it could also affect their financial viability.[125] Delays in cost recovery may, for example, affect the LDC's credit rating and thus its ability to obtain financing on reasonable terms. Moreover, by increasing the length of time the LDC must cover financing costs internally, delays can also lead to declining profits.

Concerned about the impact of regulatory lag, LDCs have consistently sought to recover the costs of AMI deployment through tracking. This has been permitted by some, but not all, state PSC/PUCs.[126] Notably, the Maryland PSC (MPSC) has refused to allow cost tracking, in part because:

> "AMI deployment would represent a large, but classic, investment in . . . distribution infrastructure, precisely the kind of investment that . . . has [been] recovered through traditional ratemaking for a century. We were not persuaded to deviate from these principles by . . .arguments regarding the magnitude of the AMI investment or the possibility of negative reactions from credit rating agencies."[127]

[123] *Id*. *See also* MARK NEWTON LOWRY ET AL., ALTERNATIVE REGULATION FOR EVOLVING UTILITY CHALLENGES: AN UPDATED SURVEY 5 (2013), https://perma.cc/7Q62-2YA2 [hereinafter 2013 Alternative Regulation Study]; MARK NEWTON LOWRY ET AL., ALTERNATIVE REGULATION FOR EMERGING UTILITY CHALLENGES: 2015 UPDATE 5 (2015), https://perma.cc/TE63-LFUE [hereinafter 2015 Alternative Regulation Study].

[124] 2015 Alternative Regulation Study, *supra* note 123, at 6

[125] Costello, *supra* note 118, at 4 & 14 (2009), https://perma.cc/3LV7-VBKK. *See also* Application of Baltimore Gas & Electric Company for Authorization to Deploy a Smart Grid Initiative and to Establish a Tracker Mechanism for the Recovery of Costs (July 13, 2009) (arguing that "[t]imely cost recovery . . . is imperative not only to maintain the steady cash flow needed to support the investments required [to deploy AMI], but also to send the appropriate signals to the credit markets that the Company's revenue stream is predictable so that it can obtain financing for this project at more reasonable rate").

[126] *See generally*, 2011 Innovative Regulation Study, *supra* note 122, at 5 & 7-9; 2013 Alternative Regulation Study, *supra* note 123, at 7-11; 2015 Alternative Regulation Study, *supra* note 123, 9-16.

[127] MPSC, Order No. 83531: In the Matter of the Application of Baltimore Gas and Electric Company for Authorization to Deploy a Smart Grid Initiative and to Establish a Surcharge for the Recovery of Cost 32 (Aug. 13, 2010).

The MPSC has also expressed concern about the potential for cost tracking to adversely affect customers. In a 2010 decision refusing to allow BG&E to recover the costs of AMI deployment through tracking, the MPSC argued that doing so would impose an undue burden on customers, requiring them to pay for infrastructure before it is installed and delivering benefits.[128] According to the MPSC, cost tracking would shift the risk of AMI deployment to customers, thus presenting BG&E with a "no-lose proposition."[129] The tracker would "guarantee [BG&E] dollar-for-dollar recovery" of AMI deployment costs and thereby "diminish [its] incentive to control those costs," whereas traditional rate regulation would encourage BG&E to minimize costs so as to maximize the profits earned between rate cases.[130]

Notwithstanding the above, PSC/PUCs in other states have allowed cost tracking for AMI deployment, while taking steps to strengthen incentives for cost containment. To that end, the CPUC has capped the total amount each LDC can recover for AMI deployment through cost tracking, and established risk sharing mechanisms to deal with cost variations.[131] According to the CPUC, the mechanisms provide "an incentive [for LDCs] to manage and control overall AMI project costs" by limiting the amount of any cost over-runs that can be allocated to customers, and requiring the balance to be borne by the LDC's shareholders.[132] SoCalGas, for example, must share cost over-runs equally between its customers and shareholders.[133] Cost under-runs are also shared,

[128] MPSC, Order No. 83410: In the Matter of the Application of Baltimore Gas and Electric Company for Authorization to Deploy a Smart Grid Initiative and to Establish a Surcharge for the Recovery of Costs (Aug. 13, 2010). *See also* Application of Baltimore Gas & Electric Company for Authorization to Deploy a Smart Grid Initiative and to Establish a Tracker Mechanism for the Recovery of Costs 3 (July 13, 2009) (noting that a "tracker surcharge would begin appearing on [customer] bills . . . almost immediately" and well "before any of the infrastructure is installed or any benefits are realized").

[129] *Id*. at 3 (concluding that cost tracking would "shift[] all financial risk to . . . customers" and thus make the project a "no-lose proposition for the Company and its investors").

[130] *Id*. at 29.

[131] *See e.g.*, CPUC, Decision on Application of Southern California Gas Company for Approval of Advanced Metering Infrastructure (Apr. 8, 2010) (indicating that SoCalGas can recover no more than $1.0507 billion, plus any amount authorized through its risk sharing mechanism, for AMI deployment).

[132] *Id*. at 42.

[133] *Id*. Note that SoCalGas' risk sharing mechanism only applies to cost over- and under-runs of up to $100 million (above or below the $1.0507 billion cap on total cost recovery).

with ninety percent of any under-run being allocated to customers and ten percent to shareholders, providing an incentive for SoCalGas to keep costs low.[134]

4.3 Effect of Regulation on Incentives for AMI Deployment

Due to LDCs' status as regulated entities, their investment decisions are not driven solely by market forces, but also by regulatory considerations. Past research has identified a range of relevant considerations, two of which are thought to have a particularly important bearing on investment decisions, namely:

1. whether and how the LDC will be permitted to recover the cost of its investment; and
2. the impact of investment on the LDC's total (regulated) earnings.[135]

Those two considerations, as they pertain to investment in AMI, are discussed below.

4.3.1 Cost Recovery for AMI

PSC/PUCs have adopted differing approaches to cost recovery for AMI, with some permitting the use of cost trackers, and others requiring recovery in general rate cases.[136] While a complete review of the benefits and drawbacks of each approach is beyond the scope of this paper,[137] focusing solely on incentives for AMI investment, cost tracking has the advantage of minimizing regulatory lag and associated issues that may discourage investment.[138]

Avoiding regulatory lag is particularly important in the context of AMI deployment due to the significant upfront investment required and the long payback period. Citing those reasons, in its application to the MPSC for approval to deploy AMI, BG&E indicated that it would not invest

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[134] *Id*. The same 90:10 sharing regime applies to cost over- and under-runs incurred by PG&E and SDG&E. *See* CPUC, Final Opinion Authorizing Pacific Gas and Electric Company to Deploy Advanced Metering Infrastructure (July 20, 2006); CPUC, Opinion Approving Settlement on San Diego Gas and Electric Company's Advanced Metering Infrastructure Project (Apr. 12, 2007).

[135] MARTIN KUSHLER ET AL., AMERICAN COUNCIL FOR AN ENERGY-EFFICIENT ECONOMY, ALIGNING UTILITY INTERNS WITH ENERGY EFFICIENCY OBJECTIVES: A REVIEW OF RECENT EFFORTS AT DECOUPLING AND PERFORMANCE INCENTIVES (2006), https://perma.cc/DD86-LWT4. *See also* Oracle Utilities, *supra* note 35, at 10.

[136] *See supra* Part 4.2.

[137] For a discussion of these issues, see Costello, *supra* note 118; 2011 Innovative Regulation Study, *supra* note 122; 2013 Alternative Regulation Study, *supra* note 123; 2015 Alternative Regulation Study, *supra* note 123; RALPH SMITH ET AL., INCREASING USE OF SURCHARGES ON CONSUMER UTILITY BILLS (2012), https://perma.cc/U5BC-FFH7.

[137] Costello, *supra* note 118, 14. *See also* Innovative Regulation Study, *supra* note 122, at 5; 2013 Alternative Regulation Study, *supra* note 123, at 5; 2015 Alternative Regulation Study, *supra* note 123, at 6.

[138] *See supra* Part 4.2.

unless permitted to recover its costs through a tracking mechanism.[139] While BG&E later changed its position and invested without cost tracking, its decision to do so was driven by external factors. BG&E is a dual service utility that simultaneously deployed AMI on both its natural gas and electricity systems after receiving a $200 million grant through the federal government's Smart Grid Investment Grant Program.[140] Statements by BG&E suggest that, absent the grant, it would not have deployed AMI without cost tracking because it "cannot invest several hundred million dollars and subject its investors to the uncertainties and risks associated with waiting several years before" cost recovery in a general rate case.[141] This is likely also a concern for other entities and may explain why, following the MPSC's decision not allow cost tracking for AMI, no other Maryland-based LDC has invested in the technology.

4.3.2 Impact of AMI Deployment on Total Earnings

In determining whether to invest in AMI, LDCs will also consider the impact of investment on their overall earnings, including the potential for lost revenues, which may occur due to lower natural gas sales and/or reduced gas losses.

As explained in Part 3.1, deploying AMI is likely to encourage natural gas conservation, with usage in the residential and commercial sectors expected to fall by up to four percent.[142] This will result in a decline in gas pipeline throughput which, under traditional rate regulation, translates into lower LDC revenues.[143] Traditionally, LDC rates were set equal to the estimated cost of providing services (i.e., as reflected in the LDC's revenue requirement), divided by the volume

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[139] *See e.g.*, BG&E, Application of Baltimore Gas and Electric Company for Authorization to Deploy a Smart Grid Initiative and to Establish a Surcharge Mechanism for the Recovery of Costs (July 13, 2009) (indicating that cost recovery via a tracker is "imperative" and "essential" and suggesting that BG&E will withdraw its proposal if the tracker is not approved).

[140] DOE, *Project Information*, SMARTGRID.GOV, https://perma.cc/6XPK-V829 (last visited May 17, 2018). *See also* DOE, *Baltimore Gas and Electric Company: Smart Grid Initiative*, SMARTGRID.GOV, https://perma.cc/93RV-C5RF (last visited May 17, 2018).

[141] Application for Rehearing of Baltimore Gas and Electric Company: In the Matter of the Application of Baltimore Gas and Electric Company for Authorization to Deploy a Smart Grid Initiative and to Establish a Surcharge Mechanism for the Recovery of Cost 6-7 (Jul 12, 2010).

[142] Kerr & Tondro, *supra* note 25, at ix.

[143] SANDY GLATT & MYKA DUNKLE, NATURAL GAS REVENUE DECOUPLING REGULATION: IMPACTS ON INDUSTRY 3 (2010), https://perma.cc/MR5K-ES8R.

of natural gas expected to be delivered via the pipeline system.[144] Under this approach, if actual pipeline throughput is lower than forecast, the LDC will earn less revenue and may be unable to recover its costs.[145] Thus, economists have long argued that traditional rate regulation creates an incentive for LDCs to maximize natural gas use and discourages investment in conservation and other programs "that may result in lower [gas] sales, as this will reduce [the LDC's] fixed cost recovery and . . . their amount of profit."[146]

Seeking to encourage greater investment in conservation, several states have adopted decoupling policies, intended to break the link between LDC revenues and sales (see Figure 1).[147] While the policies vary,[148] their basic goal is to ensure that LDCs recover no more or less than their approved revenue requirement, regardless of sales.[149] This is generally achieved using a true-up mechanism that adjusts rates to account for discrepancies between actual and forecast levels of natural gas distribution.[150] While this approach has been criticized, primarily on the grounds that it may result in less scrutiny of rate increases,[151] it has the benefit of removing incentives for LDCs to maximize pipeline throughput.[152] Past studies undertaken in the electricity sector, where a similar incentive problem arises, have found decoupling to be "very important" to encourage investment in conservation and other programs that generate energy savings.[153]

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144 *Id*. at 4 – 5. This approach was historically, and in some areas still is, used to calculate prices for both vertically-integrated LDCs and distribution only entities. *See* Kushler et al., *supra* note 135, at 3.

145 *Id*.

146 *Id*. at 2-3.

147 *Id*. at 5.

148 State policies fall into three key categories: (1) full decoupling, (2) partial decoupling, and (3) limited decoupling. Full decoupling completely severs the link between utility revenues and sales, such that the utility always recovers its full allowed revenue, regardless of the reasons for any variation therefrom. Partial decoupling enables the utility to recover only part of the different between its allowed and actual revenues. With limited decoupling, the utility can only recover where actual revenue deviates from the allowed level for specified reasons, such as unusual weather. *See* Glatt & Dunkle, *supra* note 143, at 1.

149 *Id*. at ii.

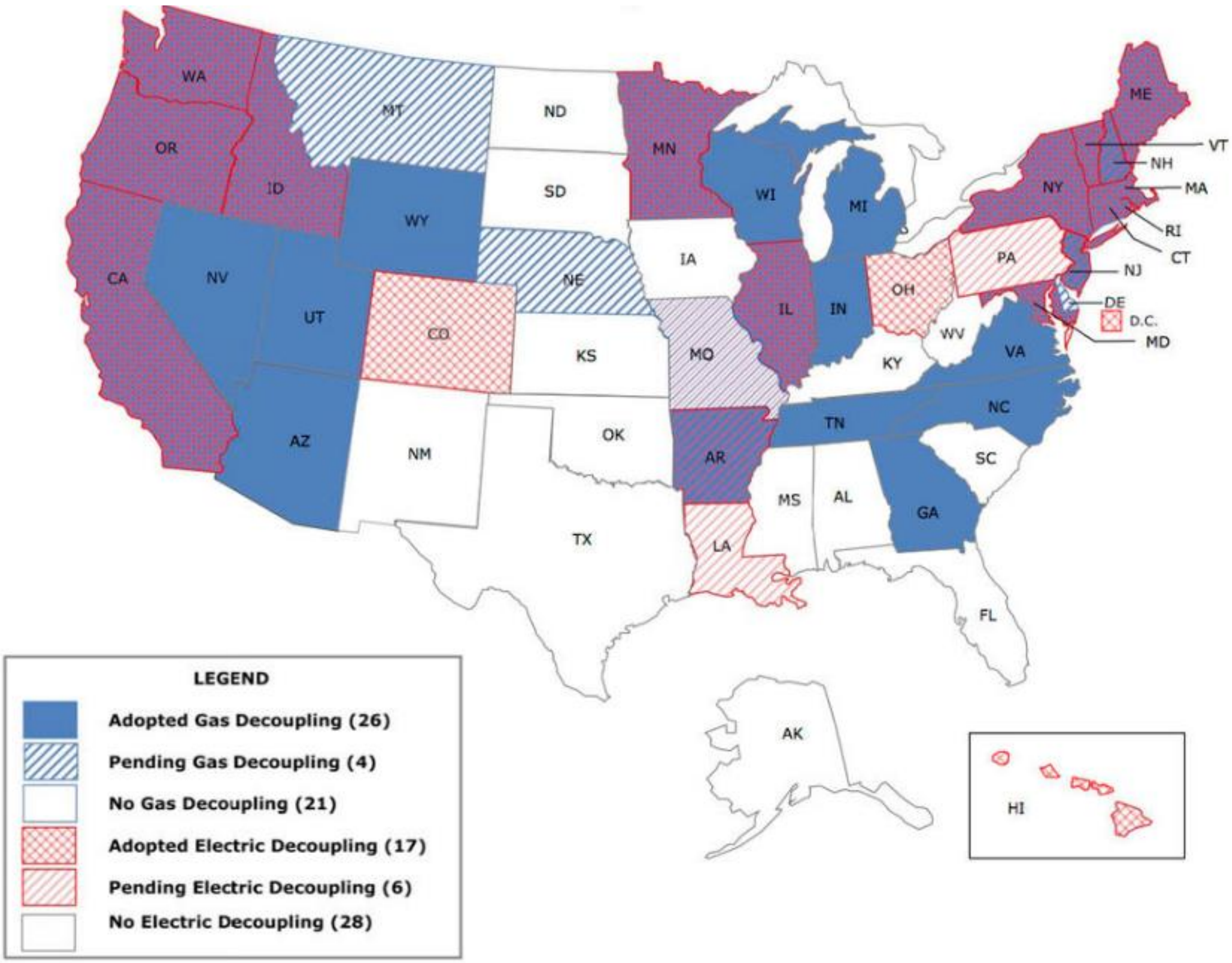
150 If actual gas distribution rates are lower than forecast, prices are increased to ensure the LDC recovers its full revenue requirement. Conversely, if actual gas distribution rates are higher than forecast, prices are decreased to prevent any over-recovery. *See id*. at 4.

151 SHELLEY WELTON ET AL., PUBLIC UTILITY COMMISSIONS AND ENERGY EFFICIENCY: A HANDBOOK OF LEGAL & REGULATORY TOOLS FOR COMMISSIONERS AND ADVOCATES 33 (2012),

152 This is because, the LDC receives the same revenue, regardless of the amount of natural gas it distributes. *See id*.

153 *See e.g.*, Kushler et al., *supra* note 135, at 15.

Figure 1: States with Electricity and Natural Gas Decoupling in the U.S. (as of May 2018)[154]



Even in decoupled states, LDCs may be reluctant to invest in AMI, due to the potential for reduced gas losses and associated revenues. As discussed in Part 3.1 above, LDC rates currently include an allowance for lost and unaccounted-for gas, measured as the difference between gas flows into and out of the pipeline system.[155] This is the result of a 1935 Supreme Court decision – *West Ohio Gas Co. v. Public Utilities Commission* – holding that rates must include an allowance for

[154] Natural Resources Defense Council, *Gas and Electric Decoupling*, https://perma.cc/3N5N-S2U4 (last visited May 16, 2018).
[155] *See generally* Webb, *supra* note 46.

natural gas "lost as a result of leakage, condensation, expansion or contraction."[156] The court reasoned that, because "a certain loss through these causes is unavoidable, no matter how carefully the business is conducted," LDCs must be permitted to recover the associated costs to maintain their financial viability.[157] The same reasoning does not, however, apply to natural gas losses that are avoidable. Thus, according to the court, an LDC "will not be permitted to include negligent or wasteful losses among its operating charges."[158]

In the more than eighty years since *West Ohio Gas Co. v. Public Utilities Commission* was decided, there have been profound changes in the management of natural gas distribution systems, with new technologies enabling many formerly unavoidable gas losses to be avoided. For example, as discussed in Part 3.1 above, AMI can be used to avoid adverse changes in system temperature and pressure that historically resulted in natural gas losses. Moreover, AMI can also help to avoid natural gas losses due to leaks, including by enabling faster detection of pipelines at risk of corrosion.

Notwithstanding the above, PSC/PUCs typically allow cost recovery for all lost and unaccounted-for gas, without considering whether it is avoidable.[159] Recovery may occur in various ways depending on the nature of LDC operations. LDCs that offer bundled services, combining natural gas sales with transportation, generally recover lost and unaccounted-for gas through a charge levied on customers.[160] Where services have been unbundled, LDCs transporting gas on behalf of other entities (shippers) may recover lost and unaccounted-for gas in kind, with the shipper providing additional gas to make up for losses.[161] The amount of lost and unaccounted-for gas that can be recovered – either in dollars or in kind – may be fixed during the LDC's rate case or subject to tracking.[162] Where tracking is used, LDCs are required to periodically adjust rates to account for changes in the amount of lost and unaccounted-for gas over time, and reconcile any

[156] West Ohio Gas Co. v. Public Utilities Commission, 294 U.S. 63, 67 (1935).
[157] *Id*.
[158] *Id*. at 68.
[159] Webb, *supra* note 46, at 19-22.
[160] The charge is intended to reflect the cost of gas purchased by the LDC to make-up for losses during transportation. *See id*. at 13.
[161] *Id*.
[162] *Id*. at 14.

past under- or over-recoveries (i.e., compared to actual losses).[163] As part of the reconciliation, the LDC is typically "made whole" and can recover actual losses in excess of those forecast from customers, but must provide customers with refunds if losses are below forecasts.[164] Under this approach, then, customers bear the risk of any increase and enjoy the benefit of any reduction in lost and unaccounted-for gas. As LDCs are unaffected by such changes, they have little incentive to invest in AMI or other technologies capable of reducing natural gas losses. In fact, in some cases, the potential for reduced natural gas losses and associated revenues may actually discourage LDCs from investing in AMI. This is particularly likely where uncertainty exists as to how and when LDCs will be permitted to recover their investment costs. In such cases, LDCs may be reluctant to invest in AMI and thereby forego the guaranteed revenues associated with lost gas recovery, even if investment could yield long-term benefits.[165]

5. WHERE TO FROM HERE? SUPPORTING AMI DEPLOYMENT IN THE NATURAL GAS SECTOR

Numerous factors – both market-based and regulatory – have likely contributed to the slow rate of AMI deployment in the natural gas sector. On the market side, past studies indicate that the high upfront cost of deploying AMI, as well as the technical challenges associated with deployment, often make it difficult for LDCs to justify investment.[166] This problem is compounded by uncertainty as to whether LDCs will be permitted to recover their investment costs and concerns that investment will reduce their overall (regulated) earnings.[167] By addressing these regulatory issues, state PSC/PUCs can encourage greater investment in AMI, which will deliver widespread benefits.[168]

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[163] *Id*.

[164] *Id*. It should be noted that some jurisdictions require the sharing of under- and over-recoveries between LDCs and their customers. *See id*.

[165] In theory, investment could lead to higher earnings for LDCs because the cost of purchasing natural gas meters is generally treated as a capital expense on which LDCs can earn a return, whereas the cost of lost gas is treated as an operating expense and recovered on a one-for-one basis. However, cost recovery for lost gas is virtually guaranteed, while cost recovery for investment will generally be more uncertain.

[166] *See e.g.*, Oracle Utilities, *supra* note 35; Storther & Stimmel, *supra* note 106.

[167] *See supra* Part 4.3.

[168] *See supra* Part 3.1.

Of course, as statutory creations, PSC/PUCs' ability to adopt regulatory reforms will be constrained by their authorizing statutes and related judicial decisions. In many cases, however, PSC/PUCs will have broad latitude to adopt reforms as part of their mandate to ensure just and reasonable rates. That standard has been held to afford PSC/PUCs "great deference . . . in rate decisions"[169] and arguably provides them with significant flexibility to pursue innovative approaches to rate regulation that will, for example, encourage investment in AMI as a means of promoting energy conservation.

In assessing options to encourage investment, state PSC/PUCs may learn from the experience of California, where multiple LDCs have deployed AMI.[170] The CPUC has successfully encouraged investment, in part, through the use of policy statements expressing support for AMI.[171] Those statements help to increase regulatory certainty, promoting confidence among LDCs that AMI costs will be recoverable, and thus should be issued by other state PSC/PUCs (to the extent permitted by law).[172] State PSC/PUCs should consider allowing AMI costs to be recovered through a tracking mechanism, rather than in the LDC's general rate case, as this will minimize disincentives for investment. However, as cost tracking can give rise to customer protection and other issues, its use must be assessed on a case-by-case basis.

As well as establishing an effective cost recovery framework, state PSC/PUCs should also take steps to address disincentives for AMI investment, arising from traditional rate regulation. Some progress has already been made in this area, with twenty-six states decoupling LDC revenues from sales to remove disincentives for investment in technologies that lower natural gas consumption, such as AMI.[173] While decoupling is not without issues,[174] it may be a necessary precondition for AMI investment,[175] and thus should be carefully considered by other states.

[169] Morgan Stanley Capital Group Inc. v. Pub. Util. Dist. No. 1, 554 U.S. 527, 532 (2008).

[170] AMI has been deployed by three of the state's four largest LDCs. *See supra* Part 4.1.

[171] California Energy Commission et al., *supra* note 80, at 3; CPUC, Decision on Application of Southern California Gas Company for Approval of Advanced Metering Infrastructure 24 (Apr. 8, 2010).

[172] It would also be beneficial for other state agencies to issue policy statements in support of AMI deployment. For example, AMI deployment could be advocated in state climate action plans and other environmental documents. This may lead to increased state funding for AMI and/or encourage greater private investment therein.

[173] The states that have implemented decoupling are shown in Figure 1 above.

[174] *For a discussion of this issue, see* Welton et al., *supra* note 151, at 33.

[175] *See supra* Part 4.3.2.

Consideration should also be given to reforming the regulatory framework for lost and unaccounted for gas to remove disincentives for investment in AMI and other technologies that reduce gas losses. This could be – and in some states already has been – achieved by changing the way in which LDCs recover the cost of lost gas. Here, the experience of New York is instructive. Whereas the New York PSC historically allowed rates of recovery to be tracked and updated to reflect actual gas losses,[176] it now requires rates to be fixed every three years based on historical averages.[177] If losses are below historic levels, the LDC can retain the financial value of the difference, which encourages action to minimize the amount of lost gas.[178] Thus, in this way, reforming the cost recovery framework may support investment in AMI. Previous studies have also identified other possible reforms, such as changes to the way in which lost gas is quantified and verified, which should be considered by state PSC/PUCs.[179] In particular, as recommended in the previous studies, PSC/PUCs should consider disallowing cost recovery for natural gas losses that can be avoided through the use of AMI and/or other technologies.[180]

It should be noted that, the above reforms focus primarily on lessening disincentives for investment in AMI, and may do little to incentivize LDCs to invest. To strengthen incentives for investment, PSC/PUCs should consider adopting performance incentive schemes, which reward LDCs for AMI deployment. That approach has been successfully used in the electricity sector to encourage investment in conservation and efficiency programs.[181] In that context, several state PSC/PUCs have established incentive schemes that pay utilities for achieving specified energy savings, and/or allow them to share in the benefits therefrom.[182] A similar approach could be used

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176 Central Hudson Gas & Elec. Corp. for Gas Serv., 31 N.Y. P.S.C. 1823 (July 1,1991).
177 N.Y. COMP. CODES R. & REGS. tit. 16, §720-6.5(g) (2015).
178 N.Y. DEPARTMENT OF PUBLIC SERVICE, STAFF WHITE PAPER ON LOST AND UNACCOUNTED FOR (LAUF) GAS 6 (2013), *available at* https://perma.cc/52GT-LJYP.
179 *For a discussion of other possible reforms, see* Webb, *supra* note 46; SEN. EDWARD J. MARKEY, AMERICA PAYS FOR GAS LEAKS: NATURAL GAS PIPELINE LEAKS COST CONSUMERS BILLIONS (2013), https://perma.cc/63YQ-LMAY; SHANA CLEVELAND, CONSERVATION LAW FOUNDATION, INTO THINK AIR: HOW LEAKING NATURAL GAS INFRASTRUCTURE IS HARMING OUR ENVIRONMENT AND WASTING A VALUABLE RESOURCE (2012), https://perma.cc/A9HX-XU3J.
180 *See generally* Webb, *supra* note 46, at 18.
181 Welton et al., *supra* note 151, at 35.
182 Kushler et al., *supra* note 135, at 9 - 10.

to incentivize investment in AMI by, for example, allowing LDCs to retain a share of the cost savings generated through use of the technology.

6. CONCLUSION

Deploying AMI on the natural gas system has the potential to deliver widespread benefits to LDCs, their customers, and society as a whole. Perhaps most importantly, AMI deployment is likely to encourage natural gas conservation by providing customers with more accurate and timely gas usage information. Research suggests that natural gas use in the residential and commercial sectors could decline by up to four percent, reducing greenhouse gas emissions that contribute to climate change. Further emissions reductions may also result from improved natural gas system management where, for example, the communication networks deployed with AMI are used to accelerate gas leak detection.

Despite these benefits, to date, only a handful of LDCs have deployed AMI on their natural gas distribution systems. Past studies have attributed this to market factors, including the high cost of deploying AMI, and the long timeframe for realizing benefits. As this paper shows, however, regulatory factors have likely also played a significant role. The current regulatory framework governing cost recovery by LDCs disincentivizes investment in AMI, due to uncertainty as to whether and how investment costs will be recoverable, and the potential for investment to reduce LDCs' overall (regulated) earnings. It may, therefore, be necessary for state PSC/PUCs to reform cost recovery frameworks to encourage investment in AMI. Options that should be considered include:

- allowing LDCs to recover the costs of AMI investment through a tracking mechanism, rather than in their general rate case, because this will minimize regulatory lag and associated problems that can discourage investment;
- decoupling LDC revenues from sales so as to remove the disincentive, arising under traditional rate regulation, for investment in AMI and other technologies that lower natural gas consumption;

- changing the way in which lost and unaccounted-for gas is calculated and recovered, such that LDCs are not discouraged from investing in AMI by the potential for reduced gas losses and associated revenues; and
- adopting a performance incentive scheme that rewards LDCs for investment in AMI by, for example, allowing them to retain a share of the cost savings generated through use of the technology.

Implementing the first three reforms above would remove disincentives for investment, while the fourth would actively incentivize LDCs to invest, helping to accelerate the deployment of AMI. While this would have broad-ranging benefits, the reforms may also present risks, which will need to be considered on a case-by-case basis, taking into account local conditions.