BEFORE THE
MARYLAND PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF THE BALTIMORE GAS & ELECTRIC COMPANY FOR A MULTI-YEAR PLAN	* * * *	Case No. 9692

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DIRECT TESTIMONY

OF

DR. ASA S. HOPKINS

ON BEHALF OF THE OFFICE OF PEOPLE'S COUNSEL

JUNE 20, 2023

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DR. ASA S. HOPKINS

INTRODUCTION

Q. Please state your name, business address, and position.

A. My name is Asa S. Hopkins. My business address is 485 Massachusetts Ave., Suite 3, Cambridge, Massachusetts 02139. I am a Vice President at Synapse Energy Economics, Inc. Among other work, I lead Synapse's consulting regarding the future of gas utilities, and I also work extensively in the related area of building decarbonization technology and policy.

Q. Please describe Synapse Energy Economics.

A. Synapse Energy Economics is a research and consulting firm specializing in energy industry regulation, planning, and analysis. Synapse works for a variety of clients, with an emphasis on consumer advocates, regulatory commissions, and environmental advocates.

Q. Please describe your professional experience before beginning your current position at Synapse Energy Economics.

A. Before joining Synapse Energy Economics in 2017, I was the Director of Energy Policy and Planning at the Vermont Public Service Department from 2011 to 2016. In that role, I was the director of regulated utility planning for the state's public advocate office, and the director of the state energy office. I served on the Board of Directors of the National Association of State Energy Officials. Prior to my work in Vermont, I was an AAAS Science and Technology Policy Fellow at the U.S. Department of Energy ("DOE"), where I worked in the Office of the

Undersecretary for Science to develop the first DOE Quadrennial Technology Review. Prior to my time at the U.S. DOE, I was a postdoctoral fellow at Lawrence Berkeley National Laboratory, working on appliance energy efficiency standards. I earned my PhD and master's degrees in physics from the California Institute of Technology and my Bachelor of Science degree in physics from Haverford College. My resume is included as Exhibit 1.

Q. Please describe your experience on gas utility matters.

A. I have assisted a number of clients to understand the future of gas utilities in the context of deep building decarbonization objectives. This work includes assisting Conservation Law Foundation in Massachusetts Department of Public Utilities Docket 20-80 (an investigation into "the role of gas local distribution companies as the Commonwealth achieves its target 2050 climate goals"); the Industrial Gas Users Association in evaluation of energy-transition-related business risk to Quebecois and Ontario gas utilities; Natural Resources Defense Council in New York and Nevada's regulatory proceedings regarding the future of gas; the Colorado Energy Office regarding approaches to decision-making in the face of uncertainty, in the context of Colorado's regulatory proceedings regarding gas utility Clean Heat plans and building decarbonization; the County of San Diego (with the University of California San Diego) in developing the buildings and utilities portion of its Regional Decarbonization Framework; the Maryland Office of People's Counsel in modeling the impact of the state's decarbonization objectives on utility sales and finances; and the District of Columbia Department of Energy and Environment in assessing Washington Gas Light Company's Climate Business Plan and rate case filings.

Q. Have you previously provided evidence before the Maryland Public Service Commission?

A. No.

Q. On whose behalf are you providing evidence in this case?

A. The Maryland Office of People's Counsel.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to evaluate BGE's gas capital investments—as they have occurred in 2021 and 2022 (the first multi-year rate plan period, or MRP I), and as proposed for the coming multi-year rate plan (MRP II) period (2024–2026).

Q. How is your testimony organized?

A. My testimony begins with a summary of my conclusions and recommendations. I then address the principles of prudence review of utility investments and the importance of taking policy and market context into account for utility planning (with a summary of relevant state and federal policies). Section III of my testimony applies these principles to BGE's leak-prone pipe (LPP) replacement investments. Sections IV and V address replacement of transmission assets and gas meters, respectively. I conclude by reiterating my recommendations.

Q. Have you prepared exhibits to accompany your testimony?

A. Yes. I have prepared Exhibits ASH-1 through ASH-5.

- Exhibit ASH-1 is my CV.
- Exhibit ASH-2 is a collection of data requests (DRs) that I refer to in this testimony. This includes: OPC DR 3-01, OPC DR 3-02, OPC DR 03-04, OPC DR 03-10, OPC DR 03-11, OPC DR 03-18, OPC DR19-01 through 19-08, OPC DR 26-01, OPC DR 27-02, OPC DR 27-03, OPC DR 27-09, Sierra Club DR 04-01, Staff DR10-11, Staff DR 81-04, Staff DR 81-07, Staff DR 81-08, and Staff DR 81-08 Attachment 2.
- Exhibit ASH-3 surveys the actions being taken by dual-fuel utilities in multiple states to address decarbonization objectives.
- Exhibit ASH-4 is *Climate Policy for Maryland's Gas Utilities | Financial Implications* prepared by Synapse Energy Economics and published by the Maryland OPC, November 2022.
- Exhibit ASH-5 is *Long-Term Planning to Support the Transition of New York's Gas Utility Industry*, prepared by Synapse Energy Economics on behalf of the Natural Resources Defense Council, 2022.
- Exhibit ASH-6 is *The Prudent Investment Test in the 1980s*, a research report by Burns, Poling, Whinihan, and Kelly of the National Regulatory Research Institute, 1985.

I. Summary and Recommendations

Q. Please summarize your primary conclusions.

A. I summarize my primary conclusions as follows:

- In order to be prudent, gas system planning must be conducted accounting for the policy and market context, the cost-effectiveness of selected approaches, and the availability of alternatives.
- BGE's expenditures for Projects 60677 ("BGE Operation Pipeline-STRIDE") and 58034 ("Centrally Managed Gas Main Replacements") in the first multi-year rate plan (MRP I) were imprudently planned because (1) BGE's informal processes for project selection means that it does not prioritize risk reduction or the cost-effectiveness of different LPP actions to reduce risk; (2) BGE's failure to conduct long-term asset planning that reflects known climate change policy and market changes increases the risk of imprudently investing in assets that may retire well before the end of the replacement pipe's useful life, thereby needlessly increasing costs and stranded asset risks; and (3) BGE's failure to consider alternatives to pipeline replacement (that is, non-pipeline alternatives) means that ratepayers are paying more for improvements in safety, reliability, and emissions than they would if BGE used better planning processes.
- BGE's proposal to recover Strategic Infrastructure Development and Enhancement (STRIDE) exceedances from 2021 and 2022 through the multi-

year rate plan ("MRP" or "MYP") Adjustment Rider is contrary to the intent of the STRIDE law.

- BGE's continuation of Project 60677 and 58034 into the MRP II period show no signs of improved planning processes that remedy the issues I identified with BGE's imprudent planning during MRP I. These projects would increase stranded cost risk, result in very high ratepayer costs per ton of greenhouse gas (GHG) emissions reduction, and compare unfavorably with electrification as a cost-effective method to increase safety or reduce emissions.
- BGE's proposal to proactively replace services through Project 56695 ("Proactive Service Renewals") is expensive compared with reasonable alternatives.
- BGE did not adequately consider lower-cost alternative approaches for compliance with federal transmission pipeline safety regulations.
- BGE's proposal to replace gas meters before the end of their useful life has not been subjected to a cost-benefit analysis and does not account for the reasonable expectation that BGE will have substantially fewer gas customers (and therefore meters) within the expected useful life of the new meters.

Q. Please summarize your primary recommendations.

A. I recommend that the PSC:

- direct BGE to improve its capital planning processes and align them with state policy;

- disallow $6.06 million of BGE's capital expenditures to reflect imprudent capital planning during MRP I regarding leak-prone pipe replacement programs;
- reject BGE's request to approve recovery of STRIDE exceedances from MRP I;
- remove the projected capital costs for Projects 60677 and 58034 from the going-forward calculations used to set rates in this proceeding;
- reject BGE's proposal for Project 56695 and remove the cost of this program from any future rate year used in setting rates in this docket;
- direct BGE to file any leak-prone pipe replacement program through the STRIDE mechanism;
- set high expectations for BGE regarding analysis of risk reduction and cost-effectiveness for leak-prone pipe replacement proposals;
- not include expenditures on Projects 55633 ("Granite Pipeline – Stokes Drive to Russell Street"), 58079 ("Manor Loop Pipeline"), and 58080 ("Manor System South") in MRP II rates set for 2024–2026;
- remove any planned capital expenditure on new "smart" meters from projections used to set forward-going rates; and
- open a proceeding to examine long-term planning for Maryland's gas utilities.

Q. Could you summarize your recommended disallowances and rejected proposals by year of expenditure?

A. Of course. Here is a table:

Category	Project	2021	2022	2024	2025	2026
Leak-Prone Pipe	60677	1,531,608	1,852,715	151,023,844	152,956,646	155,302,110
Leak-Prone Pipe	58034			24,438,384	24,781,898	24,854,193
Leak-Prone Pipe	56695			4,827,303	7,232,658	8,951,384
Transmission	55633			4,393,845	4,785,031	51,597,236
Transmission	58079			6,483,728	50,573,402	8,401,518
Transmission	58080			856,704	1,612,223	17,041,700
Meters	81516			6,540,500	22,275,726	28,947,297

II. Context Matters for Gas System Planning and Investment

A. Utilities are responsible for making prudent decisions

Q. Could you please describe the role of prudence review in utility ratemaking?

A. Prudence review is the process by which regulators review utility investments and expenditures to provide the discipline on expenditures that the competitive marketplace would otherwise provide. Unlike a company in a competitive market, regulated public utilities earn a return on their rate base rather than from their ability to outcompete other firms in a free market. In a competitive market, if a company makes imprudent investments, it will earn a lower rate of return because competing firms that do not make that error will earn a greater market share, or the firm will otherwise have less revenue relative to its costs. In the regulated context, then, regulators must disallow imprudent investments to impose the same kind of discipline.

Q. Are there established principles about how to conduct prudence reviews?

A. Yes. *The Prudent Investment Test in the 1980s*, a research report by Burns, Poling, Whinihan, and Kelly of the National Regulatory Research Institute published in 1985 (Exhibit ASH-6), contains a clear and cogent summary of the underlying philosophy and application of a prudence test for public utility investments. Of particular interest here are four principles for prudence reviews:[1]

- "[T]here should exist a presumption that the investment decisions of utilities are prudent. The presumption of prudence can be overcome, however, by the allegation of imprudence that is backed up by substantive evidence creating a serious doubt about the prudence of an investment decision."
- "[U]se the standard of reasonableness under the circumstances. That is, to be prudent, a utility decision must have been reasonable under the circumstances that were known or could have been known at the time the decision was made. A corollary to the standard of reasonableness under the circumstance is a proscription against the use of hindsight in determining prudence."
- "The proscription against hindsight makes it unwise for a commission to supplement the reasonableness standard for prudence with other standards that look at the final outcome of a utility's decision, though consideration of outcome may legitimately have been used to overcome the presumption of prudence."

[1] ASH-6 at *iv*. Nothing in these statements of principle should be taken as superseding state law, such as regarding a utility's burden of proof and persuasion.

- "[D]etermine prudence in a retrospective, factual inquiry. The evidence needs to be retrospective in that it must be concerned with the time at which the decision was made."

Burns *et al.* also state that "[T]he concept of prudence protects the rights of individuals not in control of investment decision making. It does not require perfection in decision making but does require, for example, avoidance of deliberate exposure to substantial risk where the individuals not in control could suffer financially."[2]

Q. When a regulator or legislature provides some kind of pre-approval for spending, does that change the need for retrospective prudence review?

A. No. Preapproval to spend funds does not insulate a utility from a finding of imprudence. Utility management has an ongoing obligation each day to decide whether to continue with, expand, or restrict each investment. If information becomes available that shows that a decision is imprudent, even after it has been approved by a regulator or legislature, utility management has an obligation to make a different, prudent, choice.

Q. Is prudence review of expenses from the first MRP appropriate in this case?

[2] *Id*. at *iii-iv*.

A. Yes, the Maryland PSC made clear in its order on the first MRP that all investments and expenditures during the first two years of the MRP period would be subject to prudence review in this case.[3]

Q. What is the role of prudence analysis in setting rates for the next MRP period, if the Commission approves a second MRP?

While full prudence review is deferred until the next rate case, the Commission has a choice about how to treat each investment over the course of the MRP period in order to set just and reasonable rates. It could (1) include the expected cost in the forecast rates collected over the period, or (2) treat the expense like it would be treated in traditional ratemaking: not include it in rates until the next rate case, after it has been judged to be prudently incurred. The Commission's review in this case can enable it to choose which course to take for each projected expense, and how to thereby allocate risk between ratepayers and investors. As Burns et al., state, "The concept of prudence provides commission with a principle that does not necessarily require an 'all or nothing' decision in favor of one side, but can allow some sharing of the risks between investors and ratepayers. The prudent investment test is a tool that regulators are using to provide an answer to the question of who should bear which risks and associated costs."[4]

Q. Please describe your approach to prudence review in this proceeding.

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[3] Order No. 89678, 96–97 ¶ 199, *In the Matter of the Application of Baltimore Gas & Electric Co. for a Multi-Year Rate Plan* (Case No. 9645, 2020).
[4] ASH-6 at *vi*.

A. I reviewed BGE's filings regarding the many different projects that the utility spent capital and operating funds on during 2021 and 2022, with particular emphasis on those projects with substantial budgets. I also examined the answers provided in discovery regarding those projects. As an outside reviewer of the utility's actions, it is very difficult to review the veracity and completeness of the utility's statements on each project. It would be impractical for an outside expert to review primary documents regarding each expenditure over two years, while simultaneously reviewing plans and projections for the three-year period covered by the next proposed MRP. Filtering review through utility responses to discovery, rather than reviewing primary documents, however, means that the utility has the ability to frame its response and deflect potential critique. This structure risks enabling ineffective or imprudent utility actions to avoid close scrutiny. In order to address these challenges, I focused on projects with substantial budget (such as those relating to leak-prone pipe) and on those for which matters of principle and best practice can be applied rather than relying on the day-to-day details of project implementation and planning.

B. The Maryland and national policy and market context

Q. What impact does public policy have on gas system capital planning?

A. Customer needs are shaped by the policy, market, and technology context in which customers live and work. The gas system exists to serve the needs of those customers. Gas system planning, therefore, must be conducted with an eye to the impact of changes in policy, markets, and technology on customer needs.

Q. Please provide a timeline of the policies relevant to this case.

A. Policies that inform gas capital planning decisions have developed and evolved over the last decade. Here is a timeline:

- 2013: STRIDE program established by Maryland legislature[5]
- 2015: Maryland Commission on Climate Change established[6]
- 2015: Paris Agreement under the United Nations Framework Convention on Climate Change. United States withdraws from Paris Agreement in 2017.
- 2021:
    - United States rejoins the Paris Agreement and makes a nationally determined contribution commitment for 2030, as well as committing to net zero for 2050
    - Maryland Commission on Climate Change's Building Energy Transition Plan published
- 2022:
    - Inflation Reduction Act enacted
    - Maryland Climate Solutions Now Act (CSNA) enacted[7]

[5] 2013 Md. Laws Ch. 161, *codified at* Md. Code Ann., Pub. Util. ("PUA") § 4-210.
[6] 2015 Md. Laws Ch. 429 § 1, *codified at* Md. Code Ann., Environment § 2-1301 *et seq.*
[7] 2022 Md. Laws Ch. 38.

STRIDE

Q. What is the purpose of Maryland's STRIDE program?

A. The purpose of the STRIDE program is to "accelerate gas infrastructure improvements."[8] The Maryland legislature created the STRIDE program in 2013 to provide gas utilities with a mechanism for promptly recovering the cost of eligible infrastructure replacement projects. To be eligible, projects must improve public safety or infrastructure reliability, reduce natural gas system leaks, and not increase revenue or be included in the utility's existing rate base.[9] The Commission may approve a STRIDE program if it finds the investments and estimated costs "reasonable and prudent" and designed to improve public safety or infrastructure reliability over the short term and long term.[10]

Q. How do utilities recover the cost of STRIDE investments?

A. Utilities recover the cost of STRIDE investments through a surcharge on customer bills, which enables them to begin cost recovery at the same time as they make eligible infrastructure replacements.[11] Importantly, state law caps the monthly surcharge at $2 per residential customer and a comparable value for other customer classes.[12] Any project costs that cannot be recovered through the

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[8] PUA § 4-210(b).
[9] PUA § 4-210(a)(3).
[10] *Id.* § 4-210(e)(3).
[11] *Id.* § 4-210(d)(3)(ii).
[12] *Id.* § 4-210(d)(4)(i).

surcharge without exceeding the cap move into the utility's rate base at minimum every five years after a review for prudence in a subsequent rate case.[13]

Q. How has BGE participated in STRIDE?

A. BGE has participated in STRIDE twice. Its STRIDE I program ran from 2014 to 2018;[14] STRIDE II began in 2019 and will continue through 2023.[15]

Q. Does BGE plan to continue its participation in STRIDE after 2023?

A. No. In the Company's CY 2023 STRIDE project list filing, BGE stated that it "does not plan to file a STRIDE III plan application with the Commission for gas asset replacement work beyond 2023. Rather, BGE intends to plan, perform, and seek cost recovery for all post-2023 gas asset replacement work through its multi-year rate plans."[16]

Federal Policy and Laws

Q. Has the federal government established GHG emission reduction goals?

A. Yes. The federal government has established a series of emissions reduction goals, which have become stricter over time. In 2016, the Obama administration committed the United States to a 26-28 percent reduction by 2025 (from 2005

[13] *Id.* § 4-210(g).
[14] Order No. 96147, *In the Matter of the Application of the Baltimore Gas and Electric Company for Approval of a Gas System Strategic Infrastructure Development and Enhancement Plan and Accompanying Cost Recovery Mechanism* ("*In re BGE STRIDE I*") (Case No. 9331, 2013).
[15] Order No. 88714, 18, *In the Matter of the Application of the Baltimore Gas and Electric Company for Approval of a New Gas System Strategic Infrastructure Development and Enhancement Plan and Accompanying Cost Recovery Mechanism* ("*In re BGE STRIDE II*") (Case No. 9468, 2018).
[16] *Baltimore Gas & Electric 2023 Proposed STRIDE Project List and Surcharge Calculations*, ML# 242893 at 4, (Case No. 9468, Nov. 1, 2022).

levels), and presented a mid-century strategy (MCS) laying out a path to 80 percent reductions by 2050. In 2021, the Biden administration established a national emissions reduction target of 50-52 percent from the 2005 level by 2030 and net zero emissions by 2050.

Q. Has the federal government provided details of its envisioned pathway to achieving its 2050 GHG reduction goals?

A. Yes. In 2016, the *United States Mid-Century Strategy for Deep Decarbonization*, filed with the United Nations under the Paris Agreement, demonstrated how the United States could meet its then-goal of 80 percent reduction in emissions by 2050.[17] In 2021, an updated plan, *The Long Term Strategy of the United States*, identified pathways to achieve the net zero target.[18]

Q. Does the 2016 strategy make explicit statements about the long-term role of electricity and gas in buildings?

A. Yes, it does. The 2016 MCS states that the United States will use three levers, of which one is "[s]hifting to clean electricity and low-carbon fuels in transportation, buildings, and industry."[19] Regarding buildings, the plan states "[t]he electricity generating capacity additions displayed in [a figure in the plan] are therefore needed not only to decarbonize the electricity sector but also to electrify the

[17] THE WHITE HOUSE, *United States Mid-Century Strategy for Deep Decarbonization* (2016), https://unfccc.int/files/focus/long-term_strategies/application/pdf/mid_century_strategy_report-final_red.pdf.
[18] U.S. DEP'T OF STATE & U.S. EXEC. OFFICE OF THE PRESIDENT, *The Long-Term Strategy of the United States: Pathways to Net-Zero Greenhouse Gas Emissions by 2050* (Nov. 2021), https://www.whitehouse.gov/wp-content/uploads/2021/10/US-Long-Term-Strategy.pdf.
[19] *United States Mid-Century Strategy* at 8.

buildings, transportation, and industrial sectors…. In the MCS Benchmark scenario, direct fossil fuel use (i.e., not including electricity generated using fossil fuels) decreases by 58 percent, 55 percent, and 63 percent in buildings, industry, and transportation, respectively, from 2005 to 2050."[20] The MCS Vision for the Buildings Sector has two primary strategies: energy efficiency and "[e]lectrification of end-uses. Further electrifying building end-uses—combined with the near-complete decarbonization of the grid—is an important strategy to reduce building emissions. A key opportunity for electrification in buildings lies in space heating and hot water heating appliances."[21] The MCS has a call-out box about the importance of electric heat pumps.

Q. Did the 2021 Long-Term Strategy reaffirm the strategy to electrify buildings?

A. Yes, it did. One identified strategy in the 2021 plan is to "affordably and efficiently electrify most of the economy – from cars to buildings and industrial processes."[22] The plan further elaborates that "The key driver of reducing building emissions is efficient use of electricity for end uses (such as heating, hot water, cooking, and others). Alongside the decarbonization of electricity, these changes can bring building sector emissions to near-zero by 2050…. [T]he share of electricity in final energy demand grows as end uses are electrified, from about

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[20] *Id*.
[21] *Id*. at 60.
[22] *Long-Term Strategy of United States* at 18.

50% in 2020 to 90% or more by 2050 because the on-site combustion of gas, oil, and other fuels decreases substantially; however, the growth is also limited through energy efficiency and efficient electrification. Heat pumps and other electric heaters and electric cooking account for more than 60% of sales by 2030 and nearly 100% of sales by 2050. Energy demand in buildings is reduced by 9% in 2030 and 30% in 2050."[23] Heat pumps again receive particular attention: "The rapid deployment of heat pumps for space heating and cooling and water heating is the central strategy for the efficient, flexible electrification of buildings."[24]

Q. Have there been other developments at the federal level than can affect the pace of the energy transition identified in the Long-Term Strategy of the United States?

A. Yes, the Inflation Reduction Act (IRA) of 2022 includes substantial investment in climate change actions. It includes tax code modification to support private investment in renewable energy technology, energy efficiency, and low-carbon materials and buildings, as well as federal funding for rebate programs and loan guarantees for GHG emission reduction projects. The IRA created a home energy rebate program to support electrification—the High-Efficiency Electric Home Rebate Act (HEEHRA) program.[25] The program provides point-of-sale consumer rebates to help homeowners electrify their homes. These rebates are targeted at

[23] *Id*. at 32.
[24] *Id*. at 33.
[25] 42 U.S.C. § 18795a.

low- or moderate-income homeowners.[26] Governmental or commercial entities owning a multifamily building where the majority of residents make under 150 percent of the area median income can also apply for rebates for electrification projects in their building.[27]

Q. Are these federal policies and programs reflective of changes in the market for heating systems?

A. Yes. Federal support for electrification and heat pumps, for example, is made possible by the growing range and performance of heat pump equipment to meet customer needs, which is reflected in increasing sales. Air-source heat pump sales in the United States passed 4 million units for the first time in 2022, just three years after passing 3 million units of the first time.[28] Sales in 2022 were more than double the average sales from the first decade of this century and exceeded sales of gas furnaces for the first time.[29]

Maryland Commission on Climate Change and CSNA

Q. What are Maryland's GHG emissions goals?

A. Maryland adopted the Climate Solutions Now Act of 2022, which establishes state goals of a 60 percent reduction in GHG emissions (from a 2006 baseline) by 2031 and net zero emissions by 2045. The CSNA established a clear policy direction

[26] *Id.* § 18795a(d)(1)(A).
[27] *Id.* § 18795a(c)(4)(C).
[28] AIR-CONDITIONING, HEATING, AND REFRIGERATION INSTITUTE ("AHRI"), "Central Air Conditioners and Air-Source Heat Pumps," AHRINET.ORG, https://www.ahrinet.org/analytics/statistics/historical-data/central-air-conditioners-and-air-source-heat-pumps.
[29] *Id.*; AHRI, "Furnaces Historical Data," AHRINET.ORG, https://www.ahrinet.org/analytics/statistics/historical-data/furnaces-historical-data.

that electrification is the most important strategy to help the state meet its aggressive GHG reduction mandates. For example, the Act states, "the General Assembly supports moving toward broader electrification of both existing buildings and new construction as a component of decarbonization."[30] The Act also requires the Building Codes Administration to "develop recommendations for an all-electric building code for the State"[31] as well as to "develop recommendations regarding efficient cost-effectiveness measures for the electrification of new and existing buildings."[32]

Q. Were Maryland's present GHG goals its first such goals?

A. No. Maryland established emissions reduction goals in 2009[33] and reaffirmed them in 2016.[34] These laws established both near-term (25 percent by 2025, 40 percent by 2030) and long-term (80 to 95 percent by 2050) emissions reduction goals. These goals are broadly aligned with the federal commitments detailed above, and they imply a similar transformation of the energy sector in Maryland as is envisioned in the federal strategies.

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[30] 2022 Md. Laws. Ch. 38 § 10(a)(1).
[31] *Id.* § 10(b)(i).
[32] *Id.* § 10(b)(v).
[33] Greenhouse Gas Emissions Reduction Act of 2009 ("GGRA"), 2009 Md. Laws Ch. 171, *codified at* Md. Code Ann., Environment § 2-1201 *et seq.*
[34] Greenhouse Gas Emissions Reduction Act – Reauthorization, 2016 Md. Laws Ch. 11, *codified at* Env. Art. § 2-1204 *et seq.*

Q. What is the Maryland Commission on Climate Change?

A. The Maryland Commission on Climate Change (MCCC) was codified into law by the Maryland General Assembly at the 2015 session.[35] The MCCC is responsible for advising the Governor and state legislature on "ways to mitigate the causes of, prepare for, and adapt to the consequences of climate change."[36] MCCC is charged with developing proposals that allow the state to reach the ambitious emissions reduction targets embedded in the CSNA. The MCCC also has eight working groups, including the Greenhouse Gas Mitigation Working Group (MWG), that develops recommendations for dealing with climate change.

Q. Has the state conducted planning processes to inform a preferred pathway to achieve its objectives?

A. Yes. The Mitigation Working Group (MWG) of the Maryland Commission on Climate Change (MCCC) released the Building Energy Transition Plan report in 2021.[37] This plan included two major components: (a) major findings from a study conducted by E3 ("the Statewide E3 Study") analyzing scenarios for achieving reductions in emissions to near net-zero level for Maryland's residential and commercial buildings by 2045 and (b) recommendations based on the study

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[35] Env. Art. § 2-1301.

[36] DEPT. OF ENVIRONMENT, "Maryland Commission on Climate Change," https://mde.maryland.gov/programs/air/ClimateChange/MCCC/Pages/index.aspx.

[37] MARYLAND COMMISSION ON CLIMATE CHANGE ("MCCC"), *Building Energy Transition Plan: A Roadmap for Decarbonizing the Residential and Commercial Building Sectors in Maryland* at 12 (November 2021), https://mde.maryland.gov/programs/air/ClimateChange/MCCC/Documents/2021%20Annual%20Report%20Appendices%20FINAL.pdf.

findings and stakeholder feedback. The Statewide E3 Study modeled four scenarios, including the MWG Policy Scenario, and found that the MWG Policy Scenario was the lowest-cost scenario of all the decarbonization scenarios. This scenario incorporates the following four core concepts and objectives:

- Ensure an equitable and just transition, especially for low-income households.
- Construct new buildings to meet space and water heating demand without fossil fuels.
- Replace almost all fossil fuel heaters with heat pumps in existing homes by 2045.
- Implement a flexible Building Emissions Standard for commercial buildings.

Of particular relevance to gas system planning, the MCCC's Building Energy Transition Plan recommends a "[g]radual transition to an all-electric residential buildings sector" on the way to "zero direct emissions by 2045."[38] It is also important to note that the MCCC's recommendations include (a) encouraging fuel-switching and beneficial electrification through EmPOWER beginning in 2024 and (b) targeting 50 percent of residential heating system, cooling system, and water heater sales to be heat pumps by 2025 and 95 percent by 2030. The MCCC's plan further recommends that the Public Service Commission oversee electric and

[38] *Id*.

gas utility planning processes with the following objectives for gas transition plans:[39]

- "Appropriate gas system investments/divestments for a shrinking customer base and reductions in gas throughput in the range of 50 to 100 percent by 2045;
- Comprehensive equity strategy to enable LMI households to improve energy efficiency and electrify affordably;
- Regulatory, legislative, and other policy changes needed for a managed and just transition of the gas system and infrastructure;
- Operational practices to meet current customer needs and maintain safe and reliable service while minimizing infrastructure investments;
- Assessment of existing gas infrastructure and options for contraction;
- Alternative models for the gas utility's long-term role, business model, ownership structure, and regulatory compact, as part of a managed transition."

In its 2022 Annual Report, the MCCC added two additional related items: (1) that the gas transition plans should also examine the feasibility of the gas delivery system to carry green hydrogen and the role of lower carbon fuels including biogenic methane, green hydrogen, and hydrogen blending; and (2) that, in the event there is not an all-electric construction code, the PSC should align gas line

[39] *Id*. at 23.

extension policy with the goal of broader electrification and new construction and declining gas sales.[40]

Q. What are the implications of the evolving state and federal policy and market environment you have just detailed for evaluation of the prudence of BGE's investments?

A. As I detailed above, to make prudent decisions, BGE is obligated to take into account continuous information regarding the policy and market conditions in which it operates. If the context changes and a utility fails to make informed choices in the new context, given information available at the time the decisions are made, the utility is acting imprudently and its investments are subject to disallowance. BGE's policy context has changed substantially since the STRIDE law was passed in 2013, and change has continued since the first MRP was established in 2020, so the PSC must evaluate BGE's investments and planning processes based on how BGE has adapted, or not, to this changing environment.

Q. What are the implications of the evolving state and federal policy and market environment you have just detailed for gas planning in this case?

A. BGE shows no signs of having adapted its capital planning approach to its evolving policy context. Its capital planning approach is generally the same today as it has been since STRIDE became law, even though the difference for the gas system resulting from intervening and strengthening GHG plans and commitments

[40] MCCC, *2022 Annual Report* at 17 (Nov. 2022), https://mde.maryland.gov/programs/air/ClimateChange/MCCC/Documents/2022%20Annual%20Report%20-%20Final%20%284%29.pdf.

made at the state and federal levels will be profound. Given the broad engagement and analysis that informed the MCCC's recommendations, and the plain language of the CSNA in support of electrification, BGE should be planning for a reasonable likelihood that the state follows a path with dramatic reductions in gas use, and a reduction in both its number of customers and the extent of its gas distribution system. Instead, BGE has conducted a separate analysis—the *BGE Integrated Decarbonization Strategy* ("BGE Study")[41]—and is pursuing a distinct path, which is not fully aligned with the MCCC's recommended path and the stated goals of the CSNA.[42] The PSC should make clear to BGE that as a regulated public utility serving the state of Maryland, BGE does not have discretion to select its own pathway without creating serious risks for a determination of imprudent investment. Instead, the PSC should direct BGE to improve its planning processes and align them with state policy.

Q. Could you please elaborate on why you say that BGE's path is not consistent with the MCCC's recommended path?

A. BGE states: "BGE's planned contributions to this effort are informed by the [BGE Study] that shows that an integrated energy system (including safe and reliable gas infrastructure) can achieve the net-zero goals at significantly lower costs and lower risks. The integrated approach also delivers greater resiliency, fuel diversity,

[41] Energy + Environmental Economics ("E3"), *BGE Integrated Decarbonization Strategy* (Oct. 2022), https://www.bge.com/SafetyCommunity/Environment/Documents/BGE%20Integrated%20Decarbonization%20White%20Paper_FINAL%202022-10-06.pdf.
[42] Exhibit ASH-2 (BGE Response to Staff DR 10-11).

more realistic constructability, and less disruption to customers and Maryland's economy, compared to other approaches with less or no gas system capabilities."[43] BGE is pursuing the "integrated" approach described in that study, reflected in its "hybrid" or "diverse" pathways. These pathways retain a large number of gas system customers in both the residential and commercial sectors (with a reduction in gas system customer count of only about one-quarter in each case). In contrast, the MCCC recommends an all-electric residential sector and replacing nearly all fossil fuel heaters with heat pumps, and the CSNA speaks of "moving toward broader electrification of both existing buildings and new construction."[44]

Q. Q: What is your understanding of the assumptions BGE asked its consultant to use for the BGE Study?

A. BGE asked E3 to evaluate pathways that assumed continued use of its gas infrastructure. This is supported by page 11 of the BGE Study, where it states: "BGE specifically asked E3 to build on its prior efforts in the State by evaluating the implications of decarbonization strategies that achieve the state's newly legislated net-zero targets with an intent to understand how BGE's electric and gas businesses and infrastructure could play a supporting role."[45]

C. Planning is prudent and essential

[43] *Id.* For a further discussion of the merits of the BGE Study and its conclusions, see the Direct Testimony of Kenji Takahashi at 44:14–53:2.
[44] 2022 Md. Laws. Ch. 38 § 10(a)(1).
[45] *BGE Study* at 11.

Q. What role does gas system planning play in prudent utility system management?

A. Planning is essential to prudent management. Gas system capital planning, for both the short term (e.g., less than five years) and for the longer term (over a decade or more) is a key tool for identifying options for system growth and optimization. By looking ahead multiple years, and considering the usefulness of assets over their lifetimes, system planners can weigh alternatives to meet evolving system needs at the lowest cost. For example, with appropriate tools and processes in place, a system planner can compare the costs and benefits of a repair-focused effort for leak-prone pipe (aimed at reactive responses to leaks and repair of pipe sections that show the greatest leak history) with a replacement-based approach (aimed at proactively replacing high-risk pipe). Each action in a repair-focused approach may have a shorter effective lifetime for resolving safety issues than would replacement, but it can also be more targeted and nimble with respect to changing system utilization. Replacement offers a longer lifetime, with associated reduction in flexibility and increase in the need to manage stranded costs risks. If a utility is not conducting planning practices that take this kind of analysis into account, it risks making imprudent decisions for the development of and investment in its system.

Q. Can you suggest some principles for long-term gas system planning?

A. Yes. My colleagues and I published a white paper in the context of New York's gas planning proceeding,[46] which identified the following principles and practices:

- Design all scenarios to comply with state emissions objectives.
- Integrate gas and electricity planning.
- Assess impacts on gas and electricity sales.
- Use appropriate asset lives and depreciation schedules.
- Articulate GHG constraints.
- Apply a high threshold for approving new gas infrastructure investments.
- Assess multiple gas utility business models.
- Develop comprehensive non-pipeline alternative (NPA) screening frameworks.
- Adopt practices for strategic asset retirement.
- Update gas load forecasting practices.
- Account for customer actions.
- Account for risk.
- Articulate an action plan.
- Update plans periodically.

Q. How does the evolving state and federal policy context interact with prudent gas system planning?

A. In order to be prudent, gas system planning must be conducted with an eye to its policy and market context. Where policies and market transitions may limit the

[46] Exhibit ASH-5.

future utility of a gas system asset, a prudent decision to invest in that asset or pursue an alternative must take those potential future limits into account. For example, the economic evaluation of alternative approaches to solve a gas system problem must account for the useful lives of the approaches and the associated depreciation rates.

Q. Are other utilities making changes in their planning and programmatic actions to account for their changing policy and market context?

A. Yes. Exhibit ASH-3 summarizes a survey of the actions being taken by dual-fuel utilities in multiple states to reduce emissions and reduce risk while acting consistent with corporate GHG emissions reduction goals and state GHG mitigation policies.

III. BGE's Leak-Prone Pipe Investments Are Not Prudently Planned

Q. Which BGE LPP programs and projects are you addressing in this portion of your testimony?

A. I am addressing Project 60677 ("BGE Operation Pipeline-STRIDE"), Project 58034 ("Centrally Managed Gas Main Replacements"), and Project 56695 ("Proactive Service Renewals").

A. LPP expenditures during the first MRP were imprudently planned

Q. Which LPP projects did BGE conduct during the first MRP, and at what expense?

A. BGE conducted Project 60677 ("BGE Operation Pipeline-STRIDE") and Project 58034 ("Centrally Managed Gas Main Replacements") during the 2021-2023 period of the first MRP. For Project 60677, BGE expended $115.4 million in 2021 and $111.4 million 2022, and it forecasts $115.7 million in 2023. For Project 58034, BGE spent $13.9 million in 2021 and $21.8 million in 2022, and it projects spending $45.1 million in 2023.

Q. What is the difference between Project 60677 and Project 58034?

A. Project 60677 is the utility's STRIDE program: a neighborhood-based approach to replacing all assets. Project 58034 involves replacement of larger assets or more complex replacements, not based on a neighborhood approach.

Q. What were the stated purposes of Project 60677?

A. The project's "problem statement" provides: "BGE's cast iron main and bare steel mains have significantly higher leak rates than systems made of modern materials. Additionally, low pressure systems present safety and reliability concerns."[47] The identified "solution" is to "[r]eplace the cast iron and bare steel systems with modern materials and eliminate low pressure systems as part of its STRIDE replacement plan."[48]

Q. What were the stated purposes of Project 58034?

A. The stated purpose and approach for this project is nearly identical to Project 60677: "BGE's cast iron main and bare steel mains have significantly higher leak rates than systems made of modern materials. Additionally, low pressure systems present safety and reliability concerns… BGE will replace its cast iron and bare

[47] BGE Exh. DCW 1-G at 8.
[48] *Id.*

steel systems with modern materials and eliminate low pressure systems as part of its replacement plan."[49]

Q. How does BGE describe its decision-making process regarding investments in LPP replacement?

A. Witness White states that "[t]he Company considers a variety of factors and uses engineering judgement to determine which BGE Operation Pipeline projects are ultimately considered for replacement. The Company does not have specific documents or procedures on how to select Operation Pipeline."[50] Witness White then lists 12 unprioritized factors that may be considered: risk scores for cast-iron pipe using Optimain software; leak history for cost-iron pipes in a region; break history for cast-iron pipes in a region; recent leak or break history; high density paving; poor supply or pressure; state of the existing pressure system; replacement continuity in a particular region; replacement "clean up" to eliminate all remaining targeted outmoded infrastructure in a region; multiple main replacement program jobs in the region; municipal/agency coordination; and diversity in geographic location.

Q. Does BGE identify specific assets for LPP replacement more than a year in advance?

A. No. As Witness White states, "BGE has not identified a list of specific asset replacement jobs for Project 60677 BGE Operation Pipeline for the years 2024

[49] *Id.* at 10.
[50] Exhibit ASH-2 (BGE response to OPC DR03-01).

through 2026. Instead, BGE sets its forecasted spend based on an overall estimated workplan for replacements, not individual jobs. As ongoing work occurs on the system over the course of the year, BGE narrows its focus for individual jobs based on its progress as well as factors described" in the previous answer.[51]

Q. Does BGE consider alternatives to pipe replacement to achieve safety or emissions goals related to LPP?

A. When faced with an individual leak, BGE considers whether to repair or replace the leaking assets. But for leak-prone materials that are not actively leaking, BGE has simply made the decision to replace these assets over time through Projects 60677 and 58034. As the Commission noted in its STRIDE II order, this replacement process would continue until about 2043 if conducted at its current pace.[52]

Q. What concerns do you have regarding the prudence of BGE's decision-making for LPP?

A. I have three primary concerns with respect to the prudence of BGE's capital decision-making regarding LPP in Projects 60677 and 58034:

- First, BGE's informal processes for project selection means that it does not prioritize risk reduction or the cost-effectiveness of different LPP actions to reduce risk.

[51] Exhibit ASH-2 (BGE response to OPC DR 03-02).
[52] Order No. 88714 at 26, *In re BGE STRIDE II* (Case No. 9468, 2018).

- Second, BGE's failure to conduct long-term asset planning that reflects known climate change policy and market changes increases the risk of imprudently investing in assets that may retire well before the end of the replacement pipe's useful life, thereby needlessly increasing costs and stranded asset risks.
- Third, BGE's failure to consider alternatives to pipeline replacement (that is, NPAs) could mean that ratepayers are paying more for improvements in safety, reliability, and emissions than they would if BGE used better planning processes.

The following sections of my testimony address these three concerns in turn.

Q. Why have you not highlighted Project 60666 ("Regionally Managed Gas Infrastructure Improvements Program")?

A. Project 60666 does not share some of the problematic characteristics that I highlight in this section regarding the other LPP programs. In particular, Project 60666 focuses specifically on targeted replacement of high-risk assets, such as assets with a history of poor performance, leaks or breaks, corrosion or graphitization, or shallow or exposed mains. While long-term planning and alternatives could reduce costs and lower stranded cost risks associated with assets installed under this program, the potentially emergent or short-timeframe nature of the issues addressed by this program separates this program from the other LPP programs.

Risk and Cost-Effectiveness

Q. Why is it important to prioritize pipeline replacement by risk and cost-effectiveness?

A. From a safety perspective, it is critical that BGE prioritize the riskiest assets for replacement or other mitigation measures before replacing less risky assets. This is the only way to decrease risk—the likelihood and consequence of pipe failure—as quickly as possible to avoid negative outcomes. The utility should also evaluate cost-effectiveness, which compares risk reduction with mitigation costs, to maximize safety, reliability, and environmental improvements for the dollars spent. This can help guide the utility toward more optimal solutions from a cost and safety perspective by examining the tradeoff between risk reduction and costs.

Q. Has BGE adequately incorporated risk prioritization and cost-effectiveness considerations into its Operation Pipeline proposal?

A. No. As outlined in the ensuing sections, BGE has largely ignored these critical considerations. This is likely to result in, at best, a sub-optimal program, and at worst, an unnecessarily large amount of risk that will remain unmitigated over the rate plan period.

Q. Does BGE's Operation Pipeline project prioritize the riskiest assets for replacement to maximize safety benefits of the program?

A. No. BGE admits that it does not use all outputs of its risk model, called "Optimain," to scope projects under Project 60677: "Optimain risk scores and/or performance history of non-cast iron infrastructure are not generally part of the selection process for Project 60677 work."[53] BGE does use Optimain scores for

[53] Exh. ASH-2 (BGE response to OPC DR 27-09) The Company states it does consider risk as part of Project 60666: "The Company does use Optimain to determine which steel mains (protected and unprotected) to focus on for further evaluation as part of other main replacement activities, mainly under Project 60666: Regionally Managed Gas Infrastructure Improvements Program." *Id.*

cast iron assets when considering regions for participation in Project 60677, but as only one of 12 unprioritized factors. It is also not clear whether BGE uses these scores in any way other than identifying that a region ranks in the top quartile for cast iron risk.

Q. Under what circumstances would a risk-agnostic approach be acceptable?

A. BGE's low-prioritization approach might be acceptable if the risk of each segment of pipe targeted under Operation Pipeline were similar or the same. If that were the case, it would not matter where or when BGE accomplished its work, as it would have a similar level of risk reduction (assuming the same number of miles were accomplished in each project).

Q. Do different pipe materials exhibit different levels of risk?

A. Yes. For example, in 2022, BGE's cast iron main had a leak rate of 2.54 leaks per mile, while bare steel main leak rate was 1.00 leaks per mile, coated steel main had 0.08 leaks per mile, and plastic main had 0.03 leaks per mile.[54]

Q. Is it the case that each pipe segment in BGE's service territory has the same amount of risk?

A. No, it is not. First, risk varies across material types, as just discussed. Second, risk varies significantly among pipe miles within each pipe material. The following graphs show the "normalized risk," or risk per 1,000 feet of cast iron and bare steel pipe, according to BGE's "Optimain" modeling results, sorted from highest

[54] Exhibit ASH-2 (BGE response to OPC DR 03-04).

to lowest. The x axis of each graph is the count of pipe segments, ordered by decreasing level of normalized risk. The y axis is the normalized risk (risk per 1,000 feet) from BGE's Optimain modeling.

[BEGIN CONFIDENTIAL]

Figure 1. Cast iron pipe material, normalized risk score (risk per 1,000 feet)[55]

[redacted]

[55] Calculated from OPC DR27-01-CONFIDENTIAL CEII Attachment 1.

Figure 2. Bare steel pipe material, normalized risk score (risk per 1,000 feet)[56]

[redacted]

[END CONFIDENTIAL]

The line in the graphs above would be flat if risk were equal across pipe miles. Instead, the steepness of the curves suggests that risk is not equally distributed across BGE's service territory, and that BGE has not prioritized the highest risk pipe. This means that a significant number of miles of pipe have relatively low risk, while a smaller minority have a large amount of risk and should thus be prioritized for replacement or other mitigating actions. **[BEGIN CONFIDENTIAL]** For example, when sorted from highest to lowest risk pipe segments as above, [redacted]

56 Calculated from OPC DR27-01-CONFIDENTIAL CEII Attachment 1.

[redacted][57] **[END CONFIDENTIAL]** These results indicate there is an opportunity to target a minority of miles in BGE's service territory for replacement and still achieve substantial safety benefits.

Q. What do you conclude from this analysis of risk data regarding how BGE should conduct LPP replacement programs?

A. BGE should carefully target its program to the highest risk miles, whenever cost-effective and feasible, to maximize risk reduction from the program. While I would not expect the utility to be able to perfectly deploy its program from highest to lowest risk pipe segments due to logistical or other practical considerations, BGE should be scoping its projects using relative risk scores as a primary factor to achieve the positive safety, reliability, and environmental impacts that BGE states are the goals of the program.[58] When it does not do this, it is implementing projects that are sub-optimal from both a cost and a safety perspective.

Q. How do you define cost-effectiveness in relation to safety-related programs?

A. In this context, cost-effectiveness analysis examines the level of risk reduction expected from alternative measures in comparison with the cost to deploy these alternatives. This allows the utility and stakeholders to compare various mitigations against each other, such as replacement versus pipe lining, from both a safety impact and cost perspective.

[57] Calculated from OPC DR27-01-CONFIDENTIAL CEII Attachment 1.
[58] Direct Testimony of Dawn White 27:15-16.

Q. How can the utility calculate the cost-effectiveness of various safety investments?

A. Cost-effectiveness, sometimes referred to as risk spend efficiency (RSE), is calculated by dividing risk reduction of each mitigation alternative by cost. Ideally, for capital projects, costs should entail the full revenue requirement of an investment over the full depreciation life of the asset, discounted appropriately.[59] Risk reduction is calculated as the level of risk multiplied by mitigation effectiveness (percent reduction in likelihood and/or consequence), discounted appropriately in each year. Mitigation effectiveness can be determined based on historical data and/or subject matter expertise.

RSE = Risk Reduction (Risk x Mitigation Effectiveness) / Cost

Q. Does BGE consider cost-effectiveness in Project 60677?

A. No. BGE seeks to replace all assets under the scope of the program, regardless of relative risk and cost comparisons.[60] A goal of the program *should* be to maximize safety, reliability, and environmental benefits for the dollars spent. This is not reflected in BGE's actions. Instead, BGE plans to spend up to a given cap per year on as much pipeline replacement as it can achieve for what it considers an acceptable unit cost (dollars per mile). As the company explains, "the Company does seek to balance work in the portfolio to maintain an average cost per mile

[59] This allows for the comparison of O&M and capital mitigations. However, if the only mitigations available are capital investments with similar depreciation lives, the calculation of full revenue requirements is less important.
[60] Exhibit ASH-2 (BGE responses to OPC DR 27-02, OPC DR 27-03).

replaced that is in-line with historic averages when feasible." [61] This approach does not treat the expenditure of ratepayer dollars with sufficient care, nor does it utilize information on the risk of assets to achieve the most safety benefits possible, as quickly as possible. Further, since pipeline replacement is the only action considered, strategic decommissioning, pipe lining, or other alternatives that may be more cost-effective are rarely, if ever, considered by BGE.

Planning for Future System Needs

Q. Why is it important to understand the long-term system needs when planning for gas system investments?

A. Gas system assets have multi-decade physical useful lifetimes and are generally depreciated over a comparable timeframe. When making multi-decade asset investments, it is critical to understand how the assets will be used over their lifetime. If their economic useful life is distinctly shorter than their physical life, for example, it is important to account for cost recovery over a shorter period of time when considering impact on rates and competitiveness, and when evaluating alternatives (whether those alternatives are based around repair rather than replacement, or non-pipeline alternatives).

Q. Why is considering future needs particularly important now?

A. As detailed earlier in my testimony, the demands on the gas system within the next two decades will be noticeably different than today, due to ongoing policy and

[61] Exhibit ASH-2 (BGE response to OPC DR 27-02).

market transformations I discussed earlier. These changes will manifest well within the lifetime of most gas capital assets.

Q. Does BGE consider the changing future state of its system when deciding which LPP projects to undertake, and how to scope and approach them?

A. No. None of the factors BGE uses to make decisions about LPP investments incorporate any thinking about the future of the gas system. In fact, because BGE does not even know which LPP projects it is considering more than a year in advance, BGE's decision-making is blind to these considerations. Both Maryland's policy environment and federal policy have changed during the course of the first MRP, and BGE has documented no changes or adjustments to its capital plans or expenditures to reflect this changing context.

Q. What are some problems that could develop because of BGE's failure to look ahead with its LPP investments?

A. Using standard utility accounting and assuming a 65-year lifetime,[62] the LPP investments that BGE is making during the first MRP will have substantial undepreciated plant balances in 2045, when Maryland is committed to be net zero. Of the nearly $2.5 billion of cumulative revenue requirement instigated by BGE's three-year, $423 million investment during MRP I, more than $1.1 billion will remain to be recovered after 2045. BGE has not presented any analysis or demonstrated any detailed thinking about how these investments will be

[62] Calculated based on Exhibit NWA-1 (*2021 Depreciation Study)* at A-4.

worthwhile over their full lifetime and how the company will mitigate resulting stranded cost risks.

Q. Can the Commission be assured that BGE's LPP investments prudently account for the long-term need for these ratepayer-funded assets?

A. No. BGE's lack of long-term planning and failure to account for the appropriate scale and scope for LPP replacement in the face of a changing policy and market context is a symptom of imprudent gas system planning.

Consideration of Alternatives

Q. Why is it important to consider alternatives to replacement for LPP?

A. LPP replacement programs are expensive, install long-lived assets, and are built on a conception that the gas system's future needs will be similar to its present form. If cost-effective alternatives can meet safety and reliability needs while being more flexible to future policy and market context and reducing stranded cost risk, a utility acting prudently should be identifying those alternatives and pursuing them.

Q. Has BGE identified or implemented non-pipeline alternatives (NPAs) to LPP replacement?

A. No.

Q. Are other utilities considering NPAs for LPP?

A. Yes. For example, Con Edison has developed a "Whole Building Electrification Service" NPA. In this program, Con Edison has identified more than 40 segments of LPP that would otherwise be replaced at specific dates over the next decade, the number of customers served, and the length of feet implicated.[63] The utility has evaluated the cost of the traditional pipes-based solutions and alternatives based on electrification, and it has shown that the alternatives are cost-effective.[64] If the utility can identify opportunities to fully electrify all of the customers on the given segment, it will be able to avoid replacing the pipe and could retire it instead. As the utility states in its implementation plan filing: "The Company's Main Replacement Program … is designed to replace leak-prone gas mains, including small diameter, cast iron, wrought iron, and unprotected steel (pre-1972) mains. Planned main replacement can be driven by multiple reasons such as risk level, methane emissions reduction opportunity, or potential for system planning improvement. Under [a main replacement program] NPA, customers currently connected to a targeted main would be incentivized to convert all their current gas uses to electricity, thereby eliminating the need to replace the main."[65] Con Edison developed screening and suitability criteria that lay out the project cost and lead time required to be worth developing NPAs; at least 24 months of lead time is required.

Q. Would it have been prudent for BGE to develop a similar program?

[63] Consolidated Edison Company of New York, *Non-Pipeline Alternatives Implementation Plan*, NY PSC Case No. 19-G-0066 (Nov. 17, 2022).
[64] NY PSC Case No. 19-G-006, Consolidated Edison Company of New York, *Benefit Cost Analysis: MRP Non-Pipeline Alternative Projects* (Nov. 17, 2022).
[65] *Non-Pipeline Alternatives Implementation Plan* at 12.

A. Yes. However, because BGE does not project its LPP replacement projects more than a year in advance, it has foreclosed the opportunity to look out a few years and find opportunities for these savings.

Q. Are there other types of NPAs that could save BGE customers money?

A. Yes. BGE invests in increased gas service capacity to meet increased demand associated with higher pressures from LPP replacement projects, through Project 60701 ("Reinforcement - Gas System Reinforcements"). If BGE pursued demand response and targeted efficiency and electrification measures associated with its other system investments, it could potentially avoid the need for upstream reinforcements.

Prudence of BGE's Approach to LPP

Q. Is BGE's gas capital planning for LPP prudent?

A. Based on my analysis of the three major issues I described above, no.

Q. The Commission approved BGE's budget for these LPP programs, and it reviewed and approved BGE's STRIDE plans over the last three years. What impact does that have on your evaluation of prudence?

A. As I described early in this testimony, prudence review is a retrospective activity. Even with regulatory approval to spend funds (in the form of forward-looking rates which include the expected expenditures) the utility retains an obligation to be aware of all information available and to account for that information when making decisions. Therefore, it is appropriate to review all of BGE's investments since the last rate case for prudence at this time.

Q. If BGE had conducted prudent gas system capital planning, might it have invested in the same projects that BGE proposes to add to rate base in this case?

A. BGE may or may not have selected the same investments. Because BGE's LPP planning process is ad hoc and informal, without documented methods beyond the exercise of near-term engineering judgment, it is not possible to evaluate such a hypothetical case.

Q. Have you identified specific line items of LPP investments that you believe should be disallowed?

A. No. Because BGE's planning process does not lead to the utility taking prudent actions, and is not documented, it is not possible to identify specific changes in investments that would have occurred with a better planning process.

Q. How should the Commission handle BGE's imprudent planning processes if it cannot disallow a specific investment?

A. I recommend that, for this first MRP period, the Commission disallow a portion of BGE's capital budget that corresponds to the ratepayer funds spent on the capital planning function for leak-prone pipe, since this is the function that is the core of BGE's imprudence. The relevant costs are expended in BGE Projects 58449 ("Distribution Integrity Management Program (DIMP) O&M") and 60069 ("STRIDE O&M"). Actual costs for 2021 and 2022 for these programs sum to $3.38 million.[66] I therefore recommend that the Commission disallow $3.38 million of BGE's capital spending on mains and services during the first MRP.

[66] Exhibit DMV-6G at 38.

Q. Why disallow capital, rather than refunding operations and maintenance (O&M) costs immediately?

A. I considered recommending that BGE simply refund this amount of O&M expense. However, that approach would not be well aligned with the costs and form of the imprudent investment. The damage done to ratepayers resulting from imprudent planning is manifest in the capital assets themselves, not in the O&M budgets. BGE's gas planning is important to both customers and the company, and I am not suggesting that it be funded less in the future. Indeed, these functions are essential to making good decisions.

Q. Why not disallow all $423 million from both LPP projects?

A. In this first MRP prudence review, I think it is more appropriate to limit disallowance to the planning function in order to send a clear signal to utility management as to where improvements are required. For the next MRP, however, the Commission should make clear that if the planning function does not improve, all of the investments that BGE makes under its guidance are potentially subject to disallowance.

Excess STRIDE Costs

Q. How does BGE's STRIDE II program relate to its MRP?

A. Maryland piloted MRP ratemaking beginning in 2020. At the time BGE filed its first MRP (for the period 2021-2023), it was midway through its second STRIDE Plan ("STRIDE II"), so the Commission had to reconcile the existing STRIDE II program with the MRP. In a traditional ratemaking environment, STRIDE provides a unique benefit because it allows utilities to begin recovering project costs immediately, rather than needing to wait for a base rate case.[67] As costs are incurred within STRIDE, recovery begins immediately through the STRIDE surcharge (up to the surcharge cap of $2 per month per residential customer, scaled for other classes). This structure allows the utility to avoid regulatory lag and not face a loss of recovered capital due to the wait until the next rate case (which would apply to exceedances over the surcharge cap). Under MRP ratemaking, all cost recovery is based on utility projections for each year, so STRIDE and MRP base rate spending are conceptually similar.[68]

Even so, the Commission decided that BGE could only recover STRIDE II investments made during the 2021-2023 MRP period through the STRIDE surcharge, citing concerns over lack of transparency and excessive customer cost impact if BGE were to combine its STRIDE programs with contemporaneous MRP base spending.[69] BGE could then recover any remaining capital balances from LPP expenses as part of base rates in the *following* rate period, consistent with how it recovered STRIDE exceedances prior to the advent of the MRP pilot.

Q. Did the Commission allow BGE to include costs related to Project 60677 in MRP I base rates?

[67] Order No. 89678 at 26–27 ¶¶ 55, 58, *In re BGE MRP I* (Case No. 9645, 2020).
[68] *Id.* at 27–28 ¶¶ 58, 59.
[69] *Id.* at 29 ¶¶ 60, 61.

A. Yes and no. Since the MRP I proceeding occurred midway through BGE's execution of its second STRIDE five-year plan, the Commission had to address whether to incorporate the company's accelerated infrastructure replacement work planned for 2021-2023 into the MRP rates. While the Commission allowed STRIDE work that had been completed through December 2020 to be included in base rates, it rejected BGE's proposal to include costs associated with its planned STRIDE work for 2021-2023. Acknowledging that the STRIDE surcharge makes the customer impact of these investments more transparent, the Commission concluded that "placing STRIDE projects directly into the base rates circumvents that transparency by requiring the Commission to approve advanced recovery of STRIDE projects with no visibility to customers, instead of mixing STRIDE costs inextricably with all the other elements of BGE's rates."[70] Further, the Commission noted that, through imposing a surcharge cap, the General Assembly put a specific limit on customer bills. While not expressly forbidden by the STRIDE statute, the Commission found that imposing costs related to STRIDE work in excess of $2 per month "would likely be contrary to the intent of the General Assembly."[71]

Q. How is BGE proposing to recover STRIDE exceedances from 2021 and 2022?

[70] *Id.* at 29 ¶ 60.
[71] *Id.* at 29 ¶ 61.

A. BGE seeks to recover $739,000 of excess STRIDE costs associated with STRIDE investments made in 2021 and 2022 though the MYP Adjustment Rider (Rider 15),[72] which is ordinarily used to reconcile spending and revenue from MRP base rates.

Q. Should the Commission allow BGE to recover STRIDE costs through the MYP Adjustment Rider?

A. No. The Commission previously decided that BGE could recover STRIDE costs incurred during the 2021-2023 MRP period through the capped STRIDE surcharge only.[73] BGE's approach is contrary to both the Commission's instructions when it approved the 2021-2023 MRP and the intent of the STRIDE law. The MYP Adjustment Rider is meant to reconcile 2022 base rate spending and revenue, and the Commission clearly stated that BGE should keep its STRIDE spending separate from MRP base rates.[74] I recommend that the Commission not allow BGE to recover these costs through the rider. To the extent the Commission determines that the assets BGE installed that caused costs to exceed the STRIDE cap are used and useful, and that the decision to invest in those assets was a prudent decision based on the best information available at the time, those assets would be part of rate base starting in 2024 (just as past rounds of STRIDE assets

[72] Supplemental Direct Testimony of John C. Frain 9:12–10:18; ASH-2 (BGE response to OPC DR 26-01).
[73] Order No. 89678 at 30 ¶ 64.
[74] Frain Supplemental Direct at 10:5-9 ("[T]he Company understands the Commission was clear in Order No. 89678 that STRIDE investments made over the course of the 2021-2023 MYP 6 period could not be recovered in the forecasted MYP base rates and would only be allowed recovery through the STRIDE surcharge over the 2021-2023 MYP period, subject to the STRIDE surcharge cap.").

have been incorporated into rate base). The General Assembly included a surcharge cap in the STRIDE law to limit the bill impact of accelerated infrastructure replacement. Permitting recovery of STRIDE costs that exceed the surcharge cap runs contrary to the legislature's intent. As the Commission pointed out in Order No. 89678, if BGE believed that the surcharge cap should increase or be eliminated, it could have pursued that issue with the General Assembly.[75]

B. BGE's proposed leak-prone pipe programs are not justified for inclusion in MRP II rates

Projects 60677 and 58034

Q. Please describe BGE's Project 60677 proposal for 2024-2026.

A. Project 60677 refers to BGE's Operation Pipeline program. This program is focused on replacing cast iron and bare steel mains and services with modern materials. BGE is currently seeking approval for costs associated with this program for 2024 to 2026 to be included in rates. BGE projects spending $151 to $155 million per year for the three years of this program.[76]

Q. How does Project 60677 relate to BGE's participation in STRIDE?

A. In BGE's first MRP, BGE's STRIDE work was contained in its Gas Infrastructure Modernization Program (GIMP). This program housed Projects 60677, 60522, and 61258.[77] With the company's decision to no longer participate in STRIDE, all work previously contained in the GIMP will be contained in the System

[75] Order No. 89678 at 29 ¶ 62.
[76] BGE Exh. DCW-1G at 13.
[77] *Id.* at 7.

Performance – Gas Distribution program and pursued through Project 60677. In short, Project 60677—and the related spending proposed for 2024 through 2026—contains work that would otherwise be completed through STRIDE.

Q. Please describe BGE's Project 58034 proposal for 2024-2026.

A. BGE proposes to replace cast iron and bare steel mains and services with modern materials. BGE is currently seeking approval for costs associated with this program for 2024 to 2026 to be included in rates. BGE projects spending $24 million to $25 million per year for the three years of this program.[78]

Q. How many miles of pipe and number of services will BGE replace each year?

A. BGE has not stated exactly how many miles of pipe or number of services it will replace each year through Project 60677 and Project 58034. Based on the last five years of pipeline and service replacement, and BGE's stated estimates of its main replacements under Project 60677, I expect an average of 48 miles of pipe will be retired and/or replaced per year,[79] as well as almost 4,200 services, under BGE's proposed approach. The replacement rate is identical to BGE's accelerated pipeline replacement rate approved in STRIDE II discussed earlier.

Q. Based on BGE's filed information in this case, are you convinced that Projects 60677 and 58034 will make prudent investments during the next three years?

[78] *Id.* at 10.
[79] Exh. ASH-2 (BGE response to OPC DR 3-10).

A. No. BGE has made no indication of any changes in its approach to LPP replacement, other than the completion of the replacement process for ¾-inch steel services. Therefore, I believe that Projects 60677 and 58034 will continue to suffer from the same problems I detailed earlier in my testimony: inadequate prioritization, lack of consideration for the future state and needs of the gas system (informed by state policies and market conditions), and no consideration of alternatives to pipeline replacement.

Q. Have you examined the impacts of continuing BGE's approach to Projects 60677 and 58034 on ratepayers and the utility?

A. Yes, I have. I have examined this question from three perspectives: First, I evaluated the direct ratepayer costs implied by these projects and a continuing business-as-usual approach. Second, I evaluated the impact of these investments on the extent of potential stranded cost risk that the utility would need to mitigate. Third, I compared the impact of these projects on emissions and safety with alternatives such as electrification.

Cost of Pipeline Replacement Programs

Q. What would be the utility's assumed useful lifetime for Project 60677 and 58034 assets installed during the next three years?

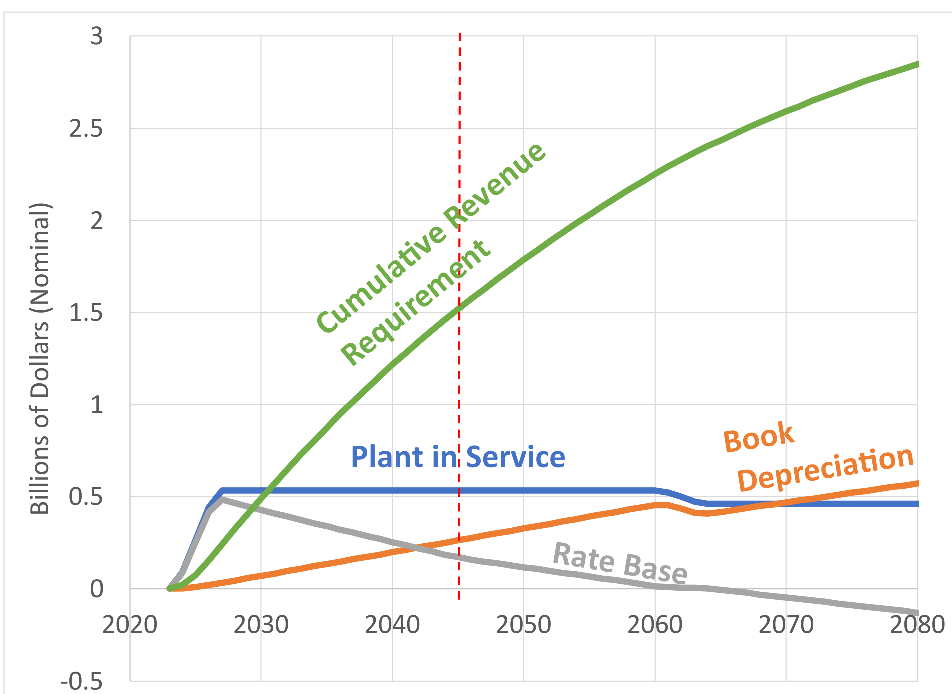
A. BGE uses depreciation rates consistent with a 65-year lifetime for newly installed mains and a 38-year lifetime for newly installed services.[80]

[80] Calculated based on Exhibit NWA-1 (*2021 Depreciation Study*) at A-4.

Q. What will be the revenue requirements associated with Project 60677 and 58034 investments from the next three years?

A. I used a modified version of a spreadsheet tool published by Con Edison in New York PSC Case No. 14-E-0302 (regarding the Brooklyn/Queens Demand Management Program) to model the depreciation, taxes, and return to investors associated with Project 60677 and 58034 investments; the results are shown in Figure 1. I estimate the annual revenue requirement in 2027 alone for these investments would be $87.4 million. In 2045, the revenue requirement associated with these investments would still be $58.6 million. The cumulative revenue requirement for these $533.3 million in investments over their lifetime totals to $3.0 billion.

Figure 3. Estimated ratepayer costs, and their components, from BGE's proposed Project 60677 and 58034 investments in 2024, 2025, and 2026



Q. Could you explain Figure 1, which shows the results of your model, in more detail?

A. Of course. The initial driver is plant in service (blue). Over the course of 2024 to 2026, BGE proposes to add $533 million through Projects 60677 and 58034. As services (which have a shorter life) are retired in the 2060s, the line starts to fall; it falls more sharply after 2089 when the mains are retired. As the installed assets depreciate over time, the reserve for depreciation (orange) grows. The reserve for depreciation dips while the services are retiring, because when they retire they cancel out the depreciation reserve accumulated for them. The depreciation reserve eventually rises above the level of plant in service, because it includes funds collected for net salvage costs for the services and mains.

Rate base (gray) is equal to plant minus depreciation and minus accumulated deferred income taxes. Rate base eventually goes negative because the depreciation reserve (with salvage) grows larger than plant in service, and the deferred income taxes (resulting from the difference in depreciation rates between tax and book depreciation) also pull rate base down.

Each year, the revenue requirement resulting from the asset investment is equal to the sum of the depreciation for that year, the property taxes paid on the asset in that year, and the return on the rate base (with income taxes). Any given year's revenue requirement is small on this scale, but the cumulative revenue requirement (green), which is equal to the sum of all revenue requirement up to a given year, ends up being much larger than the plant in service. The extent to which the cumulative revenue requirement (green) exceeds the upfront cost of the assets (blue, plant in service) is a measure and reminder that ratepayers pay other costs besides the return of capital—they pay for return on capital, income taxes, property taxes, and salvage costs.

The red dotted line shows 2045, the date by which Maryland is committed to achieving net zero GHG emissions.

Stranded Cost Mitigation

Q. If depreciation rates are set at BGE's requested values and do not change, how much of the Project 60677 investments from the next three years will remain undepreciated plant balance in 2045?

A. Of the $533.3 million that BGE proposes to spend from 2024 through 2026, I estimate that there will be a depreciation reserve balance of $263 million (about 50 percent of the original investment) in 2045. Depreciation rates are greater than the lifetime alone would suggest due to salvage costs, however, so BGE would have about $370 million more yet to recover for depreciation expense.[81]

Q. What is the unrecovered future revenue requirement after 2045 for the proposed next three years of Projects 60677 and 58034?

A. $1.48 billion of the cumulative revenue requirement would not yet have been collected by Maryland's net zero date of 2045.

Q. If BGE continued replacing LPP until all mains and services were replaced, when would all mains and services be replaced?

[81] BGE assumes that 45 percent of upfront capital costs for mains and 35 percent for services will be required for end-of-life salvage. BGE Exh. NWA-1 (*2021 Depreciation Study*) at A-4. State or local policy on abandoning retired gas pipes in place could substantially reduce this salvage cost. Federal safety regulations do not require pipes to be removed after they are retired. 49 C.F.R. § 192.727.

A. In its STRIDE filings, BGE has stated a projected end to LPP investments between 2037 and 2043. I analyzed the rate of replacement and remaining balance reflected in BGE's filings to federal pipeline safety regulators. Assuming BGE continues to replace pipes at the current rate of turnover, all cast iron and bare steel mains would be retired in 2040 and all cast iron, bare steel, and copper services would be retired in 2041.

Q. How much would it cost for BGE to replace all leak prone pipes by 2040 and services by 2041?

A. It would cost about $2.98 billion dollars (nominal), assuming BGE's per-unit costs rise at 2 percent per year and BGE continues to replace assets at its recent average pace.

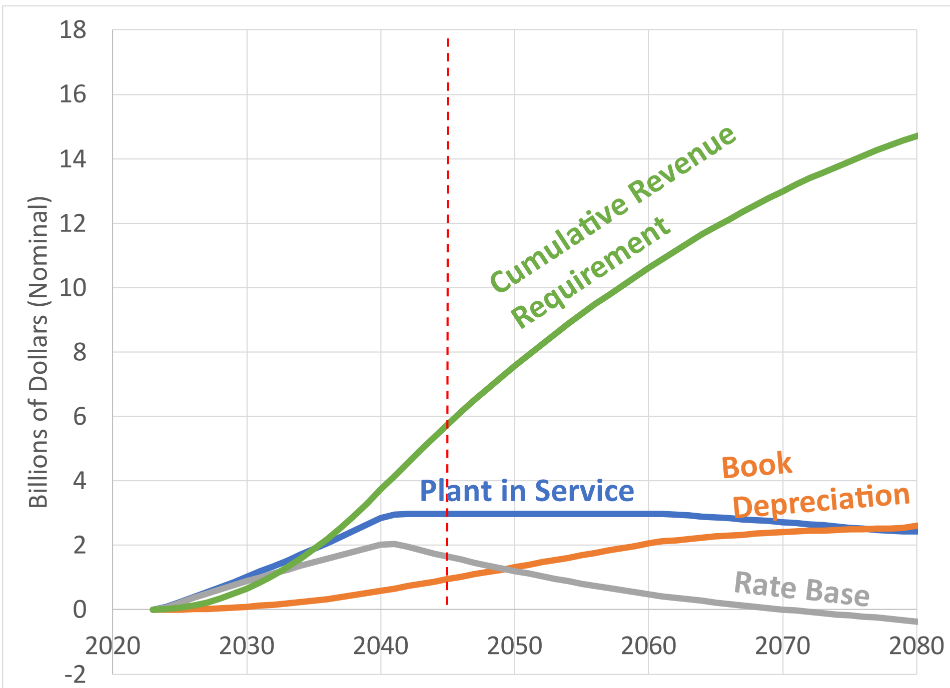
Q. If LPP replacement continues until all mains and services have been replaced (that is, 2041), what would be the resulting undepreciated plant balance in 2045?

A. Of the original $2.98 billion investment to replace all leak prone pipes by 2040 and services by 2041, the undepreciated plant balance in 2045 would be $2.03 billion. Additionally, BGE would have an estimated net salvage obligation of $1.29 billion.

Q. If LPP replacement continues until all mains and services have been replaced (2041), what would be the resulting impact on revenue requirement?

A. In 2042, immediately after the investments from 2024 through 2041 are in rate base, the annual revenue requirement for these investments alone would be about $417 million. In 2045—Maryland's net zero target year—the revenue requirement associated with this investment would still be $388 million per year. The cumulative revenue requirement for these $2.98 billion in investments over their lifetime totals to $16.5 billion, of which $10.7 billion (about 65 percent) would not yet have been paid by customers as of 2045.

Figure 4. Estimated ratepayer costs, and their components, from extending BGE's LPP replacement through 2041



Q. What do these analyses indicate to you regarding stranded cost risk?

A. These analyses show that every year of a business-as-usual approach to pipeline replacement will make it more difficult to mitigate any stranded cost risk associated with customer adoption of electric heating technologies, in line with state policy and market trends. Recovering a rapidly increasing revenue requirement while sales fall will result in increases in delivery rates, which risks encouraging more customers to electrify. While the utility has tools to mitigate these risks including financial options (such as increasing depreciation rates), limiting LPP replacement, using NPAs, and using a repair-rather-than-replace approach could also play an important role in managing the next two decades for BGE. BGE shows no signs of embracing such approaches.

Comparison with Electrification

Q. How much would BGE's proposed LPP programs reduce GHG emissions?

A. Based on historical changes of materials resulting from the STRIDE program, I estimated that each year of LPP replacement investments would reduce ongoing annual emissions by about 5,700 metric tons, or 17,200 tons per year from the combined three years proposed in this case.

Q. What would ratepayers pay to achieve these emissions reductions through this method?

A. BGE's proposed revenue requirement for the three years of LPP investment comes to about $87.4 million in 2027. On a per-ton basis, this works out to $5,081 paid per metric ton reduced in 2027. This is a very high cost to pay for emissions reduction, compared with other actions (to be discussed below) and compared with estimates of the social cost of GHG emissions. Recent analysis from the U.S.

Environmental Protection Agency estimates the social cost of CO_2 emissions at between $120 and $600 per ton.[82]

Q. Would the proposed Project 60677 eliminate methane leakage risk from the assets installed?

A. No. While new materials have lower leak rates, new pipes retain risk from leakage caused by excavation damage. In 2022, about 30 percent of all identified leaks on the BGE system were caused by excavation damage,[83] and the emissions and safety impact from these leaks would not be avoided by replacement.

Q. How would the cost of Project 60677 compare with other actions to reduce emissions and increase safety?

A. BGE expects to replace about 48 miles of cast iron and steel mains each year, along with associated services, at an annual cost of $151 million to $155 million for Project 60677. That works out to an average of about $3.2 million per mile.[84] Assuming a range of roughly 60 to 120 customers per mile (based on the ratio of services to mains), this implies a cost of $26,500 to $53,000 per customer. The BGE Study estimates that the per-household capital costs for full electrification are about $17,900, or $30,400 including building shell efficiency improvements.[85] Project 60677 operates on a neighborhood basis, so targeted electrification and

[82] U.S. EPA, *Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances.* (Sept. 2022), https://www.epa.gov/system/files/documents/2022-11/epa_scghg_report_draft_0.pdf.
[83] ASH-2 (BGE responses to OPC DR 3-4, Sierra Club DR 4-1). The response to OPC DR 3-4 lists 3,455 leaks without excavation damage; the response to Sierra Club DR 4-1 lists 5,007 total leak repairs. The difference is 1,552 excavation-associated leaks.
[84] ASH-2 (BGE response to OPC DR 3-11).
[85] *BGE Integrated Decarbonization Strategy* at 35, Figure 18.

efficiency could work as a cost-effective non-pipeline alternative to LPP replacement.[86] As I discuss later in my testimony, BGE's failure to plan multiple years in advance is a barrier to such an approach, but that is solvable with better planning.

Q. What do you recommend the Commission do with respect to BGE's proposals for Project 60677 and 58034?

A. I recommend the Commission remove the projected capital costs for these programs from the going-forward calculations used to set rates in this proceeding. If BGE conducts prudent gas capital planning and proposes the incorporation of prudent LPP investments into rate base in its next case, the Commission should evaluate the proposal it receives at that time. It should not incorporate any LPP replacement capital into rates until *after* it has judged them to be prudent.

Project 56695

Q. Please describe BGE's proposed "proactive service renewals" project (Project 56695).

A. BGE proposes to proactively replace services made of materials that show increased leak rates as they age. This program focuses on services not associated with mains whose leak rate is increasing or are slated for replacement through Project 60677 or similar actions. BGE proposes to spend $4.8 million in 2024,

[86] Customers not ready to fully electrify could be served by delivered propane until such time as they are ready to replace their equipment.

$7.2 million in 2025, and $9.0 million in 2026 on this project.[87] BGE plans to renew approximately 500 services in 2024, 750 in 2025, and 900 in 2026.[88]

Q. What is the cost per service renewed?

A. Taking the three years of the project together, the average capital cost is about $9,800 per service.

Q. Is it cost-effective to spend nearly $10,000 renewing a typical residential service line?

A. No. If a typical customer uses 500 therms per year, and the utility delivery rate is 67 cents per therm[89] (or $335 per year), it would take almost 30 years to pay back the cost of the service line renewal. This is before accounting for the time value of money, the utility's profit on the investment, or expected declines in customer use from efficiency and electrification. If a typical service renewal at this cost were evaluated according to the formulation that BGE uses for new service connection, it is likely that the customer would be required to make a substantial contribution.

Q. Does BGE's proposed investment in renewing service lines reflect an analysis of the likely future need for gas service?

A. No, it does not. BGE is implicitly assuming that the future demand for gas service will be similar to today, even though state and federal policy are headed in a different direction.[90]

Q. If it is not cost-effective to renew these services, what should BGE do?

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[87] BGE Exh. DCW-1G at 9.
[88] Exh. ASH-2 (BGE response to OPC DR 3-18(b)).
[89] BGE's residential delivery rate in 2023 is 66.84 cents per therm.
[90] *See* Direct Testimony of Ron Nelson at 38:5–40:5.

A. It would be inappropriate to leave customers without access to the services that gas provides, since they are currently being served. However, they are being served today, and the existing asset works. Investing these funds just to avoid a potential future leak or disruption of service is not a prudent use of resources. So, one option would be to do nothing regarding this service line. A better way to address concerns about future leaks in the service line would be for the state to incentivize the replacement of home gas appliances with electric appliances (using EmPOWER programs as appropriate), then retire the service. This alternative approach would increase safety relative to renewing the service (because the service line would no longer be at risk of damage), save net ratepayer funds, and be consistent with state policy.

Q. What do you recommend the Commission do regarding this program?

A. The Commission should reject BGE's proposal for Project 56695 and remove the cost of this program from any future rate year used in setting rates in this docket. As with other LPP programs, if BGE does renew some services during the next three years and can demonstrate the decisions were prudent to the satisfaction of the Commission, its investments could be included in rate base following the next rate case.

Expectations for all LPP-related expenditures going forward

Q. How should BGE proceed with respect to addressing potential safety and reliability concerns associated with LPP?

A. BGE should conduct comprehensive system planning and develop a long-term system plan. It should do so within the context of a long-term planning framework overseen by the Commission.[91] This plan should identify where replacement is appropriate, and where other approaches (such as advanced leak detection and NPAs) can more cost-effectively achieve safety goals.

Q. Should BGE use the STRIDE mechanism if the company does continue its replacement work and wants accelerated cost recovery?

A. To the extent BGE plans to continue its pipeline replacement work, such investments should be pursued through the STRIDE program. The legislature established STRIDE specifically to incent (and oversee) accelerated replacement of aging infrastructure. Given the STRIDE law's additional review and monitoring requirements—and the customer cost protections provided by the surcharge caps—the General Assembly determined that comprehensive pipeline replacement investments warrant additional regulatory scrutiny and consumer protections. Accordingly, LPP replacement investments should be proposed and reviewed pursuant to STRIDE.

Q. What are your recommendations related to the concerns you outline regarding BGE's lack of focus on maximizing benefits and minimizing costs of its program?

[91] In February 2023, OPC filed a petition with the PSC for such a process, which is currently subject to stakeholder comments. *See Petition of the Office of People's Counsel for Near-Term, Priority Actions and Comprehensive, Long-Term Planning for Maryland's Gas Companies*, Case No. 9707, ML# 301247 (Feb. 9, 2023).

A. I recommend that if BGE chooses to file its LPP replacement program under STRIDE, it does so with a much greater focus and additional analysis regarding the potential risk reduction and cost-effectiveness of its proposal. Rather than a vague proposal to replace pipe in unknown locations given certain annual and unit cost parameters, BGE should instead seek to maximize risk reduction and minimize costs, within the context of a comprehensive system plan. To demonstrate its improved assessment of risk and cost-effectiveness, BGE should incorporate the following elements into any future proposal:[92]

- A demonstration of how the utility will deploy the program from highest to lowest risk according to the utility's most current risk modeling, allowing for deviations from a pure risk-based approach due to logistical and practical constraints.
- Consideration of additional alternatives to pipeline replacement, including but not limited to strategic decommissioning and lining.
- Calculation of cost-effectiveness metrics (RSEs) for multiple alternatives at the pipe-segment or project level.
- An explanation of how cost-effectiveness metrics (RSEs) support the utility's proposal, and where they do not, why BGE has decided to propose less cost-effective solutions.

[92] If the Commission decides to include these investments in the MRP, then this information should be provided in the annual reports and reconciliation filings. If filed under STRIDE, then BGE should use the filings required under that program to share this information.

Q. What guidance should the Commission provide to BGE in its order in this case?

A. The Commission should remind BGE that all expenditures are subject to prudence review and inform BGE that imprudent gas-planning practices will result in disallowance of the resulting capital expenditures (not just a portion reflecting the cost of the planning function). The Commission should direct BGE to develop a long-term system plan that is consistent with Maryland state policy, to demonstrate that future capital expenditure decisions reflect the expected future state of the gas system, to develop non-pipeline alternative screening and suitability criteria (including for pipeline replacement projects), to screen capital investments against those criteria and develop NPAs where cost-effective, and to prudently manage uncertainty by maintaining optionality and avoiding irreversible large expenditures.

IV. BGE's Transmission Investments Are Not Sufficiently Justified

Q. Have you reviewed BGE's proposals regarding replacing transmission pipes?

A. Yes. I reviewed the testimony of Witness White, as well as discovery responses, particularly including OPC DR 19-01 through 19-08.

Q. Could you please summarize the primary reason why BGE is replacing transmission assets, and the associated cost?

A. BGE is obligated by a 2019 transmission rule promulgated by the federal Pipeline and Hazardous Material Safety Administration (PHMSA) to confirm the maximum allowable operating pressure (MAOP) for its transmission pipes.[93] Determining the MAOP requires understanding the materials used in each segment of pipe. For some of its transmission pipes, BGE is unable to use its existing records to confirm the materials and thus the MAOP. Replacing transmission pipes is one of the allowed options to determine the MAOP: Once the pipe is replaced, the utility has the necessary information to be sure of its MAOP.

Q. What are the methods BGE can use to confirm MAOP, under the PHMSA regulation?

A. The MAOP of a transmission pipe can be confirmed by (1) conducting a pressure test, (2) reducing the pressure to a level somewhat below recent operating pressure, (3) and engineering critical assessment, such as in-line inspection, (4) pipe replacement, or (5) use of alternative technology submitted to PHMSA for approval.[94]

Q. Which specific projects are you addressing in your testimony?

A. I am addressing Projects 55633 ("Granite Pipeline – Stokes Drive to Russell Street"), 58079 ("Manor Loop Pipeline"), and 58080 ("Manor System South"). These are all projects that BGE states are necessary because of the PHMSA regulation, and for which BGE chose replacement as the preferred way to comply with the regulation. BGE chose replacement as the compliance path for these

[93] *Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments*, 84 Fed. Reg. 52180 (Oct. 1, 2019) (codified at 49 C.F.R. §§ 191, 192).
[94] 49 C.F.R. § 192.624(c).

assets because the assets are relatively old. BGE proposes to spend $145.7 million over the 2024-2026 period to replace these transmission assets, and to use the MRP structure to begin to recover these costs before the next rate case.

Q. Did BGE consider alternative approaches for its older transmission assets?

A. Not seriously. When asked for its assessments of alternate approaches for these transmission projects, BGE repeatedly responded, "Based on the assessment results, age, and lack of records, BGE has selected replacement" for the given asset.[95] The bulk of these assets are generally more than 50 years old.

Q. What other options could BGE have pursued with respect to these assets?

A. BGE could have conducted pressure tests for these assets, an engineering critical assessment (such as through in-line inspection), or it could have reduced the pressure on the lines by a factor below the highest recorded sustained pressure.

Q. Would these options have been less expensive?

A. Yes, these methods are all less expensive to implement than replacing the pipes. In its analysis, when establishing the 2019 transmission rule, PHMSA estimated that pressure testing costs around 10 percent as much as replacement, or less, and engineering critical assessment costs potentially several hundred times less than replacement.[96] Reducing the pressure might result in the inability of the system to

[95] See Exh. ASH-2 (BGE responses to OPC DR 19-2, OPC DR 19-4, and OPC DR 19-5).
[96] PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION, *Regulatory Impact Analysis: Natural Gas Transmission (49 CFR Part 191 & 192) Final Rule* (Oct. 2019), https://www.regulations.gov/document/PHMSA-2011-0023-0466. PHMSA estimates a cost of $35.65 per foot to conduct a pressure test, costs ranging between $0.83 and $5.90 per foot for engineering critical assessment (plus some fixed costs per test of up to $20,000), and pipe replacement costs of $226 to

serve peak demand in the near term, so that option can, in some cases, be set aside independent of cost.

Q. What concerns do you have with respect to BGE's choice to replace these transmission pipes?

A. BGE's choice reflects the utility's lack of a long-term plan. Replacement might make sense if the gas system were going to be used in the same manner going forward as it has been in the past, and another 50 to 70 years of service at comparable service levels could be confidently expected. However, as I detailed earlier in my testimony, the future of the gas system will not be the same as the past.

It could be prudent to take incremental steps that buy time before making costly and irreversible infrastructure decisions. BGE could, for example, conduct a pressure test or engineering assessment on its aged assets in order to satisfy its time-certain obligation to PHMSA. BGE could then review its transmission system needs as part of a comprehensive review of its assets in light of its changing business. Such a review might identify the potential for some areas to see reductions in load, thereby making pressure reductions a possibility. BGE might also find that it can use repair and monitoring approaches to maintain an older pipe for a limited period until it can be retired or replaced with a lower cost

$1,377 per foot. *Id.* at 13. BGE's transmission pipe replacement costs are in the range of several million dollars per mile, which put them in line with PHMSA's estimates for the cost of pipe replacement.

asset, rather than replaced in kind. Because BGE has no long-term infrastructure plan that is grounded in changes in load resulting from decarbonization, BGE is unable to optimize for changes in capacity or to choose potentially lower cost options.

Q. What do you recommend the Commission do with respect to BGE's proposed PHMSA-related transmission replacement investments?

A. The Commission should not include expenditures on Projects 55633, 58079, and 58080 in MRP rates set for 2024-2026. These assets should be considered as part of a comprehensive gas system planning process. If BGE elects to proceed with these investments outside of the MRP, it can propose these investments for inclusion in its next base rate case and make the argument that it prudently selected and managed these investments. It is important for regulatory discipline that BGE understand that all its investments are subject to strict retrospective prudence review and may be disallowed in their entirety.

V. BGE's Plan to Install Smart Gas Meters Is Misguided

Q. Please describe BGE's proposal to replace gas meters.

A. BGE proposes to replace about 574,000 of its 718,000 gas meters with Intelis "smart" meters between 2025 and 2031.[97] BGE's estimated capital and operations and maintenance cost for this replacement program is $277.2 million over those

[97] Exhibit ASH-2 (Staff DR 81-4(b),(g)).

seven years.[98] This meter replacement project will replace approximately 428,000 meters before the end of their previously projected useful life of 33 years.[99] The new meters have an estimated useful life of 20 years.[100]

Q. What is the total cost of this program during the MRP II period?

A. Through Project 81516, BGE proposes to spend $57.76 million on gas meter conversions—$6.54 million in 2024, 22.28 million in 2025, and 28.95 million in 2026.[101]

Q. What is BGE's justification for this program?

A. BGE's current meters have failing communications modules. BGE proposes to shift from this module replacement project to installing Intelis meters because they offer additional safety technology such as autonomous shutoff, integrated thermal sensors, theft detection, and remote disconnect capability.[102]

Q. Has BGE analyzed the costs and benefits of its proposed meter replacement plan?

A. No. BGE has estimated the capital costs (assuming a business-as-usual approach to the number and lifetime of the meters), but has not presented any quantitative justification that the costs are worth it for customers. The proposed meters are capable of various actions (such as remote connection and disconnection), which should have financial implications for ratepayers, but BGE has not quantified

[98] Exhibit ASH-2 (Staff DR 81-4(d)).
[99] Exhibit ASH-2 (Staff DR 81-8(d)).
[100] Exhibit ASH-2 (Staff DR 81-7).
[101] Exhibit ASH-2 (BGE response to Staff DR 81-14, Attachment 1).
[102] Direct Testimony of Denise Galambos 17:15-20.

these benefits. If BGE had provided a benefit-cost analysis of this proposal, it would be possible to evaluate whether the investment is worthwhile and beneficial to customers.

Q. What would be the result of replacing 80 percent of BGE's meters between 2025 and 2031, and then retiring many of those meters by 2045?

A. The result of such an inefficient and poorly planned use of capital and operations and maintenance costs would be additional costs for BGE's customers, a stranded cost risk for BGE's investors, or both. Meters installed under BGE's proposed program would all be equal to or less than 20 years old (their expected useful life) when Maryland achieves its net zero goal in 2045.

Q. Could BGE delay or target its installation of smart meters to more prudently manage its energy transition risk?

A. Yes. BGE has 422,000 meters that were installed after 2000 and therefore have at least 10 years left on their expected useful life, and only 31,000 meters that have exceeded their 33-year expected life as of 2023.[103] BGE could replace the failing communications modules on its existing meters at a much lower cost than replacing them. BGE could then defer commitments to mass meter upgrades until it has a clear plan for how many meters it needs over which timeframes, and serving which areas or which customer types. In some cases, for example, it may make sense to extend the life of existing meters or repurpose meters from a departing customer to serve another customer, rather than purchase new meters to

[103] Exhibit ASH-2 (BGE response to Staff DR 81-08, Attachment 2).

have them used for only a short period of time. In short, BGE has not justified the prudence of retiring the majority of its meters before the end of their useful life, in order to replace them with other meters that may well also be retired before the end of their useful life.

Q. Does BGE's meter replacement plan account for changes in the need for meters associated with meeting Maryland's GHG objectives?

A. No. BGE Witness Galambos does not address these changes, and there is no indication in the plan itself that any changes might occur in the gas system as a result of decarbonization.

Q. Is there a substantial likelihood that BGE may have fewer customers, and therefore need fewer meters, before the state's 2045 deadline to achieve net zero emissions?

A. Yes. The BGE Study includes three scenarios for decarbonization, and all three scenarios show fewer space heating customers using pipeline gas in 2045 than today.[104] In that report's "Limited Gas" pathway—the pathway most consistent with the recommendations of the Maryland Commission on Climate Change—12 percent of customers continue to receive gas service from BGE.[105] Even under BGE's favored "integrated" pathways, BGE's gas customer count declines by at least 25 percent in 2045.[106]

Q. Would prudent utility capital planning account for this potential change in the number of meters required when deciding on a meter replacement plan?

[104] *BGE Study* at 21.
[105] *Id*. 27.
[106] *Id*.

A. Yes. Prudent utility planning would consider how many meters would be required by year, and prudent planners develop a plan to most cost-effectively deploy meters over the coming years. To the extent that there remains uncertainty regarding the number and distribution of meters required, prudent planning would consider deferring major upgrade projects until the meter plan can be pursued with certainty, to avoid wasting money.

Q. What do you recommend the Commission do with respect to BGE's proposal in this case?

A. The Commission should remove any planned capital expenditure on new "smart" meters from rate bases for MRP II. Replacing error-prone wireless units on existing meters does appear to be a prudent course of action in order to maintain remote meter reading capabilities. While the Commission ruled in the first MRP case that the prudence of investments should be evaluated during the rate case following the investment (rather than beforehand), the Commission should find that BGE has not sufficiently justified this investment to allow the interim recovery that the MRP structure allows before a full prudence review can be completed.

VI. Summary and Conclusion

Q. Please summarize your recommendations.

A. I recommend that the PSC:

- direct BGE to improve its capital planning processes and align them with state policy;

- disallow \$6.06 million of BGE's capital expenditures to reflect imprudent capital planning during MRP I regarding leak-prone pipe replacement programs;
- reject BGE's request to approve recovery of STRIDE exceedances from MRP I;
- remove the projected capital costs for Projects 60677 and 58034 from the going-forward calculations used to set rates in this proceeding;
- reject BGE's proposal for Project 56695 and remove the cost of this program from any future rate year used in setting rates in this docket;
- direct BGE to file any leak-prone pipe replacement program through the STRIDE mechanism;
- set high expectations for BGE regarding analysis of risk reduction and cost-effectiveness for leak-prone pipe replacement proposals;
- not include expenditures on Projects 55633 ("Granite Pipeline – Stokes Drive to Russell Street"), 58079 ("Manor Loop Pipeline"), and 58080 ("Manor System South") in MRP II rates set for 2024–2026;
- remove any planned capital expenditure on new "smart" meters from projections used to set forward-going rates; and
- open a proceeding to examine long-term planning for Maryland's gas utilities.

Q. Could you summarize your recommended disallowances and rejected proposals by year of expenditure?

A. Of course. Here is a table:

Category	Project	2021	2022	2024	2025	2026
Leak-Prone Pipe	60677	1,531,608	1,852,715	151,023,844	152,956,646	155,302,110
Leak-Prone Pipe	58034			24,438,384	24,781,898	24,854,193
Leak-Prone Pipe	56695			4,827,303	7,232,658	8,951,384
Transmission	55633			4,393,845	4,785,031	51,597,236
Transmission	58079			6,483,728	50,573,402	8,401,518
Transmission	58080			856,704	1,612,223	17,041,700
Meters	81516			6,540,500	22,275,726	28,947,297

Q. Does this conclude your testimony?

A. Yes, it does.

Exhibit ASH-1

Asa S. Hopkins, Ph.D., Vice President

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PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA. *Vice President*, April 2019 – present, *Principal Associate*, January 2017 – March 2019.

Conducts research and writes expert testimony and reports related to state energy policy and planning, energy efficiency, strategic electrification, deep decarbonization, and the present and future of electric and gas utility regulatory and business models.

Vermont Public Service Department, Montpelier, VT. *Director of Energy Policy and Planning,* October 2011 – December 2016

State energy planning and utility regulation

• Directed the year-long development of the 2016 Vermont Comprehensive Energy Plan, including stakeholder meetings, public forums, and coordination of contributions from other departments and the Governor's office. Primary author of the executive summary and five chapters.

• Led the Department's approach to establishing budgets and performance targets for energy efficiency utilities. Oversaw staff conducting program evaluation and savings verification.

• Submitted testimony and conducted analysis in support of public advocacy and negotiation in prominent litigated regulatory proceedings.

Policy development, analysis, and advocacy

• Developed the structure of Vermont's 2015 Renewable Energy Standard, including its novel "energy transformation" requirement. Worked with stakeholders to develop support for the policy and with the legislature to shepherd it to passage. This policy will result in more reduction of Vermont's GHG emissions than any others passed in the last 15 years.

• Led execution of Vermont's Total Energy Study, which examined technology and policy pathways for Vermont to meet GHG emission and renewable energy goals.

• Led cost-benefit analysis of Vermont's existing net metering structure and led the development of departmental proposals for a new structure.

• Prepared and delivered public, stakeholder, and interagency presentations, including to agency and business leaders, legislative committees, and the governor.

• Oversaw programs providing financing, technical, and process assistance to clean energy projects.

During tenure, Vermont rose in the rankings on national clean energy state scorecards: ACEEE State Energy Efficiency Scorecard from 5th to 3rd and U.S. Clean Tech Leadership Index from 10th to 3rd.

U.S. Department of Energy, Washington, DC. *Special Advisor to the Under Secretary for Science / AAAS Science and Technology Policy Fellow,* September 2010 – August 2011

Dr. Hopkins served as the assistant project director for the Department of Energy's first Quadrennial Technology Review. In this role, he coordinated a team that solicited input from Department of Energy and National Laboratory staff and scientists, ran a series of public workshops, facilitated coordination with the White House, developed a set of technology assessments, and ultimately drafted the Report on the First QTR, published Sept. 27, 2011.

Lawrence Berkeley National Laboratory, Berkeley, CA. *Environmental Energy Policy Postdoctoral Fellow*, January 2009 – August 2010

Conducted technical and economic analysis to support the Department of Energy in setting the energy efficiency standards that appliances must meet in order to be sold in the United States.

California Institute of Technology, Pasadena, CA. *Graduate Research Fellow,* 2002 – 2008

Los Alamos National Laboratory, Los Alamos, NM. *Post-Baccalaureate Researcher, Theoretical Division,* June 2001 – June 2002

EDUCATION

California Institute of Technology, Pasadena, CA
Doctor of Philosophy in Physics, 2008
Master of Science in Physics, 2007

Haverford College, Haverford, PA
Bachelor of Science *summa cum laude*, in Physics with minors in Computer Science and Growth and Structure of Cities, 2001

SELECTED PROJECTS

The Future of Gas Utilities – Dr. Hopkins leads Synapse's work in the area of the future of gas utilities. He and his team are assisting a number of clients to understand the future of gas utilities in the context of deep building decarbonization objectives. This work includes assisting Conservation Law Foundation in Massachusetts Department of Public Utilities Docket 20-80 (an investigation into "the role of gas local distribution companies as the Commonwealth achieves its target 2050 climate goals"); the Industrial Gas Users Association in evaluation of energy-transition-related business risk to Quebecois and Ontario gas utilities; Natural Resources Defense Council in New York and Nevada's regulatory proceedings regarding the future of gas; the Colorado Energy Office regarding approaches to decision-making in the face of uncertainty, in the context of Colorado's regulatory proceedings regarding gas utility Clean Heat plans and building decarbonization; the County of San Diego (with the University of California San Diego) in developing the buildings and utilities portion of its Regional Decarbonization Framework; the Maryland

Office of People's Counsel in modeling the impact of the state's decarbonization objectives on utility sales and finances; and the District of Columbia Department of Energy and Environment in assessing Washington Gas Light's Climate Business Plan and rate case filings.

Puerto Rico Energy Bureau – Synapse has provided extensive support to Puerto Rico's electricity regulator since 2015. Dr. Hopkins has coordinated the engagement since 2018. Dr. Hopkins has led or substantially contributed to the development of Puerto Rico's first energy efficiency and demand response regulations; emergency microgrid regulations; and the review of the island's second Integrated Resource Plan and subsequent processes to optimize resilience using both transmission and distributed generation resources.

Massachusetts Comprehensive Energy Plan – On behalf of the Massachusetts Department of Energy Resources (the state energy office), Synapse and Sustainable Energy Advantage assisted DOER and its sister agencies in the development of Massachusetts's first Comprehensive Energy Plan. Dr. Hopkins assisted DOER leadership in defining the scope and approach for the CEP, to distinguish it from other state planning processes. He worked with Pat Knight to develop an approach to modeling energy transformations toward low-carbon alternatives in electricity, buildings, and transportation that are consistent with state policy and approaches while being grounded in stock turnover rates and feasible policies and programs.

Northeastern Regional Assessment of Strategic Electrification – On behalf of the Northeast Energy Efficiency Partnerships, Synapse and Meister Consultants Group identified the opportunity, costs, and benefits available if strategic electrification is adopted as a key strategy for decarbonization in New York and New England. Dr. Hopkins, Kenji Takahashi, and Pat Knight are primary authors of the resulting report, published in July 2017, which characterizes the current markets for efficiency electrification technologies (such as heat pumps and electric vehicles), identifies policies to overcome market barriers, assesses the state of electrification technologies, and models the extent of electrification both possible given market dynamics and required to meet regional greenhouse gas emission goals.

2016 Vermont Comprehensive Energy Plan – Directed the year-long development of the 2016 plan, including setting its strategic approach to current Vermont energy planning challenges and grounding it in quantitative analysis. Developed the public engagement process, then hosted expert stakeholder meetings and public forums. Adapted the results of the 2014 Total Energy Study to produce scenarios that illustrate the proposed pathways identified in the plan. Coordinated contributions from staff and leaders in other departments, and from the Governor's office. Wrote the executive summary and 5 of the 14 chapters.

Total Energy Study – Scoped and led a legislatively-mandated report on policy and technology pathways to meet Vermont's renewable energy and greenhouse gas emission goals. Designed and facilitated a focus-group-based stakeholder engagement process to identify technology and policy visions for analysis. Retained outside modeling consultant, then worked closely with them to build credible business-as-usual and policy case models of Vermont's energy economy to the year 2050 using the

TIMES/FACETS integrated assessment model. Translated those model results to make REMI PI+ calculations of impact on Vermont GDP and jobs. Synthesized qualitative and quantitative results into intermediate and final reports identifying key outcomes for policy design.

Demand Resources Plan Proceedings – In each of three, three-year cycles, led the development of the Department of Public Service's positions regarding appropriate budgets, rate and bill impacts, and performance targets for Vermont's energy efficiency utilities. Analyzed current efficiency utility performance to calibrate expected future performance. Negotiated performance metrics that reflect policy priorities. Developed new regulatory and budget treatment of research and development for behavioral energy efficiency programs.

Quadrennial Technology Review – As Assistant Project Director, managed the project activities of the eight-person core team for the U.S. Department of Energy's first Quadrennial Technology Review. This review of DOE's energy technology activities established a robust framework and codified principles used to build DOE's energy technology portfolio (including identifying the appropriate and highest-leverage activities for DOE relative to the private sector and other government actors). Extensive collaboration and discussions within DOE, as well the public through a series of workshops with industry, government, national laboratory, and academic participation, culminated in the publication of the first DOE-QTR report in September 2011. Coordinated successful stakeholder workshops; facilitated focus groups. Drafted discussion papers that served as the basis for extensive intra- and inter-agency and White House coordination and negotiation. Primary author of the final report's section on building and industrial energy efficiency. Project was completed on schedule and on budget, and met its critical milestones.

REPORTS

Hopkins, A. S., A. Napoleon, K. Schultz. 2023. *The High Cost of New York Gas Utilities' Leak- Prone Pipe Replacement Programs.* Synapse Energy Economics for Natural Resources Defense Council.

Carlson, E., P. Eash-Gates, B. Fagan, A. Hopkins. 2023. *Review of Northwest Natural Gas 2022 Integrated Resource Plan—Final Report: Assessing Compliance with the Oregon IRP Guidelines and the Greenhouse Gas Reduction Requirements from the Climate Protection Program.* Synapse Energy Economics for Staff of Oregon Public Utilities Commission.

Hopkins, A. S., A. Napoleon, J. Litynski, K. Takahashi, J. Frost, S. Kwok. 2022. *Climate Policy for Maryland's Gas Utilities: Financial Implications*. Synapse Energy Economics for Maryland Office of the People's Counsel.

Kwok, S., K. Takahashi, J. Litynski, A. S. Hopkins. 2022. Memo: Massachusetts DPU Docket-2080: Proposed "Common Regulatory Framework." Synapse Energy Economics for Conservation Law Foundation.

Hopkins, A. S. S. Kwok, J. Litynski, A. Napoleon, K. Takahashi. 2022. Memo: Evaluation of Draft Consultant Reports in Massachusetts DPU Docket 20-80. Synapse Energy Economics for Conservation Law Foundation.

Hopkins, A. S., A. Napoleon, S. Kwok. 2022. *Factsheet: Hydrogen & Low-Carbon Gases in New York's Electricity Future*. Synapse Energy Economics for Sierra Club.

Hopkins A. S., P. Eash-Gates, J. Frost, S. Kwok, J. Litynski, K. Takahashi. 2022. "Decarbonization of Buildings." In *San Diego Regional Decarbonization Framework*, edited by SDG Policy Initiative, School of Global Policy and Strategy, University of California San Diego. San Diego.

Frost, J. S. Kwok, K. Takahashi, A.S. Hopkins, A. Napoleon. 2021. *New York Heat Pump Trajectory Analy*sis. Synapse Energy Economics for NRDC.

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Woolf, T., A. Napoleon, A. Hopkins, K. Takahashi. 2021. *Long-Term Planning to Support the Transition of New York's Gas Utility Industry*. Synapse Energy Economics for Natural Resources Defense Council.

Frost, J., J. Litynski, S. Letendre, A. S. Hopkins. 2021. *Economic Impacts of Climate Change on Cape Cod*. Synapse Energy Economics for Eastern Research Group and the Cape Cod Commission.

Hopkins, A.S., P. Knight, J. Frost. 2021. *Rhode Island Carbon Pricing Study.* Synapse Energy Economics and the Cadmus Group for the Rhode Island Office of Energy Resources.

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Takahashi, K., E. Sinclair, A. Napoleon, A. S. Hopkins, D. Goldberg. 2021. *Evaluation of EnergyWise Low-Income Energy Efficiency Program in Mississippi – Program Performance, Design, and Implications for Low-Income Efficiency Programs*. Synapse Energy Economics for Sierra Club and Gulf Coast Community Foundation.

Kallay, J., A. Napoleon, J. Hall, B. Havumaki, A. S. Hopkins, M. Whited, T. Woolf, J. Stevenson, R. Broderick, R. Jeffers, B. Garcia. 2021. *Regulatory Mechanisms to Enable Investments in Electric Utility Resilience.* Synapse Energy Economics for Sandia National Laboratories.

Kallay, J., A. Napoleon, B. Havumaki, J. Hall, C. Odom, A. S. Hopkins, M. Whited, T. Woolf, M. Chang, R. Broderick, R. Jeffers, B. Garcia. 2021. *Performance Metrics to Evaluate Utility Resilience Investments.* Synapse Energy Economics for Sandia National Laboratories.

Kallay, J., S. Letendre, T. Woolf, B. Havumaki, S. Kwok, A. S. Hopkins, R. Broderick, R. Jeffers, K. Jones, M. DeMenno. 2021. *Application of a Standard Approach to Benefit-Cost Analysis for Electric Grid Resilience Investments*. Synapse Energy Economics for Sandia National Laboratories.

Hopkins, A. S., S. Kwok, A. Napoleon, C. Roberto, K. Takahashi. 2021. *Scoping a Future of Gas Study.* Synapse Energy Economics for Conservation Law Foundation.

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Shipley, J., A. S Hopkins, K. Takahashi, D. Farnsworth, 2021. *Renovating Regulation to Electrify Buildings: A Guide for the Handy Regulator*. Regulatory Assistance Project.

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Eash-Gates, P., K. Takahashi, D. Goldberg, A. S. Hopkins, S. Kwok. 2021. *Boston Building Emissions Performance Standard: Technical Methods Overview.* Synapse Energy Economics for the City of Boston.

Camp, E., C. Odom, A. S. Hopkins. 2020. *Cost-Effectiveness of Proposed New Mexico Environment Department Oil and Gas Emissions Reduction Rules: Impacts and Co-Benefits of Reduced Volatile Organic Compound Emissions from the Oil and Gas Industry.* Synapse Energy Economics for Environmental Defense Fund.

Camacho, J., K. Takahashi, A. S. Hopkins, D. White. 2020. *Assessment of Proposed Energize Eastside Project*. Synapse Energy Economics and MaxETA Energy for the City of Newcastle, WA.

Takahashi, K., J. Frost, D. Goldberg, A. S. Hopkins, K. Nishio, K. Nakano. 2020. *Survey of U.S. State and Local Building Decarbonization Policies and Programs*. Presented at the 2020 ACEEE Summer Study of Energy Efficiency in Buildings.

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Takahashi, K., A. S. Hopkins, J. Rosenkrantz, D. White, S. Kwok, N. Garner. 2020. *Assessment of National Grid's Long-Term Capacity Report*. Synapse Energy Economics for the Eastern Environmental Law Center.

Camp, E., N. Garner, A. S. Hopkins. 2019. *Cost-Effectiveness of Comprehensive Oil and Gas Emissions Reduction Rules in New Mexico: Impacts of Reduced Methane and Volatile Organic Compound Emissions from the Oil and Gas Industry.* Synapse Energy Economics for the Environmental Defense Fund.

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Kallay, J., A. S. Hopkins, J. Frost, A. Napoleon, K. Takahashi, J. Slason, G. Freeman, D. Grover, B. Swanson. 2019. *Net Zero Energy Roadmap for the City of Burlington, Vermont*. Synapse Energy Economics and Resource Systems Group for Burlington Electric Department.

Camp, E., B. Fagan, J. Frost, D. Glick, A. S. Hopkins, A. Napoleon, N. Peluso, K. Takahashi, D. White, R. Wilson, T. Woolf. 2018. *Phase 1 Findings on Muskrat Falls Project Rate Mitigation.* Synapse Energy Economics for Board of Commissioners of Public Utilities, Province of Newfoundland and Labrador.

Hopkins, A. S., P. Knight, N. Peluso. 2018. *Massachusetts Comprehensive Energy Plan: Commonwealth and Regional Demand Analysis.* Synapse Energy Economics, Sustainable Energy Advantage, and MA DOER for the Massachusetts Department of Energy Resources.

Knight, P., D. Goldberg, E. Malone, A. S. Hopkins, D. Hurley. 2018. *Getting SMART: Making sense of the Solar Massachusetts Renewable Target (SMART) program*. Synapse Energy Economics for Cape Light Compact.

Hopkins, A. S., K. Takahashi, D. Glick, M. Whited. 2018. *Decarbonization of Heating Energy Use in California Buildings: Technology, Markets, Impacts, and Policy Solutions*. Synapse Energy Economics for the Natural Resources Defense Council.

Woolf, T., A. S. Hopkins, M. Whited, K. Takahashi, A. Napoleon. 2018. *Review of New Brunswick Power's 2018/2019 Rate Case Application.* In the Matter of the New Brunswick Power Corporation and Section 103(1) of the Electricity Act Matter No. 375. Prepared by Synapse Energy Economics for the New Brunswick Energy and Utilities Board Staff.

Hopkins, A. S., K. Takahashi. 2017. *Alternatives to Building a New Mt. Vernon Substation in Washington, DC*. Synapse Energy Economics for the District of Columbia Department of Energy and Environment.

Hopkins, A. S., S. Fields, T. Vitolo. 2017. *Policies to Cost-Effectively Retain Existing Renewables in New York*. Synapse Energy Economics for the Alliance for Clean Energy New York.

Vitolo, T., A. S. Hopkins. 2017. *The Mounting Losses at CWLP's Dallman Station: A Study of the Relative Costs of Operating Each of the Four Dallman Units*. Synapse Energy Economics for the Sierra Club.

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U.S. Department of Energy. 2011. *Report on the First Quadrennial Technology Review*. DOE/S-0001.

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Hopkins, A. S., K. Takahashi, S. Nadel. 2020. "Keep warm and carry on: Electrification and efficiency meet the 'polar vortex'." Proceedings of the 2020 ACEEE Summer Study of Energy Efficiency in Buildings.

Hopkins, A. S., K. Takahashi, L. David. 2018. "Challenges and Opportunities for Deep Decarbonization through Strategic Electrification under the Utility Regulatory Structures of the Northeast". Proceedings of the 2018 ACEEE Summer Study on Energy Efficiency in Buildings, August 2018.

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Dunsky, P., A. S. Hopkins, K. Vaillancourt, M. Fabbri. 2016. "Achieving an Ultra-Low Carbon Future: Technology and Policy Pathways to Meet Vermont's GHG Goals," *ACEEE Summer Study on Energy Efficiency in Buildings.*

Greenblatt, J., A. S. Hopkins, V. Letchert, M. Blasnik. 2012. "Energy Use of U.S. Residential Refrigerators and Freezers: Function Derivation Based on Household and Climate Characteristics," *Energy Efficiency.* 10.1007/s12053-012-9158-6.

Hopkins, A. S., L. Gu, A. Lekov, J. Lutz, G. Rosenquist. 2011. "Simulating a Nationally Representative Housing Sample Using EnergyPlus," Lawrence Berkeley National Laboratory Report, LBNL-4420E.

Lutz, J.D., A. S. Hopkins, V. Letschert, V.H. Franco, A. Sturges. 2011. "Using National Survey Data to Estimate Lifetimes of Residential Appliances," *HVAC&R Research*.

Alvarez, R.M., A. S. Hopkins, B. Sinclair. 2010. "Mobilizing Pasadena Democrats: Measuring the Effects of Partisan Campaign Contacts," *The Journal of Politics* 72, 31.

Nielsen, A.E.B., A. S. Hopkins, H. Mabuchi. 2009. "Quantum Filter Reduction for Measurement-Feedback Control Via Unsupervised Manifold Learning," *New Journal of Physics* 11, 105043.

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Hopkins, A. S., K. Jacobs, S. Habib, K. Schwab. 2003. "Feedback Cooling of a Nanomechanical Resonator," *Physical Review B* 68, 235328.

TESTIMONY

Ontario Energy Board (EB-2022-0200): Testified as an expert on the business risk facing Enbridge Gas, Inc. related to the energy transition and other risks, as part of a rate case proceeding to set the utility's capital structure. On behalf of the Industrial Gas Users Association, 2023.

Washington DC Public Service Commission (FC 1169): Provided direct and rebuttal expert testimony regarding Washington Gas's application for an increase in rates, from the standpoint of the District of Columbia's climate and clean energy policies. On behalf of the District of Columbia Government, November 2022 and January 2023.

New York Public Utilities Commission (Case No. 22-E-0064 and 22-G-0065): Direct and Rebuttal Testimony of Alice Napoleon and Asa Hopkins regarding Con Edison's proposed gas-side investments as greenhouse gas mitigation strategies and gas extension allowance rule changes and the need for long-term planning for the gas system and adequacy of the company's non-pipe alternatives framework. On behalf of Natural Resources Defense Council, May 2022.

Régie de l'énergie du Québec (R-4156-2021): Testified as an expert on the business risk facing Quebec's natural gas utilities related to the energy transition, as part of a proceeding to set the utilities' cost of capital and capital structure. On behalf of the Industrial Gas Users Association, 2022.

Vermont Public Utility Commission (Case No. 21-1107-PET and 21-1109-PET): Addressed the impact of GlobalFoundries proposed "self-managed utility" on the general good of the state and Vermont's energy policy, with particular focus on the impact on environmental soundness and greenhouse gas emissions mitigation. On behalf of Conservation Law Foundation, June 2021.

Public Service Commission of Wisconsin (Docket No. 5-CG-106): Addressed the need for a pair of liquified natural gas facilities in light of the fossil fuel use reductions required to meet state and federal goals for mitigating climate change and the potential for cost-effective demand-side alternatives. On behalf of the Sierra Club, June 2021.

Vermont Senate Finance Committee: Provided expert testimony in the form of a presentation entitled "Updating Vermont's Renewable Energy Standard" to the Vermont Senate Finance Committee in January of 2020. Dr. Hopkins presented on the history of the standard, what has changed since 2015, and future potential.

Vermont Public Utility Commission (Case No. 17-1247-NMP): Addressed the consistency of a proposed solar generation facility with the Vermont Comprehensive Energy Plan. On behalf of Derby GLC Solar LLC, January 2018.

Washington DC Public Service Commission (FC 1142): Provided expert testimony regarding the merits of the proposed merger of Washington Gas and AltaGas, Ltd. with respect to the impact on environmental quality, with particular emphasis on the impact of utility management and its approach to climate change on the ability of the District to achieve its climate change mitigation goals. On behalf of the District of Columbia Government.

Régie de l'énergie du Québec (R-3986-2016): Provided an expert report and testimony regarding best practices in utility demand response programs, in the context of Hydro Québec Distribution's ten-year Supply Plan. On behalf of the Regroupment national des conseils régionaux de l'environment du Québec (RNCREQ).

Vermont Public Service Board (Dockets No. 8586 and 8685): Addressed the need for a proposed solar PV generator and its associated contract under PURPA rates, its economic impact on the state, and its consistency with the Vermont Electric Plan. On behalf of the Vermont Department of Public Service, July 2016.

Vermont Public Service Board (Docket No. 8684): Proposed avoided energy and capacity cost rates for use in Rule 4.100, Vermont's implementation of PURPA. On behalf of the Vermont Department of Public Service, October 2015 and May 2016.

Vermont Public Service Board (Docket No. 8600): Addressed the need for a proposed solar PV generator, its economic impact on the state, and its consistency with the Vermont Electric Plan. On behalf of the Vermont Department of Public Service, March 2016.

Vermont Public Service Board (Docket No. 8525): Introduced a memorandum of understanding between the DPS and Green Mountain Power regarding a proposed rate design, with particular focus on new critical peak price rates to be available and marketed. On behalf of the Vermont Department of Public Service, November 2015.

Vermont Public Service Board (Docket No. 7970): Addressed whether increases in the expected cost of a gas pipeline expansion project were sufficient to warrant reopening the underlying proceeding, particularly with respect to the need for the project, the economic impact on the state, and consistency with the general good of the state and the Vermont Comprehensive Energy Plan. On behalf of the Vermont Department of Public Service, May 2015.

Vermont Public Service Board (Docket No. 8311): Addressed how statutory criteria for the use of electric energy efficiency funds for electrification measures (such as heat pumps) might be met. On behalf of the Vermont Department of Public Service, January 2015.

Vermont Public Service Board (Docket No. 7862): Presented the Department's positions regarding whether Entergy Vermont Yankee should be granted a continued certificate of public good, with particular focus on the need for the plant, the economic benefit of continued operation, consistency with the Vermont Electric Plan, and whether continued operation by Entergy was in the general good of the state. On behalf of the Vermont Department of Public Service, October 2012 and April 2013.

Vermont Public Service Board (Docket No. 7833): Addressed the need for a proposed biomass electric generator and its consistency with the Vermont Electric Plan. On behalf of the Vermont Department of Public Service, October and November 2012; February and September 2013.

Vermont Public Service Board (Docket No. 7770): Addressed a number of topics related to the merger of Green Mountain Power and Central Vermont Public Service, most particularly the disposition of a windfall repayment due to ratepayers. On behalf of the Vermont Department of Public Service, January and March 2012.

Vermont Public Service Board (Docket No. 7815): Addressed consistency of a proposed long-term PPA with the Vermont Electric Plan and the utility's integrated resource plan. On behalf of the Vermont Department of Public Service, January 2012.

SELECTED PRESENTATIONS

Hopkins, A. S. "IIJA, IRA, and the Growing Federal Role in Transmission—and Why States Should Care," presented at the National Association of State Energy Officials Annual Meeting, October 2022.

Hopkins, A. S., J. Litynski, A. Takasugi. "Policy approaches to increasing electricity affordability in California," presented to various California stakeholders on behalf of Natural Resources Defense Council, February 2022.

Shipley, J., Hopkins, A. S., Takahashi, K., & Farnsworth, D. "Renovating regulation to electrify buildings: A guide for the handy regulator," presented with Regulatory Assistance Project, January 2021.

Hopkins, A. S. 2019. "Efficiency, Electrification, and Renewables in New England and Puerto Rico" at 2019 ACEEE Energy Efficiency as a Resource Conference, October 2019.

Hopkins, A. S. 2019. "Strategic electrification and winter cold snaps: A resource and a challenge" at 2019 ACEEE Energy Efficiency as a Resource Conference, October 2019.

Panelist on "Deep Dive Session on State and Local Electrification Roadmaps" at Electric Power Research Institute (EPRI)/Northeast Energy Efficiency Partnerships (NEEP) Electrification Summit, August 2019.

Hopkins. A. S., K. Takahashi, D. Lis. 2018. "Decarbonization through Strategic Electrification Meets Utilities and Regulation in the Northeast" at the 2018 ACEEE Summer Study on Energy Efficiency in Buildings, August 2018.

Hopkins, A. S. 2019. "Strategic Electrification: Impacts and approaches to meeting decarbonization goals in the northeastern states (and elsewhere)" at Lawrence Berkeley National Laboratory, Energy Technologies Area, August 2018.

Hopkins, A. S. 2017. "Utility Performance Regulation" at the Western States Regional Meeting of the National Association of State Energy Officials, April 2017.

Panelist on "A Regulatory Perspective of Grid Transformation" at the IEEE Innovative Smart Grid Technologies Conference, September 2016.

Panelist on the "Comprehensive Energy Plan Update" at the Renewable Energy Vermont Conference, October 2015.

Hopkins, A. S. 2015. "Vermont's Total Energy Study." Presentation at the National Association of State Energy Officials Energy Policy Outlook Conference, February 2015.

Panelist on "The Role of Energy Efficiency in Mitigating Winter Peak Issues" at the Association of Energy Services Professionals (Northeast Chapter) & Northeast Energy Efficiency Council, November 2014.

Hopkins, A. S. 2014. "Total Energy Study." Presentation at the Renewable Energy Vermont Conference, October 2014.

Panelist on "State Energy & Economic Policy Impacts on Industry Transformation" at the Power Industry Transformation Summit, April 2014.

Hopkins, A. S. 2008. "Mobilizing Pasadena Democrats: Measuring the Effects of Partisan Campaign Contacts." Presentation at the American Political Science Association Annual Meeting, August 2008.

HONORS, AWARDS, AND FELLOWSHIPS

Certified Public Manager, 2014

AAAS Science and Technology Policy Fellowship, 2010 – 2011

Dean's Award for Community Service, 2009

Delegate to the 2004 Democratic National Convention

NSF Graduate Research Fellow, 2002 – 2005

Los Alamos National Laboratory Student Distinguished Performance Award, 2002

Two-time first-team Academic All American, 2000 and 2001

Barry M. Goldwater Scholar, 1999 – 2001

OTHER ACTIVITIES

NASEO - Electricity Committee: Affiliate Co-Chair, 2020-present

Newton, MA Citizens Commission on Energy, Member 2017-present

Guest on Synapse Energy Economics, Inc.'s *Energy Nerd Show,* Aug 6, 2020

Board Member, National Association of State Energy Officials, 2015-16

Industrial Advisory Board for ARPA-E-funded project "Packetized Energy Management," 2016

Burlington, VT Public Works Commission: Member 2012 –2014, Chair 2015

Resume updated May 2023

Exhibit ASH-2

BGE Responses to Data Requests

Case No. 9692
Baltimore Gas and Electric Co.
Response to OPC Data Request 3
Request Received: March 10, 2023
Response Date: March 24, 2023
Sponsor(s): Dawn C. White

Item No.: OPCDR03-01

Please refer to the direct testimony of BGE witness White at page 22–23 regarding Project 60677 BGE Operation Pipeline.

a. Please describe in reasonable detail the process by which BGE identifies projects for replacement through Operation Pipeline. In your answer, please discuss and explain whether/how this process differs from the approach taken by the company to identify projects for replacement through its STRIDE II plan approved in CN 9468.
b. Provide any documents, manuals, or other written materials including operating plans and/or internal operating procedures that govern the selection of projects for replacement through Operation Pipeline.

RESPONSE:

The approach used for Project 60677 BGE Operation Pipeline for MYP 2 will continue to be consistent with how projects are currently identified for replacement under the STRIDE II plan approved in Case No. 9468. The Company considers a variety of factors and uses engineering judgement to determine which BGE Operation Pipeline projects are ultimately considered for replacement. The Company does not have specific documents or procedures on how to select Operation Pipeline. Factors considered may include the following:

1. <u>Risk Scores</u>: Summation of Optimain risk scores for cast iron main in a region.
2. <u>Leak History</u>: Summation of leaks for cast iron main in a region.
3. <u>Break History</u>: Summation of breaks for cast iron main in a region.
4. <u>Recent Leak or Break History</u>: Region has high number of leak repairs over the last several years or in the last year. Includes field subject matter expertise.
5. <u>High density paving</u>: Region has “wall to wall” paving, which is considered a high risk factor.
6. <u>Poor Supply or Pressure</u>: Region has a history of poor supply, or is projected to have low pressures during cold weather, which is a reliability concern or evidence of poor performing main.
7. <u>Pressure System</u>: Consideration of the existing pressure system. Replacement of low pressure system main with a higher pressure system main provides additional safety features. Higher pressure bare steel main considered higher risk.
8. <u>Replacement Continuity</u>: Continuation of project work in a particular region, community, town, etc. As BGE starts outreach with local communities and government officials, BGE often establishes a plan to continue replacement work in the region year over year until completed.

9. Replacement "Clean up": Region contains mostly newer infrastructure and replacement work would eliminate all remaining targeted outmoded infrastructure.
10. Multiple Main Replacement Program Jobs: Region contains multiple main replacement projects, identified either through the Optimain-Points Assessment process or field driven replacements. These jobs are more effective to be replacement as part of a larger Operation Pipeline project.
11. Municipal/Agency Coordination: Project work driven by coordination with various municipal or government agencies.
12. Geographic Location: Consideration of the location of the work. BGE tries to balance work portfolio across its system to avoid overwhelming communities, municipalities, permitting agencies, traffic, parking, etc.

Case No. 9692
Baltimore Gas and Electric Co.
Response to OPC Data Request 3
Request Received: March 10, 2023
Response Date: March 24, 2023
Sponsor(s): Dawn C. White

Item No.: OPCDR03-02

Please provide a list of specific projects with costs exceeding $1 million identified for completion through Operation Pipeline for years 2024, 2025, and 2026, including the assets targeted by each project and estimated cost.

RESPONSE:

BGE has not identified a list of specific asset replacement jobs for Project 60677 BGE Operation Pipeline for the years 2024 through 2026. Instead, BGE sets its forecasted spend based on an overall estimated workplan for replacements, not individual jobs. As ongoing work occurs on the system over the course of the year, BGE narrows its focus for individual jobs based on its progress as well as factors described in the response to OPCDR03-01.

Case No. 9692
Baltimore Gas and Electric Co.
Response to OPC Data Request 3
Request Received: March 10, 2023
Response Date: March 24, 2023
Sponsor(s): Dawn C. White

Item No.: OPCDR03-04

Please provide the historical leak rate for pre-1970 ¾ Steel Services from 2016-2022 using the following chart:

Pre-1970 ¾" HP Steel Services	2017	2018	2019	2020	2021	2022
End of Year Population (# of Services)						
Leaks (w/o excavation damages)						
Leak Rate (w/o excavation damages)						

RESPONSE:

Please see the table below for historical leak rate data by main and service and material.

		2017	2018	2019	2020	2021	2022
Cast Iron Main	End of Year Population (miles)	1,168	1,118	1,068	1,016	974	932
	Leaks (w/o excavation damages)	2,781	2,654	2,491	2,564	2,629	2364
	Leak Rate (w/o excavation damages)	2.38	2.37	2.33	2.52	2.70	2.54
Bare Steel Main	End of Year Population (miles)	20	18	16	14	14	13
	Leaks (w/o excavation damages)	17	15	39	34	24	13
	Leak Rate (w/o excavation damages)	0.85	0.83	2.44	2.43	1.71	1.00
Coated Steel Main	End of Year Population (miles)	2,795	2,789	2,793	2,778	2,779	2,777
	Leaks (w/o excavation damages)	330	310	358	347	375	226
	Leak Rate (w/o excavation damages)	0.12	0.11	0.13	0.12	0.13	0.08
Plastic Main [1]	End of Year Population (miles)	3,363	3,459	3,565	3,660	3,757	3,838
	Leaks (w/o excavation damages)	117	155	144	165	119	124
	Leak Rate (w/o excavation damages)	0.03	0.04	0.04	0.05	0.03	0.03
Bare Steel Services (w/o pre-1970 3/4" HP steel services)	End of Year Population (# of services)	60,538	57,357	54,371	50,685	48,347	48,174
	Leaks (w/o excavation damages)	607	583	427	388	404	609
	Leak Rate (w/o excavation damages)	0.85	0.87	0.67	0.65	0.71	1.08
Pre-1970 3/4" HP Steel Services	End of Year Population (# of services)	31,686	27,107	21,409	13,708	8,115	4,909
	Leaks (w/o excavation damages)	2,143	1,535	894	561	373	119
	Leak Rate (w/o excavation damages)	5.76	4.82	3.56	3.49	3.91	2.06

[1] Plastic main data reflects all plastic main infrastructure on the Company's gas distribution system.

Case No. 9692
Baltimore Gas and Electric Co.
Response to OPC Data Request 3
Request Received: March 10, 2023
Response Date: March 24, 2023
Sponsor(s): Dawn C. White

Item No.: OPCDR03-10

Regarding the Operation Pipeline program, please provide the projected annual replacement goal and estimated cost for each asset listed below for years 2024–2026:

a. Cast iron main;
b. Bare steel main;
c. Coated steel main;
d. Vintage plastic main;
e. Bare steel services;
f. Copper services;
g. Pre-1970 ¾" HP steel services.

RESPONSE:

For Project 60677: BGE Operation Pipeline, BGE estimates about 48 miles of cast iron and bare steel main in total to be retired each year of the MYP 2024-2026 period. In addition, because Operation Pipeline replaces infrastructure on a neighborhood level, often transitioning to a new pressure system, there will be coated steel and plastic main retired as part of the work. However, BGE does not forecast or target specific quantities of coated steel and plastic main replaced through the program, as the quantities vary year to year, depending on individual projects.

For services, BGE does not have a specific annual goal within Operation Pipeline. Bare steel, copper, and other service materials are eliminated through the targeted main replacement activities within the program, not through targeted service replacement. As BGE replaces cast iron and bare steel mains, the services are replaced as well. This prevents performing rework in neighborhoods with different replacement programs. These quantities will vary year to year and are dependent on the individual projects. BGE does not retire pre-1970 ¾" HP services through BGE Operation Pipeline.

Please see the response to StaffDR11-02 for more information on estimated total outmoded asset retirements for all project work, including Operation Pipeline.

Please refer to Company Exhibit DCW-1G, page 9, for total forecasted BGE Operation Pipeline investments. BGE does not budget this program by material type.

Case No. 9692
Baltimore Gas and Electric Co.
Response to OPC Data Request 3
Request Received: March 10, 2023
Response Date: March 24, 2023
Sponsor(s): Dawn C. White

Item No.: OPCDR03-11

For each type of main targeted for replacement through the Operation Pipeline program, please provide the cost per mile used to estimate the Operation Pipeline program spend for years 2024–2026.

a. Cast iron main;
b. Bare steel main;
c. Coated steel main;
d. Plastic main.

RESPONSE:

BGE estimates Project 60677: BGE Operation Pipeline program based on an average cost per mile of cast iron / bare steel main retirement. These per mile costs include all work needed to perform these regional replacement projects, including, but not limited to, main installation, service replacement activities, other main material retirements, and restoration. The estimated cost per mile of cast iron / bare steel main retired for the MYP 2024-2026 period is as follows.

- 2024: $3.146 million
- 2025: $3.187 million
- 2026: $3.235 million

Case No. 9692
Baltimore Gas and Electric Co.
Response to OPC Data Request 3
Request Received: March 10, 2023
Response Date: March 24, 2023
Sponsor(s): Dawn C. White

Item No.: OPCDR03-18

Refer to witness White's direct testimony at page 24 regarding Project 56695 Proactive Service Renewals.

a. Please identify the "other poor performing service asset classes" this program will target.
b. For each asset class identified in question 18(a) above, please detail the annual replacement targets identified and estimated annual cost for 2024, 2025, and 2026.
c. Please provide a list of specific projects with costs exceeding $1 million identified for completion through this program for years 2024-2026, including assets targeted by each project and estimated cost.
d. Please detail the criteria by which assets are identified for replacement under this program.

RESPONSE:

a. BGE will target leak-prone population subsets that demonstrate relatively poorer performance than other services. These may include older metallic services and certain plastic services, with these subsets being selected and confirmed through ongoing analysis in 2023, in preparation for work initiation and execution in 2024.

b. BGE estimates the number of leak-prone services that will be replaced proactively in Project 56695 Proactive Service Renewals will be approximately 500 in 2024, 750 in 2025, and 900 in 2026.

c. There will not be any jobs exceeding $1 million within Project 56695.

d. This program is intended to target BGE's worst-performing service population subsets, thereby improving safety and reliability, and reducing risk. BGE will perform analyses through its DIMP program to determine which population subsets are the most appropriate target(s) for this program, and it is expected that targeted subsets will change as service population subsets change in quantity or performance over time. In general, services targeted within this program are not populations that would be replaced through expected main replacement activities, such as BGE Operation Pipeline.

Case No. 9692
Baltimore Gas and Electric Co.
Response to OPC Data Request 19
Request Received: April 27, 2023
Response Date: May 11, 2023
Sponsor(s): Dawn C. White

Item No.: OPCDR19-01

Please refer to generally witness White's direct testimony at 21, beginning at line 1, which states "as a result of the new Final Transmission 1 Rule published by PHMSA under DOT Part 192, BGE is committed to meeting the new requirements for traceable, verifiable, and complete records to reconfirm MAOP. In many cases, this will require BGE to replace transmission infrastructure at a faster pace, as the new rule provides specific guidelines on the schedule. Finally, much of the remaining work performed is required to maintain compliance with regulations and engineering standards." Has BGE developed a decision-making framework or structure regarding how and under what conditions it will use each of the different methods identified in the new Final Transmission Rule published by PHMSA (i.e., Methods 1-6 in *Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments)* to meet the new requirements under that rule? If yes, please provide the workpapers and references showing the framework, any application of that framework, and its results, including worksheets if applicable. If not, please explain why not.

RESPONSE:

BGE conducted an extensive assessment effort to review all records necessary for Maximum Allowable Operating Pressure (MAOP) and gas transmission pipeline material properties from 2020 through 2021. As part of the assessment report, there is discussion regarding the consideration of each of the MAOP reconfirmation methods established by PHMSA. Please see the Company's response to StaffDR11-12 as well as StaffDR11-12--CONFIDENTIAL CEII Attachment 1 for the assessment.

Case No. 9692
Baltimore Gas and Electric Co.
Response to OPC Data Request 19
Request Received: April 27, 2023
Response Date: May 11, 2023
Sponsor(s): Dawn C. White

Item No.: OPCDR19-02

Please refer to witness White's direct testimony at 30, lines 5–12, regarding Project 55633: Granite Pipeline-Stokes Drive-Russell Road:

a. For each type of asset to be replaced in this project, please provide:
   i. the average age of the components to be replaced in this project
   ii. the book life of that asset type
   iii. the book value of the components to be replaced in this project
   iv. the book value of the components to be installed in this project
b. Referring to PHMSA's regulation on Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments
   i. Has BGE conducted a pressure test (Method 1) regarding these assets? If so, what were the results? If not, why not?
   ii. Has BGE considered reducing the pressure in these assets (Method 2 or Method 5)? If so, please provide the results of the analysis. If not, why not?
   iii. Has BGE considered conducting an engineering critical assessment (Method 3) regarding these assets? If so, what were the results of that consideration? If not, why not?
   iv. Has BGE conducted an engineering critical assessment (Method 3) regarding these assets? If so, what were the results? If not, why not?
   v. Has BGE considered using alternative technology (Method 6) regarding these assets? If so, what alternative technologies were considered? What were the results of that consideration? If not, why not?

RESPONSE:

a. Project 55633: Granite Pipeline-Stokes Drive-Russell Road consists primarily of main replacement work along a portion of the Granite transmission line, with the potential for replacement of minor quantities of services or other assets, to be determined once the design and engineering phase is finalized. The majority of the main to be replaced is 70 years old or older. Please refer to StaffDR78-01-Attachment 1 for the useful life for gas mains.

   BGE uses the group method for depreciating its assets. Under the group depreciation method, individual assets are not tracked thus it is not possible to know the book value (gross cost less accumulated depreciation reserve) of specific assets when they are retired. Additionally, utility mass plant assets (like gas main) are not tracked by location

in company accounting records. For these reasons, the book value of the components to be replaced cannot be provided.

The original cost of the project within the MYP period is disclosed in Company Exhibit DCW-1G. To the extent capital expenditures extend beyond the MYP period, the final installed cost of a given project will be higher than the capital expenditures reflected in the testimony of Company Witness White.

b. Based on the assessment results, age, and lack of records, BGE has selected replacement for the Granite Transmission Line. Please refer to StaffDR11-12-CONFIDENTIAL CEII Attachment 1 for more details.

Case No. 9692
Baltimore Gas and Electric Co.
Response to OPC Data Request 19
Request Received: April 27, 2023
Response Date: May 11, 2023
Sponsor(s): Dawn C. White

Item No.: OPCDR19-03

Please refer to Company Exhibit DCW 1-G at 20 regarding Project 60080: Granite Pipeline-Gate Station to Lord Baltimore:

a. For each type of asset to be replaced in this project, please provide:
   i. the average age of the components to be replaced in this project
   ii. the book life of that asset type
   iii. the book value of the components to be replaced in this project
   iv. the book value of the components to be installed in this project
b. Referring to PHMSA's regulation on Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments
   i. Has BGE conducted a pressure test (Method 1) regarding these assets? If so, what were the results? If not, why not?
   ii. Has BGE considered reducing the pressure in these assets (Method 2 or Method 5)? If so, please provide the results of the analysis. If not, why not?
   iii. Has BGE considered conducting an engineering critical assessment (Method 3) regarding these assets? If so, what were the results of that consideration? If not, why not?
   iv. Has BGE conducted an engineering critical assessment (Method 3) regarding these assets? If so, what were the results? If not, why not?
   v. Has BGE considered using alternative technology (Method 6) regarding these assets? If so, what alternative technologies were considered? What were the results of that consideration? If not, why not?
c. Provide the analysis supporting its classification as a Priority 1 project.
   i. Confirm if Project 60080 is required to provide service to new customers. Please provide supporting workpapers and spreadsheets.
   ii. Confirm if Project 60080 is required to meet regulations. Please provide supporting workpapers and spreadsheets.
   iii. Confirm if Project 60080 is required for facility relocations. Please provide supporting workpapers and spreadsheets.
   iv. Confirm if Project 60080 is required to prevent or restore outages. Please provide supporting workpapers and spreadsheets.
   v. Confirm if Project 60080 is currently under construction. Please provide supporting workpapers and spreadsheets.
   vi. Confirm if Project 60080 is required to maintain COMAR compliance. Please provide supporting workpapers and spreadsheets.

RESPONSE:

a. Project 60800: Granite Pipeline-Gate Station to Lord Baltimore consists primarily of main replacement work along a portion of the Granite transmission line, with the potential for replacement of minor quantities of services or other assets, to be determined once the design and engineering phase is finalized. The majority of the main to be replaced is 70 years old or older. Please refer to StaffDR78-01-Attachment 1 for the useful life for gas mains.

   BGE uses the group method for depreciating its assets. Under the group depreciation method, individual assets are not tracked thus it is not possible to know the book value (gross cost less accumulated depreciation reserve) of specific assets when they are retired. Additionally, utility mass plant assets (like gas main) are not tracked by location in company accounting records. For these reasons, the book value of the components to be replaced cannot be provided.

   The original cost of the project within the MYP period is disclosed in Company Exhibit DCW-1G. To the extent capital expenditures extend beyond the MYP period, the final installed cost of a given project will be higher than the capital expenditures reflected in the Direct Testimony of Company Witness White.

b. Based on the assessment results, age, and lack of records, BGE has selected replacement for the Granite transmission line. Please refer to StaffDR11-12--CONFIDENTIAL CEII Attachment 1 for more details.

c. This project is required to meet the new regulatory requirements of the Final Transmission Rule under DOT Part 192. Please see Company Witness White's Direct Testimony at page 29 for more information on the requirements.

Case No. 9692
Baltimore Gas and Electric Co.
Response to OPC Data Request 19
Request Received: April 27, 2023
Response Date: May 11, 2023
Sponsor(s): Dawn C. White

Item No.: OPCDR19-04

Please refer to witness White's direct testimony at 30, lines 13–16, regarding Project 58079: Manor Loop Pipeline:

a. For each type of asset to be replaced in this project, please provide:
   i. the average age of the components to be replaced in this project
   ii. the book life of that asset type
   iii. the book value of the components to be replaced in this project
   iv. the book value of the components to be installed in this project
b. Referring to PHMSA's regulation on Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments
   i. Has BGE conducted a pressure test (Method 1) regarding these assets? If so, what were the results? If not, why not?
   ii. Has BGE considered reducing the pressure in these assets (Method 2 or Method 5)? If so, please provide the results of the analysis. If not, why not?
   iii. Has BGE considered conducting an engineering critical assessment (Method 3) regarding these assets? If so, what were the results of that consideration? If not, why not?
   iv. Has BGE conducted an engineering critical assessment (Method 3) regarding these assets? If so, what were the results? If not, why not?
   v. Has BGE considered using alternative technology (Method 6) regarding these assets? If so, what alternative technologies were considered? What were the results of that consideration? If not, why not?

RESPONSE:

a. Project 58079: Manor Loop Pipeline consists primarily of main replacement work along the Manor Loop and a portion of the Manor Extension transmission lines, with the potential for replacement of minor quantities of services or other assets, to be determined once the design and engineering phase is finalized. The majority of the main to be replaced is 57 years old or older. Please refer to StaffDR78-01-Attachment 1 for the useful life for gas mains.

   BGE uses the group method for depreciating its assets. Under the group depreciation method, individual assets are not tracked thus it is not possible to know the book value (gross cost less accumulated depreciation reserve) of specific assets when they are retired. Additionally, utility mass plant assets (like gas main) are not tracked by location

in company accounting records. For these reasons, the book value of the components to be replaced cannot be provided.

The original cost of the project within the MYP period is disclosed in Company Exhibit DCW-1G. To the extent capital expenditures extend beyond the MYP period, the final installed cost of a given project will be higher than the capital expenditures reflected in the Direct Testimony of Company Witness White.

b. Based on the assessment results, age, and lack of records, BGE has selected replacement for the Manor Loop and this portion of the Manor Extension transmission line. Please refer to StaffDR11-12-CONFIDENTIAL CEII Attachment 1 for more details.

Case No. 9692
Baltimore Gas and Electric Co.
Response to OPC Data Request 19
Request Received: April 27, 2023
Response Date: May 11, 2023
Sponsor(s): Dawn C. White

Item No.: OPCDR19-05

Please refer to witness White's direct testimony at 30, lines 17–20, regarding Project 58080: Manor System South:

a. For each type of asset to be replaced in this project, please provide:
   i. the average age of the components to be replaced in this project
   ii. the book life of that asset type
   iii. the book value of the components to be replaced in this project
   iv. the book value of the components to be installed in this project

b. Referring to PHMSA's regulation on Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments
   i. Has BGE conducted a pressure test (Method 1) regarding these assets? If so, what were the results? If not, why not?
   ii. Has BGE considered reducing the pressure in these assets (Method 2 or Method 5)? If so, please provide the results of the analysis. If not, why not?
   iii. Has BGE considered conducting an engineering critical assessment (Method 3) regarding these assets? If so, what were the results of that consideration? If not, why not?
   iv. Has BGE conducted an engineering critical assessment (Method 3) regarding these assets? If so, what were the results? If not, why not?
   v. Has BGE considered using alternative technology (Method 6) regarding these assets? If so, what alternative technologies were considered? What were the results of that consideration? If not, why not?

RESPONSE:

a. Project 58080: Manor System South consists primarily of main replacement work along the Joppa, a portion of the Manor Extension, and Eastpoint transmission lines, with the potential for replacement of minor quantities of services or other assets, to be determined once the design and engineering phase is finalized. In addition, a portion of these pipelines will be MAOP downrated in lieu of replacement. The majority of the main to be addressed is 65 years old or older. Please refer to StaffDR78-01-Attachment 1 for the useful life for gas mains.

   BGE uses the group method for depreciating its assets. Under the group depreciation method, individual assets are not tracked thus it is not possible to know the book value (gross cost less accumulated depreciation reserve) of specific assets when they are retired. Additionally, utility mass plant assets (like gas main) are not tracked by location

in company accounting records. For these reasons, the book value of the components to be replaced cannot be provided.

The original cost of the project within the MYP period is disclosed in Company Exhibit DCW-1G. To the extent capital expenditures extend beyond the MYP period, the final installed cost of a given project will be higher than the capital expenditures reflected in the Direct Testimony of Company Witness White.

b. Based on the assessment results, age, and lack of records, BGE has selected replacement for the majority of these transmission lines. Please refer to StaffDR11-12-CONFIDENTIAL CEII Attachment 1 for more details. In the instance of the Eastpoint line and a portion of Manor Extension, BGE has determined that MAOP downrating is feasible and will be pursuing this method of reconfirmation.

Case No. 9692
Baltimore Gas and Electric Co.
Response to OPC Data Request 19
Request Received: April 27, 2023
Response Date: May 11, 2023
Sponsor(s): Dawn C. White

Item No.: OPCDR19-06

Please refer to witness White's direct testimony at 30, lines 21-23, regarding Project 58083: Marly Neck Pipeline:

a. For each type of asset to be replaced in this project, please provide:
   i. the average age of the components to be replaced in this project
   ii. the book life of that asset type
   iii. the book value of the components to be replaced in this project
   iv. the book value of the components to be installed in this project
b. Referring to PHMSA's regulation on Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments
   i. Has BGE conducted a pressure test (Method 1) regarding these assets? If so, what were the results? If not, why not?
   ii. Has BGE considered reducing the pressure in these assets (Method 2 or Method 5)? If so, please provide the results of the analysis. If not, why not?
   iii. Has BGE considered conducting an engineering critical assessment (Method 3) regarding these assets? If so, what were the results of that consideration? If not, why not?
   iv. Has BGE conducted an engineering critical assessment (Method 3) regarding these assets? If so, what were the results? If not, why not?
   v. Has BGE considered using alternative technology (Method 6) regarding these assets? If so, what alternative technologies were considered? What were the results of that consideration? If not, why not?

RESPONSE:

a. Project 58083: Marley Neck Pipeline project is currently projected to be a MAOP reduction and pressure downrating project. The majority of the main to be addressed is 54 years old or older. Please refer to StaffDR78-01-Attachment 1 for the useful life for gas mains. As a result of BGE's method of reconfirmation, BGE does not currently project transmission main replacement for this project.

   The original cost of the project within the MYP period is disclosed in Company Exhibit DCW-1G. To the extent capital expenditures extend beyond the MYP period, the final installed cost of a given project will be higher than the capital expenditures reflected in the Direct Testimony of Company Witness White.

b. BGE has determined that it is feasible for the Marley Neck transmission line to undergo an MAOP reduction as the method of MAOP reconfirmation instead of replacement. BGE will be performing other system work within this project to support the downrate to ensure system integrity.

Case No. 9692
Baltimore Gas and Electric Co.
Response to OPC Data Request 19
Request Received: April 27, 2023
Response Date: May 11, 2023
Sponsor(s): Dawn C. White

Item No.: OPCDR19-07

Please refer to witness White's direct testimony at 31, lines 1-7, regarding Project 60693: Gate Station Owings Mills:

a. For each type of asset to be replaced in this project, please provide:
   i. the average age of the components to be replaced in this project
   ii. the book life of that asset type
   iii. the book value of the components to be replaced in this project
   iv. the book value of the components to be installed in this project
b. Referring to PHMSA's regulation on Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments
   i. Has BGE conducted a pressure test (Method 1) regarding these assets? If so, what were the results? If not, why not?
   ii. Has BGE considered reducing the pressure in these assets (Method 2 or Method 5)? If so, please provide the results of the analysis. If not, why not?
   iii. Has BGE considered conducting an engineering critical assessment (Method 3) regarding these assets? If so, what were the results of that consideration? If not, why not?
   iv. Has BGE conducted an engineering critical assessment (Method 3) regarding these assets? If so, what were the results? If not, why not?
   v. Has BGE considered using alternative technology (Method 6) regarding these assets? If so, what alternative technologies were considered? What were the results of that consideration? If not, why not?

RESPONSE:

a. Project 60693: Gate Station Owings Mills is the replacement of a City Gate, which has a useful life of 40 years. Owings Mills Gate Station was originally built over 60 years ago, with certain capital improvements completed during the intervening years. Please also note that gate stations include a variety of assets which are accounted for in a variety of utility accounts with a variety of estimated useful lives. In the case of the Owings Mills Gate Station, estimated useful lives range from 20 years for communication equipment to 50- years for gas structures.

   BGE uses the group method for depreciating its assets. Under the group depreciation method, individual assets are not tracked, thus it is not possible to know the book value (gross cost less accumulated depreciation reserve) of specific assets when they are retired. Additionally, utility mass plant assets (like gas main) are not tracked by location

in company accounting records. For these reasons, the book value of the components to be replaced cannot be provided.

The original cost of the project within the MYP period is disclosed in Company Exhibit DCW-1G. To the extent capital expenditures extend beyond the MYP period, the final installed cost of a given project will be higher than the capital expenditures reflected in the Direct Testimony of Company Witness White.

b. While the replacement of Owings Mills Gate Station supports the Final Transmission Rule, the primary reason for the inclusion of this project in the MYP period of 2024 through 2026 is a result of TransCanada work taking place onsite. Please see the Company's responses to SCDR02-01 and StaffDR39-55 for more information.

Case No. 9692
Baltimore Gas and Electric Co.
Response to OPC Data Request 19
Request Received: April 27, 2023
Response Date: May 11, 2023
Sponsor(s): Dawn C. White

Item No.: OPCDR19-08

Please refer to witness White's direct testimony at 31, lines 8-11, regarding Project 58447: Harbor Crossing Upgrades:

a. For each type of asset to be replaced in this project, please provide:
   i. the average age of the components to be replaced in this project
   ii. the book life of that asset type
   iii. the book value of the components to be replaced in this project
   iv. the book value of the components to be installed in this project
b. Referring to PHMSA's regulation on Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments
   i. Has BGE conducted a pressure test (Method 1) regarding these assets? If so, what were the results? If not, why not?
   ii. Has BGE considered reducing the pressure in these assets (Method 2 or Method 5)? If so, please provide the results of the analysis. If not, why not?
   iii. Has BGE considered conducting an engineering critical assessment (Method 3) regarding these assets? If so, what were the results of that consideration? If not, why not?
   iv. Has BGE conducted an engineering critical assessment (Method 3) regarding these assets? If so, what were the results? If not, why not?
   v. Has BGE considered using alternative technology (Method 6) regarding these assets? If so, what alternative technologies were considered? What were the results of that consideration? If not, why not?

RESPONSE:

a. Project 58447 Harbor Crossing Upgrades currently does not contain any significant transmission replacement activities. The project focuses on the installation of infrastructure to support in-line inspection tools to facilitate the requalification of a portion of the Harbor Crossing transmission line to meet the Final Transmission Rule.

b. BGE is not performing replacement on this line but instead will be performing an engineering critical assessment and pressure test on portions of this line. Please refer to StaffDR11-12-CONFIDENTIAL CEII Attachment 1 for more details.

Case No. 9692
Baltimore Gas and Electric Co.
Response to OPC Data Request 26
Request Received: May 12, 2023
Response Date: May 23, 2023
Sponsor(s): John C. Frain

Item No.: OPCDR26-01

Please refer to page 10 of the Prepared Supplemental Direct Testimony of John C. Frain. On lines 9–13, Witness Frain states that "the Company is respectfully requesting that the Commission consider inclusion of any revenue requirement amounts not recovered through the STRIDE surcharge as the Company is seeking to recover those amounts beginning in 2024, after the STRIDE surcharge is uncapped."

a. Please identify all filings (with reference to line numbers, cell numbers, etc.) in this docket which specifically quantify the "revenue requirement amounts not recovered through the STRIDE surcharge" that Witness Frain refers to in this statement, including any supporting documentation or workpapers.
b. In the event that there are no filings to date which quantify this amount, please provide BGE's expected or known value for the "revenue requirement amounts not recovered through the STRIDE surcharge", broken out by year, along with all supporting workpapers and documentation sufficient to understand these values.
c. Please explain in detail how and when BGE is proposing to recover the "revenue requirement amounts not recovered through the STRIDE surcharge."

RESPONSE:

a. Footnote 7 of the Supplemental Direct Testimony of Company Witness Frain specifically quantifies the STRIDE revenue requirement amounts proposed for recovery in the 2022 Reconciliation.

b. Please see OPCDR26-01-*Attachment 1*. The amounts shown in the "Amount" column of Attachment 1 are sourced from the "Imbalance Before Interest" row of Exhibit E of BGE's 2022 STRIDE Reconciliation filing, submitted to the Commission on March 15, 2023, under Mail Log #301802.

c. As noted on page 8 of the Supplemental Direct Testimony of Company Witness Frain, BGE proposes to use gas Rider 15, the Multi-Year Plan ("MYP") Adjustment Rider, to recover the 2022 gas under-recoveries. BGE is proposing to recover these STRIDE under-recoveries using the same rider which will be used to recover all other gas reconciliation amounts.

Case No. 9692
Baltimore Gas and Electric Co.
Response to OPC Data Request 27
Request Received: May 12, 2023
Response Date: May 26, 2023
Sponsor(s): Dawn C. White

Item No.: OPCDR27-02

For the "Operation Pipeline" program, does BGE consider the cost-effectiveness – e.g., the cost in relation to safety impact (reduction) – of proposed projects?

a. Does BGE utilize any quantitative cost-effectiveness thresholds to determine whether to proceed with a project? If yes, please provide them and explain how they were derived.
b. If BGE does not consider the cost-effectiveness of potential projects, please explain why not.

RESPONSE:

The aged and outmoded infrastructure that is targeted through Project 60677: BGE Operation Pipeline is considered a safety risk in the Company's DIMP and replacement is included as the primary mitigation activity for these assets. In addition, these assets are recognized as safety risks in the gas industry as well as by PHMSA. Finally, these assets have been contributing factors to significant gas system incidents throughout the United States in recent years. For all of these reasons, BGE's goal is to replace all of these assets over time.

However, with respect to Project 60677, the Company does seek to balance work in the portfolio to maintain an average cost per mile replaced that is in-line with historic averages when feasible. In other words, a more costly job may be counterbalanced with a lower cost job in any given year to manage overall costs in the project for that year.

Case No. 9692
Baltimore Gas and Electric Co.
Response to OPC Data Request 27
Request Received: May 12, 2023
Response Date: May 26, 2023
Sponsor(s): Dawn C. White

Item No.: OPCDR27-03

For the “Operation Pipeline” program, does BGE consider the cost-effectiveness of various alternatives to mitigate safety risk (e.g., repair, replace, etc.)? Please explain and provide any numerical thresholds used for cost-effectiveness.

RESPONSE:

For Project 60677: BGE Operation Pipeline, BGE does not consider alternatives to replacement, as the goals of the program are to eliminate aged and outmoded infrastructure. Please see the Company’s responses to OPCDR19-22 and OPCDR27-02.

Case No. 9692
Baltimore Gas and Electric Co.
Response to OPC Data Request 27
Request Received: May 12, 2023
Response Date: May 26, 2023
Sponsor(s): Dawn C. White

Item No.: OPCDR27-09

Regarding OPDCR03-01, does the Company only consider the Optimain risk scores, leak history, and break history of cast iron mains? If so, please explain how BGE assesses the riskiness of non-cast iron mains, particularly bare steel mains.

RESPONSE:

Concerning Project 60677: BGE Operation Pipeline, the Company may consider the presence of bare steel main in the area as a factor for job selection, as the vast majority of the remaining 13 miles of bare steel are embedded in cast iron systems. However, Optimain risk scores and/or performance history of non-cast iron infrastructure are not generally part of the selection process for Project 60677 work.

The Company does use Optimain to determine which steel mains (protected and unprotected) to focus on for further evaluation as part of other main replacement activities, mainly under Project 60666: Regionally Managed Gas Infrastructure Improvements Program.

Case No. 9692
Baltimore Gas and Electric Co.
Response to Sierra Club Data Request 4
Request Received: April 28, 2023
Response Date: May 12, 2023
Sponsor(s): Dawn C. White

Item No.: SCDR04-01

Regarding SCDR01-01, which states, “Leak Repairs are a maintenance function and can also be managed by work load dispatch”:

a) Please provide a list of Leaks found on your system by main and services that coincides with Table 2: Leak Repairs on page 13 of Ms. White’s testimony.
b) How many of these leaks were repaired under “maintenance” (replacing a clamp or short piece of pipe) vs “capital” (replacing the service or section of main)?
c) The Company’s stated GHG reductions of 20% appear to be based on the removal of outmoded pipe material and their replacement with newer materials, rather than by repairing known leaks. Please confirm that this interpretation is correct. If it is not correct, please clarify what these GHG reductions are based on. Further, has the Company gathered its own empirical data via direct testing to confirm these stated reductions or are they theoretical at this point?

RESPONSE:

BGE notes that the response to SCDR01-01 does not contain “Leak Repairs are a maintenance function and can also be managed by work load dispatch.” In addition, BGE cannot find reference to this quote in any of its data request responses.

a) Table 2, on page 13 of Company Witness White’s Direct Testimony, provides leak repairs as defined by PHMSA for the annual DOT report. The leak repairs, provided in Table 2, equate to the total number of underground leaks found and repaired on BGE’s gas distribution system. The leak backlog, provided in Table 2, equates to the number of known system leaks at the end of each year scheduled for repair as defined by PHMSA for the annual DOT report.

b) Please see the below table for the estimated number of leak repairs performed under capital and O&M for 2016 through 2022.

	Category	2016	2017	2018	2019	2020	2021	2022
Main Leak Repairs	Capital	791	756	709	1,189	1,305	1,173	1,030
	O&M	2,608	2,550	2,475	1,899	1,821	2,007	1,713
	Total	3,399	3,306	3,184	3,088	3,126	3,180	2,743
Service Leak Repairs**	Capital	5,705	4,460	3,757	3,136	2,517	2,257	1,995
	O&M	549	460	414	420	358	317	269
	Total	6,254	4,920	4,171	3,556	2,875	2,574	2,264
Total Leak Repairs		9,653	8,226	7,355	6,644	6,001	5,754	5,007

***Service leak repair numbers do not include "fitter" leaks. Fitter leaks are leaks on above-ground equipment in the vicinity of the meter and are often plumbing-like in nature.*

c) Please refer to the Company's responses to OPCDR03-13 and OPCDR13-33. Per guidance from the Environmental Protection Agency, the calculation of BGE's gas distribution system greenhouse gas (GHG) fugitive emissions is based on the population of gas infrastructure (miles of main or number of services) by material type for a given year, not known leaks.

Case No. 9692
Baltimore Gas and Electric Co.
Response to Staff Data Request 10
Request Received: March 02, 2023
Response Date: March 16, 2023
Sponsor(s): Dawn C. White; Mark D. Case

Item No.: StaffDR10-11

Please indicate whether a strategy expansion that seeks to connect additional gas capital investment for the purpose of expansion is not contrary to decarbonization/electrification pathway discussed by Mr. Case.

RESPONSE:

Additional gas capital investment for expansion purposes is not contrary to the Company's decarbonization/electrification plans discussed in Company Witness Case's Direct Testimony. As set forth in Company Witness White's Direct Testimony, "expansion" addresses inadequate capacity on the existing gas distribution and transmission system to address load growth, capacity requirements, poor supply, and system performance. In addition, capacity expansion projects support the necessary upgrades required to facilitate future asset replacement work as BGE continues to modernize the gas system by eliminating the low pressure system through BGE Operation Pipeline and other programs.

As the public service company with a gas distribution franchise for its service territory, BGE has an obligation per the terms of its Commission-approved gas service tariff to provide eligible customers with requested utility gas service if able. As demonstrated by the annual increases in the number of gas customers on the gas system, BGE continues to receive requests from customers that want gas service. In addition, BGE has statutory, regulatory, and tariff-based requirements to ensure that the existing system has adequate capacity and is engineered to deliver gas safely and reliably. Accordingly, the Company's efforts to meet the State's climate goals does not mean that BGE can neglect its obligation to operate a safe and reliable gas system for existing or expected customers. Meeting these requirements, however, does not contradict the Company's decarbonization/electrification plans discussed by Company Witness Case.

The State's goal is net-zero greenhouse gas emissions by 2045. Net-zero does not mean no greenhouse gas emissions. Nor does it necessarily require the elimination of the natural gas system as a part of Maryland's energy future. As Company Witness Case notes in his Direct Testimony, BGE's planned contributions to this effort are informed by the E3 study that shows that an integrated energy system (including safe and reliable gas infrastructure) can achieve the net-zero goals at significantly lower costs and lower risks. The integrated approach also delivers greater resiliency, fuel diversity, more realistic constructability, and less disruption to customers and Maryland's economy, compared to other approaches with less or no gas system capabilities. Furthermore, as noted in Company Witness White's Direct Testimony, gas infrastructure replacement programs significantly reduce natural gas leaks and associated greenhouse gas emissions, to the benefit of the environment. These replacement programs, as discussed, are directly supported by capacity expansion program work. Therefore, the noted gas capital investments complement, rather than contradict, the Company's decarbonization and electrification goals.

Case No. 9692
Baltimore Gas and Electric Co.
Response to Staff Data Request 81
Request Received: April 25, 2023
Response Date: May 09, 2023
Sponsor(s): Denise Galambos

Item No.: StaffDR81-04

Staff DR 12-05 states that BGE expects to complete approximately 40,000 and 60,000 Intelis gas meter conversions in 2025 and 2026 respectively. Please answer the following:

a. If the meter conversions are to begin in 2025, why does the Capital spending for this program begin in 2024?
b. The Company currently has approximately 710,000 gas meters on the system. In TOTAL, what percentage of the 710,000 gas meters will be replaced with Intelis gas meters?
c. When will the gas meter conversion program end?
d. What is the TOTAL cost of the program?
e. Why has the Company decided to replace only 100,000 meters between 2025 and 2026?
f. What are the criteria for gas meter conversions?
g. Assuming that he Company begins replacing meters in 2024, how many years will it take to replace the existing meters? How many meters are involved?

RESPONSE:

a. The gas meter conversions to Intelis are expected to begin in 2025. The forecasted capital expenditures in 2024 are for the 500G module upgrades and the preorder of materials for the Intelis meter conversions. Please see the response to StaffDR81-14 for more information.

b. There are approximately 718,000 gas meters on the system. Approximately 80% of the total 718,000 gas meters will be replaced by Intelis meters. See StaffDR81-04-*Attachment 1*.

c. BGE expects that the gas meter conversions to Intelis meters will begin in 2025 and end in 2031.

d. The current estimated cost for capital and O&M for the Intelis gas meter conversion program from 2025 through 2031 is approximately $277.2 million.

e. The Company is prioritizing meters with non-communicating modules and the 100,000 meters have been estimated through 2026.

f. All meters identified in the response to subpart (b), above, are eligible to be replaced by Intelis gas meters, with the exception of meters whose modules have been replaced with

500G modules. See StaffDR81-08 Attachment 1 for a breakout of the gas meters on BGE's gas distribution system.

g. Please see the response to StaffDR12-05, subpart (h), and the response to subpart (c) above. BGE expects to begin installing Intelis meters in 2025, not in 2024. Approximately 574,000 gas meters will be replaced with Intelis meters between 2025 and 2031. Please see StaffDR81-03-Attachment 1 for a breakdown of planned module and meter replacements and StaffDR81-08 Attachment 1 for a breakout of the gas meters on BGE's gas distribution system.

Case No. 9692
Baltimore Gas and Electric Co.
Response to Staff Data Request 81
Request Received: April 25, 2023
Response Date: May 09, 2023
Sponsor(s): Denise Galambos

Item No.: StaffDR81-07

What is the expected life of the new Intelis gas meters?

RESPONSE:

The manufacturer of the Intelis gas meter has set an expectation of a 20-year useful life.

Case No. 9692
Baltimore Gas and Electric Co.
Response to Staff Data Request 81
Request Received: April 25, 2023
Response Date: May 09, 2023
Sponsor(s): Denise Galambos

Item No.: StaffDR81-08

Regarding BGE's existing meters, please answer the following:

a. How many existing meters does BGE currently have on the system?
b. What meter types are there by decade?
c. Without consideration of 300G modules, how many existing meters are past their useful life?
d. How many meters are being replaced under BGE's proposal before the end of their useful life?

RESPONSE:

a. Please see StaffDR81-08-*Attachment 1* for a breakout of the existing approximately 718,000 gas meters on BGE's gas distribution system.

b. Please see StaffDR81-08-*Attachment 2* for a breakout of gas meter type by decade.

c. There are approximately 35,000 gas meters older than the 33-year average useful life for legacy gas meters.

d. Approximately 428,000 gas meters will be replaced prior to the 33-year average useful life.

Case No. 9692
StaffDR81-08
Attachment 2

Meter Type	2020-2023	2010-2019	2000-2009	1990-1999	1980-1989	1970-1979	1960-1969	1950-1959	1940-1949	1930-1939	Total
Residential & Small Commercial	32,511	135,429	208,332	261,216	20,940	8,470	749	13	3	4	667,667
Large Residential & Commercial	12,465	25,444	7,930	4,202	471	16	41	1			50,570
Total	**44,976**	**160,873**	**216,262**	**265,418**	**21,411**	**8,486**	**790**	**14**	**3**	**4**	**718,237**

Case No. 9692
StaffDR81-14
Attachment 1

	Table 1 - Revised Budget				
	81516: Gas Meter Conversion Project - Capital	**2024**	**2025**	**2026**	**Total**
A	500G Gas Module Replacements	2,344,786			**2,344,786**
B	Intelis Meter Conversion	6,540,500	22,275,726	28,947,297	**57,763,523**
C	**81516: Gas Meter Conversion Project - Capital Total**	**8,885,286**	**22,275,726**	**28,947,297**	**60,108,308**

	Table 2 - Comparison of Original to Revised Budget				
	81516: Gas Meter Conversion Project - Capital	**2024**	**2025**	**2026**	**Total**
D	Original Budget in Company Exhibit DG-1G	24,641,034	41,427,782	39,919,539	**105,988,355**
E	Revised Budget	8,885,286	22,275,726	28,947,297	**60,108,308**
F	**Variance**	**(15,755,748)**	**(19,152,056)**	**(10,972,242)**	**(45,880,047)**

Exhibit ASH-3

BEFORE THE
PUBLIC SERVICE COMMISSION OF MARYLAND

IN THE MATTER OF THE	*	
PETITION OF THE OFFICE	*	
OF PEOPLE'S COUNSEL FOR	*	
NEAR-TERM, PRIORITY ACTIONS	*	CASE NO.
AND COMPREHENSIVE,	*	
LONG-TERM PLANNING FOR	*	
MARYLAND'S GAS	*	
COMPANIES	*	

PETITION OF THE OFFICE OF PEOPLE'S COUNSEL FOR NEAR-TERM, PRIORITY ACTIONS AND COMPREHENSIVE, LONG-TERM PLANNING FOR MARYLAND'S GAS COMPANIES

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February 9, 2023

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PETITION OF THE OFFICE OF PEOPLE'S COUNSEL FOR NEAR-TERM, PRIORITY ACTIONS AND COMPREHENSIVE, LONG-TERM PLANNING FOR MARYLAND'S GAS COMPANIES

To further its mandate to protect the interests of residential utility customers and the State's progress toward meeting State greenhouse gas emissions reduction goals,[1] the Office of People's Counsel respectfully requests that the Public Service Commission initiate a proceeding to address the planning, practices, and future operations of the gas public service companies (the "gas companies") to ensure they are consistent with the "interest of the public"[2] and that the rates they charge utility customers are and continue to be "just and reasonable."[3] The gas companies' escalating capital spending on infrastructure—as well as their procurement, line-extension, marketing, and EmPOWER practices, among others—are misaligned with technological and economic trends toward the replacement of fossil gas with electricity, Maryland's greenhouse gas reduction goals, and Maryland's evidence-backed policy to convert buildings to electricity to meet the challenge of climate change. Left unaddressed, this misalignment will have significant adverse consequences for Maryland's residential customers and utilities, including possible financial responsibility for tens of billions of dollars of utility assets that are "stranded" because market forces render them unused or cause their early retirement.

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[1] Md. Code Ann., Pub. Util. Art. ("PUA") § 2-204(a). OPC also files this petition in response to the Commission's notice dated October 6, 2021, seeking comment regarding the Commission's newly established statutory obligation to expressly consider the "protection of the global climate…[and] the achievement of the State's climate commitments for reducing statewide greenhouse gas emissions" in the exercise of its duties. *Notice of Consideration of New Statutory Factors*, Maillog No. 237335 (Oct. 6, 2021) (quoting PUA § 2-113(a)(2)(v)-(vi) (added by 2021 Md. Laws Chs. 614 & 615)).
[2] PUA § 2-113(a)(1)(i).
[3] PUA §§ 4-101, 4-102(b), 4-201.

Allowing these practices to continue unchecked conflicts with the Commission's obligations to (i) "supervise and regulate" the gas companies to "ensure their operation in the interest of the public"[4] and that their rates are "just and reasonable;"[5] and to (ii) consider "the preservation of environmental quality, including protection of the global climate … and the achievement of the State's climate commitments for reducing statewide, greenhouse gas emissions."[6]

The natural gas distribution industry in Maryland is at a point in time where the usual progression of traditional cost-of-service regulation will lead to massive rate increases or an unviable business model for the utilities, leaving both gas customers and gas utilities at tremendous risk. The Commission should act now in an open and transparent proceeding to gather the information it needs to determine what regulatory actions should be taken immediately and over the long term to mitigate the risks associated with the untenable mismatch between escalating capital investments and declining sales. The General Assembly has signaled its "support [for] moving toward broader electrification of both existing buildings and new construction as a component of decarbonization,"[7] and even the State's largest gas utility anticipates reductions in gas delivered on its system of at least 60 percent,[8] yet the Commission has no forum to

[4] PUA § 2-113(a)(1)(i).
[5] PUA §§ 4-102(b), 4-201.
[6] PUA §§ 2-113(a)(2)(v)-(vi).
[7] *See, e.g.*, Climate Solutions Now Act of 2022 ("CSNA") §§ 10(a)(1)-(2), 2022 Md Laws Ch. 38.
[8] Energy and Environmental Economics ("E3"), *BGE Integrated Decarbonization Strategy* (Oct. 2022), at 25, https://www.bge.com/SafetyCommunity/Environment/Documents/BGE%20Integrated%20Decarbonization%20White%20Paper_FINAL%202022-10-06.pdf.

examine the potential reductions in gas use and the resulting impact on gas customers' rates. A gas utility proceeding—with two tracks, one for long-term planning and another for priority actions that do not need extensive investigation and fact-finding—will mitigate the challenges facing both gas customers and gas utilities as costs rise and sales decline.

For the reasons set forth in this petition, OPC requests that the Commission initiate a two-track proceeding to address these issues proactively and comprehensively. On one track, the Commission should establish an open and transparent investigation to make findings on gas usage reductions, potential rate impacts, and related operational and financial matters caused by the transition to electrification, as well as issue guidance on regulatory strategies to reduce the costs and risks for gas customers. We will refer to this as the "Transition Track." The Transition Track would lead to the adoption of regulations governing gas utility transition plans and the Commission's oversight of those plans. Once those regulations are adopted, the utilities would file their individual transition plans for public comment. The Commission then would review those plans and oversee implementation for the individual gas utilities.

On the other track, the Commission should address priority near-term actions. This "Priority Track" would identify actions that can be taken in the near-term based on the widely accepted fact that gas sales will decline because (i) technologies for electrifying many end-uses already are more cost-effective than continued gas use, and (ii) the State cannot meet its greenhouse gas reduction goals without substantially reducing fossil gas consumption, if not eliminating it altogether. This track should result in Commission orders requiring gas utilities to take actions in the near-term to reflect the projections of declining gas sales and align utility practices with the public interest and statutory requirements. As discussed in more detail in Part III.C below, these priority actions should, at a minimum, include modifying gas procurement practices, gas line extension policies, gas company marketing practices, and EmPOWER Maryland programs.

The two-track proceeding OPC requests in this petition is critical to ensuring that future gas utility operations and practices are consistent with the public interest and the law. Especially under the circumstances here, where the fundamental nature of an important utility service is changing, the public interest requires the Commission to proactively lead comprehensive industry reform. The Commission—rather than utility proposals—should set the agenda for the transition and guide a process that is robust, transparent, and inclusive of all stakeholders. The significant reforms, while urgently needed, should be well-planned, not subject to the timing of individual rates cases, and consistent across the State. This petition intends to assist the Commission with leading that process.

INTRODUCTION

Technological advances already have made electric heating and appliances more affordable than fossil gas for many building applications.[9] At the same time, the dire consequences of climate change are leading national, state, and local governments to

[9] *See* Part II.A below.

adopt ambitious climate polices that depend on the widespread electrification of end-uses, including the heating of buildings, that are now met mainly with fossil gas.[10] In enacting the Climate Solutions Now Act of 2022 (the "CSNA"), Maryland adopted some of the most aggressive goals in the nation, targeting economy-wide greenhouse gas ("GHG") emissions reductions of 60 percent (from a 2006 baseline) by 2031 and net zero GHG emissions by 2045.[11] Maryland cannot reach these targets without substantially reducing fossil gas use in buildings.[12] That substantial reduction in fossil gas use has major implications for the traditional business model of Maryland's gas companies.

The State's largest utility has acknowledged that its gas deliveries will decline by at least 60 percent to meet the State's climate goals.[13] Yet, instead of slowing capital spending to align with projected decreases in gas consumption, the gas companies continue to make, and even accelerate, new investment in their gas systems, locking in costs based on the fiction that the infrastructure investments will serve out their useful lives for the next 40 to 70 years—well beyond the time horizon for implementation of the State's GHG emissions reductions goals.[14] Eventually, gas customers, shareholders, or even taxpayers may have to pay for these stranded investments in new and replacement pipes that are no longer "used or useful"[15] for providing service.

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[10] *See* Part II.B below.
[11] CSNA §§ 3-4 (codified in relevant part at Md. Code Ann., Envir. ("EN") §§ 2-1201, 2-1204.1, 2-1204.2).
[12] *See* Part II.B.1 below.
[13] *BGE Strategy* at 25.
[14] *See* Part IV.A below.
[15] *See* PUA § 4-101.

Put simply, the gas companies' focus on rapid investment in fossil fuel infrastructure fails to account for the fact that customers have begun to switch from fossil gas to electricity, a trend that will accelerate as every level of government acts to achieve its climate goals.[16] The decline in the volume of gas that gas companies distribute means that rates have to increase for remaining gas customers to defray the gas companies' fixed costs over a smaller customer base. This scenario is economically unsustainable, and gas companies may face challenges in funding the basic system maintenance needed to ensure they can comply with their obligations to provide safe and reliable service.[17]

Advances in technology and the State's GHG reduction policies necessitate immediate State action to ensure that the gas companies' planning, processes, and future operations align with economic and technological realities and the State's plans for addressing the climate crisis. The Commission has the expertise, the legal authority, and the statutory obligation to investigate, make determinations, and issue guidance about anticipated supply and demand developments, including a shrinking gas system; investment recovery; and customer impacts—all of which are intrinsically tied to technological trends toward electrification and the State's GHG emissions reduction targets.[18] The Commission's diligent pursuit of the dual-track proceeding presented here is urgently needed to ensure that utilities take both short- and long-term actions to provide safe and adequate service to customers at just and reasonable prices, to provide a

[16] *See* Part II.B below.
[17] *See* PUA §§ 5-303, 2-113.
[18] *See* Part I below.

forum for fact-finding and guidance to the Maryland legislature and other State and local agencies, and to assist the gas companies and their customers in planning for the coming transition.

ARGUMENT

This petition proceeds in five primary parts. **Part I** identifies the Commission's existing authority to initiate proceedings regarding gas utility operations and transition planning. **Part II** explains how technological advances and climate policy are jointly rendering the gas distribution business a declining industry. **Part III** explains how the gas companies' current practices are misaligned with these realities, putting customers at risk and implicating the Commission's statutory obligations. **Part IV** explains how a failure of the Commission to engage in long-term planning is to defer to the gas companies' private interests over the public interest. **Part V** highlights some of the extensive guidance available to the Commission in designing the requested proceedings. In several **appendices**, we provide potential questions to be addressed for transition planning, a proposed order, a summary of other states' related proceedings, and OPC's two recent gas utility reports that are discussed below.

I. The Commission has authority to investigate and reform gas company planning, practices, and operations.

The transition to clean energy is changing the business and economic environment in which the gas companies operate,[19] but the gas companies continue to operate largely as if change is not happening,[20] placing the companies and their customers at risk.[21] This increasing misalignment between the utilities' practices and the implications of technological change and climate policy implicates many, if not all, of the Commission's core obligations and authorities to supervise, oversee, and regulate the gas companies under its jurisdiction.

Foremost, the Commission has the duty to "supervise and regulate" the public service companies to "ensure their operation in the interest of the public."[22] In 2021, the General Assembly directed that in carrying out this legislative directive, the Commission "*shall* consider" the "preservation of environmental quality, including protection of the global climate from continued short-term and long-term warming based on the best available scientific information recognized by the Intergovernmental Panel on Climate Change [IPCC]" and "the achievement of the State's climate commitments for reducing statewide, greenhouse gas emissions."[23] According to "the best available scientific information" that the Commission by law must consider, "limiting human-induced global warming … requires limiting cumulative CO_2 emissions, reaching at least net zero CO_2

[19] *See* Part II.A below.
[20] *See* Parts III.A, III.C below.
[21] *See* Part III.B below.
[22] PUA § 2-113(a)(1).
[23] PUA § 2-113(a)(2)(v)-(vi) (emphasis added).

emissions, along with strong reductions in other greenhouse gas emissions," such as CH_4, commonly known as methane,[24] the primary component of fossil gas.[25]

The Commission also has broad regulatory authority over the planning and business models of the public service companies subject to its jurisdiction. For example, the Commission is charged with setting "just and reasonable" rates for public service companies,[26] and it is tasked with mandating and approving "long-range plans" "formulate[d]" and "implement[ed]" by the public service companies "to provide regulated service."[27] The statute directs a broad interpretation of these express "powers and duties,"[28] and explicitly requires that "[t]he Commission *shall* initiate and conduct any investigation necessary to execute its powers or perform its duties."[29] Just as the Federal Energy Regulatory Commission ("FERC") has broadly interpreted its authority to set "just and reasonable rates" as authorizing the agency to reform long-term regional transmission planning,[30] the Commission's traditional statutory duties obligate the

[24] IPCC, *Climate Change 2021, The Physical Science Basis, Working Group I Contribution to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change* (Aug. 7, 2021), at 27, https://www.ipcc.ch/report/ar6/wg1/.
[25] Fossil gas delivered by the gas companies to final customers is predominantly (92.8 percent) composed of methane. James Bradbury et al., *Greenhouse Gas Emissions and Fuel Use within the Natural Gas Supply Chain- Sankey Diagram Methodology*, U.S. DEP'T OF ENERGY, OFFICE OF ENERGY POLICY AND SYSTEMS ANALYSIS (July 2015), at 6.
[26] PUA §§ 4-102(b), 4-201. *See also* PUA § 5-303.
[27] PUA § 2-118(b).
[28] PUA § 2-113(b) ("The powers and duties listed in this title do not limit the scope of the general powers and duties of the Commission.").
[29] PUA § 2-115(a) (emphasis added).
[30] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, Docket No. RM21-17-000, 179 FERC ¶ 61,028 (Apr. 21, 2022). As FERC explained in its proposed rule, long-term planning—20 to 30 years into the future—lowers customer costs and brings customer benefits. *Id.* at 28-29. By contrast, the lack of effective long-term planning "is resulting in unjust, unreasonable, unduly discriminatory, and preferential" rates. *Id.*

Commission to initiate the proactive and comprehensive long-term planning this petition seeks.

The Commission itself has emphasized its "broad authority under PUA § 2-113 to regulate the activities of utility companies providing services within the State."[31] In finding it had authority to rule on the electric utilities' petition to invest in electric vehicle programs, the Commission observed that utility "infrastructure investments" are core services subject to the Commission's jurisdiction, and noted its obligation to consider "the economy of the State, the conservation of natural resources, and the preservation of environmental quality" when supervising and regulating public service companies—authority that since has been expanded to require consideration of the "global climate" and "the achievement of the State's climate commitments for reducing statewide greenhouse gas reduction goals."[32] In addressing Columbia Gas of Maryland's proposed Green Path Rider program in a recent administrative meeting, the Commission chair further emphasized that "the Commission has very broad jurisdictions, and even more so recently with respect to environmental matters involving its utilities."[33] These same observations apply with greater force to the gas utilities' current massive infrastructure spending programs and other policies that are misaligned with the State's policy goals.

Moreover, section 2-1305 of the Environment Article ("EN") requires that the Commission, like "each State agency," take certain additional actions to ensure that its

[31] Order No. 88997, Case No. 9478 (Jan. 14, 2019), at 39.
[32] *Id.* at 39-40 (quoting PUA § 2-113(a)(2)).
[33] Pub. Serv. Comm'n, *Administrative Meeting – 01/18/23* at 1:26:11, https://www.youtube.com/watch?v=HFZybYciUsw.

operations align with the State's GHG emissions reduction goals. For example, the statute requires that the Commission "*shall* review its planning, regulatory and fiscal programs to identify and recommend actions to more fully integrate the consideration of Maryland's greenhouse gas reduction goal and the impacts of climate change"[34] and "*shall* identify and recommend specific policy, planning, regulatory and fiscal changes to existing programs that do not currently support the State's greenhouse gas reduction efforts or address climate change."[35] That subtitle further provides that the Commission "*shall* report annually on the status of programs that support the State's greenhouse gas reduction efforts or address climate change,"[36] and "when conducting long-term planning, developing policy, and drafting regulations," the Commission "*shall* take into consideration . . . [t]he likely climate impact of the agency's decisions relative to Maryland's greenhouse gas emissions reduction goals… ."[37]

In sum, effective planning produces better utility performance, saving customers money. Robust long-term planning is, therefore, fundamental to ensuring utility infrastructure investments are consistent with the public interest, and such long-term planning therefore falls well within the Commission's authority. Whether under its traditional duties to supervise and regulate public service companies or its updated mandate to consider the impacts of climate, the Commission has authority to reform gas company planning, practices, and operations so that they are consistent with substantial

[34] EN § 2-1305(a)(1) (emphasis added).
[35] EN § 2-1305(b) (emphasis added).
[36] EN § 2-1305(c)(1) (emphasis added).
[37] EN § 2-1305(d) (emphasis added).

declines in gas sales. Further, the Commission has jurisdiction to require the gas companies to take immediate actions—examples of which are described in Part III.C, below—to align utility practices with technological and economic realities, State policy, and customers' and the public's interests.

Finally, while the Commission's existing authority is substantial, proceedings on long-term gas utility planning and near-term priority actions could result in identifying measures for which additional statutory authority is necessary or desirable. Having initiated an investigation and proceeding, the Commission will be well-positioned to identify any matters for legislation and make appropriate recommendations to the General Assembly.

II. Technology, market trends, and climate policy are rendering the gas distribution business a declining industry.

This Part II explains how advances in technology, market trends, and climate policy are combining to make the traditional fossil gas distribution business obsolete. Part II.A explains that electric technologies are already driving changes to fossil gas consumption, regardless of climate policy. For buildings, the primary driver is highly efficient electric heat pump technologies for heating homes and water, although electric induction stoves are also improving and can be expected to reduce fossil gas market share, especially with growing awareness of the health effects associated with the indoor combustion of fossil gas. Part II.B explains how the reality of climate change, and the role of fossil gas, is driving policy at all levels of government that will further accelerate the transition from fossil fuels to electricity.

A. Technology is already driving customers to switch from fossil gas heating and appliances to electric ones.

Electrification technologies are increasingly rendering gas uncompetitive for many residential and commercial buildings. Electric heat pumps provide a prime example. Heat pumps provide both energy-efficient cooling and heating with far lower emissions than cooling with electricity and heating with gas.[38] The total cost of installing heat pumps in residential new construction is much less than the cost of installing fossil gas equipment for heat plus central air conditioning (AC) for cooling.[39] For retrofitting an existing building, the cost of installing heat pumps is similar to or less than the combined installed cost of the furnace and central AC.[40] A study by the Lawrence Berkeley National Laboratory (LBNL) found that, on average nationally, a new gas furnace and AC have a combined installed cost of almost $11,000 for residential retrofits. In contrast, the installed cost of heat pumps is substantially less, at just over $8,000.[41] Comparatively, a gas furnace cannot be used for home cooling and requires an additional system for AC.[42]

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[38] *See* Pistochini et al., *Greenhouse Gas Emission Forecasts for Electrification of Space Heating in Residential Homes in the US*, 163 ENERGY POLICY 112813 (Apr. 2022) (comparing emissions from heating with heat pumps to heating with gas furnaces).
[39] *See, e.g.,* Lacey Tan et al., *The Economics of Electrifying Buildings: Residential New Construction*, RMI (Dec. 2022), https://rmi.org/insight/the-economics-of-electrifying-buildings-residential-new-construction/.
[40] Synapse Energy Economics, Inc., *Climate Policy for Maryland's Gas Utilities: Financial Implications* (Nov. 2022), at 5, https://opc.maryland.gov/Gas-Rates-Climate-Report (attached as Appendix D).
[41] Brennan. D. Less et al., *The Cost of Decarbonization and Energy Upgrade Retrofits for US Homes*, LAWRENCE BERKELEY NAT'L LAB., https://escholarship.org/uc/item/0818n68p.
[42] For commercial heating and cooling systems, retrofit costs are harder to compare than for residential ones, because costs vary by building type and data are relatively sparse for the variety of building types in use for commercial applications. Some studies suggest that installed costs for heat pumps are comparable to the cost of gas heating and separate electric AC systems for commercial buildings. *See, e.g.*, Group 14 Engineering, *Electrification of Commercial and Residential Buildings* (Nov. 2020). For small commercial customers, E3's study for Maryland found that all-electric new construction is cheaper than mixed-fuel new construction due to lower capital and operating costs. E3, *Maryland Building Decarbonization Study:*

In the absence of extreme price volatility, operating costs, including fuel, are similar for these options.[43]

Growing consumer awareness of the health effects associated with the use of gas stoves is likely to further motivate consumers to make the switch from gas to electric. Although the scrutiny is not new,[44] recent research connecting the elevated levels of nitrogen dioxide produced by gas stoves with childhood asthma in the United States[45] has received widespread media attention.[46] The American Medical Association recently recognized the association between the use of gas stoves, indoor nitrogen dioxide levels,

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Final Report (October 20, 2021), https://mde.maryland.gov/programs/Air/ClimateChange/MCCC/Documents/MWG_Buildings%20Ad%20Hoc%20Group/E3%20Maryland%20Building%20Decarbonization%20Study%20-%20Final%20Report.pdf.

[43] *Md. Building Decarbonization Study.*

[44] *See, e.g.*, Weiwei Lin et al., *Meta-Analysis of the Effects of Indoor Nitrogen Dioxide and Gas Cooking on Asthma and Wheeze in Children*, 42 INT'L J. OF EPIDEMIOLOGY 1724 (Aug. 20, 2013) (providing quantitative evidence that gas cooking increases risk of asthma in children); Brady Seals & Andee Krasner, *Gas Stoves: Health and Air Quality Impacts and Solutions* (2020), RMI, PHYSICIANS FOR SOC. RESPONSIBILITY, MOTHERS OUT FRONT, AND SIERRA CLUB, https://rmi.org/insight/gas-stoves-pollution-health/ (synthesizing the last two decades of research and offering recommendations regarding the health risks associated with gas stoves).

[45] *See, e.g.,* Talor Gruenwald et al., *Population Attributable Fraction of Gas Stoves and Childhood Asthma in the United States*, 20(1) INT'L J. OF ENVTL. RESEARCH AND PUB. HEALTH 75 (2023) (finding that more than 12 percent of current childhood asthma cases in the U.S. can be attributed to gas stove use).

[46] *See, e.g.,* Maxine Joselow & Vanessa Montalbano, *Gas Stove Pollution Causes 12.7% of Childhood Asthma, Study Finds,* WASH. POST (Jan. 6, 2023), https://www.washingtonpost.com/politics/2023/01/06/gas-stove-pollution-causes-127-childhood-asthma-study-finds/; Ari Natter, *Ban on Gas Stoves Considered After New Study Draws Connection to Childhood Asthma*, BALT. SUN/BLOOMBERG NEWS (Jan. 9, 2023), https://www.baltimoresun.com/business/gas-stove-ban-20230109-rh27f73tmnabvg23723yjuazd4-story.html; Laura Baisas, *Gas Stoves Could Be Making Thousands of Children in America Sick*, POPULAR SCI. (Jan. 6, 2023), https://www.popsci.com/health/gas-stove-childhood-asthma/; Oliver Milman, *One in Eight Cases of Asthma in US Kids Caused by Gas Stove Pollution – Study*, THE GUARDIAN (Jan. 6, 2023), https://www.theguardian.com/environment/2023/jan/06/us-kids-asthma-gas-stove-pollution.

and asthma,[47] and the U.S. Consumer Product Safety Commission reportedly plans to open a proceeding to consider the hazards of gas stoves and potential solutions.[48]

Electrification is already occurring across the country. Between 2015 and 2020, the number of U.S. households using heat pumps for space heating doubled.[49] And based on a review of U.S. Census Bureau data, the Brattle Group concluded in a 2021 study that at then-current rates—i.e., before taking into account the effect of the 2022 federal Inflation Reduction Act—"the number of homes with electric space heating could exceed the number of homes with gas space heating by 2032" in some parts of the country.[50] Figure 1 shows that electrification is happening here in Maryland as the electric heating stock (mostly heat pumps) has been increasing for years now, while gas heating stock has stagnated.

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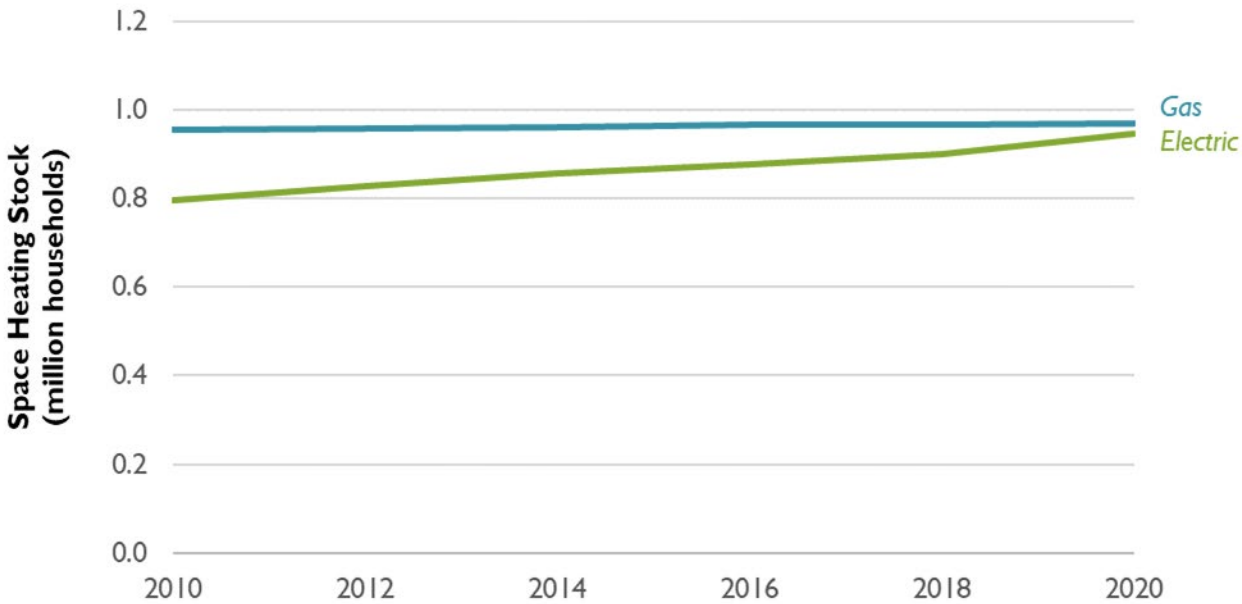
[47] Proceedings of the Am. Med. Ass'n's 2022 Annual Meeting of the H.D. - Resolutions, at 459 (Nov. 13, 2022), https://www.ama-assn.org/system/files/a22-resolutions.pdf.
[48] *See, e.g.,* Natter.
[49] *See* Ana Sophia Mifsud & Rachel Golden, *Millions of US Homes Are Installing Heat Pumps. Will It Be Enough?*, RMI (Nov. 1, 2022), https://rmi.org/millions-of-us-homes-are-installing-heat-pumps-will-it-be-enough/ (citing EIA Residential Energy Consumption Survey).
[50] Brattle Grp., *The Future of Gas Utilities Series: Transitioning Gas Utilities to a Decarbonized Future, Part 1 of 3* (Aug. 2021), at 9, https://www.brattle.com/wp-content/uploads/2022/01/The-Future-of-Gas-Utilities-Series__Part-1.pdf.

Figure 1. Gas and Electric Space Heating Stock in Maryland Households, 2010-2020 [51]



US Census Bureau: American Community Survey. Table DP04: Selected Housing Characteristics for Maryland, 5-year Estimates. June 2, 2022, available at:
https://data.census.gov/cedsci/table?q=DP04&g=0400000US24&tid=ACSDP5Y2020.DP04

While the figure shows electric heating gradually eating into gas's market share through 2020, subsequent federal and State policy enactments will accelerate that trend.

B. Climate change policy will further drive the shift from gas to electricity.

Over the last decade, building electrification in Maryland has been driven largely by the economic benefits of highly efficient electric heat pump technology. In the decades ahead, electrification will accelerate dramatically due to an increasing number of governmental policies to address our changing climate.[52] The "best available scientific information"—which the law mandates the Commission to consider[53]—establishes the

[51] Figure 1 is taken from OPC's *Synapse Report* at 3.
[52] *Synapse Report* at 3-4.
[53] PUA § 2-113(a)(2)(v).

urgency of addressing greenhouse gas emissions. According to the world-wide scientific consensus developed under the auspices of the IPCC—the forum convened by the United Nations and the authority expressly relied upon by the Maryland General Assembly[54]—our climate, at world scale, is heating up at an accelerated pace and in an unprecedented manner.[55] Maryland is already experiencing these impacts.[56] Because of its extensive shoreline, Maryland is being and will be adversely impacted by sea-level rise, warming of coastal waters, severity of precipitation, and associated flooding, extreme heat events, and adverse public health impacts.[57] As described below, Maryland and federal buildings policy reflect this well-established science.

1. State policy strongly favors reduced gas consumption and looks to the Commission to guide the gas utility transition.

Carbon dioxide produced from the combustion of fossil fuels—including gas—is the main component of the GHG emissions that the IPCC and the State have targeted for

[54] *Id.*
[55] *See generally 6th Assessment Report*; IPCC, *Climate Change 2022, Mitigation of Climate Change, Working Group III Contribution to Sixth Assessment Report* (Apr. 4, 2022), https://www.ipcc.ch/report/sixth-assessment-report-working-group-3/; *see also* U.S. Global Change Res. Program, *Fifth National Climate Assessment, Third Order Draft* (Nov. 7, 2022), https://review.globalchange.gov/ (discussing impacts in the US).
[56] *See generally,* Md. Comm'n on Climate Change ("MCCC"), *2022 Annual Report* at 27-29 (discussing the relevance of the IPCC's findings in Maryland); MCCC, *2021 Annual Report* at 20-26 (same).
[57] U.S. Nat'l Oceanic and Atmospheric Admin., Nat'l Ctrs. for Envtl. Info., State Climate Summaries (2022), *Maryland and the District of Columbia* (2022), available at https://statesummaries.ncics.org/chapter/md/ (describing projected increases in temperature, severity of precipitation and sea level rise in Maryland); Pl.'s Compl. 28-47, *Mayor and the City Council of Balt. v. BP P.L.C. et al.*, No. 24C18004219 (Balt. City Cir. Ct., July 20, 2018) (outlining through pleadings of fact, with extensive citations, the increased occurrence and future increased risk, driven by climate change, of sea-level rise, flooding, volatility in the hydrologic regime—leading to more droughts—temperature rise, extreme heat events, and adverse public health impacts in Maryland and in the City of Baltimore); MDE, *Greenhouse Gas Emissions Reduction Act: 2030 GGRA Plan* (Feb. 19, 2021), at 7-20, https://mde.maryland.gov/programs/air/ClimateChange/Documents/2030%20GGRA%20Plan/THE%202030%20GGRA%20PLAN.pdf (describing the impacts of climate change and "the cost of inaction" in Maryland).

reduction, and leaks from gas production, transmission, and distribution infrastructure increase the atmospheric concentrations of methane (CH_4). Both trap heat and increase atmospheric temperatures. Methane from fossil gas production and consumption is a particularly potent GHG—a fact the General Assembly recently recognized in changes to the State's GHG inventory tracking requirements.[58] According to the Maryland Department of the Environment's ("MDE") most recent report, the delivery of gas to end users is responsible for 16.68 percent of Maryland's statewide GHG emissions.[59]

Informed by this science, Maryland adopted a statutory framework aimed at reducing GHG emissions, including by reducing fossil gas use in buildings in favor of electricity.[60] The 2009 Greenhouse Gas Reduction Act ("GGRA") required a 25 percent

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[58] Although methane persists in the atmosphere for a shorter time than carbon dioxide, its relative warming impact is far greater. When combusted as an end-use by customers, 1 kilogram of fossil gas (both methane and non-methane components) is converted into 2.72 kilograms of emissions of carbon dioxide. U.S. DEP'T OF ENERGY at 16-17 (Appendix 3). When leaked without combustion into the atmosphere, however, methane has 84-86 times the global warming potential of carbon dioxide when evaluated over a 20-year period. Such fugitive methane emissions can occur up and down the stream of gas production and distribution and, in addition to combustion itself, are a necessary part of accounting for the industry's impact on overall emissions. Accurate translation of levels of CH_4 emissions into their CO_2 equivalent, associated with natural gas end-use consumption requires specification of which measure of global warming potential ("GWP") of CH_4 is utilized, based on metrics developed by the IPCC, and an estimate of the CH_4 leakage resulting from that consumption. Based on IPCC guidance, the CSNA now requires MDE to use the global warming potential of methane over a 20-year time horizon (of "GWP20") in accounting for fugitive methane emissions in the development of Maryland's inventory of GHG emissions. CSNA § 4 (codified at EN § 2-1205(e)(3)). MDE first incorporated this change in accounting in its recent update of the State's GHG inventory for 2020, having previously used a GWP over a 100-year time horizon ("GWP100") for evaluating methane. Overall, methane emissions are reported to account for roughly half of the currently observed net warming of 1.0°C above pre-industrial levels. EXEC. OFFICE OF THE PRESIDENT, DEP. OF SEC. OF STATE, *The Long-Term Strategy of the United States, Pathways to Net-Zero Greenhouse Gas Emissions by 2050* (Nov. 2021), at 3, 18, 37, https://www.whitehouse.gov/wp-content/uploads/2021/10/US-Long-Term-Strategy.pdf.

[59] GHG emissions resulting from the delivery and combustion at end-use (including residential, commercial, and industrial use) of fossil gas accounts for 11.54 percent of statewide gross GHG emissions, while emissions resulting from the upstream gas industry accounts for 5.14 percent of the State's gross emissions. MDE, *2020 Maryland GHG Inventory* (Sep. 24, 2022), https://mde.maryland.gov/programs/Air/ClimateChange/Pages/GreenhouseGasInventory.aspx.

[60] *See, e.g.*, CSNA §§ 10(a)(1)-(2).

reduction in GHG emissions from 2006 levels by 2020.[61] The General Assembly has since raised the targets for GHG emissions reductions, first modifying the law in 2016 to require a 40 percent reduction from 2006 statewide GHG emissions levels by 2030[62] and then, in the Climate Solutions Now Act of 2022 ("CSNA"), requiring a reduction of 60 percent from 2006 levels by 2031 and net zero GHG emissions by 2045.[63]

In support of these policy goals, the State established the Maryland Commission on Climate Change ("MCCC") "to advise the Governor and General Assembly on ways to mitigate the causes of, prepare for, and adapt to the consequences of climate change."[64] Informed by the findings of the IPCC, the MCCC issues annual recommendations to lawmakers about how to meet the State's GHG goals. In 2021, the MCCC released a technical report finding that "[r]esidential customers can save costs by electrifying all building end-uses compared to using gas."[65] Consistent with this analysis, the MCCC concluded in its *Building Energy Transition Plan* that building gas consumption "is expected to decrease between 62 and 96 percent by 2045" and made numerous recommendations in support of building electrification.[66] Significantly, the General Assembly in 2022 endorsed the MCCC's strategy, declaring itself "[i]n alignment with

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[61] GGRA, 2009 Md. Laws Ch. 171, 172 (codified at former EN § 2-1204).
[62] GGRA – Reauthorization, 2016 Md. Laws Ch. 11 (codified at former EN § 2-1204.1).
[63] CSNA §§ 3-4 (codified at EN §§ 2-1201, 2-1204.1, 2-1204.2).
[64] EN § 2-1301(a). Two governors established the MCCC by executive order; and it has since been codified in statute. Md. Code Regs. 01.01.2007.07; Md. Code Regs. 01.01.2014.14; 2015 Md. Laws Ch. 429 (codified at EN §§ 2-1301, et seq.).
[65] *Md. Building Decarbonization Study* at 72.
[66] MCCC, *Building Energy Transition Plan: A Roadmap for Achieving Net-Zero Emissions in the Residential and Commercial Buildings Sector* (Nov. 2021), at 9, 19-23, https://mde.maryland.gov/programs/air/ClimateChange/MCCC/Documents/2021%20Annual%20Report%20Appendices%20FINAL.pdf.

the [MCCC's] recommendation to transition to an all-electric building code" and stating its support for "moving toward broader electrification of both existing buildings and new construction as a component of decarbonization."[67]

More recently, the MCCC's *2022 Annual Report* called for the General Assembly to mandate that the Commission issue "orders and regulations … for managing a transition to meet the GHG reduction goals of the [CSNA] that establishes requirements for gas utility planning for achieving a structured and just transition to a near-zero emissions buildings sector in Maryland."[68] The report further recommends that the gas companies, under the Commission's oversight, develop transition plans containing elements outlined in the recommendations.[69] Among these elements is the call for "appropriate gas system investments/abandonments for a shrinking customer base and reduction in gas throughput in the range of 60 to 100 percent by 2045."[70]

Separately, State law requires MDE to develop a statewide GHG reduction plan.[71] MDE's initial plan, issued in 2021 before the CSNA was enacted, identified strategies for achieving reductions across broad sectors of the Maryland economy (electricity generation, transportation, and buildings).[72] The plan promoted converting buildings to electricity by replacing the use of gas for space and hot water heating with more efficient

[67] CSNA § 10.
[68] *MCCC 2022 Annual Report* at 16-17.
[69] *Id.*
[70] *Id.*
[71] EN § 2-1205.
[72] *2030 GGRA Plan* at unnumbered introductory page ("The 2030 GGRA Plan sets forth a comprehensive set of measures to reduce and sequester GHGs, including investments in energy efficiency and clean and renewable energy solutions, clean transportation projects and widespread adoption of electric vehicles, and improved management of forests and farms to sequester more carbon in trees and soils.").

electric-powered technology.[73] In an update following enactment of the CSNA, MDE found that the new State goal to reduce statewide emissions by 60 percent by 2031 will require taking more aggressive measures, including further reductions of fossil fuel use in buildings.[74] MDE's updated report identifies as one of four priorities for immediate action: "Rapidly replace space heating and water heating equipment [fired with fossil fuels, including gas] with efficient electric heat pumps…."[75]

In sum, the General Assembly, the MCCC, and MDE all have identified building electrification as priority policy, recognizing its capacity to reduce emissions from fossil fuel use for space and water heating and to help Marylanders save more money on energy.[76] Their findings, recommendations, and declarations of policy conclusively establish electrification as a cost-effective compliance pathway for Maryland's State climate policy.

[73] *Id.* at xvii ("A 100% clean electricity system will enable decarbonization and electrification of the transportation and building sectors, as EVs and electric heating systems use carbon-free energy sources."); *id.* at xix ("Combustion of fossil fuels in buildings is a substantial source of emissions in Maryland. Most of this energy is for space and water heating. The 2030 GGRA Plan reduces emissions from energy use in residential and commercial buildings by prioritizing energy efficiency… and by converting fossil fuel heating systems to efficient electric heat pumps that are powered by increasingly clean and renewable Maryland electricity."), *id.* at 47-48 ("[T]he 2030 GGRA Plan incorporates estimates of the emissions reductions from converting fossil fuel burning systems to efficient heat pumps that are powered by increasingly clean and renewable Maryland electricity.").
[74] MDE, *Reducing Greenhouse Gas Emissions in Maryland: A Progress Report* (Sept. 2022), https://mde.maryland.gov/programs/air/ClimateChange/Documents/GGRA%20PROGRESSS%20REPORT%202022.pdf.
[75] *MDE Progress Report* at 2.
[76] *See* CSNA §10(a)(1)-(2); *MCCC 2022 Annual Report* at 16-17*; MDE Progress Report* at 2.

2. Federal policy and local government policy make the need for Commission action even more urgent.

In addition to the State policy that the Commission must consider in weighing its duties to regulate in the public interest, the Commission should also take notice of federal and local government policies that will further drive electrification, discussed below.

i. Federal policy

Like the State, the federal government has proposed aggressive targets to reduce GHG emissions economy-wide. In 2021, President Biden announced a renewed national commitment to tackling climate change. Through Executive Order, the President committed to taking a whole-of-government approach to the issues, directing agencies "to immediately commence work to confront the climate crisis,"[77] and to "prioritize action on climate change in their policy-making and budget processes, in their contracting and procurement, and in their engagement with State, local, Tribal, and territorial governments; workers and communities; and leaders across all sectors of [the] economy."[78]

Federal climate policies have taken both a carrot and stick approach to reduce fossil gas use, providing for investments and incentives as well as regulation. The Environmental Protection Agency ("EPA") continues to exercise its authority to set and implement environmental standards,[79] the Department of Energy and Council on

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[77] Exec. Order 13990, 86 Fed. Reg. 7037 (Jan. 20, 2021).
[78] Exec. Order 14008, 86 Fed. Reg. 7619 (Jan. 27, 2021).
[79] *See e.g.,* Climate Change Regulatory Actions and Initiatives, EPA, https://www.epa.gov/climate-change/climate-change-regulatory-actions-and-initiatives (last updated Dec. 19, 2022) (describing recent rulemakings to, among other things, strengthen emissions reduction requirements for oil and natural gas sources).

Environmental Quality recently announced efforts to electrifying federal buildings,[80] and Congress recently took unprecedented action to advance emissions reductions through large-scale investments in renewable technologies and tax credits for electrification technologies.[81]

While the Infrastructure Investment and Jobs Act (IIJA) provided for substantial spending on physical infrastructure to support electrification, the Inflation Reduction Act (IRA) contains hundreds of billions of dollars in spending and tax credits to encourage consumers to electrify and to incentivize companies to invest in these electric technologies. The IRA, for example, provides numerous credits and rebates for electric heating and cooling systems and certain electric appliances. These incentives will accelerate the market trend toward building electrification described above.

Together, these federal laws provide substantial potential for climate-focused investments that could ultimately help the nation reach its 2030 and 2050 goals by electrifying end-uses.[82]

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[80] U.S. Dep't of Energy, *Biden-Harris Administration Announces Steps to Electrify and Cut Emissions from Federal Buildings* (Dec. 7, 2022), https://www.energy.gov/articles/biden-harris-administration-announces-steps-electrify-and-cut-emissions-federal-buildings (announcing a new proposed rule requiring new or newly renovated federal buildings to reduce their on-site emissions associated with the energy consumption of the building by 90 percent relative to 2003 levels beginning in 2025, and to fully decarbonize their on-site emissions by 2030); Office of the Fed. Chief Sustainability Officer, Council on Env'tl Quality, *Building Performance Standard* (Dec. 7, 2022), https://www.sustainability.gov/federalbuildingstandard.html (announcing the first ever federal building performance standard, requiring agencies to cut energy use and electrify equipment and appliances to achieve zero scope 1 emissions in 30 percent of the building space owned by the Federal government by square footage by 2030).

[81] *See* Infrastructure Investment and Jobs Act, Pub. L. No. 117-58 (2021); Inflation Reduction Act of 2022, Pub. L. No. 117-169 (2022).

[82] Megan Mhajan et al., *Updated Inflation Reduction Act Modeling Using the Energy Policy Simulator*, ENERGY INNOVATION POLICY & TECH., LLC (Aug. 2022), https://energyinnovation.org/publication/updated-inflation-reduction-act-modeling-using-the-energy-policy-simulator/ (finding that provisions in the IRA could cut greenhouse gas (GHG) emissions 37 to 43

ii. *Local policies*

At the same time that the State and federal governments are enacting ambitious policies to reduce GHG emissions state and nation-wide, several local governments in Maryland have proposed their own electrification policies to reduce GHG emissions, in some cases more ambitiously. In 2021, Montgomery County enacted a strategic plan to cut community-wide GHG emissions 80 percent by 2027 and 100 percent by 2035, compared to 2005 levels.[83] The plan includes goals for 100 percent building electrification by 2035.[84] To this end, the County Council recently passed Building Energy Performance Standards legislation, which set minimum energy performance thresholds for existing commercial and multifamily buildings of 25,000 gross square feet or more.[85] Even more recently, the County Council passed a Comprehensive Building Decarbonization bill—the first of its kind in the State—which will ban new buildings from using gas, beginning in 2027.[86]

Other local jurisdictions are considering their own actions. In early 2022, Prince George's County released a draft *Climate Action Plan*, which includes a commitment "to

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percent below 2005 levels by 2030); John Larsen et al., *A Turning Point for US Climate Progress: Assessing the Climate and Clean Energy Provisions in the Inflation Reduction Act*, RHODIUM GRP. (Aug. 12, 2022), https://rhg.com/research/climate-clean-energy-inflation-reduction-act/ (finding that the IRA has the potential to drive GHG emissions down to 32-42 percent below 2005 levels by 2030).

[83] *Montgomery County Climate Action Plan: Building a Healthy, Equitable, Resilient Community* (June 2021), https://www.montgomerycountymd.gov/climate/.

[84] *Id.* at xxi.

[85] Environmental Sustainability - Building Energy Use Benchmarking and Performance Standards, Bill 16-21 (Montgomery Cnty. Council, 2022)

[86] Buildings – Comprehensive Building Decarbonization, Bill 13-2022 (Montgomery Cnty. Council, 2022). The bill includes exemptions for certain buildings that need emergency backup systems such as hospitals, wastewater treatment plants, crematories, or high-energy industrial or commercial cooking facilities. It also exempts "major renovations and additions" from the requirements.

undertake a community-wide, just and equitable transition away from fossil fuels and toward renewable sources of energy" and to reduce GHG emissions by 50 percent by 2030, compared with 2005 levels, with the ultimate goal of achieving carbon neutrality by 2050.[87] Howard County[88] and Baltimore City[89] are also in the process of updating their climate action plans to account for new GHG emissions reduction goals.

As national policies push reform from the top down, ambitious county-level policies are pushing from the bottom up, impacting the building sector's heating systems and use of fossil fuels, all further heightening the need for long-term planning for utility infrastructure systems. On the other hand, just as states need to act quickly and decisively to take advantage of national-level policies like the IIJA and the IRA, these local government efforts can be enhanced or frustrated, depending on whether state regulation supports such efforts. The current absence of Commission action requiring comprehensive gas company planning undermines these efforts of local Maryland governments.

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[87] Prince George's Cnty. Climate Action Comm'n, *Draft Climate Action Plan* (Jan. 15, 2022), https://pgccouncil.us/DocumentCenter/View/7349/Draft-Climate-Action-Plan, at iii, 4.

[88] Howard Cnty. Office of Cmty. Sustainability, *Howard County Climate Forward: Climate Action and Resiliency Plan* (Preliminary Report 2022), https://livegreenhoward.com/wp-content/uploads/2022/12/HoCo-Climate-Forward.pdf (accounting for Howard County's new goals to achieve a 60 percent reduction in GHG emissions over 2005 levels by 2030 and net zero emissions by 2045).

[89] Balt. Office of Sustainability, *Climate Action Plan*, https://www.baltimoresustainability.org/plans/climate-action-plan/ (last accessed Jan. 18, 2023) (accounting for the City's new targets to achieve a 30 percent reduction in carbon emissions by 2025, a 60 percent reduction by 2030, and full carbon neutrality – or 100 percent reduction in net emissions by 2045 (relative to 2007)).

III. The Commission should act now because the gas companies' planning, practices, and operations are misaligned with economic reality, government policy, and the interests of residential utility customers.

Basic economics—combined with basic ratemaking principles—explain how electrification will cause customers to migrate away from gas use, with enormous impacts on gas companies and their remaining customers. The traditional ratemaking model allows utilities to invest in and earn a return on assets such as gas mains and service lines. Utilities recover and earn a return on their investment, typically over the asset's useful lifetime, by including the costs of their investments and the returns on them in the rates charged to customers. This traditional utility business model is designed to ensure that utilities can attract shareholders who will put up the money for the investments in exchange for a fair return of—and on—their investments. The business model presumes that without such investments, utilities would not be able to ensure reliability or meet customers' needs. This model works reasonably well when sales increase over time, but it leads to higher rates when sales are decreasing. And, as building electrification takes effect, gas utility sales *will* decrease.[90]

The gas companies are substantial, capital-intensive businesses, with operating assets that have long-lived physical functionality. They necessarily must plan, over long horizons, to properly construct, operate, and maintain this infrastructure. While current gas rate and planning arrangements, as supervised and regulated by the Commission, reflect the long-term nature of gas company business, these arrangements conflict with

[90] *See Synapse Report* at 13, Fig. 4.

technological advances that favor electrification, the State's climate policies, and the downsizing of the gas system that those policies necessarily entail.

The need for the Commission to mandate and oversee gas utility transition planning is urgent. Customer investments in buildings and company investments in delivery systems and supply commitments require advance planning. Both sets of investments are long-term; decisions that customers and gas companies are making now have ramifications for many years to come. Customer investments in appliances may last 20 years and, for new buildings, even longer. Utility rates are set based on the expectation that customers will pay for many gas utility investments over 40 years and sometimes over as long as 70 years. To induce the required changes in gas company plans and customer choices, it is imperative that the Commission send accurate investment signals—consistent with advances in technology and the State's climate change policies—to effectively reform the gas companies' businesses and the State's economy.

In this part of the petition, OPC describes: (1) how the gas companies' capital spending programs are inconsistent with the projected large reductions in gas consumption; (2) how these misaligned capital spending practices put customers at risk of significant price increases; and (3) how other gas company practices, aside from capital spending, are also inconsistent with customer interests.

A. Maryland gas companies' capital spending programs are inconsistent with the projected large reductions in gas consumption.

The State's targets to reduce GHG emissions by 60 percent from 2006 levels by 2031 and to achieve net zero emissions by 2045 will require significant change to the business models of the gas companies regulated by the Commission, and, therefore, require significant changes to the Commission's regulatory approach. Those changes must both grapple with decreasing consumption of gas and accommodate the long time it takes to roll over relatively inflexible capital investment in Maryland's building stock as electricity replaces fossil-based heating systems and appliances.

At present, the gas companies are spending on an accelerated basis to replace legacy infrastructure with new infrastructure that has a lifetime of 40 years or more, seeking to expand business for new customers and capacity. Their business-as-usual approach to planning and spending is based on historic levels of sales growth that are no longer realistic. Given the long-term consequences of *today's* decisions and *today's* investments, the current business models of the gas companies do not reflect the market realities of the coming declines in gas consumption and implementation of the State's climate change response strategies. As documented in detail in OPC's recent report, *Maryland Gas Utility Spending: Projections and Analysis*, the State's largest gas utilities are in the process of spending tens of billions of dollars on capital investments over the coming decades, with customers ultimately paying $125 billion by the end of the century, largely for investments gas utilities plan to make in the next ten to 20 years.[91] Further, the gas companies are spending tens of millions annually to add new gas customers and to

[91] DHInfrastructure, *Maryland Gas Utility Spending: Projections and Analysis* (Oct. 2022), at 23, 26, https://opc.maryland.gov/Gas-Utility-Spending-Report (attached as Appendix E).

expand the gas system.[92] In 2022 alone, BGE spent $78 million and Washington Gas more than $50 million on new customer acquisition and system expansion.[93]

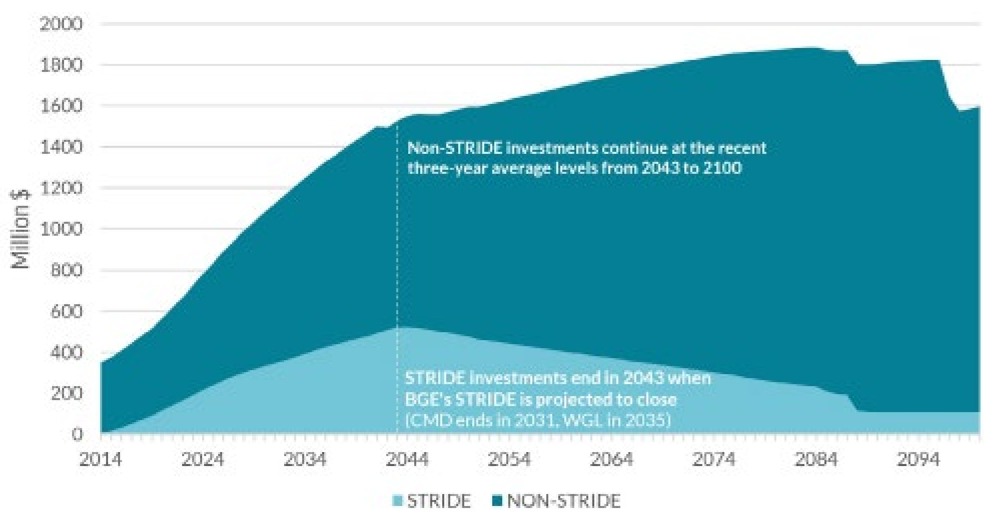
The gas companies have no plans to slow this accelerated pace of capital spending to add new infrastructure and reconstruct their legacy systems. BGE, for example, plans to continue Operation Pipeline—its program to replace its entire gas infrastructure, as it existed in 2013—until 2043, at a cost of more than $4 billion.[94] Operation Pipeline's costs will not be fully recovered until the end of the century, by which time customers would pay three to four times more than the initial costs after accounting for the utility's return.[95] These plans clearly serve the interests of the major gas companies' utility holding companies, which earn their profits from spending on capital infrastructure. Indeed, Exelon recently told its investors that BGE will increase its annual gas distribution capital spending to $500 million per year in 2024 and 2025, up from $475 million per year in 2022 and 2023.[96] However, that planned spending is not consistent with the public interest.

The long-term consequences of this spending are significant, given that these costs are recovered slowly, over many decades, just as gas consumption is declining. In fact, while Maryland's three largest gas utilities collectively are about one-third of the way through replacing their legacy systems built up over nearly a hundred years, they have

[92] *Gas Spending Report* at 35-37.
[93] *Id.*
[94] *Id.* at 11, Table 2.2.
[95] *Id.* at 3.
[96] Exelon, *Fall and Winter 2022 Investor Meetings* at 26, https://investors.exeloncorp.com/static-files/98091533-da5b-40c8-bef7-5abfacc0d2d0.

recovered only about 3 percent of the replacement costs.[97] The *Maryland Gas Spending Report* shows that the gas companies' current spending programs, if carried forward without adjustment, will lead to a cumulative capital investment of some $13 billion by 2043, with approximately a third incurred under the Strategic Infrastructure Development and Enhancement (STRIDE) pipe replacement program.[98] Moreover, the *annual* revenue requirement of this investment charged to the gas companies' customers rises to $1.5 billion by 2043 (including both STRIDE and non-STRIDE investments), assuming the use of current depreciation rates.[99] These revenue requirements are depicted in the following figure from the report:

Figure 1.2: Combined Three-Company STRIDE and Non-STRIDE CAPEX Annual Revenue Requirement



[97] *Gas Spending Report* at 32.

[98] PUA § 4-210; *Gas Spending Report* at 2, Table 1.2 ($4.76 billion in STRIDE capital expenditures + $8.29 billion in non-STRIDE capital expenditures). BGE recently informed the Commission that it will propose to complete its STRIDE replacement program through its multi-year rate plan. *Baltimore Gas and Electric Co. 2023 STRIDE Project List and Factor Filing*, Case No. 9468, Maillog No. 242893 (Nov. 1, 2023).

[99] *Gas Spending Report* at 4.

As the figure shows, 97 percent of STRIDE replacement costs will be recovered in *future* years—when gas consumption must decline significantly for Maryland to meet its GHG reduction targets. And STRIDE replacement costs (the light blue portion of the graph) are less than half of the ongoing gas utility capital spending.

These investments must be assessed in light of the projected large reductions in gas sales. Those sales reductions raise the critical question of how—and if—the gas companies will recover the costs of these ongoing investments in infrastructure while maintaining their core obligations to provide safe and reliable service to remaining customers.

B. The gas companies' misaligned capital spending practices put customers at risk of significant price increases.

As a result of market forces and government policies driving electrification, fewer utility customers will be buying less gas to pay for these massive investments. To recover both the return of and on those investments, gas utilities will have to increase distribution rates. In turn, higher gas rates are likely to spur more customers to electrify their gas end-uses (furnaces and appliances), leaving even fewer customers on the system to pay for the massive investments. As this process goes on, those with the means to electrify—*i.e.*, those who can afford the upfront costs of changing their gas appliances to electric ones and can modify their buildings to accommodate the switch—will be the fastest to do so.[100] Without changes to regulatory practices or direct assistance, those without access to capital (*e.g.*, low- and moderate-income customers) or the ability to make changes to their

[100] *See, e.g.*, *Synapse Report* at 4; *BGE Strategy* at 35.

dwellings (*e.g.*, renters) will be the customers left behind on an increasingly costly gas system. Rate escalation will hit these groups the hardest, even though they are least able to afford higher utility bills.

The ramifications of continuing business-as-usual are profound. The *Maryland Gas Spending Report* showed huge increases in gas utility annual revenue requirements as a result of current capital spending on existing and new infrastructure. Using conservative assumptions, the report finds that BGE's annual revenue requirement will peak at $1.532 billion in 2084, an amount that is 2.3 times 2023 levels.[101] While 2084 may seem distant, the investments BGE intends to make over the next 10-20 years underlies that record-setting 2084 rate base.

Meanwhile, long before 2084—that is, by 2045—gas sales are projected to decline by at least 60 percent, even using the most conservative assumptions.[102] Yet it is through those declining gas sales that the gas companies will recover their increasing revenue requirements resulting from their investments on the delivery system. Delivery rates are based on gas usage, and as recovery of those fixed costs fall to an ever-shrinking base of customers and sales, massive increases in rates will be necessary. The report prepared for OPC by Synapse, *Climate Policy for Maryland's Gas Utilities: Financial Implications* (the "*Synapse Report*") projected this upwards trajectory of gas rates in the residential sector as Marylanders switch from fossil-fuel fired building furnaces and appliances to electricity in conformity with the State's GHG reduction targets. Synapse modeled the

[101] *Gas Spending Report* at 24.
[102] *BGE Strategy* at 25; *MCC Transition Plan* at 10.

impact on rate base, revenues, and expenses for each of the three major Maryland gas companies. For each utility, Synapse modeled the increases in the delivery rates as well as the residential customer rate impact of using alternative gaseous fuels to offset increasing portions of the gas distribution system's emissions.

Synapse's modelling projects devastating customer impacts in both the high- and low-cost scenario for the price of non-fossil fuels (alternative gaseous fuels, or AGF). The report assumed that new construction is all-electric by the late 2020s and that, for existing buildings, electrification is achieved through steady increases in heat pumps' share of the Maryland market based on recent trends documented in U.S. Census data. Under Synapse's model, heat pumps replace fossil fuel furnaces at the end of the furnaces' useful life, such that by 2030, over 95 percent of households replacing space heating equipment are buying heat pumps, increasing to 100 percent by 2035.[103] The cost impacts for remaining gas customers are as follows: [104]

[103] *Synapse Report* at 11-12.
[104] Figures 16 through 18 are from the *Synapse Report* at 20.

Figure 16. BGE residential building total gas costs (Low and High AGF Price)

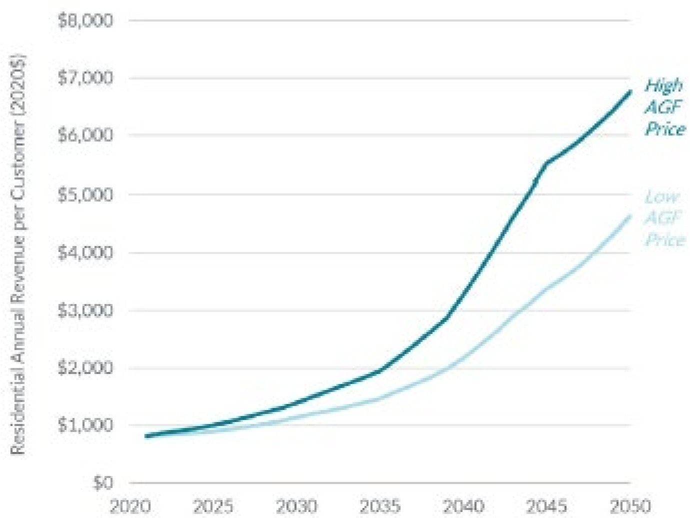


Figure 17. WGL residential building total gas costs (Low and High AGF Price)

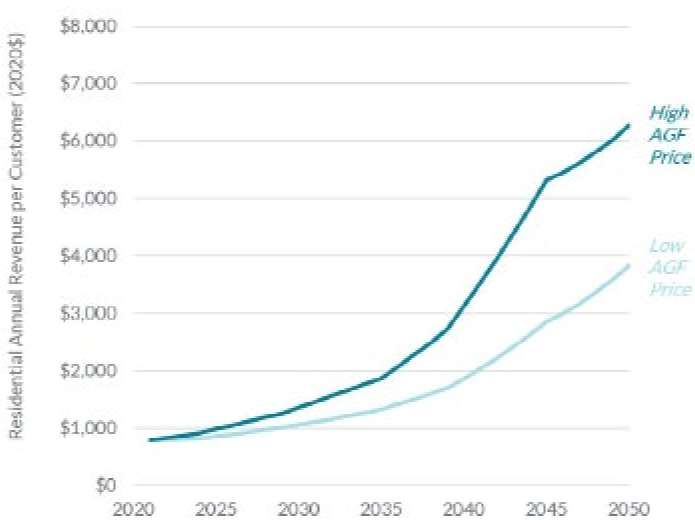


Figure 18. Columbia residential building total gas costs (Low and High AGF Price)

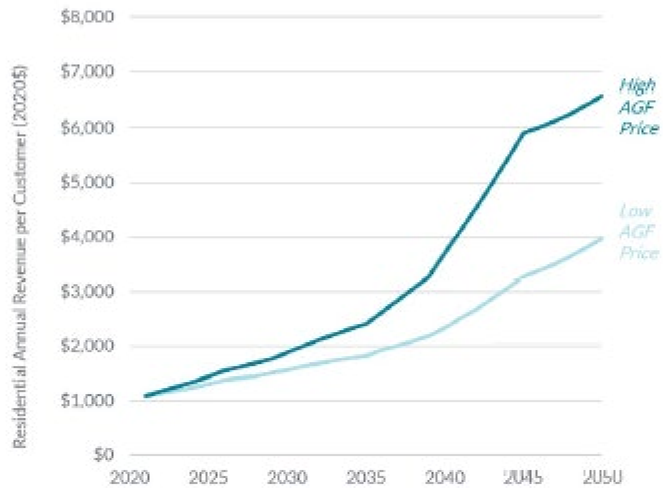


Figure 16 illustrates that with increasingly larger annual bills, customers remaining with BGE for gas service in 2050 could see rate increases of up to *ten times* today's rates. The study projects BGE average customers who paid $820 for gas service in 2021 will pay as much as $1,994 in 2035 and $6,759 in 2050.[105] Figures 17 and 18 show that other gas utilities will also need substantial rate increases as well. Notably, these rate increases will be avoided by those with the means to leave the gas system through electrification. Low-income customers and those that cannot control their energy source, like renters, will be most adversely affected.

As the *Synapse Report* explains, electrification will happen gradually as the building stock turns over. Gas rate increases due to electrification will also be gradual. But at some point, it will no longer be possible for the gas utilities to raise rates to the

[105] *Id.*

levels necessary for recovering their fixed rate base costs while remaining economically viable. As customer departures increase and rates rise to unaffordable levels, gas utilities are likely to have substantial unrecovered and uneconomic assets remaining in rate base and on their books.[106]

The potential for stranded costs is not unique to Maryland; a Brattle Group analysis found that declining costs for electrification in conjunction with policy initiatives could lead to approximately $150-180 billion in unrecovered gas distribution infrastructure across the United States.[107] Comprehensive planning, however, can help lessen the probability or amount of stranded costs and mitigate the hardship of increasing rates on customers. Further, comprehensive planning and transparent regulatory policies can help insulate customers from stranded cost exposure by assigning the risks of speculative investments to those who will reap any benefit and can mitigate those risks—the gas companies themselves, rather than their captive customers.

C. Other gas company practices are inconsistent with customer interests, do not require significant investigation, and are ripe for priority action.

This petition requests that contemporaneously with the investigation into capital expenditures and long-term planning in the Transition Track, the Commission open a Priority Track to address—on an expedited basis—at least four utility practices that are plainly contrary to the public interest and the interests of customers and are ripe for action now. Action by the Commission concerning these practices would constitute

[106] *Id.* at 21.
[107] Brattle Grp. at 11.

"no-regrets" actions in that they would not prejudice or otherwise affect the outcome of the investigation and rulemaking concerning long-term transition planning. At least four areas of priority measures are already identifiable today: (a) gas commodity procurement practices; (b) gas line-extension policies; (c) gas marketing practices; and (d) EmPOWER Maryland gas appliance programs. We briefly touch on these four, while urging the Commission to seek stakeholder input to identify additional priority areas and allow for a period of discovery on the issues raised.

1. Procurement practices

The gas companies' current procurement practices for gas supply and pipeline capacity are documented in filings made with the Commission each year. Companies file annual capacity plans, extending for a five-year forward period.[108] Through these plans, the gas companies disclose their long-term commitments for gas pipeline capacity to meet demand annually and during colder periods. Gas supply procurements are reviewed during annual evidentiary hearings, pursuant to PUA § 4-402(d). The gas companies appear to determine how much gas supply and pipeline capacity to procure by using econometric analysis to estimate how customer growth, weather, and other drivers have impacted demand historically, then projecting values for those drivers going forward to forecast demand in the future.

[108] *Baltimore Gas and Electric Company Gas Capacity Plan, Winters 2022/2023 through 2026/2027*, Maillog No. 242865 (Oct. 31, 2022); *Washington Gas Light Company Energy Acquisition 2023-2027 Portfolio Plan*, Maillog No. 300182 (November 15, 2022); *Columbia Gas of Maryland, Inc., Strategic Gas Supply Plan 2023-2027*, Maillog No. 242655 (Oct. 14, 2022).

Writ large, such "capacity planning" is complex and warrants consideration by the Commission in the long-term transition track of the proposed proceeding.[109] However, because the Commission requires the gas companies to update their gas supply filings annually, and because gas companies likewise enter into gas supply contracts every year, the Commission should include an examination of the companies' current procurement practices in the near-term priority track of the proceeding.

Currently, as with their current capital investment programs, the gas companies' gas procurement practices fail to plan sufficiently for the reductions in gas demand attendant on decarbonization. Although at least one gas company has pledged to "adjust [its] natural gas procurement strategy to align with" the goals in the CSNA "when appropriate,"[110] all of the gas companies continue to commit to long-term contracts based on models that assume steady or growing gas consumption, as though Maryland's State policy to reduce gas consumption did not exist. The Commission should immediately require the gas companies to align their procurement strategies with the CSNA and the reality that gas sales will drop over time.

2. Gas line-extension policy

Current utility line-extension policies expose ratepayers to risks of stranded gas infrastructure costs caused by system expansion. Washington Gas's line-extension policy provides an example. Whether Washington Gas's existing customers pay for the company to extend its distribution facilities to serve a new location or whether the

[109] *See* Appendix A.
[110] *BGE Gas Capacity Plan* at 6.

proposed customer is required to pay depends on whether the anticipated future revenues from the extension are sufficient to cover the extension's cost.[111] If the projected revenues are not realized, existing customers wind up compensating the utility for the unrecovered cost of extending its service to the new customer.

The problem is that Washington Gas's current test assumes a life cycle for line extension of 30 years.[112] In the past, it may have been reasonable to assume that added customers would remain on the system for 30 years. Now, however, the technological, market, and policy trends described in this petition cast doubt upon the future of gas as an energy source in the State 30 years into the future. Revenue projections that assume steady gas system growth exacerbate the risks of stranded infrastructure costs by adding projects to the gas system that may not be economic in the long term. Current line extension policies do not protect customers from the risks of such uncertainty.

3. Gas company marketing practices

If the State is to achieve its climate goals, the Commission must change its regulatory policies that permit gas companies to promote the purchase and use of fossil gas in homes. These messages encourage customers to make investment decisions that are detrimental to their long-term interests. They fail to consider, for example, that purchasing a gas furnace today will likely result in higher lifetime costs than if the customer has purchased an electric heat pump. The data are clear that rates for gas utility

[111] *Washington Gas Light Company Maryland Rate Schedules and General Service Provisions for Gas Service*, P.S.C. Md. No. 6, G.S.P. 13-14, at 67-69 (Nov. 22, 2011).
[112] *Id.* at G.S.P. 14(e), at 69A (Oct. 14, 2022).

service are increasing—both for distribution and commodity costs. And they will continue to increase as gas companies continue to spend on new and replacement infrastructure and as the building sector moves—even incrementally—to electrify. Put simply, it is contrary to customer interests to buy gas equipment that has a service life extending ten years or even longer.

An example is Washington Gas's marketing campaign describing gas as "a clean energy" that is less emissions-intensive and more environmentally beneficial than an all-electric home.[113] Washington Gas's promotional materials failed to disclose the well-established fact that fossil gas production, distribution, and consumption are major sources of greenhouse gas emissions. Yet, the Commission's order allowing Washington Gas's marketing message effectively allows gas utilities to engage in such forms of "green marketing." This petition would facilitate the broader inquiry about gas utility marketing practices that the Commission indicated was appropriate when it dismissed OPC's complaint alleging that Washington Gas's marketing violated the public interest standard of PUA § 2-113.[114]

4. EmPOWER Maryland programs

Current gas utility EmPOWER programs are misaligned with customers' interests and State climate policy in two readily identifiable ways. First, they incentivize consumer purchases of gas appliances. Such incentives are contrary to the long-term interests of

[113] *See* OPC Comp., Case No. 9673 (Nov. 23, 2021).
[114] Order No. 90057, Case No. 9673 (Feb. 7, 2022), at 6, ¶ 18 (finding that "a complaint against one utility is an inappropriate forum to address the broader issues raised by natural gas and its role in greenhouse gas emissions").

residential customers and State policy. Ending incentives for household gas appliances is required to conform Commission policy with the public interest, in particular long-term customer interests in minimizing their energy bills. As explained above, it is contrary to customer interests to buy gas equipment that has a service life extending ten years or even longer. In its 2021 and 2022 recommendations, the MCCC also called for ending fossil fuel appliance incentives.[115]

Second, EmPOWER is not being used to incentivize fuel switching to electric heat pumps. Ending incentives for gas appliances and using the funding to incentivize electric heat pump purchases instead will bring about several benefits. These actions will: (1) help insulate ratepayers from rising gas delivery rates in both the short and long term, (2) prioritize the adoption of electric heat pumps, consistent with the General Assembly's support of "moving toward broader electrification of both existing buildings and new construction as a component of decarbonization,"[116] and (3) lead to net-reduced GHG emissions statewide. In its past three annual reports, the MCCC has recommended that EmPOWER encourage fuel switching.[117]

Notably, small levels of participation in programs incentivizing electric heat pumps will provide more GHG reductions than continued funding of gas appliance incentives. A May 2022 analysis of Washington Gas Light's gas equipment programs found that more reductions in GHG emissions would occur if just one in five participants

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[115] *MCCC 2022 Annual Report* at 16 (citing a similar recommendation from 2021).
[116] CSNA §§ 10(a)(1)-(2).
[117] *MCCC 2022 Annual Report* at 16 (citing similar recommendations from 2020 and 2021).

in the existing gas equipment program chose an electric heat pump instead of a gas furnace, even if the other four consumers chose a less efficient gas furnace in the absence of gas incentives.[118] OPC's analysis of the GHG Abatement Potential Study confirmed a similar finding: "the utilities and DHCD can achieve greater GHG reductions by promoting and installing electrification measures instead of gas appliances—even if some customers install less efficient gas equipment as a result."[119] Thus, ending EmPOWER gas appliance incentives is a "no-regrets" policy that the Commission should not delay in implementing.

IV. A comprehensive and proactive planning proceeding is necessary to ensure that the rates, service, and operations of Maryland's gas companies are consistent with the public interest, not just the gas companies' private interests.

The Maryland Supreme Court has observed, that with respect to public utilities, "the public good [is] best served by not only permitting, but assuring, a monopolistic structure, coupled with *extensive government control* over the rates, service, and operations of such a structure."[120] In statutory terms, the Commission is charged with exercising "extensive government control" through its duty to "supervise and regulate" public utilities to ensure that they operate in the public interest.[121]

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[118] *Office of People's Counsel Response in Support of Maryland Energy Efficiency Advocate's Motion to End Gas Appliance Incentives*, Case No. 9648, Maillog No. 240629 (May 10, 2022), at 2, Appendix 1.
[119] *Office of People's Counsel's Comments on EmPOWER Goals for the 2024-2026 Program Cycle, Case No. 9648, Maillog No.* 301064 (January 27, 2023), at 4.
[120] *Delmarva Power & Light Co. v. Pub. Serv. Comm'n*, 370 Md. 1, 6 (2002) (emphasis added).
[121] PUA § 2-113.

The Commission's role as "the representative of the public interest … does not permit it to act as an umpire blandly calling balls and strikes for adversaries appearing before it[. Rather,] the right of the public must receive active and affirmative protection at the hands of the [regulator]."[122] In other words, the Commission cannot fulfill its statutory obligation by merely reacting to utility proposals; rather it must, instead, articulate an affirmative vision of the public interest and take the initiative to ensure that utilities meet it. Among other things, that means directing gas companies to plan for substantially declining sales.

The gas companies themselves recognize that major changes to their industry are coming and that those changes demand comprehensive gas planning.[123] But without the Commission's "active and affirmative" oversight, company plans will be influenced by the incentive structure that rewards the companies' private interest in profit-making based on investments in capital, which can result in serious misalignments with the public interest.[124]

Moreover, because the impending challenges facing the gas companies and their customers are industry-wide, and not specific to individual gas companies, they must be dealt with in the comprehensive, proactive, and Commission-driven proceeding that this petition proposes, rather than in a piecemeal, reactive, and utility-driven proceeding such

[122] *Scenic Hudson Pres. Conference et al. v. Fed. Power Comm'n*, 354 F.2d 608, 620 (2d Cir. 1965).
[123] *See* Part IV.A below.
[124] A central consequence of rate of return regulation is the incentive it gives regulated utilities to make capital investments, inconsistent with and in excess of the most efficient, least cost level. This phenomenon is often called the Averch-Johnson effect after a seminal article describing the concept authored by the term's namesakes. Harvey Averch & Leland Johnson, *Behavior of the Firm Under Regulatory Constraint*, 52 AM. ECON. REV. 1052 (1962).

as an individual rate case. The Commission exists to provide effective regulatory oversight of these companies so that they perform in the public interest. A planning process that defers to the gas companies, in which the Commission plays a passive role, undermines the Commission's function and seriously threatens the public interest.

Part IV.A of this section explains how the statements and actions of the gas companies demonstrate support for the long-term planning called for by this petition. Parts IV.B and IV.C show, through two examples, why the public interest demands that the Commission address long-term gas company planning in a statewide proceeding, rather than allow the gas companies to lead the planning process through rate cases. Specifically, Part IV.B addresses the problems with the gas companies' reliance on low or zero-carbon fuels as a solution, while Part IV.C addresses fundamental flaws in BGE's recent *Integrated Decarbonization Strategy*.

A. Statements and actions of the Maryland gas companies support the need for comprehensive gas planning.

The gas companies' statements and actions support the need for comprehensive gas planning consistent with this petition. Exelon, BGE's parent, for example, participated in a recent roundtable discussion that National Grid and RMI convened "to explore what it may take to decarbonize the gas distribution system in the US and the customer end uses it serves today."[125] The roundtable discussions culminated in a report that recommends, among other matters: "urgent action by all parties, but especially from

[125] Nat'l Grid & RMI, *Collaborating for Gas Utility Decarbonization* (Oct. 2022), at 2, https://www.raponline.org/wp-content/uploads/2022/11/rap-rmi-natgrid-collaborating-gas-utility-decarbonization-2022-october.pdf.

policymakers and regulators, to enable near-term emissions reductions and guide utility investment and decision-making toward economy-wide decarbonization by 2050."[126] The report's policy recommendations expressly advise "utilities and regulators [to] conduct gas infrastructure planning as part of comprehensive equitable integrated energy system planning at the state or regional level."[127] More specifically, the report calls for "an inclusive, comprehensive, and iterative long-term planning process at the state level," the result of which "should then guide the development of utility-specific plans."[128]

BGE's recently published *Integrated Decarbonization Strategy* ("*BGE Strategy*") also supports the Commission's commencement of the proceeding this petition requests. BGE and its consultant E3 emphasize in the report that "*regulatory and policy support will be necessary* to both *manage* the challenges associated with decarbonization and capture new opportunities."[129] The language of "manage" and "regulatory and policy support" is planning language.

Washington Gas has similarly recognized the need to adapt its business practices to align with emissions reduction targets. In 2020, Washington Gas engaged the consulting firm ICF to conduct a study of alternative approaches to emissions reductions to align with the District of Columbia's legislated commitments to reduce GHG emissions by 60 percent by 2030 (relative to 2006 levels) and achieve carbon neutrality

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[126] *Id.* at 3.
[127] *Id.* at 5.
[128] *Id.*
[129] *BGE Strategy* at 42 (emphasis added); *see also id.* at 7, 46.

by 2045.[130] Like the *BGE Strategy*, Washington Gas's resulting report highlights the complexity of the issues and the need for regulatory oversight. It further offers a glimpse into the implications of a failure to act, finding that Washington Gas faces billions of dollars in potential stranded costs from high levels of electrification.[131] The Commission should take the cues from the BGE and Washington Gas studies and open proceedings to manage the gas transition so that it occurs consistent with customers' and the public's interest, including mitigating stranded costs.

B. Alternative low or zero carbon fuels are not a viable large-scale substitute for fossil gas.

The *BGE Strategy* advances what has become a common gas company narrative: that decarbonization of the gas companies' operations in line with Maryland's climate change policies can be achieved by depending heavily on the large-scale replacement of conventional gas with renewable natural gas ("RNG"), green hydrogen, or various types of synthetic gas.[132] This narrative is seriously flawed. As explained in the *Synapse Report*, multiple recent studies regarding the availability and cost of RNG—including studies by industry consultants—have concluded that it is not available at anywhere near the scale required to meet current demand and can only be procured at significantly higher costs.[133] Significant cost, availability, and technical compatibility issues also exist

[130] Climate Commitment Act of 2022, 69 D.C. Reg. 009919 (Sept. 21, 2022) (codified at D.C. Code § 8-151.09d); ICF Resources, LLC, *Opportunities for Evolving the Natural Gas Distribution Business to Support the District of Columbia's Climate Goals* (Apr. 2020).
[131] *ICF DC Report* at 27.
[132] *BGE Strategy* at 4-5, 8-9.
[133] *See, e.g.,* ICF prepared for Michigan Pub. Serv. Comm'n, *Michigan Renewable Natural Gas Study, Final Report* (Sept. 23, 2022), at 4-6 (Michigan assessment of RNG potential: achievable – 57 tBtu/yr., feasible – 148 tBtu/yr., inventory – 313 tBtu/yr.; current Michigan gas consumption across all sectors

with blending hydrogen with methane in the gas companies' existing gas distribution network to allow utilization of the existing gas delivery network and end-use gas appliances.[134] While there may be a need for low-emissions hydrogen and other alternative fuels to power certain end-uses that are far more expensive to electrify or for which there are no available electric alternatives (such as heavy industry and heavy-duty transportation), none of the alternatives that would reduce GHG emissions are available at scale to replace fossil gas across-the-board.[135] Any reliance on the projected future use of alternative gaseous fuels to justify maintaining business-as-usual investment in gas infrastructure is speculative at best and serves to promote the gas companies' interests in

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average of 673 tBtu/yr. 2016-2020, costs ranging from $9.92-49.17/MMBtu); ICF prepared for NYSERDA, *Potential of Renewable Natural Gas in New York State*: *Final Report, No. 21-34* (Apr. 2022), at ES-1-2 (New York assessment of RNG potential estimated at between 47 tBtu/yr. and 147 tBtu/yr. (2040) with estimated average weighted costs between $11.29/MMBtu and $34.56/MMBtu; vs. natural gas consumption across all sectors in New York of 1,280 tBtu in 2017); ICF prepared for Am. Gas Found., *Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment* (Dec. 2019), at 2,5 (US national assessment - low scenario of 1,660 tBtu/yr. (by 2040), high scenario 3,780 tBtu/yr. (2040) vs. 10 year average residential only gas consumption of 4,846 tBtu/yr. (2009-2018); cost of production estimated to range from $7 to $45/MMBtu); *see also Synapse Report*, Part 3.3, at 7-8.

[134] *See, e.g*., Jochen Bard et al., *The Limitations of Hydrogen Blending in the European Gas Grid*, FRAUNHOFER INST. FOR ENERGY ECON. AND ENERGY SYS. TECH. (Jan. 2022) (identifying severe technical upper limits to the blending of hydrogen depending on type of network equipment and component materials); Int'l Renewable Energy Agency ("IRENA"), *Global Hydrogen Trade to Meet the 1.5 °C Climate Goal: Part II, Technology Review of Hydrogen Carriers* (2022), at 103 (identifying a higher risk of pipe metal embrittlement and decreases in the energy content of a given volume of hydrogen compared to methane); *id.* at 101 (identifying that the hydrogen blending option "faces multiple challenges. The CO_2 benefit is small, equivalent to about a third of the blending fraction (i.e., a blending target of 20 percent by volume only leads to about 7 percent lower CO_2 emissions). It increases the gas price, as relatively cheap hydrogen of USD_3/kgH_2 is about 10 times the typical natural gas price in the US [assumed to be 2.5 USD/MMBtu]."); Jan Rosenow, *Is Heating Homes with Hydrogen All but a Pipe Dream? An Evidence Review* (2022), http://www.janrosenow.com/uploads/4/7/1/2/4712328/is_heating_homes_with_hydrogen_all_but_a_pipe_dream_final.pdf (assessing multiple studies showing that cost and technical issues with hydrogen preclude significant deployment for supply of residential heating); Cal. Pub. Util. Comm'n, *Final Report, Hydrogen Blending Impacts Study*, Case No. R1302008 (Jul. 18, 2022) (arriving at similar conclusions regarding severe technical limits to hydrogen blending with methane above 5 percent by volume in the existing gas distribution network)*;see also Synapse Report* at 8-9.

[135] *Synapse Report* at 10.

maintaining and expanding the infrastructure over the public's interest in transitioning to more reliable sources of energy.

C. Other flaws in the *BGE Strategy* further highlight the need for a Commission-driven, long-term planning process.

In the *BGE Strategy*, the company's consultant, E3, describes three alternative scenarios for the evolution of the company's gas business over the period 2020-2045 to address the challenges of climate change and to enable the State to achieve its goals of net zero GHG emissions.[136] In each of the three scenarios, the company proposes a radical change in its business operating model, based on analysis that assumes high levels of electrification and the introduction of alternative low or zero carbon fuels—such as "renewable natural gas" ("RNG"), other low carbon fuel mixes (e.g., synthetic natural gas or biomethane), or hydrogen—into its facilities for delivery to customers in varying amounts. However, in all of the scenarios modelled, BGE projects a very significant decrease in the amount of gas delivered through its pipelines—from 60 to 78 percent.[137] This drastic reduction in throughput is a fundamental driver of the need for the comprehensive planning proceeding sought by this petition.

Although it contains important acknowledgments that "[e]lectrification is the primary driver of decarbonization,"[138] that the number of gas customers and overall throughput will decline under any scenario that achieves the State's emissions reduction

[136] *BGE Strategy* at 16-17.
[137] *Id.* at 25.
[138] *Id.* at 37; *see also id.* at 25 ("Electrification is a key driver of decarbonization across all three scenarios considered."); *id.* at 5 ("Electrification is the core engine of decarbonization across all scenarios considered."); *id.* at 44 (same).

targets,[139] and that regulatory support will be necessary to manage the transition,[140] the *BGE Strategy* is flawed in numerous respects, reflecting BGE's own private interests and rendering its recommendations and conclusions fatally infirm for the public interest.

First, the strategy rests on several false premises. Even though each of its scenarios anticipates drastic reductions in gas throughput (at least 60 percent), none of the scenarios foresees any reduction in BGE's capital spending on its gas system. In fact, BGE directed its consultant to arrive at decarbonization strategies that depend on BGE maintaining both its electric and gas systems as they exist today, implicitly also maintaining its current plans to replace its gas system under its current capital investment program.[141] Thus, no pathway reflects any significant avoided gas infrastructure spending. As noted above, BGE plans to spend tens of billions of dollars, substantial portions of which potentially can be avoided with electrification. Fundamentally, BGE's plan illustrates the utility incentive—common to all Maryland gas companies—to spend on capital. It elevates Exelon's economic incentives and interest in maintaining two capital intensive infrastructures—one for gas and one for electricity—over the public interest.

Moreover, to support its findings, the study relies on the false premise that its "Integrated Energy System Scenarios" (meaning those that "rely on a combination of

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[139] *Id.* at 25.
[140] *Id.* at 42.
[141] *Id.* at 11 ("BGE specifically asked E3 to build on its prior efforts in the State by evaluating the implications of decarbonization strategies that achieve the state's newly legislated net zero targets with an intent to understand how BGE's electric and gas businesses and infrastructure could play a supporting role.").

electric and gas infrastructure to achieve decarbonization")[142] can "take advantage of the *existing* BGE gas distribution system to meet heating capacity requirements."[143] In fact, the "existing" infrastructure that BGE seeks to leverage in 2022 is only 30 percent built—BGE's plan to modernize its gas system will not be complete for 20 years.[144]

Second, the *BGE Strategy* appears to be based on numerous analytical flaws, including, but not limited to, the following:

- The report assumes that there will be a continuing need for back-up gas or electric resistance heating systems to accompany the deployment of high efficiency cold-climate air source heat pumps in Maryland.[145]

- The report fails to adequately estimate the reductions in electric demand resulting from the change-out of inefficient electric resistance heating with the highly efficient cold climate air source heat pumps, leading to inaccurate assumptions about electric load growth.

- The report fails to account for the impacts of the policies—including significant tax incentives and rebates—in the Inflation Reduction Act that will accelerate electrification by lowering its costs.

- The report counts biomethane as zero-emission, although when it is burned, it emits carbon that MDE counts in its inventory of Maryland GHG emissions.

[142] *Id.* at 4.
[143] *Id.* at 32 (emphasis added); *see also id.* at 5 ("Gas infrastructure serves as an existing, low-cost source of capacity that reduces the amount of electric generation, transmission and distribution capacity that will need to be added over the coming decade."); *id.* at 28 ("The gas backup utilizes the existing firm capacity of BGE's gas infrastructure …"); *id.* at 33 ("The Hybrid and Diverse scenarios substantially reduce incremental electric system expenditures by leveraging the existing capacity of BGE's gas infrastructure.").
[144] *But see Gas Spending Report* at 11-13.
[145] *Synapse Report*, Part 3.2, at 6-7.

Third, the *BGE Strategy* is largely based on hypotheses rather than facts. For example, while it purports to achieve decarbonization in line with Maryland's climate change policies, the *BGE Strategy* depends heavily on the large-scale replacement of conventional gas with renewable natural gas ("RNG"), hydrogen, or various types of synthetic gas, which, as discussed above, are not cost-effectively available at scale now, are unlikely to be cost-effectively scalable, and are themselves potential sources of GHG emissions.[146] The *BGE Strategy* admits that its conclusion that "decarbonization strategies that leverage the advantages of both electrification measures and gas infrastructure carry a lower overall level of challenge relative to an all electric approach" is a "hypothesis."[147] Yet BGE's approach seeks to place all the risk for failure of its "hypothesis" on customers. While OPC shares BGE's hope that new technologies will make alternative fuels a more viable alternative, the Commission should make it clear that the gas company—not customers—bears the risk for any strategies that speculate on alternative fuels. As things are now, the gas companies are speculating on the backs of customers by investing massively in infrastructure that locks in costs for 40 or more years, long after fossil gas sales will substantially decline or end altogether.

These failings in the *BGE Strategy* wholly undermine its recommendations and conclusions. Notwithstanding its failings, if the Commission is to consider the strategy, it should be tested and investigated through the comprehensive, broader investigative proceeding that OPC here requests. Failure to engage in proactive, comprehensive,

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[146] *See* Part IV.B above.
[147] *BGE Strategy* at 29.

Commission-driven planning would be to defer by default to the gas companies' private plans, such as the *BGE Strategy*. It is the Commission's duty to ensure that utilities operate in the public interest, not merely their own private interests.[148]

V. The Commission should take advantage of existing guidance and resources in deciding how to proceed with gas utility planning.

From the Maryland Commission on Climate Change's *Building Energy Transition Plan*, to independent expert reports, to actions undertaken by other state utility regulators, the Commission has at its disposal significant resources about how best to conduct the long-term gas planning proceeding this petition requests. The gas transition proceedings held by other state regulators are particularly informative. Many of these proceedings point out the same challenges Maryland faces from the transition away from gas to electricity to meet State climate goals. For example, Maryland must address the same issues as the New Jersey Board of Public Utilities pointed out in a 2020 report: "As NJBPU endeavors to ensure just and prudent investments, it must examine if ratepayers are socializing and subsidizing unnecessary fossil fuel infrastructure costs, and if doing so will risk ratepayers shouldering the burden of stranded assets in the future."[149] Having no planning process in place, Maryland is behind New Jersey and other states. The

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[148] PUA § 2-113(a)(1).

[149] *2019 New Jersey Energy Master Plan: Pathway to 2050*, at 191, https://www.nj.gov/emp/.

Commission should use these other states' experience to fashion a proceeding that quickly advances policies necessary to protect customers and Maryland's climate goals.

In part making use of these other states' proceedings, OPC includes in Appendix A a list of issues for the Commission's consideration for the purpose of structuring and defining the scope of the requested proceeding. The remainder of this part (1) highlights relevant recommendations of the MCCC, (2) points out relevant recommendations from independent expert reports, and (3) summarizes gas transition proceedings ongoing in other states. A fuller description of other states' proceedings is provided in Appendix C. Appendix A includes a list of issues for the Commission's consideration for the purpose of structuring and defining the scope of the requested proceeding.

A. The Maryland Commission on Climate Change recommends planning for shrinking gas distribution systems.

In 2021, the MCCC recommended that the Commission oversee the preparation of utility transition plans to achieve a "structured and just transition to a near-zero emissions building sector in Maryland."[150] The MCCC listed the key objectives of the gas transition plans as follows:

- Appropriate gas system investments/divestments for a shrinking customer base and reductions in gas throughput in the range of 50 to 100 percent by 2045
- Comprehensive equity strategy to enable low-to-moderate income households to improve energy efficiency and electrify affordably
- Regulatory, legislative, and other policy changes needed for a managed and just transition of the gas system and infrastructure

[150] *MCCC Transition Plan* at 23.

- Operational practices to meet current customer needs and maintain safe and reliable service while minimizing infrastructure investments
- Assessment of existing gas infrastructure and options for contraction
- Alternative models for the gas utility's long-term role, business model, ownership structure, and regulatory compact, as part of a managed transition[151]

In its *2022 Annual Report*, the MCCC largely restated these recommendations, but made more explicit the pace of the transition, calling on the Commission "to issue orders and regulations by no later than January 1, 2025," and specifically targeting the gas companies.[152] Notably, the MCCC included as an objective of the gas transition plans "appropriate gas system investments/abandonments for a shrinking customer base and reductions in gas throughput in the range of 60 to 100 percent by 2045."[153] The MCCC characterized the recommendation in both its 2021 and 2022 Annual Reports as one directed to the General Assembly—seeking that it mandate the Commission to undertake a process incorporating its recommendations. But, as discussed above, the Commission has the requisite legal authority, and an obligation, to perform these duties now under existing law.[154]

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[151] *Id.*
[152] *MCCC 2022 Annual Report* at 16.
[153] *Id.* at 16-17.
[154] The MCCC's styling of its request as one directed to the legislature to mandate PSC action is an acknowledgement that the Commission has thus far declined to institute such a proceeding despite the apparent need—not as foreclosing the PSC from acting on its own initiative. Indeed, the initial draft of the 2022 recommendation circulated to the MCCC—which was simplified to largely track the 2021 language—stated: "The PSC *thus far* has not engaged in a process to plan for the future of the natural gas utilities and the decrease in gas throughput resulting from electrification *using the legal authority it has now that enables it to do so*." (emphasis added). The recommendation to the legislature, thus, does not limit in any manner the PSC's independent legal authority to implement the MCCC's recommendations.

B. Numerous expert reports describe the benefits of planning and the risks of failing to plan.

A number of expert reports confirm the logic of advance thinking and proactive planning for the impact of technological change and climate policy on gas utilities. According to Brattle, "The transition process will play out over many years, but the planning must start now."[155] Industry experts have described in some detail the need to investigate gas distribution planning procedures and practices in the context of climate change policy implementation. These reports may be of use as the Commission considers the structure of the requested investigation and rulemaking and near-term no-regrets actions. Consider two examples:

- The Regulatory Assistance Project's report, *Under Pressure: Gas Utility Regulation for a Time of Transition,* explains how the interrelated issues of improved electric end-use technologies, increasingly stringent GHG emissions policies, greater awareness of the public health risks associated with fossil gas, and the limitations of alternative fuels, are putting pressure on current gas practices and regulation.[156] The report suggests a range of specific, practical strategies for regulators to consider in facilitating the transition away from gas, including requiring gas companies to develop transition plans to "ensure that regulators, utilities and stakeholders have the information they need to develop pathways that take into account policy goals, changing demand and potential impact to customers;"[157] enhancing energy efficiency and electrification programs to facilitate the gas transition;[158] and reforming gas rate-making to lower short-term barriers and enable an equitable and efficient long-term transition.[159]

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[155] Brattle Grp. at 4.
[156] Megan Anderson et al., *Under Pressure: Gas Utility Regulation for a Time of Transition*, REG. ASSISTANCE PROJECT (May 2021), at 8, 10-15, https://www.raponline.org/wp-content/uploads/2021/05/rap-anderson-lebel-dupuy-under-pressure-gas-utility-regulation-time-transition-2021-may.pdf.
[157] *Id.* at 17-29.
[158] *Id.* at 30-36.
[159] *Id.* at 37-53.

- *Aligning Gas Regulation and Climate Goals, A Road Map for State Regulators,* released by the Environmental Defense Fund, also explains how the traditional policy framework relating to gas supply, use, planning, expansion, cost recovery, and review is misaligned with GHG emissions reduction goals and provides recommendations for regulators to "begin to bridge the disconnect between gas policy and climate commitments."[160] The report sets out specific, actionable recommendations to help regulators (1) "establish inclusive and transparent decision making;"[161] (2) "require rigorous long-term planning;"[162] and (3) "coordinate near-term decisions and long-term goals."[163]

C. The Commission should learn from the proceedings of other state regulators.

The Commission should also consider the actions of other public utility regulators that have already begun comprehensive, long-term planning proceedings to investigate the operations of the gas companies under their jurisdiction. These initiatives demonstrate the challenges of managing an effective transition, including the collateral impacts on ratepayers and other stakeholder groups. While differences in other states' weather, geography, supply portfolio, demographics, and economics must be accounted for, these initiatives nonetheless present valuable lessons from which the Commission can learn in structuring its own proceeding. Given their long timelines, they also demonstrate the

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[160] Natalie Karas et al., *Aligning Gas Regulation and Climate Goals: A Roadmap for State Regulators*, ENVTL. DEF. FUND (Jan. 2021), at 4, 10-11, https://blogs.edf.org/energyexchange/files/2021/01/Aligning-Gas-Regulation-and-Climate-Goals.pdf.
[161] *Id.* at 12-15.
[162] *Id.* at 16-23.
[163] *Id.* at 24-36.

urgency with which the Commission needs to engage immediately in the proactive and comprehensive regulation called for by this petition.

Appendix C details the gas planning and related proceedings in eight jurisdictions of varying sizes, climates, demographics, and economies: California, Colorado, the District of Columbia, Massachusetts, Minnesota, New Jersey, New York, and Rhode Island. Here, we provide brief highlights of the proceedings in each jurisdiction:

1. California

In 2020, the California Public Utilities Commission ("PUC") opened a proceeding to review the issues facing the gas utilities, including ratemaking and avoidance of stranded costs.[164] It grouped the issues into three separate investigative "tracks," including one regarding the anticipated large reductions in gas volumes delivered due to GHG emissions reduction legislation. Under this track, the California PUC is aiming to "determine the regulatory solutions and planning strategy that [it] should implement to ensure that, as the demand for gas declines, gas utilities maintain safe and reliable gas systems at just and reasonable rates, and with minimal or no stranded costs."[165]

2. Colorado

In 2020, the Colorado PUC kicked off the first in a series of proceedings to investigate retail gas industry GHG emissions in light of statewide emissions reduction

[164] *Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Safe and Reliable Gas Systems in California and Perform Long-Term Gas System Planning*, Case No. R20-01-007 (Jan. 27, 2020).
[165] *Id.* at 14.

goals.[166] Recognizing the importance of comprehensive planning to ensure that "broad utility planning and investment protocols are conducted in a manner that are fully cognizant of, and consistent with, statutory emission reduction goals," the Colorado PUC recently took what it described as an "incremental step in the larger evolution of the shifting regulatory framework for the gas industry" by amending its rules governing gas line extension policies and gas infrastructure planning.[167]

3. District of Columbia

In 2020, the D.C. Public Service Commission ("PSC") initiated a comprehensive climate policy proceeding to review the planning, operations, and practices of both its franchised electric distribution company, Pepco, and its franchised gas distribution company, WGL.[168] The D.C. PSC established as its initial scope to "consider whether and to what extent utility or energy companies under our purview are helping the District of Columbia achieve its energy and climate goals and then take action, where necessary, to guide the companies in the right direction."[169]

4. Massachusetts

Responding to a petition by the Massachusetts Attorney General, the Massachusetts Department of Public Utilities ("DPU") opened an investigation in 2020 "into the role of the local distribution companies as the Commonwealth achieves its

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[166] *Decision Opening Repository Proceeding; Scheduling Commissioners' Information Meeting; and Designating Hearing Commissioner*, Proceeding No. 20M-0439G (Nov. 4, 2020).
[167] *Commission Decision Adopting Rules*, Proceeding No. 21R-0449G (Dec. 1, 2022), at 31, 13.
[168] Order No. 20662, Case No. 1167 (Nov. 18, 2020).
[169] *Id.* at 4-5.

target 2050 goals."[170] Through this proceeding, the DPU is "explor[ing] strategies to enable the Commonwealth to move into its net-zero greenhouse gas ("GHG") emissions energy future while simultaneously safeguarding ratepayer interests; ensuring safe, reliable, and cost-effective natural gas service; and potentially recasting the role of [local distribution companies] in the Commonwealth."[171]

5. Minnesota

In 2021, the Minnesota PUC opened two proceedings to address the role that gas companies play in helping the state reach its emissions reduction goals. The first aimed to guide the gas companies in developing "innovation plans" to decarbonize their operations.[172] The second is a broad proceeding looking at the future of gas, in which the Minnesota PUC is considering policy and regulatory changes needed to meet or exceed the state's climate goals.[173]

6. New Jersey

In 2019, the New Jersey Board of Public Utilities ("BPU") initiated a proceeding to explore whether sufficient capacity exists to deliver natural gas to meet consumer needs.[174] After receiving conflicting reports from the various parties to the proceeding, the New Jersey BPU recognized the need to determine "how evolving environmental

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[170] *Vote and Order Opening Investigation*, Case No. 20-80 (Oct. 29, 2020).
[171] *Id.* at 1.
[172] *Notice of Comment Period on Natural Gas Innovation Act, Section 21*, Docket No. G-999/CI-21-566 (Sept. 3, 2021).
[173] *Notice of New Docket, In the Matter of a Commission Evaluation of Changes to Natural Gas Utility Regulatory and Policy Structures to Meet State Greenhouse Gas Reduction Goals*, Docket No. G-999/CI-21-565 (July 23, 2021).
[174] 2-27-19M, *Decision and Order*, Docket No. GO17121241 (February 27, 2019).

concerns may drive changes in the way natural gas is transported and used in New Jersey."[175] The BPU also serves as the lead agency for development and oversight of the State's *Energy Master Plan*, which the BPU and its partners updated most recently in 2019.[176] The plan directs that "[a]s NJBPU endeavors to ensure just and prudent investments, it must examine if ratepayers are socializing and subsidizing unnecessary fossil fuel infrastructure costs, and if doing so will risk ratepayers shouldering the burden of stranded assets in the future."[177]

7. New York

Recognizing the need for gas utilities to "adopt improved planning and operational practices that enable them to meet current customer needs and expectations in a transparent and equitable way while minimizing infrastructure investments and maintaining safe and reliable service," the New York PSC began proceedings in 2020 to bring long-term gas planning in line with the State's GHG reduction goals.[178] Through the proceeding, the New York PSC has collected supply and demand analyses from the utilities, adopted a proposal from staff to require the utilities to file long-term plans every three years, and ordered the utilities to prepare a study on depreciation practices.[179]

8. Rhode Island

In 2022, the Rhode Island PUC opened a docket to investigate the future of the regulated gas distribution business with the purpose of "examin[ing] the extent to which

[175] 5-20-20-9A, *Order Soliciting an Independent Consultant*, Docket No. GO19070846, at 4.
[176] *2019 New Jersey Energy Master Plan: Pathway to 2050*, at 190-91, https://www.nj.gov/emp/.
[177] *Id.* at 191.
[178] *Order Instituting Proceeding*, Case No. 20-G-0131 (Mar. 19, 2020), at 2-3.
[179] *Order Adopting Gas System Planning Process*, Case No. 20-G-0131 (May 12, 2022).

the requirements of the [recently passed Act on Climate] impact the conduct, regulation, ratemaking, and the future of gas supply and gas distribution within Rhode Island."[180] The PUC recently adopted a scope for the proceeding, dividing it into three phases—policy planning, technical analysis, and policy development—and laying out a series of questions to be incorporated into each.[181]

CONCLUSION AND REQUESTED RELIEF

Maryland's policies to address climate change for the energy sector seek significant reductions in GHG emissions levels, with interim goals for emissions reduction over the intermediate term. These policies particularly address the State's building sector and call for substantial reductions in the sector's usage of fossil fuels, including fossil gas. As electric technologies continue to advance, and governments at all levels, together with their constituents, implement climate change policies over the next two decades that include switching from fossil fuels to electricity in buildings, the anticipated decreases in gas consumption will have transformative effects on Maryland's gas companies. The transformation will impact all aspects of gas companies' operations—including planning, ratemaking, cost recovery, investment, and procurement activities.

Despite these fundamental impending changes, Maryland's gas companies are embarked on a program of huge investments in their gas utility plant, utilizing historical

[180] *Notice of Commencement of Docket*, Docket No. 22-01-NG (June 9, 2022).
[181] *Proceeding Scope*, Docket No. 22-01-NG (Jan. 3, 2023).

assumptions about recovery in rates and consumer affordability that are no longer relevant. They continue to deploy operations and practices—for gas procurement, gas-line extensions, marketing, and energy-efficiency programs, among others—that are drastically mis-aligned with the State's climate change policies and the resultant decline in gas usage that even gas companies themselves now anticipate.

The gas companies' investments, operations, and practices, designed as they are for an increasingly bygone era, have dire implications for customers. The gas companies' current business plans—encompassing everything from procurement and line extension polices to massive investments in gas distribution pipes and other infrastructure—threaten to lock customers into massive costs in increasingly inappropriate plant investment as Maryland transitions to a net-zero GHG emissions economy. Such negative potential consequences for Maryland customers call out the urgent need for the Commission to effectively regulate the gas companies in the public interest. The Commission is uniquely positioned, possessing the requisite expertise, legal authorities, and legal obligations, to take a pro-active role to commence a proceeding now, structured to address the issues set forth in this petition.

As explained above, the proceeding should consist of two tracks. One track, the Transition Track, is a proactive and comprehensive investigation that ends in a rulemaking that governs the procedures and requirements for gas utility transition plans. The other, simultaneous track, the Priority Track, would consider near-term, priority actions that gas utilities should take to address current policies adverse to customer interests.

Critical to both tracks are procedures that enable and facilitate transparency. Open and transparent comprehensive proceedings will ensure the broad participation necessary to create public support for gas utility transition plans that have buy-in from all stakeholders, including utilities, consumers, public interest organizations, and others. For both tracks, the procedures must include time allocated for discovery as well as for motions and briefings. Robust public participation and transparency—including, importantly, access to utility information—will facilitate better decision-making and support the legitimacy of the resulting regulations and transition plans.

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Appendix A

PROPOSED QUESTIONS FOR THE MARYLAND PUBLIC SERVICE COMMISSION TO CONSIDER IN ESTABLISHING THE SCOPE OF THE TRANSITION TRACK

APPENDIX A

Proposed Questions for the Maryland Public Service Commission to Consider in Establishing the Scope of the Transition Track

A. Data Collection

1. What data should the Commission collect from the gas companies to forecast the expected decline in demand for each customer class?

2. What data should the Commission collect from the gas companies to determine actual decline in demand and where it is occurring?

3. What data inputs and assumptions should the Commission require the gas companies to integrate into their gas demand forecasts for each customer class?

4. Should the Commission require the gas companies to report granular data on the location, condition, depreciation schedule, and repair and replacement schedule of their transmission and distribution pipelines?

5. To what extent is the collection of data from Maryland's electric utilities necessary to inform and support long-term gas system planning?

6. What other data is needed from the gas companies to assist the Commission and stakeholders in long-term gas system planning?

B. Long-Term Planning Considerations

1. What actions have the gas companies taken to date to harmonize their long-term planning with Maryland's statutory greenhouse gas (GHG) emissions reduction mandates?

2. What information, forecasts, analyses, and actions should the Commission require the gas companies to include in long-term transition plans?

3. Should plans include all of the following components?

    a. Descriptions of capacity planning models and methodologies

  b. Plans for coordinating with electricity providers to meet electric reliability needs

  c. Plans for cost-effectively maintaining aging infrastructure

  d. Specific steps to transition customers and/or segments of a gas company's service base to electricity

  e. Plans for strategically decommissioning or "pruning" parts of the distribution system

4. What additional components should long-term transition plans include?

5. Should the Commission establish uniform reliability and design standards for the gas companies, including uniform standards to forecast demand?

6. Should the Commission establish uniform rules or standards for the procurement of gas supply?

7. Should the Commission require that long-term transition plans meet near-term and/or long-term GHG emissions reduction targets or any other goals prescribed by the Commission or the State? If so, what targets and goals should plans include?

8. What is the proper time horizon for long-term transition plans?

9. What standards and criteria should the Commission use to evaluate and approve or disapprove long-term transition plans?

10. What stakeholder and public input processes should the Commission prescribe for the development and evaluation of long-term transition plans?

11. Should the Commission establish a process in which decisions made in this proceeding can be reevaluated over certain time intervals or in the face of changing conditions such as updated weather forecasts and new technologies?

12. Should cost recovery issues arising from the implementation of a gas company's long-term transition plans be addressed in each company's general rate case or in a separate proceeding?

13. How should the gas companies' obligations to customers be defined, given the State's decarbonization goals? What regulatory or statutory changes are needed?

14. What gas company workforce considerations are raised by a transition away from gas, and how should these be included in the long-term gas planning process?

C. Potential Substitutes for Fossil Gas

1. To what extent are potential substitutes for conventional fossil gas—such as "renewable natural gas" (RNG), "responsibly sourced gas" (RSG or "certified gas"), and hydrogen—commercially available and cost-effective?

2. At what scale are such alternative fuels commercially available now and expected to be available in the future, relative to the current demand for gas by the utility sector and other sectors?

3. Are such alternative fuels compatible with (i) the gas companies' existing gas delivery infrastructure, and (ii) consumer appliances?

4. Should procurements of such alternative fuels be included in the gas companies' standard commodity supply offered to customers?

5. What new transmission infrastructure is needed for the gas companies to include alternative fuels in their supply procurements?

6. Should the Commission establish uniform standards for interconnection and cost allocation of RNG or hydrogen facilities and related infrastructure?

7. Should the Commission consider minimum GHG intensity standards for alternative fuels procured by the gas companies?

D. Gas infrastructure

1. What methodology should the Commission use to determine whether the gas companies' infrastructure portfolios are consistent with the State's GHG emissions reduction mandates and the gas companies' obligations to customers within their service territories?

2. As gas demand declines in accordance with Maryland's GHG emissions

reduction goals, what gas infrastructure will be needed to ensure safe and reliable gas service: (i) between now and 2031, when emissions must be reduced to 60% below 2006 levels, (ii) between 2031 and 2045, when emissions must be reduced to net zero, and (iii) beyond 2045?

3. For each of the three time horizons identified above:

   a. What assumptions are necessary to determine how much infrastructure is needed?

   b. As gas throughput declines, what criteria and processes should be used to identify infrastructure that can be decommissioned without compromising reliability?

   c. How should the Commission manage gas infrastructure to mitigate stranded costs and operations and maintenance expenses caused by declining throughput?

   d. Should the Commission consider targeted infrastructure decommissioning?

   e. Should the Commission consider accelerated depreciation?

4. Should the Commission require site-specific approvals for gas infrastructure projects that exceed a certain size or cost?

5. Should the Commission establish technical and operational standards for leak detection to ensure that repair and replacement activities are prioritized appropriately?

6. How should the Commission ensure that leak detection standards applicable to gas companies incorporate technological advances and improvements in best practices?

7. When a gas company requests ratepayer funds to upgrade aging infrastructure, what criteria should the Commission use to determine whether the infrastructure should be repaired, replaced, or decommissioned?

   a. Should the Commission require the gas company to provide information on the methods it has used and actions it has taken to detect and repair leaks?

b. Where it is necessary to repair or replace infrastructure, should the Commission adopt standards that prioritize repair over replacement?

c. Should repair or replacement criteria depend on whether the infrastructure is necessary to meet the gas company's design standard?

d. How should the cost to repair or replace the infrastructure be balanced against the safety and reliability benefits of the repair?

e. What pipeline-related characteristics should be considered when determining whether to repair or replace distribution infrastructure (e.g., safety, age of pipe, pipe material)?

f. What community characteristics, such as designation as an underserved community (as defined under Environment Art. sec. 1-701), should be considered?

g. What goals should be considered in determinations about repairing or replacing infrastructure (e.g., cost savings, minimizing stranded assets, pipeline safety, net greenhouse gas reductions, environmental justice)?

h. What non-pipeline alternatives should be considered?

i. How should the cost of non-pipeline alternatives be compared to the cost of gas pipeline replacement or repair?

8. How should avoided operations and maintenance (O&M) and infrastructure replacement costs for decommissioning distribution pipelines be estimated and incorporated into cost effectiveness analysis?

9. For prioritizing distribution and transmission lines for decommissioning, what pipeline-related characteristics should be considered (e.g., safety, age of pipe, depreciation schedule, pipe material location or customer density, type of load or customer served, proximity to a lower-carbon source of gas)?

10. What procedural mechanism should be used to proactively decommission

distribution pipelines?

11. If the Commission determines that a distribution pipeline should be decommissioned,

    a. What notice, timing, and public input standards should apply?

    b. What planning and procedures are necessary to ensure that there is sufficient local electric capacity available to reliably serve customers that move off the gas system?

    c. Are there health and safety issues that need to be addressed from decommissioned distribution lines?

12. What infrastructure is needed to fulfill the needs of customers who are likely to remain on the gas system the longest, such as electric generators or difficult-to-electrify industrial users?

13. What should be the role of existing gas storage facilities as a component of the gas companies' infrastructure portfolio?

14. Should the Commission require the achievement of certain milestones (e.g., replacement energy resources are built and operational) before a significant gas asset is decommissioned?

15. How should the Commission consider the need for gas infrastructure that may be needed to serve new industrial gas customers in difficult-to-electrify sectors as part of the long-term gas system planning process?

16. What should the regulatory process be for de-rating a transmission pipeline to a distribution pipeline?

E. Rate Design and Cost Allocation

1. As customers migrate to electricity, how can the Commission ensure just, reasonable, and nondiscriminatory rates and service?

2. Should the Commission reconsider rate design and cost allocation methods currently employed by gas companies?

3. Do current rate design and cost allocation methodologies raise particular concerns for low-income customers and customers in disadvantaged communities?

4. What structural, policy, economic, accessibility, and other barriers do low-income customers and disadvantaged communities face regarding the transition away from gas, and how can the commission take action to address those barriers?

5. How will EmPOWER be impacted by any proposed rate design changes?

6. How can the Commission ensure that rates are allocated appropriately between current and future ratepayers?

7. Should the Commission consider new financial mechanisms to allocate costs between current and future ratepayers?

8. If the Commission pursues alternative depreciation methods, are there any rate protections for low-income and disadvantaged customers that the Commission should consider to mitigate any resulting near-term rate increases?

9. Are any additional measures needed to ensure that the gas companies remain financially viable and credit-worthy for as long as gas is necessary for energy reliability?

F. Workforce Issues

1. What authority does the Commission have to address gas company workforce issues?

2. Should the Commission consider measures to ensure a qualified gas workforce continues to be available to operate the gas companies' systems safely throughout the transition away from gas? If so, what measures should be considered?

3. How can any potential negative impacts on gas industry workers be mitigated?

   a. Which employees are likely to be at greatest risk of job loss from a transition away from gas? What are the characteristics of those jobs and work? What types of jobs could such workers transition to?

b. What share of the gas company workforce at greatest risk of job loss is suitable for early retirement? Should the gas companies develop plans to support early retirement for affected employees?

c. Does the Commission have a role in ensuring what types of retraining should be made available to the gas company employees, including training necessary for gas workers in disadvantaged or low-income communities?

4. What are the potential costs associated with workforce mitigation strategies? Who should be responsible for paying these costs?

5. Should the Commission establish requirements for tracking data on implementation of mitigation measures, including retraining, job quality, and job access?

G. Legislation

1. For any issues identified for which the Commission lacks authority, should the Commission:

   a. not address the issue as part of its long-term planning?

   b. request the General Assembly to provide it additional authority?

   c. inform the General Assembly and recommend another State agency address the issue?

Appendix B

PROPOSED ORDER

APPENDIX B

Proposed Order

1. The Commission establishes a docket to solicit comments on the Office of People's Counsel petition for gas utility transition planning and priority actions.

2. Within 30 days of the issuance of this order, interested parties shall file initial comments on the proposal for:

    a. A "Priority Track" covering gas utility practices and operations that should be taken in the short term to ensure practices and operations are consistent with the public interest, just and reasonable rates, and the State's greenhouse gas reduction goals; and

    b. A "Transition Track" on the future role of Maryland's gas utilities in anticipation of, among other possible changes, substantial declines in gas sales and a shrinking customer base.

3. The Commission welcomes specific comments on (i) the questions proposed in OPC's petition Appendix A, (ii) any additional proposed questions for a Transition Track, (iii) the Priority Track issues identified by OPC, and (iv) any additional proposed priority actions.

4. Interested parties shall file comments responsive to initial comments within 30 days from the date initial comments are due.

5. Following receipt of comments, the Commission will schedule a hearing on the scope of the proposed proceeding and, as appropriate, procedures and schedules, after which it will issue a written decision.

So ordered.

Appendix C

COMPREHENSIVE PLANNING PROCEEDINGS IN OTHER STATES

APPENDIX C

Comprehensive Planning Proceedings in Other States

State	Proceeding #
California	R19 01-011, R20-01-007
Colorado	21R-0449G
District of Columbia	FC1167, GD2019-04-M
Massachusetts	20-80
Minnesota	G-999/CI-21-565, G-999/CI-21-566
New Jersey	GO17121241, GO19070846
New York	20-G-0131
Rhode Island	22-01-NG

1. California

Like Maryland, California has set aggressive GHG emissions reduction goals in recent years.[1] New legislation signed into law in September of 2022 codified the state's most ambitious goal yet to achieve net zero emissions no later than 2045 and reduce statewide anthropogenic GHG emissions to at least 85 percent below 1990 levels by 2045.[2] Additional legislation set interim targets for these reductions, calling for eligible renewable energy resources and zero-carbon resources to supply 90 percent of all retail sales of electricity to California end-use customers by 2035, 95 percent of all retail sales of electricity to California end-use customers by 2040, 100 percent of all retail sales of electricity to California end-use customers by 2045, and 100 percent of electricity procured to serve all state agencies by 2035.[3]

[1] *See e.g.* California Global Warming Solutions Act of 2006, 2006 Cal. Legis. Serv. Ch. 488 (codified at Cal. Health & Safety Code § 38500, et seq.) (requiring that the state reduce its GHG emissions to 1990 levels by 2020); California Global Warming Solutions Act of 2006: emissions limit, 2016 Cal. Legis. Serv. Ch. 249 (codified at Cal. Health & Safety Code § 38566) (further requiring that GHG emissions are reduced to 40 percent below the 1990 levels by 2030); 100 Percent Clean Energy Act of 2018, 2018 Cal. Legis. Serv. Ch. 312 (codified at Cal. Pub. Util. §§ 399.11, 399.15, 399.30 & 454.53) (targeting 60 percent renewable energy by 2030 and 100 percent by 2045); California Gov. Exec. Order B-55-18 (Sep. 10, 2018) (setting a statewide goal to reach carbon neutrality no later than 2045).
[2] The Climate Crisis Act, 2022 Cal. Legis. Serv. Ch. 337 (Sept. 16, 2022) (codified at Cal. Health & Safety Code § 38562.2).
[3] Clean Energy, Jobs and Affordability Act of 2022, 2022 Cal. Legis. Serv. Ch. 361 (Sept. 16, 2022) (codified at Cal. Gov't Code § 7921.505; Cal. Health & Safety Code § 38561; Cal. Pub. Util. Code §§ 454.53, 454.59, 583, 739.13; Cal. Water Code § 80400).

2018 legislation also specifically targeted the California PUC, requiring the PUC to work with other agencies to assess the potential for reducing GHG emissions from buildings by at least 40 percent below 1990 levels by 2030,[4] and to oversee the development of two new building decarbonization programs.[5] In response, the PUC instituted several of its own proceedings. The first was a rulemaking to support decarbonization of buildings,[6] in which the PUC recently issued a decision eliminating subsidies for new gas line hookups.[7] According to the PUC:

> This will eliminate a financial incentive for expanding the natural gas system to serve new buildings, accelerating the electrification of homes and commercial buildings, and reduce the risk of stranded assets, saving ratepayers approximately $164 million every year. These changes move the state closer to meeting its ambitious goals of reducing greenhouse gas, combating climate change, and attaining a decarbonized energy system.[8]

Second, the PUC opened a generic proceeding to address the long-term planning issues affecting the gas utility companies, as well as to address concerns about operational reliability.[9] The PUC subsequently issued three "scoping orders" defining the issues to be investigated during the proceeding.[10] The PUC directed that the proceeding include a review of important issues facing the gas utilities subject to its jurisdiction, including ratemaking and avoidance of stranded costs. The PUC has grouped the issues into three separate investigative "tracks," arising from (1) ongoing operational issues and constraints (designated Track 1A), (2) gas pipeline and storage safety-related incidents (following on the PG&E/San Bruno explosion and the SoCalGas Aliso Canyon gas storage field leak) (designated Track 1B), and (3) the anticipated large reductions in gas volumes delivered due to GHG emissions reduction legislation (designated Track 2 of the proceeding).[11] Under Track 2, the PUC aimed to "determine the regulatory solutions and

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[4] Zero-Emissions Buildings and Sources of Heat Energy, 2018 Cal. Legis. Serv. Ch. 373 (Sept. 13, 2018) (codified at Cal. Pub. Res. Code § 25403).
[5] Low-Emissions Buildings and Sources of Heat Energy, 2018 Cal. Legis Serv. Ch. 378 (Sept. 13, 2018) (codified at Cal. Pub. Util. Code §§ 748.6, 910.4, 921-22).
[6] *Order Instituting Rulemaking Regarding Building Decarbonization*, Case No. R.19-01-011 (Feb. 8, 2019).
[7] *Decision 22-09-026*, Case No. R19-01-011 (Sept. 20, 2022).
[8] *CPUC Decision Makes California First State in Country to Eliminate Natural Gas Subsidies*, CAL. PUC (Sept. 15, 2022), https://www.cpuc.ca.gov/news-and-updates/all-news/cpuc-decision-makes-ca-first-state-in-country-to-eliminate-natural-gas-subsidies.
[9] *Order Instituting Rulemaking to Establish Policies, Processes and Rules to Ensure Safe and Reliable Gas Systems in California and perform Long-Term Gas System Planning*, Case No. R20-01-007 (Jan. 7, 2020).
[10] *Scoping Memo and Rulings*, Case No. R20-01-007 (Apr. 23, 2020) (Oct. 14, 2021) (Jan. 5, 2022).
[11] *Order Instituting Rulemaking* at 3, 10-12 (specifically discussing GHG emissions reductions developments).

planning strategy that the Commission should implement to ensure that, as the demand for natural gas declines, gas utilities maintain safe and reliable gas systems at just and reasonable rates, and with minimal or no stranded costs."[12]

In July of 2022, the PUC issued a proposed decision on Track 1A & 1B issues regarding reliability and market structure.[13] More relevant to this petition, in December of 2022, the PUC adopted a general order developed under Track 2—analogous to its pre-existing general order for electric infrastructure projects—requiring gas corporations to (1) submit an annual report of planned gas investments for comment and (2) seek PUC approval for gas infrastructure projects of $75 million or more and those expected to have significant air quality impacts.[14] According to the PUC, "[t]his portion of Track 2, consideration of a gas infrastructure [general order], addresses an identified gap in the Commission's active regulation of gas infrastructure. It also serves as an intermediary step towards development of a more a comprehensive long-term gas planning process later in this proceeding."[15] In its order, the PUC offered the following explanation of the need to adopt a general order as an immediate interim step, which the Commission may wish to consider:

> [W]ork to advance California's landmark greenhouse gas emission reduction goals has led to steadily declining gas consumption levels within California, at the rate of approximately one percent annually. Declining gas consumption levels in turn have three main causes: the installation of more renewable electricity resources on the grid, city ordinances banning the installation of gas appliances in new homes and commercial buildings, and progression of the State's building code toward all electric buildings. As more renewable electricity resources are installed, demand for gas-powered base load generation declines. Senate Bill (SB) 1477 promotes decarbonization of California's building supply. Incentive programs and pilot projects to advance building decarbonization are rapidly emerging. As of Fall 2022, nearly 50 cities and counties in California have adopted local ordinances requiring all-electric appliances in new homes or buildings, in some form. These trends and related decreases in natural gas consumption in California are predicted to continue, particularly with the passage of Assembly Bill (AB) 1279 establishing an economywide target of carbon neutrality by 2045. This decline in demand means there may be less need for large gas infrastructure projects in the future. It also means there may be a

[12] *Id.* at 14.
[13] *Decision 22-07-00*, Case No. R20-01-007 (July 20, 2022).
[14] *Decision Adopting Gas Infrastructure General Order*, Case No. R20-01-007 (Dec. 8, 2022), at 2.
[15] *Id.* at 3-4.

> declining customer base across which to distribute the costs of existing and any new infrastructure. Together, these trends amplify the Commission's responsibility to carefully scrutinize large gas infrastructure projects to ensure they are necessary. If a given facility is not necessary over its estimated useful life, a project could become a "stranded asset," imposing costs but providing limited benefits to a declining pool of ratepayers and increasing rates for the customers left behind on the gas system. Alternatively, some projects may be necessary for reliability in the next 10 to 25 years, even if they are not used for their full useful life. This balance between reliability and cost requires careful scrutiny in the years ahead.
>
> The GO we adopt here provides a mechanism for project review for large and environmentally significant gas infrastructure projects in the near term as we continue to work towards developing a long-term gas planning process and strategy later in this proceeding. The long-term gas planning process and strategy will consider additional ways to avoid the risk of stranded assets and may build upon or refine the GO we adopt here.[16]

Even more recently, the PUC directed gas utilities and other interested stakeholders to comment on staff's proposed *Gas Distribution Decommissioning Framework*, which suggests a framework for gas infrastructure decommissioning in support of the state's climate goals.[17]

The same trends are converging here in Maryland, resulting in the same need for immediate action towards comprehensive, long-term planning. The extensive work the California PUC has done in scoping its proceedings helps to inform the issues OPC proposes the Commission consider in establishing the scope of a similar proceeding in Maryland.[18]

2. Colorado

The Colorado PUC has also taken action in recent years to align the utilities under its jurisdiction with the state's goals to reduce GHG emissions: by 26 percent by 2025, 50 percent by 2030, and 90 percent by 2050, all measured against 2005 levels.[19] In its *2020 Operational Modernization Plan,* the Colorado PUC committed to "explore the electric

[16] *Id.* at 10-12 (internal citations omitted).
[17] *ALJ's Ruling Directing Parties to File Comments on Staff Gas Infrastructure Decommissioning Proposal*, Case No. R20-01-007 (Dec. 22, 2022).
[18] *See* Appendix A.
[19] Climate Action Plan to Reduce Pollution, HB19-2061 (codified at Colo. Rev. Stat. § 25-7-102(2)).

and natural gas utility systems required by Colorado in the future, examining electricity storage, beneficial electrification, and GHG emissions reductions for the purpose of proactively applying consistent policy directives across various dockets in accordance with the Commission's strategic plan."[20] Around the same time, the PUC kicked off a series of relevant proceedings when it approved a settlement including provisions in which the parties agreed to collaborate on a petition for rulemaking to address short-term (5-year) natural gas capacity and infrastructure planning.[21] The PUC later denied the request to open a rulemaking to implement the proposed rules, opting instead to address short-term and long-term planning together.[22] In November of 2020, the PUC opened a proceeding to serve as a repository for presentations, comments, and other materials related to its investigation of retail natural gas industry GHG emissions in light of the statewide greenhouse gas emissions reduction goals.[23] The PUC explained its reasons for opening the proceeding as follows:

> Potential changes to the business model or scale of usage are of great consequence to the Commission in ensuring effective regulation of the natural gas sector. The Commission is responsible for regulation of several aspects of the retail natural gas industry in Colorado including rate setting, system safety and integrity riders, demand-side management programs, reliability of service, and gas pipeline safety. This market uncertainty and the relatively short timeline to make significant progress on the statutory greenhouse gas emission reduction goals makes it important for the Commission to obtain more information about potential impacts to utility systems and how those impacts may affect utility investments and the rates utilities charge Colorado customers.[24]

The PUC held three Commission information meetings under this proceeding before the Colorado legislature passed several new climate measures that affect the work of the PUC in 2021. This included HB 21-1238, requiring gas utilities to file long-term demand side management planning applications to develop energy savings targets;[25] SB 21-246,

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[20] Colo. Dep't of Reg. Agencies: Pub. Utilities Comm'n, *The Colorado Public Utilities Commission's Operational Modernization Plan* (Sept. 2020), at 5 https://puc.colorado.gov/puc-modernization-plan.
[21] *Unopposed and Comprehensive Amended Stipulation and Settlement Agreement to Reflect Corrections*, Proceeding No. 20AL-0049G (Sept. 22, 2020), at 20-21.
[22] *Commission Decision Declining to Accept Petition for Rulemaking*, Proceeding No. 21M-0168G (July 23, 2021).
[23] *Decision Opening Repository Proceeding; Scheduling Commissioners' Information Meeting; and Designating Hearing Commissioner*, Proceeding No. 20M-0439G (Nov. 4, 2020).
[24] *Id.* at 2-3.
[25] Public Utilities Commission Modernize Gas Utility Demand-side Management Standards, HB 21-1238 (codified at Colo. Rev. Stat. §§ 40-3.2-103, 40-3.2-106, and 40-3.2-107).

adopting new requirements for utilities to develop beneficial electrification plans;[26] and SB 21-264, requiring Colorado gas utilities with more than 90,000 retail customers to develop, file, and acquire Commission approval of comprehensive Clean Heat Plans designed to achieve GHG emissions reductions.[27] SB 21-264 also directed the Commission to create rules that require gas utilities to file Clean Heat Plans and take other actions to reduce carbon emissions.[28] In January of 2021, Colorado released its *Greenhouse Gas Pollution Reduction Roadmap*, which lays out a pathway to achieving these goals.[29]

In response, the Colorado PUC opened a new proceeding to collect comment and information from utilities and interested stakeholders regarding proposed rulemakings required under the new laws.[30] In so doing, the PUC recognized "that state-mandated required GHG emission reductions will inevitably have an impact on gas utilities' investments, sales, depreciation schedules, revenue requirements, and rates."[31] In October of 2021, the PUC issued a notice of proposed rulemaking to make substantial revisions to the state's gas utility regulations to reduce the sector's GHG emissions and align infrastructure planning with statewide emissions reductions goals.[32] The proposed rules aimed to improve planning to protect the public interest by establishing a process to determine the need for additional investment and spending, consistent with new climate considerations.

Specifically, the amendments revise the rules governing (1) utility line extension policies, requiring them to be based on the principle that the connecting customer pays its share of the estimated full incremental cost of growth, and (2) infrastructure planning, requiring gas utilities to file a gas infrastructure plan for PUC approval every two years and to seek PUC approval for construction and operation of a facility, or an extension or expansion of a facility of a certain size. After holding multiple workshops and public hearings on the proposed amendments, the PUC issued a decision adopting the amendments on Dec. 1, 2022.[33] In so doing, the PUC explained that "additional insights into system planning, forecasting and investments as provided by the Gas Infrastructure Planning Rules provides a necessary component of the regulatory structure going forward

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[26] Electric Utility Promote Beneficial Electrification, SB 21-246 (codified at Colo. Rev. Stat. §§ 38-33.3-106.7, 40-1-102, and 40-3.2-105.6, -106, and -109).
[27] Adopt Programs Reduce Greenhouse Gas Emissions Utilities, SB21-264 (codified at Colo. Rev. Stat. § 40-3.2-108).
[28] Colo. Rev. Stat. § 40-3.2-108(5).
[29] Colo. Energy Office, *GHG Pollution Reduction Roadmap*, https://energyoffice.colorado.gov/climate-energy/ghg-pollution-reduction-roadmap.
[30] *Decision Opening Miscellaneous Proceeding to Engage with Gas Utilities and Interested Stakeholders and Collect Comment and Information to Inform Future Commission Rulemaking Proceedings*, Proceeding No. 21M-0395G (Aug. 25, 2021).
[31] *Id.* at 9.
[32] *Notice of Proposed Rulemaking*, Proceeding No. 21R-0449G (Oct.1, 2021).
[33] *Commission Decision Adopting Rules*, Proceeding No. 21R-0449G (Dec. 1, 2022).

to ensure appropriate oversight of long-term and costly investments in gas system infrastructure."[34] The Colorado PUC emphasized the importance of comprehensive planning[35] and like the California PUC, described "this rulemaking as one incremental step in the larger evolution of the shifting regulatory framework for the gas industry."[36] Again, the same need exists here in Maryland for the immediate commencement of comprehensive planning.

3. District of Columbia

Like Maryland, the District of Columbia has enacted aggressive targets to address the effects of climate change. Recently amended legislative commitments call for a 60 percent reduction in District-wide GHG emissions by 2030 (relative to 2006 levels) and carbon neutrality by 2045.[37] As did Montgomery County, Maryland, the District also recently passed amendments to its building code requiring that all new construction or substantial improvements of "covered buildings" (including commercial buildings, multifamily buildings, and single family buildings over three stories) be constructed to be net zero and prohibiting most uses of gas in covered buildings.[38]

Similar to the Maryland Commission's obligation to consider "the preservation of environmental quality, including protection of the global climate … and the achievement of the State's climate commitments for reducing statewide, greenhouse gas emissions,"[39] the DC PSC is statutorily required to consider "the conservation of natural resources, and the preservation of environmental quality, including effects on global climate change and the District's public climate commitments."[40] The DC PSC has interpreted this mandate as requiring it to proactively consider how the District's GHG reduction targets impact the long-term planning of its regulated gas and electric utilities. As a result, in November of 2020, the PSC initiated a comprehensive climate policy proceeding to review the planning, operations, and practices of both its franchised electric distribution company, Pepco, and its franchised gas distribution company, WGL.[41]

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[34] *Id.* at 13.
[35] *Id.* at 31 ("A comprehensive approach also ensures broad utility planning and investment protocols are conducted in a manner that are fully cognizant of, and consistent with, statutory emission reduction goals.").
[36] *Id.* at 13.
[37] Climate Commitment Act of 2022, 69 D.C. Reg. 009924 (July 27, 2022) (codified at D.C. Code § 8-151.09d).
[38] Clean Energy DC Building Code Amendment Act of 2022, 69 D.C. Reg. 009924 (Aug. 5, 2022) (codified at D.C. Code § 6–1453.01).
[39] PUA §§ 2-113(a)(2)(v)-(vi).
[40] Clean Energy DC Omnibus Amendment Act of 2018, 66 D.C. Reg. 1344 (Feb. 1, 2019) (codified at D.C. Code § 34-808.02).
[41] Order No. 20662, Case No. FC1167 (Nov. 18, 2020).

The PSC established the initial scope of the proceeding to "consider whether and to what extent utility or energy companies under our purview are helping the District of Columbia achieve its energy and climate goals and then take action, where necessary, to guide the companies in the right direction."[42]

The PSC consolidated into this new proceeding its existing investigation of WGL's climate change plans, which it was previously considering as part of WGL's compliance with conditions to the Altagas merger approval.[43] In subsequent orders, the DC PSC directed Pepco and WGL to file climate change plans[44] and requested briefing on its authority to order electrification.[45] At the end of September of 2022, interested parties began submitting their briefs.

The PSC also opened a generic proceeding to establish integrated metrics for addressing climate change across the electric and gas companies subject to its jurisdiction.[46] In November of 2021, a working group submitted a 300+ page report to the PSC regarding a framework for compliance with the Clean Energy Act. The PSC has not yet issued an order on the working group's recommendations.

Although still mid-stream, the PSC's comprehensive investigation has advanced well beyond the incipient present status of matters before the Maryland Commission. The PSC's investigation and its outcome is likely to have direct relevance to WGL's operations in Maryland, given the integrated nature of much of WGL's gas infrastructure and operations in Maryland and the District. It also provides another model for taking proactive action to consider long-term planning comprehensively, rather than piecemeal in individual proceedings.

4. Massachusetts

Massachusetts, too, has launched aggressive legislative efforts to reduce GHG emissions. Current reduction goals were codified in 2021, targeting net zero GHG

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[42] *Id.* at 4-5.
[43] *Id.* (converting proceeding to address WGL's merger settlement compliance filing regarding climate change in Case No. FC1142 into new proceeding, Case No. FC1167, to address proposals requested from WGL and Pepco to "assist the District in meeting and advancing [the District's] climate goals.").
[44] Order No. 20754, Case No. FC1167 (June 4, 2021), at 16-17.
[45] *Request for Briefs*, Case No. FC1167 (July 12, 2022), at 2.
[46] *Notice of Inquiry*, Case No. GD2019-04-M (Sep. 26, 2019).

emissions by 2050, with interim targets of 50 percent by 2030 and 75 percent by 2040 (as measured against 1990 baseline emissions).[47]

In June of 2020, the Massachusetts Attorney General filed a petition with the Massachusetts DPU asking the DPU to initiate a generic proceeding to update the long-term planning activities of the gas companies in the context of the state's efforts to reduce its GHG emissions.[48] Following the Attorney General's petition, the DPU issued an order opening an investigation "into the role of the local distribution companies as the Commonwealth achieves its target 2050 goals."[49] In the order, the DPU described the goals of the proceeding as follows:

> [W]e will explore strategies to enable the Commonwealth to move into its net-zero greenhouse gas ("GHG") emissions energy future while simultaneously safeguarding ratepayer interests; ensuring safe, reliable, and cost-effective natural gas service; and potentially recasting the role of LDCs in the Commonwealth.[50]
>
> ...
>
> Through this proceeding the Department will solicit utility and stakeholder input and develop a regulatory and policy roadmap to guide the evolution of the gas distribution industry, while providing ratepayer protection and helping the Commonwealth achieve its goal of net-zero GHG emissions energy.[51]

The DPU required responsive compliance filings by each of the individual gas utilities, set out specific questions to be pursued during the proceeding, and called for the utilities to arrange for an independent consultant study and report on the gas utilities' filings.[52] Despite the insistence of various stakeholders, the DPU declined to oversee the independent study itself.[53] In March of 2022, the gas utilities collectively submitted the required independent study and report as well as required individual Initial Net Zero Enablement Plans. The DPU held two virtual public hearings, two virtual technical sessions, and a discovery period and accepted final stakeholder comments. The DPU then intended to make certain determinations and issue guidance in the form of an order to establish the future steps.[54]

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[47] An Act Creating a Next Generation Roadmap for Massachusetts Climate Policy, 2021 Mass. Acts Ch. 8 (codified at Mass. Gen. Laws Ch. 21N, § 3 et seq.).
[48] *Petition of the Office of the Attorney General,* Case No. 20-80 (June 4, 2020).
[49] *Vote and Order Opening Investigation*, Case No. 20-80 (Oct. 29, 2020).
[50] *Id.* at 1.
[51] *Id.* at 4.
[52] *Id.* at 4-5.
[53] *Order on the Attorney General's Motion for Clarification*, Case No. 20-80 (Feb. 10, 2021).
[54] *Hearing Officer Memorandum Regarding Stakeholder Final Comment Deadline*, MA DPU Case No. 20-80 (Sept. 8, 2022).

On August 11, 2022, however, the Governor signed into law new climate legislation that, among other things, addresses the future of gas.[55] News coverage described relevant provisions as "tak[ing] aim at the Department of Public Utilities' ongoing work on the future of natural gas in the state. The department has been criticized for letting the utility companies write their own plans, and this law gives environmental groups and the public a bigger role in the planning process."[56]

The new law requires DPU to "convene a stakeholder working group to develop recommendations for regulatory and legislative changes that may be necessary to align gas system enhancement plans … with the applicable statewide greenhouse gas emission limits and sublimits … and the commonwealth's emissions strategies."[57] The working group is required to submit its report to DPU and others no later than July 31, 2023. The law also prohibits DPU from approving "any company-specific plan filed pursuant to the DPU Docket No. 20-80, … prior to conducting an adjudicatory proceeding with respect to such plan."[58] Such legislative action provides a cautionary note about the risks of allowing the planning proceeding to be too heavily led by the utilities themselves. As identified by numerous stakeholders in the Massachusetts proceeding, and ultimately embodied by the recent legislation, Commission oversight is necessary to ensure that planning prioritizes the public interest over utilities' private interests.

5. Minnesota

In 2007, Minnesota passed legislation establishing statewide goals to reduce GHG emissions by 15 percent, as compared to 2005 levels, by 2015; 30 percent by 2025; and 80 percent by 2050.[59] In 2021, the state passed additional legislation, the Natural Gas Innovation Act (NGIA), designed to encourage natural gas utilities to develop "innovative resources" to help the state reach its GHG emissions reduction goals.[60] Under the 2021 law, gas utilities can file with the Minnesota PUC "innovation plans" for the development or provision of "innovative resources" that decarbonize their operations.[61] If approved by the PUC, the "prudently incurred costs" associated with these pilot programs can be recovered through rates.

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[55] An Act Driving Clean Energy & Offshore Wind, 2022 Mass. Acts Ch. 179 (August 11, 2022).
[56] Miriam Wasser, *What to Know about the New Mass. Climate Law*, WBUR (last updated Aug. 11, 2022), https://www.wbur.org/news/2022/07/22/massachusetts-climate-bill-baker-desk.
[57] An Act Driving Clean Energy & Offshore Wind at § 68.
[58] *Id.*at § 77.
[59] Next Generation Act of 2007, 2007 Minn. Laws Ch. 136 (codified at Minn. Stat. § 216H.02).
[60] Natural Gas Innovation Act, 2021 (1st Spec. Sess.) Minn. Laws Ch. 4 (codified at Minn. Stat. §§ 216B.2427 & 216B.2428).
[61] "Innovative resources" are defined in the law as "biogas, renewable natural gas, power-to-hydrogen, power-to-ammonia, carbon capture and utilization, strategic electrification, district energy, and energy efficiency." Minn. Stat. § 216B.2427.

In response to the NGIA, the PUC opened two dockets. The first docket, directed by the NGIA, aimed to guide the gas companies in developing innovation plans by establishing (1) frameworks for comparing the lifecycle GHG emissions intensities of "innovative resources," and (2) cost-benefit analysis to compare the cost effectiveness of innovative resources and innovation plans that gas utilities file under the Act.[62] In June, the PUC issued an order adopting the required frameworks,[63] and soon thereafter adopted eligibility criteria for energy efficiency and strategic electrification investments proposed and implemented under the NGIA.[64]

More directly analogous to the proceeding requested by this petition, the PUC's second docket is a broader proceeding looking at the future of gas, in which the PUC is considering policy and regulatory changes needed to meet or exceed the state's climate goals.[65] The PUC is currently in the process of holding a series of technical conferences as a primer to interested parties on the existing state of gas regulation and issues.[66]

6. New Jersey

New Jersey has similarly positioned itself as a national leader in developing a cleaner energy future. In 2007, the New Jersey Global Warming Response Act directed state agencies to develop plans and make recommendations for reducing emissions of climate pollutants to 80 percent below their 2006 levels by the year 2050.[67] In 2018, Executive Order No. 28 further directed the development of an updated statewide *Energy Master Plan* to achieve 100 percent clean energy by 2050 and tasked the New Jersey BPU to serve as the lead agency for development and oversight.[68] In January of 2020, the BPU and its partners released the updated plan, which among other things, highlights the tension between the need to maintain safe and reliable gas infrastructure and service on the one hand, and the incompatibility of gas infrastructure expansion with the state's GHG emissions reduction goals on the other.[69] The Plan directs that "[a]s NJBPU endeavors to ensure just and prudent investments, it must examine if ratepayers are socializing and subsidizing unnecessary fossil fuel infrastructure costs, and if doing so will risk ratepayers shouldering the burden of stranded assets in the future."[70]

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[62] *Order Establishing Frameworks for Implementing Minnesota's Natural Gas Innovation Act*, Docket No. G-999/CI-21-566 (June 1, 2022).
[63] *Id.*
[64] *Order Adopting Eligibility Criteria for Energy Efficiency and Strategic Electrification Investments*, Docket No. G-999/CI-21-566 (Sept. 12, 2022).
[65] *Notice of New Docket*, Docket No. G-999/CI-21-565 (July 23, 2021).
[66] *Notice of Second Technical Conference*, Docket No. G-999/CI-21-565 (Nov. 17, 2022).
[67] New Jersey Global Warming Response Act, P.L. 2007 Ch. 340 (Jan. 13, 2008) (codified at N.J. Rev. Stat. §§ 26:2C-45 et seq., 48:3-87, 48:3-98.1).
[68] Exec. Order No. 28 (May 23, 2018), https://www.nj.gov/infobank/eo/056murphy/pdf/EO-28.pdf.
[69] *2019 New Jersey Energy Master Plan: Pathway to 2050,* https://www.nj.gov/emp/, at 190-91.
[70] *Id.* at 191.

As part of its investigatory process, the BPU commissioned an independent analysis of rate impacts to quantify the impact of the Energy Master Plan on customers' energy costs.[71] In August, the BPU voted to accept the resulting report, explaining that the analysis therein will help the BPU fulfill its role "to ensure policies implemented are fair to ratepayers and to identify ways to mitigate the impact of energy industry changes, particularly on low-income customers."[72]

In February of 2019, the BPU directed staff to initiate a stakeholder process to explore the issue of whether there is sufficient capacity to deliver natural gas to meet consumer needs.[73] After receiving conflicting reports from the utilities and environmental groups, the BPU hired an independent consultant to compare the results of the reports and to determine if New Jersey has adequate gas capacity through 2030.[74] In so doing, the BPU recognized the need to determine "how evolving environmental concerns may drive changes in the way natural gas is transported and used in New Jersey."[75] In June of 2022, the BPU accepted the resulting report's findings, which determined that there is sufficient capacity and which "support the [BPU]'s aggressive policy approach to reduce the State's overall reliance on fossil fuels, and achieve Governor Murphy's goal of 100 percent clean energy by 2050."[76]

On the basis of these findings, the BPU, together with the Division of the Rate Counsel, subsequently intervened in a FERC proceeding regarding the CPCN application for a gas pipeline expansion.[77] Seeking to lodge the report as evidence, the BPU objected to the utility's claim that the pipeline expansion is necessary to serve customer demand, arguing instead that the expansion would burden residents with "unneeded natural gas capacity."[78] Although FERC recently granted the CPCN, finding that "the weight of the record supports the need for the … project,"[79] the BPU's efforts nonetheless provide an example of creative, affirmative advocacy in the public interest and the value of long-term planning.

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[71] Sanem Sergici et al., *New Jersey Energy Master Plan Ratepayer Impact Study* (Aug. 2022).
[72] NJ BPU, *New Jersey Board of Public Utilities Accepts Final Energy Master Plan Ratepayer Impact Study* (August 17, 2022), https://www.nj.gov/bpu/newsroom/2022/approved/20220817.html.
[73] *2-27-19M, Decision and Order*, Docket No. GO17121241 (February 27, 2019).
[74] *5-20-20-9A, Order Soliciting an Independent Consultant*, Docket No. GO19070846.
[75] *Id.* at 4.
[76] *6-29-22-A, Order Accepting Report*, Docket No. GO19070846 (June 29, 2022).
[77] *Motion to Intervene Out of Time and to Lodge of the New Jersey Parties*, FERC Docket No. CP21-94 (July 11, 2022).
[78] *Id.* at 2.
[79] *Order Issuing Certificate and Approving Abandonment*, Docket No. CP21-94-000, 182 FERC ¶ 61,006 (Jan. 11, 2023), at 17.

7. New York

In 2020, the New York PSC also began proceedings to bring long-term gas planning in line with the state's GHG reduction goals.[80] After several gas utilities cited insufficient capacity when instituting moratoria on new gas service connections, the PSC determined a need for gas utilities to "adopt improved planning and operational practices that enable them to meet current customer needs and expectations in a transparent and equitable way while minimizing infrastructure investments and maintaining safe and reliable service."[81]

In addition to addressing potential constraints on supply, the PSC acknowledged that "planning must [also] be conducted in a manner consistent with the recently enacted Climate Leadership and Community Protection Act."[82] That law requires the state to reduce GHG emissions from all anthropogenic sources 100 percent over 1990 levels by 2050, with an incremental target of at least a 40 percent reduction in GHG emissions levels by 2030.[83] The law also requires the PSC to establish a program to decarbonize the electric sector, with targets of 70 percent of the state's electricity deriving from renewable energy by 2030 and 100 percent carbon-free energy by 2040.[84] As in Maryland, the law further directed state agencies, including the PSC, to consider GHG emissions and limits in permitting, licensing, contracting, and other approvals and decisions.[85]

In a March 2020 order instituting long-term planning proceedings, the PSC directed gas utilities to file supply and demand analyses and directed PSC staff to submit a proposal to modernize the gas system planning process.[86] In February of 2021, the PSC published staff's proposal and invited stakeholder engagement through public hearings and comment; and in May of 2022, the PSC adopted the proposed plan with modifications.[87] Among other things, the adopted proposal requires that utilities file long-term plans every three years and lays out various substantive requirements for these filings. The plan also requires the utilities to file interim annual updates; calls for stakeholder participation at multiple stages; and directs staff to hire, and the utilities to pay for, an independent consulting firm to review each utility's long-term gas plans. Additionally, the plan identifies next steps for dealing with issues like the avoided cost of gas by establishing a working group, and depreciation by ordering the gas companies to prepare a study "that examines both the structure of accelerated depreciation and its

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[80] *Order Instituting Proceeding*, Case No. 20-G-0131 (Mar. 19, 2020).
[81] *Id.* at 2-3.
[82] *Id.* at 3.
[83] Climate Leadership and Community Protection Act, 2019 N.Y. Laws Ch. 106, § 1 (July 18, 2019).
[84] *Id.* at §4 (codified at NY Pub. Serv. Law § 66-p(2)).
[85] *Id.* at §§ 2 and 7(2) (codified at Envtl. Conserv. Law § 75-0103).
[86] *Order Instituting Proceeding*, Case No. 20-G-0131 (Mar. 19, 2020).
[87] *Order Adopting Proposal*, Case No. 20-G-0131 (May 12, 2022), at 17-18.

potential impact on customers" with the goal to "inform future discussions of how best to recover the costs of assets and reduce potential."[88] The gas companies recently filed the required depreciation studies, and due dates for long-term plans are staggered over the next three years, with the first utility's filing due December 15, 2022.[89]

8. Rhode Island

In 2020, Rhode Island established through executive order a goal to meet 100 percent of the state's electricity demand with renewable energy resources by 2030.[90] In 2021, the state passed the Act on Climate, which accelerated existing economy-wide GHG reduction targets to net zero by 2050 and updated the statutory duties of state agencies to obligate each agency to address "the impacts on climate change … in the exercise of its existing authority."[91]

In light of the new legislation, the Rhode Island PUC opened a docket in June of 2022 to investigate the future of the regulated gas distribution business with the stated purpose "to examine the extent to which the requirements of the Act impact the conduct, regulation, ratemaking, and the future of gas supply and gas distribution within Rhode Island."[92] The PUC began the proceeding by seeking public comment on the proposed scope of the docket, in which it anticipated exploring the two primary alternatives for reducing emissions associated with gas consumption: (1) "creat[ing] a scalable and sustainable market for low- and no-carbon natural gas;" and (2) "transition[ing] customers from the gas system to alternative fuels with clearer pathways for meeting the mandated targets (such as electricity)."[93] The public comment period ended in October 2022, and the PUC recently adopted staff's proposed scope, dividing the proceeding into three phases—policy planning, technical analysis, and policy development—and laying out a series of questions to be incorporated into each phase.[94]

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[88] *Id.* at 61-62.
[89] *Id.* at 65.
[90] Exec. Order 20-01 (2020).
[91] 2021 Act on Climate, 2021 R.I. Pub. Laws Ch. 002 (codified at R.I. Gen Laws § 42-6.2 et seq.)
[92] *Notice of Commencement of Docket*, Docket No. 22-01-NG (June 9, 2022).
[93] *Draft Staff Recommendation for Public Comment*, Docket No. 22-01-NG (Aug. 31, 2022), at 2.
[94] *Proceeding Scope*, Docket No. 22-01-NG (Jan. 3, 2023).

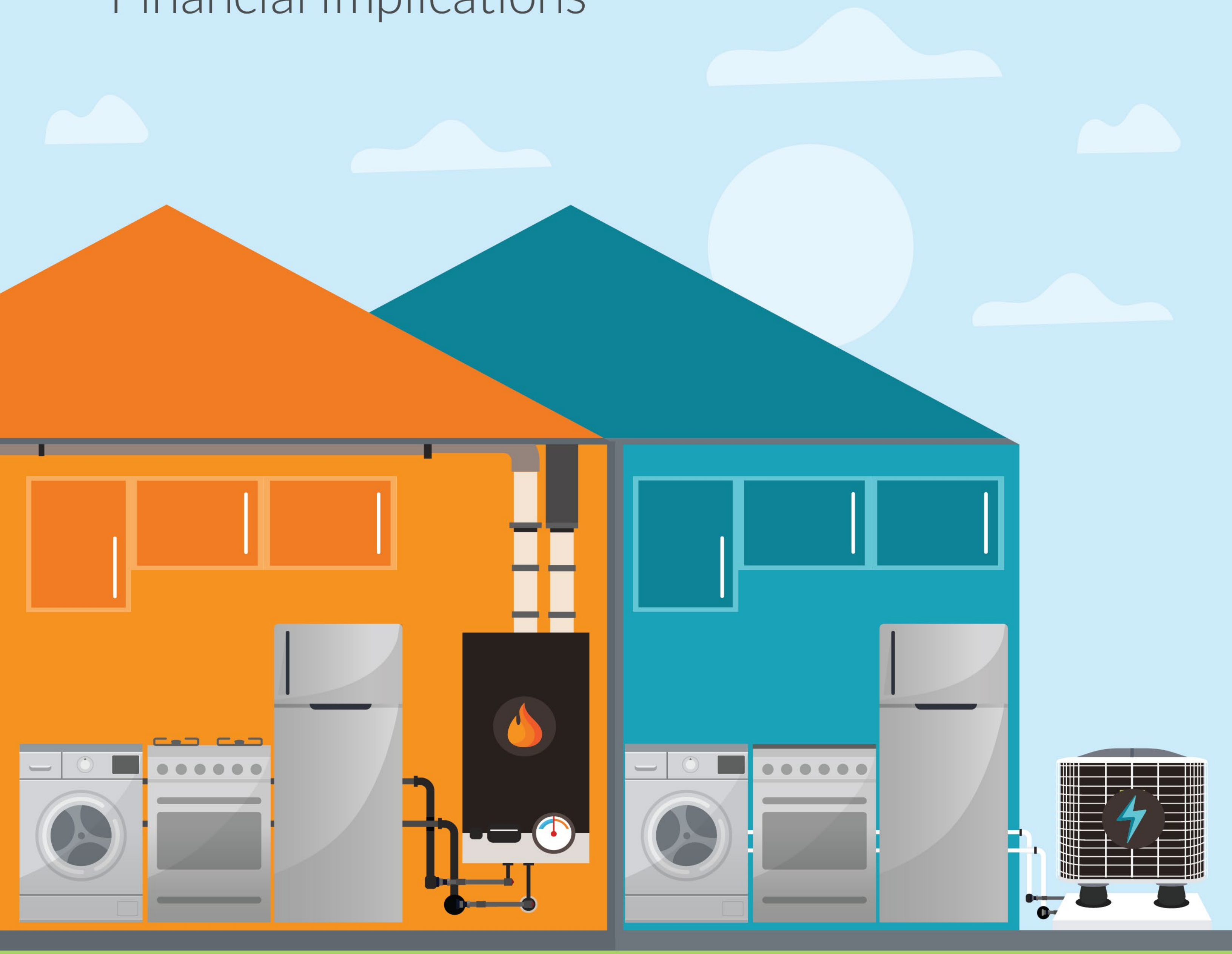
Appendix D

OPC CLIMATE POLICY REPORT

OPC
OFFICE OF PEOPLE'S COUNSEL
State of Maryland

Climate Policy for Maryland's Gas Utilities

Financial Implications



November 2022

DEAR READERS

The most promising path to transforming Maryland's homes and apartments to meet the State's climate goals involves transitioning to electric heating and cooling systems and appliances. This point is not seriously disputed.

What remains at issue for a decarbonized future is the role of the gas utilities' distribution infrastructure and gas itself. As our recent report, Maryland Gas Utility Spending: Projections and Analysis, shows, despite the State's electrification goals, Maryland's gas utilities are on a business-as-usual path, spending tens of billions of dollars on their delivery systems. Gas utilities hope to recover the costs of this spending over many future decades through higher customer rates. Yet these investments are being made in a declining market—inevitably, the number of gas customers and gas sales will decline with electrification. In fact, electrification already is slowly and steadily eating into gas's market share. Residential customers have been turning more and more to electricity for home heating for more than a decade. These declines in gas use will only accelerate in coming years as federal and State policies favoring electrification take effect.

This dynamic of decreasing gas sales and escalating rates raises a fundamental question: Should Maryland's gas utilities continue to invest heavily in gas distribution infrastructure given the declining market?

How this important question is resolved has significant implications for utility customers in the near and long term. The answer determines whether billions of customer dollars will go toward retaining and enhancing the gas distribution infrastructure or whether those dollars can be used to fund any costs associated with electrification or otherwise reduce customer burdens and help Maryland's economy.

Should Maryland's gas utilities continue to invest heavily in gas distribution infrastructure given the declining market?

To better understand the scale of the problem, our office engaged a consultant, Synapse Energy Economics, to evaluate what happens to residential utility rates under the current regulatory model and utility spending trajectory as gas sales decline. The results—described in this report—are telling: Replacing fossil gas with lower carbon alternatives causes the rates of the State's largest gas utility, Baltimore Gas & Electric, to increase two to three times 2021 levels by 2035 and seven to 11 times 2021 levels by 2050, with similar ranges of rate increases for Maryland's two other large gas utilities. Such rates are not sustainable. As rates increase to these levels, the resulting high bills will lead many customers—likely most all customers who have options—to leave the gas system, leaving behind customers without alternatives; those remaining gas customers will be unable to afford continued gas service.

No matter the path forward, electrification holds major consequences for gas utilities and their customers. The potential consequences of business-as-usual spending—tens of billions of stranded

Electrification holds major consequences for gas utilities and their customers.

gas infrastructure assets—has huge implications for the State. Who will bear the consequences of the uneconomic investments? Shareholders? Electricity customers? Taxpayers? Indeed, a recent BGE report acknowledges the unsustainability of maintaining its gas distribution system, foreshadowing that it may seek subsidies for its gas business through "transfer payments from the company's electric business."

Similar to our October 2022 report on gas utility business-as-usual capital spending, our estimates are generally conservative. For the price of fossil gas, the report uses prices ranging from \$2.94/MMBtu to \$4.05/MMBtu, based on U.S. Energy Information Administration's Annual Energy Outlook 2022 Henry Hub natural gas spot price projections (in 2020 dollars). These prices are well below the EIA's September 2022 price of \$7.88/MMBtu. For alternative fuel prices, we use a low-price scenario based on a study prepared for Washington Gas Light, and for the high-price scenario we use estimates from E3's 2021 study for the Maryland Commission on Climate Change.

We hope this report helps educate stakeholders and policymakers on the significance of unmitigated gas utility spending for Maryland's gas utility customers as the State electrifies and initiates policies to meet its greenhouse gas reduction goals, with corresponding reductions in gas utility customer base and gas sales.

David S. Lapp
People's Counsel

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SECTION 1

INTRODUCTION

The Maryland Office of People's Counsel (OPC) asked Synapse Energy Economics, Inc. (Synapse) to analyze the gas rates likely to materialize as more Marylanders switch from fossil-fuel-fired building furnaces and appliances to electric ones as part of the effort to meet the State's greenhouse gas (GHG) reduction targets.

Released in 2021, the Maryland Department of Environment's *2030 Greenhouse Gas Emissions Reduction Act (GGRA) Plan* recommends reducing emissions from buildings using energy efficiency and by electrifying building heating systems. Under this plan, the Mitigation Working Group (MWG) of the Maryland Commission on Climate Change (MCCC) developed and issued the *Building Energy Transition Plan*.[1] To inform this plan, Energy + Environmental Economics (E3) analyzed scenarios for achieving reductions in emissions to near net-zero levels for Maryland's residential and commercial buildings by 2045. In total, E3 modeled four scenarios, including the *MWG Policy Scenario*, which was found both to be the lowest-cost scenario and to reduce residential and commercial building emissions by 95 percent. This scenario reflects four core concepts and objectives, including: ensuring an equitable and just transition; shifting to fossil-free space and water heating for new construction; replacing almost all fossil heating systems in homes with heat pumps by 2045; and implementing an emissions standard that provides commercial buildings compliance alternatives.[2]

In 2022, the Maryland State House and Senate passed the *Climate Solutions Now Act*, which requires the State to reduce GHG emissions by 60 percent from a 2006 baseline by 2031 and to achieve net-zero GHG emissions by 2045.[3] On April 8, 2022, Governor Hogan released a letter stating that he would allow the bill to pass without his signature.[4]

To better understand the potential effects of the MCCC Mitigation Working Group's *MWG Policy*

The **MWG Policy Scenario** was found to be the lowest-cost scenario and to reduce residential and commercial building emissions by 95 percent.

1 Maryland Commission on Climate Change. *Building Energy Transition Plan: A Roadmap for Decarbonizing the Residential and Commercial Building Sectors in Maryland.* Approved by the Mitigation Work Group on Oct. 13, 2021.

2 Id., p. 4.

3 Maryland Senate Bill 528. "Chapter 38: an Act Concerning Climate Solutions Now Act of 2022." Available at: https://mgaleg.maryland.gov/2022RS/Chapters_noln/CH_38_sb0528e.pdf.

4 Governor Larry Hogan. April 8, 2022. *Letter from Governor Hogan to State Senate President Ferguson and State House Speaker Jones.* Available at: https://governor.maryland.gov/wp-content/uploads/2022/04/SB-528-CSNA-SB-566-Investment-Climate-Risk-EWS-Letter.pdf.

To achieve net zero GHG emissions by 2045, the vast majority of **buildings will have to either fully electrify their loads or use alternative gaseous fuels for any gas needs**, including backup heating.

Scenario, we modeled the progress of Maryland's electrification to project GHG emissions, trends in gas consumption, and space heating type and space heating equipment sales. Synapse then used these projections to analyze the financial implications of Maryland's climate goals for gas utilities in the State through 2050. Our analysis focuses on the residential sector, consistent with OPC's statutory mission.

To achieve net zero GHG emissions by 2045, the vast majority of buildings will have to either fully electrify their loads or use alternative gaseous fuels[5] for any gas needs, including backup heating. Buildings are relatively low-cost to electrify with commercially available technologies. On the other hand, the most likely candidates for alternative gaseous fuels pose issues related to cost, availability, emissions, safety, and energy use during production. However, certain end-uses would be far more expensive to electrify or have no viable electric alternatives. Given these considerations, it is important to consider how alternative gaseous fuels should be used.

If alternative gaseous fuels are used for building end-uses, the cost of the commodity will increase, and that additional cost will be reflected in customers' bills. Given the availability of cost-competitive electric alternatives, increased gas costs will drive customers off the gas system and decrease gas sales. At the same time, the utilities' investments in pipeline infrastructure, documented in OPC's recent report, Maryland Gas Utility Spending: Projections and Analysis, will also increase gas customers' bills. With more customers leaving the gas system due to electrification, these higher gas commodity and infrastructure costs will have to be recovered through fewer sales. This will mean higher rates for those remaining customers, which will further drive customers off the gas system and increase the risk that the utility will have stranded assets.

In the remainder of this document, we provide context and describe our findings. Section 2 describes how, under traditional ratemaking, gas companies will be affected as customers migrate away from gas use with increasing electrification of their end-uses. In Section 3, we describe technologies available for decarbonizing buildings. In Section 4, we describe our methodology for analyzing decarbonization trajectories and gas utility financials as sales decline. Appendix A features a list of definitions and abbreviations. Appendix B provides figures for the commercial sector.

Given the availability of cost-competitive electric alternatives, **increased gas costs will drive customers off the gas system and decrease gas sales**.

5 Here we assume that Alternative Gaseous Fuels reduce GHG emissions. However, as explained below, recent studies suggest otherwise.

SECTION 2

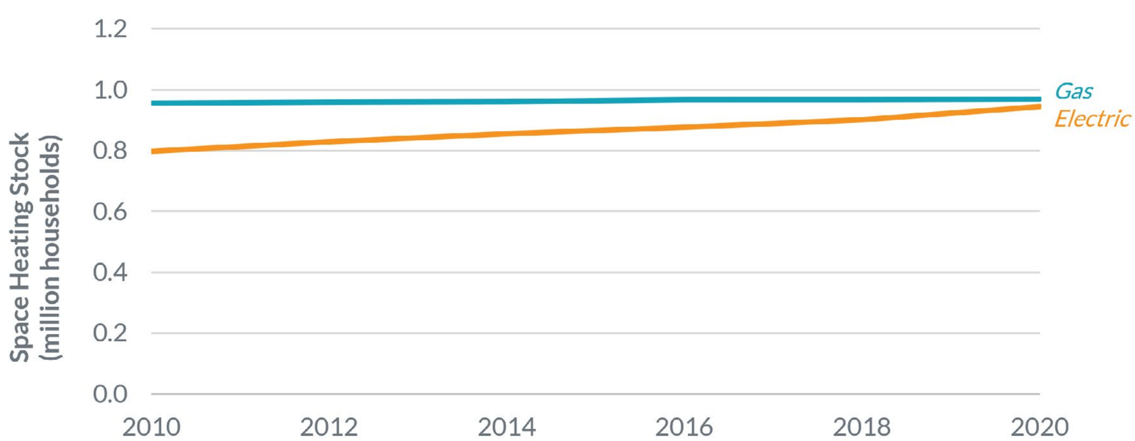
ELECTRIFICATION'S IMPACTS ON GAS RATES

Electric heating stock has been increasing for years now, while gas heating stock has stagnated.

Basic ratemaking principles explain how electrification (the process of switching fossil-fuel-based appliances and other energy end-uses over to electric ones) will affect gas companies by causing customers to migrate away from gas use. The traditional ratemaking model allows utilities to invest in and earn a return on assets such as gas mains and service lines. Utilities recover and earn a return on their investment, typically over the asset's useful lifetime, by including the costs of their investments and the returns on them in the rates they charge customers. This traditional utility business model is designed to ensure utilities can attract shareholders who will put up the money for the investments in exchange for a fair return of—and on—the utility's investments. Without such investments, the thinking goes, utilities would not be able to ensure reliability or meet customers' needs. This model works reasonably well when sales increase over time, but it leads to higher rates when sales are decreasing. Whether occurring as a result of market trends or policy intervention, building electrification will result in declines in gas utility sales, holding all else equal.

Figure 1 shows electric heating stock (mostly heat pumps) has been increasing for years now, while gas heating stock has stagnated. Data from the American Community Survey show that this trend of electrification is occurring across the country. It is notable that

Figure 1. Gas and Electric Space Heating Stock in Maryland Households, 2010-2020



Source: US Census Bureau: American Community Survey. Table DP04: Selected Housing Characteristics for Maryland, 5-year Estimates. June 2, 2022. Available at: https://data.census.gov/cedsci/table?q=DP04&g=0400000US24&tid=ACSDP5Y2020.DP04

this trend toward heating buildings with electricity rather than gas is occurring without significant policy initiatives at the State or local level. While federal and State electrification policies are being discussed (and recently adopted as is the case of the recently enacted *Inflation Reduction Act*, for example), their effects have largely yet to be realized. These policy efforts can be expected to accelerate electrification.

This trend toward heating buildings with electricity rather than gas is occurring **without significant policy initiatives at the State or local level**.

This electrification trend means fewer gas sales. If gas sales decline faster than utilities' asset bases depreciate and faster than the utilities can lower their operating and maintenance costs, gas utilities will seek approval for increasing gas rates to recover the capital invested over fewer unit sales. In turn, higher gas rates are likely to spur more customers to electrify their gas end-uses (furnaces and appliances). As this process goes on, those with the means to electrify—i.e., those who can afford the upfront costs of changing their gas appliances to electric ones and can modify their buildings to accommodate the switch—will do so first. Without changes to regulatory practices or direct assistance, those without access to capital (e.g., low- and moderate-income customers) or the ability to make changes to their dwellings (e.g., renters) will be left on an increasingly costly gas system. Rate escalation will likely hit these groups the hardest.

SECTION 3

TECHNOLOGIES THAT SUPPORT DECARBONIZATION

Achieving net zero by 2045 means that buildings will have to either fully electrify their energy loads or use alternative gaseous fuels for any gas needs, including backup heating. This section discusses key considerations about the available building decarbonization technologies to provide context for the rate analysis in Section 4.

The total cost of installing heat pumps in residential new construction is much less than the cost of installing fossil gas equipment for heat plus central air conditioning (AC) for cooling.

3.1. Electric Space and Water Heating

Heat pumps. Heat pumps provide both energy-efficient cooling and heating. The total cost of installing heat pumps in residential new construction is much less than the cost of installing fossil gas equipment for heat plus central air conditioning (AC) for cooling. For retrofitting an existing building, the cost of installing heat pumps is similar to or less than the combined installed cost of the furnace and central AC. A study by the Lawrence Berkeley National Laboratory (LBNL) found that, on average nationally, a new gas furnace and AC have a combined installed cost of almost $11,000 for residential retrofits. In contrast, the installed cost of heat pumps is substantially less, at just over $8,000.[6] In the absence of extreme price volatility, operating costs, including fuel, are similar for these options.[7] In addition to cheaper up-front costs, heat pumps serve as both the heating and cooling device for a home, requiring a household to only maintain one system. Comparatively, a gas furnace cannot be used for home cooling and requires an additional system for air conditioning.[8]

Electrification will gradually advance as current heating stock reaches the end of its useful life and is increasingly replaced with heat pumps. Moreover, since almost 50 percent of residential buildings in

6 Less, B. D., et al. 2021. *The Cost of Decarbonization and Energy Upgrade Retrofits for US Homes*. Lawrence Berkeley National Laboratory. Available at: https://escholarship.org/uc/item/0818n68p.

7 Energy + Environmental Economics. "Maryland Building Decarbonization Study: Final Report." October 20, 2021.

8 For commercial heating and cooling systems, retrofit costs are harder to compare than for residential ones, because costs vary by building type and data are relatively sparse for the variety of building types in use for commercial applications. Some studies suggest that installed costs for heat pumps are comparable to the cost of gas heating and separate electric AC systems for commercial buildings. (Group 14 Engineering, *Electrification of Commercial and Residential Buildings*, (2020) available at: https://bit.ly/3skNqAp.) For small commercial customers, E3's study for Maryland found that all-electric new construction is cheaper than mixed-fuel new construction due to lower capital and operating costs. (Energy + Environmental Economics. "Maryland Building Decarbonization Study: Final Report." October 20, 2021.)

Maryland are already heated primarily with an electric heating unit (either electric resistance or heat pumps), electrification is already underway in the State.[9]

Hot water heaters. The total equipment and installation costs of electric heat pump water heater (HPWH) retrofits are generally much higher than those of gas storage water heaters.[10] As with space heating, the operating costs of electric and gas appliances are generally similar. Considering fuel costs, electric rate structures such as time-of-use rates can give electric appliances and equipment an edge over gas systems. (Customers billed under a time-of-use rate generally pay more during peak energy-usage hours than during off-peak hours, such as late at night or early in the morning.)

Panel upgrades. Electrification may require upgrades to electrical circuits and panels to accommodate additional load. The cost of upgrading the electrical panel typically ranges from about $500 to $2,000 for most homes, while the costs could be more than $3,000 for others.[11] For some households, these costs can be mitigated. Newer buildings generally have high electrical capacity and thus may not need upgrades. Some customers may upgrade their electrical panels to support electric vehicles and be ready for building electrification measures without additional upgrades. Finally, these costs also can be avoided in the future by using low-amp appliances that are currently in development.

Inflation Reduction Act. The recently enacted federal Inflation Reduction Act (IRA) could substantially reduce the costs of electrification through tax credits. Homeowners can receive a tax credit of up to $2,000 per year to install heat pumps or electric water heaters and up to $600 per year for electrical panel upgrades.[12] The IRA also authorizes rebates for qualifying households for electrification and efficiency measures, including heat pumps, heat pump water heaters, electric stoves, heat pump clothes dryers, circuit panels, wiring, and insulation and air sealing.

3.2. Heat Pumps with Fuel Backup (Hybrid Systems)

Heat pumps can be used in concert with fossil fuel backup or supplemental heating systems. Such backup systems could reduce pressure on the electric system to accommodate higher loads from electrification. However, in a moderate climate like Maryland (with only around 4,000 heating degree days annually)[13] fuel backup is unnecessary. ACEEE found that households in the State would not need fuel backups when using cold-climate heat pumps, which are advanced heat pump systems that provide

Fuel backup systems are unnecessary, and deploying them is costly for consumers.

9 U.S. Energy Information Administration. Residential Energy Consumption Survey: 2020 RECS Survey Data. Available at https://www.eia.gov/consumption/residential/data/2020/index.php?view=state&src=%E2%80%B9%20Consumption%20%20%20%20%20%20Residential%20Energy%20Consumption%20Survey%20(RECS)-f2, accessed October 20, 2022.

10 Less, B. D., et al. 2021. *The Cost of Decarbonization and Energy Upgrade Retrofits for US Homes*. Lawrence Berkeley National Laboratory. Available at: https://escholarship.org/uc/item/0818n68p.

11 HomeAdvisor. July 6, 2022. "Cost to Upgrade an Electrical Panel." Available at: https://www.homeadvisor.com/cost/electrical/upgrade-an-electrical-panel/.

12 Inflation Reduction Act of 2022, §13301. Available at: https://www.congress.gov/bill/117th-congress/house-bill/5376/text.

13 Heating degree days measure how cold the outdoor temperature is relative to a standard temperature, generally 65° Fahrenheit (F), over a period of time. For example, a day with a mean temperature of 40°F would have 25 HDD. (U.S. Energy Information Administration, Units and calculators explained: Degree days. Available at: https://www.eia.gov/energyexplained/units-and-calculators/degree-days.php.) Over the course of a year, Maryland has approximately 4,000 HDD. (Nadel, S. and L. Fadali. 2022. *Analysis of Electric and Gas Decarbonization Options for Homes and Apartments*. Washington, DC. ACEEE. Available at: https://www.aceee.org/sites/default/files/pdfs/b2205.pdf.)

heat down to 5 degrees Fahrenheit or lower.[14] Fuel backup systems are unnecessary, and deploying them is costly for consumers because the gas utilities would need to upgrade old parts of the distribution system and maintain the entire system for use during just a small portion of the year.

3.3. Alternative Gaseous Fuels

Considering that some uses of fossil gas do not currently have electric alternatives, replacing fossil fuel gas with lower carbon alternatives will play an important role for the State's achievement of its climate goals. The most likely alternative gaseous fuels that have potential for replacing fossil gas are biomethane, recovered methane, hydrogen, and synthetic natural gas or synthetic methane.

3.3.1. Biomethane and recovered methane

Recovered methane is methane captured from gas distribution system leaks or other sources. *Biomethane* (also called renewable natural gas, or RNG) is a mixture of carbon dioxide and hydrocarbons released from the decomposition of organic matter. Biomethane must be processed to remove impurities, liquid water, and hydrocarbons, and to attain acceptable heat content.[15] Processing increases costs, consumes energy, and requires investment in processing facilities.

Both biomethane and recovered methane pose collection, processing, and transportation challenges that raise their costs. It may be more economical to use these fuels for some other purpose, in a less-processed form and closer to their sources, rather than using them in distant buildings to replace fossil gas consumption.

> Both biomethane and recovered methane pose **collection, processing, and transportation challenges that raise their costs.**

Both biomethane and recovered methane supplies are currently limited and likely to remain constrained well into the future. According to the consulting firm ICF International's 2019 report for the American Gas Foundation, constraints in available biomass feedstocks severely limit biomethane that is potentially carbon-negative, which includes anaerobic digestion of food waste, dairy, and swine manure. (Other feedstocks—gasification of agricultural and forest residue, municipal solid waste, and energy crops—have fewer supply constraints but unfavorable carbon footprints.) The 2019 ICF International report estimates that supplies of the feedstocks that are likely to be carbon negative from Maryland sources will amount to just 5.766 tBtu in 2040 in a high-potential scenario.[16] Relative to current residential gas consumption in Maryland—80.418 tBtu for the residential sector alone in 2020—carbon negative biomethane could displace only a small portion of current gas sales in the State, even assuming

14 One field study in Vermont observed that cold climate heat pumps operated under -20° F at above 1 coefficient of performance (COP) but with reduced capacity. (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.) *See also*, Nadel, S. and L. Fadali. 2022. *Analysis of Electric and Gas Decarbonization Options for Homes and Apartments.* Washington, DC. ACEEE. Available at: https://www.aceee.org/sites/default/files/pdfs/b2205.pdf.

15 Gas quality specifications may vary by pipeline. (Thomson Reuters Practical Law: Pipeline Quality Natural Gas (US). Available at: https://content.next.westlaw.com/practical-law/document/Iee1c892db6ea11eabea4f0dc9fb69570/pipeline-quality-natural-gas?viewType=FullText&originationContext=document&transitionType=DocumentItem&ppcid=b60bf2510cb649d7a374f9f88d3199f5&contextData=(sc.DocLink)&firstPage=true, accessed October 18, 2022.)

16 ICF International. 2019. *Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment. Prepared for the American Gas Foundation.* Available at https://gasfoundation.org/wp-content/uploads/2019/12/AGF-2019-RNG-Study-Full-Report-FINAL-12-18-19.pdf.

Carbon negative biomethane could displace only a **small portion** of current gas sales in the State.

declining gas sales in future years.[17] There also will be competition for the limited biomethane supplies as other states seek to decarbonize their economies.[18]

Because methane is a potent GHG, leaks undercut overall climate efforts. A GHG emissions mitigation strategy that integrates these fuels into the existing distribution system for widespread use should account for fugitive emissions during transport.

Methane leakage also poses safety concerns. Local fire departments in the United States respond to 4,200 home fires caused by ignition of fossil gas per year, most of which involve some type of leak. Each year on average, these fires result in $54 million in direct property damage, 140 civilian injuries, and 40 civilian deaths.[19]

Like fossil gas, in-home use of biomethane and recovered methane poses health and safety concerns due to combustion and leaks.[20] Indoor nitrogen oxide (NO_X) emissions contribute to increased respiratory symptoms and asthma attacks.[21]

3.3.2. Hydrogen

There are different methods of producing hydrogen that impact its carbon footprint. "Gray" hydrogen is produced from fossil gas. As the most common hydrogen production method, gray hydrogen accounts for 6 percent of fossil gas consumption worldwide.[22] "Blue" hydrogen is produced using the same process, but the associated GHG emissions are captured and stored. With both gray and blue hydrogen, emissions result from fossil gas extraction, processing, and use. As a result, gray and blue hydrogen do not provide emissions reductions relative to direct combustion of fossil gas, diesel, or coal for generating heat, as shown in Figure 2.

Gray and blue hydrogen do not provide emissions reductions relative to direct combustion of fossil gas, diesel, or coal for generating heat.

17 Maryland Department of the Environment. 2020. "GHG Emission Inventory." Available at: https://mde.maryland.gov/programs/air/climatechange/pages/greenhousegasinventory.aspx.

18 For example, New York will likely dramatically reduce gas consumption in compliance with its Climate Leadership and Community Protection Act, with likely high demands for RNG for difficult-to-electrify end uses. Current gas consumption in New York, excluding gas for electric power generation, is about 950 Tbtu—far outstripping a recent study's projected statewide potential RNG supply of 47 tBtu/yr. and 147 tBtu/yr. (New York State Energy Research and Development Authority (NYSERDA). 2021. "Potential of Renewable Natural Gas in New York State," NYSERDA Report Number 21-34. Prepared by ICF Resources, L.L.C., Fairfax, VA 22031. nyserda.ny.gov/publications.)

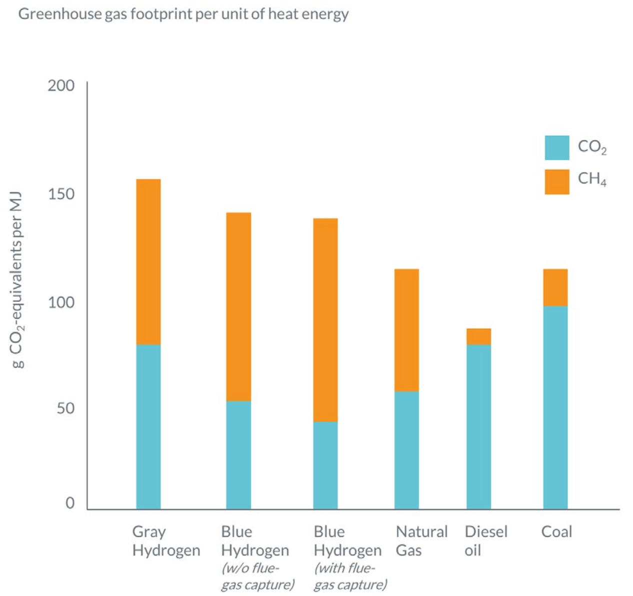
19 The National Fire Protection Association. 2018. "Natural Gas and Propane Fires, Explosions and Leaks: Estimates and Incident Descriptions." Available at https://bit.ly/3vCjxLw.

20 California Energy Commission 2020. *Final Project Report: Air Quality Implications of Using Biogas to Replace Natural Gas in California.* Available at: https://www.energy.ca.gov/sites/default/files/2021-05/CEC-500-2020-034.pdf.

21 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/.

22 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.

Figure 2. Comparison of GHG emissions intensity of gray and blue hydrogen with direct consumption of gas, oil, and coal



Note: Assumes a methane leakage rate of 3.5 percent.

Source: "Greenhouse gas footprint per unit of heat energy" © by Howarth, R., Jacobson, M. 2021. Retrieved from https://onlinelibrary.wiley.com/doi/full/10.1002/ese3.956. Used under Creative Commons Attribution 4.0 International (CC BY 4.0)-Modified to be black and white, remove title, and remove 200 g CO2-equivalents per MJ axis label.

"Green" hydrogen is produced using water as the source of the hydrogen and a carbon-free resource to convert the water to hydrogen. Green hydrogen is not currently cost-competitive with gray hydrogen, although the relative costs may decline as renewable energy costs continue to decrease or policies are enacted that raise the price of fossil fuels.[23]

Hydrogen poses **difficulties for integration** into existing gas infrastructure.

Hydrogen poses difficulties for integration into existing gas infrastructure. Hydrogen can be blended into the gas in the existing pipeline network in small quantities. While some literature has suggested that it may be safe to blend hydrogen into the existing infrastructure up to 20 percent by volume (equivalent to 7 percent by energy content), analysis for the California Public Utilities Commission indicates that only up to 5 percent by volume can be blended in safely.[24] Even if blending hydrogen up to 20 percent by volume (7 percent by energy content) into the existing gas network is safe, doing so would have a limited impact on offsetting fossil fuel use and the corresponding emissions. Higher concentrations of hydrogen would require replacing much of the existing distribution system, since the heat content of hydrogen is lower than methane (requiring larger pipes to accommodate the same energy content) and since some metals (such as those used for pipes) become brittle when exposed to hydrogen.[25]

Hydrogen cannot be interchanged with methane in today's household gas appliances. Beyond relatively low hydrogen blends, consumers would need to purchase new appliances to burn hydrogen safely. As with fossil gas, hydrogen will leak and thereby have reduced carbon benefits. Finally, hydrogen raises safety concerns because it can ignite more easily than natural gas.[26]

23 Howarth, R., Jacobson, M. 2021.

24 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. Penchev, M., T. Lim, M. Todd, O. Lever, E. Lever, S. Mathaudhu, A. Martinez-Morales, and A.S.K. Raju. 2022. *Hydrogen Blending Impacts Study Final Report.* Agreement Number: 19NS1662. California Public Utilities Commission. Available at: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M493/K760/493760600.PDF.

25 U.S. Department of Energy. 2022. "Safe Use of Hydrogen." Available at: https://www.energy.gov/eere/fuelcells/safe-use-hydrogen#:~:text=A%20number%20of%20hydrogen's%20properties,in%20case%20of%20a%20leak.

26 For a technical discussion of the issues discussed here, see Livermore, S., "Exploring the potential for domestic hydrogen appliances," *The Engineer* (2018), available at https://bit.ly/3C2vigD.

3.3.3. Synthetic methane

Synthetic methane can be produced with hydrogen (obtained from electrolysis) and carbon dioxide, (captured either from the ambient air or from exhaust streams before it is released into the air). If renewable energy is used for electrolysis, carbon capture, and other processing, the fuel can have a low-carbon footprint but requires large quantities of energy to produce.[27] Similar to fossil gas, synthetic methane will leak from pipes, and there will be costs associated with fixing leaks, replacing leak-prone pipes, or losses of the fuel. Synthetic methane poses safety risks similar to fossil gas, biomethane, and recovered methane. Leaks of synthetic methane can lead to fires. In addition, synthetic methane combustion causes releases of NOx and other harmful air pollutants, which can lead to serious respiratory health impacts.[28]

3.3.4. Observations about Alternative Gaseous Fuels

The discussion above shows that the most likely candidates for alternative gaseous fuels pose challenges related to cost, emissions, safety, and energy use during production. None of the alternatives that would reduce GHG emissions are available now at scale or at a price similar to natural gas.

The most likely candidates for alternative gaseous fuels pose **challenges related to cost, emissions, safety, and energy use during production.**

Finally, competition for alternative gaseous fuels could be fierce, in Maryland and elsewhere. Other economic sectors—transportation, industrial processes, and electric generation—will compete with buildings for low-carbon alternative fuels. Alternative gaseous fuels will be important for certain of these non-building end-uses because they involve activities that are far more expensive to electrify or for which there are no available electric alternatives. In contrast, buildings are relatively low-cost to electrify and can take advantage of commercially available technologies for space and water heating and for other uses. As a policy matter, it may be important to reserve alternative gaseous fuels for activities that cannot easily be electrified.

27 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.

28 The NOx that is formed when natural gas, biogas, or SNG is combusted comes primarily from nitrogen and oxygen in the air interacting in the high-heat conditions of combustion. Exposure to NOx pollution can aggravate existing respiratory problems and potentially lead to development of respiratory disease. (NRDC 2020. A Pipe Dream or Climate Solution? The Opportunities and Limits of Biogas and Synthetic Gas to Replace Fossil Gas." Available at https://www.nrdc.org/sites/default/files/pipe-dream-climate-solution-bio-synthetic-gas-ib.pdf.)

SECTION 4

MODELING

To better understand the potential effects of the *MWG Policy Scenario*, we modeled the progress of Maryland's electrification under E3's *MWG Policy Scenario,* which we call "Sector Specific Electrification" (SSE). Using our Building Decarbonization Calculator (BDC), we modeled total GHG emissions, trends in gas consumption, and residential and commercial building stock by space heating type and space heating equipment sales under SSE. The model analyzed the turnover of residential and commercial space and water heating systems across Maryland and calculated the corresponding emissions impacts. Our BDC assumptions are detailed in Section 4.1.1, below.

Synapse then applied its Gas Rate Model (GRM) to the BDC modeling results to assess the financial implications for Maryland's three largest gas utilities through 2050. The GRM uses the utilities' historical data and the BDC modeling results to project SSE's impacts on rate base, revenues, and expenses for each of the utilities: Baltimore Gas and Electric (BGE), Washington Gas Light (WGL), and Columbia Gas of Maryland (Columbia or CMD). We also evaluated the residential customer rate impact of using alternative gaseous fuels to offset increasing portions of remaining gas system emissions, culminating in zero remaining fossil gas by 2045.

The BDC modeling, combined with the GRM results, ultimately sheds light on the *MWG Policy Scenario's* effects on gas utilities. It also assesses the scenario's implications for residential customer rates and the stranding of gas utility investments.

4.1. Building Decarbonization Calculator

4.1.1. Assumptions

The BDC uses Maryland-specific data on existing buildings from the U.S. Census Bureau's *American Community Survey,* along with the U.S. Energy Information Administration's *Residential Energy Consumption Survey* and *Commercial Buildings Energy Consumption Survey,* to develop estimates for the characteristics of Maryland's building space and water heating system stock. To determine the current heat pump market share of new installations, we analyzed recent annual increases in the number of homes heated primarily with electricity as reported by the *American Community Survey.*[29]

Residential building electrification target: Consistent with the *MWG Policy Scenario*, under our SSE scenario heat pumps are the sole source of heating in over 95 percent of residential buildings by 2050. To achieve this, we assume that all new construction is all-electric by the late 2020s. In existing buildings, this level of electrification is achieved through steady increases in

29 American Community Survey. 2019. *Table B25040: House Heating Fuel for Maryland, 5-year Estimates.* Available at: https://data.census.gov/cedsci/table?q=house%20heating%20fuel&tid=ACSDT5Y2020.B25040.

We assumed that gas heating will be phased out as **heating units are replaced at the end of their useful lives**.

heat pumps' share of the Maryland market. By 2030, over 95 percent of households that are replacing space heating equipment at the end of the equipment's useful life use heat pumps, increasing to 100 percent by 2035.[30]

Heat pump market share: Based on recent historical data from the *American Community Survey*, we assumed that the number of residential households heating with heat pumps increased by about 8,000 households between 2019 and 2020. We calculated that this level of annual increase implied a heat pump market share (i.e., the percent of space heating equipment sales that are heat pumps) of approximately 10 percent of new heating systems replacing retiring residential fossil fuel systems. We modeled residential heat pump adoption curves starting at these market share values in 2020, and then escalating toward the electrification target over time.[31] While there is no fixed date by which all buildings will be all-electric, the modeling is designed to convert the market to 100 percent heat pumps, such that gas heating will be phased out as heating units are replaced at the end of their useful lives.

Multi-family housing units: Throughout our analysis, we categorized all households in Maryland as being in the residential sector, even though large multifamily residential buildings may require different types of heat pump systems than single-family homes. We measure the sizes of heat pump systems by the number of households they serve. For example, one large heat pump system serving 100 apartments is modeled as 100 individual heat pump systems. Where we were able to break out residential results from total, we present the residential sector here. The results for the commercial sector are provided in Appendix B. Industrial sector gas consumption is not included in this report.

4.1.2. Results

For each year between 2020 and 2050, our modeling shows how SSE impacts the new space and water heating system installations, the total stock of operating space and water heating systems, and the resulting on-site GHG emissions. We discuss these results in the paragraphs below:

- Residential GHG emissions
- Residential gas consumption
- Residential building stock by space heating type and space heating equipment sales

Residential GHG emissions

Figure 3 shows total residential space and water heating emissions. Figure 3 does not account for using low- or zero-carbon gases to reduce emissions. Also, this figure does not include off-site GHG emissions, such as those resulting from the generation of electricity[32] or the upstream methane emissions from

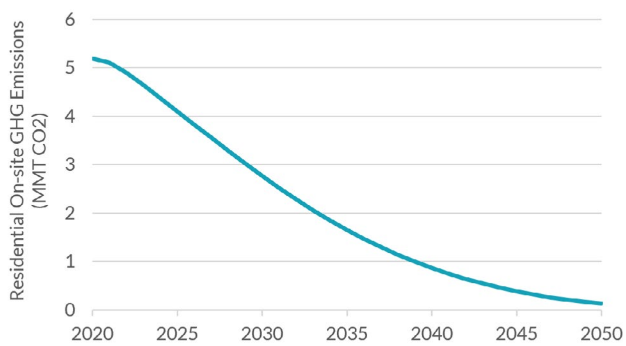
30 In commercial buildings, by 2050, 60 percent of gas-connected buildings switch to heat pumps as the sole source of heating and 40 percent of gas-connected buildings stay on gas for heating. Over 99 percent of all new construction is 100 percent electrified by 2035. Existing buildings with electric resistance heat convert to heat pumps by 2050 and existing buildings with heat pumps continue to use heat pumps.

31 Given that existing commercial buildings would have a harder time switching to heat pumps due to the complexity of their HVAC system configurations, we assumed initial commercial market shares equal to half of the historical residential sales rate. We assumed these market share rates to meet the residential and commercial building electrification targets, described above.

32 While increasing electricity consumption to power heat pumps will lead to some increase in electric generation emissions, that impact is beyond the scope of this report. The emissions increase will be mitigated by Maryland's Renewable Portfolio Standard, which requires 50 percent of electricity to come from renewable resources by 2030, as well as other future policies that may further decarbonize the power sector beyond 2030. Expanded demand-side management and demand response can also reduce electrification's impact on load and emissions.

leaks associated with production, distribution, and transmission of fossil or alternative gaseous fuels.

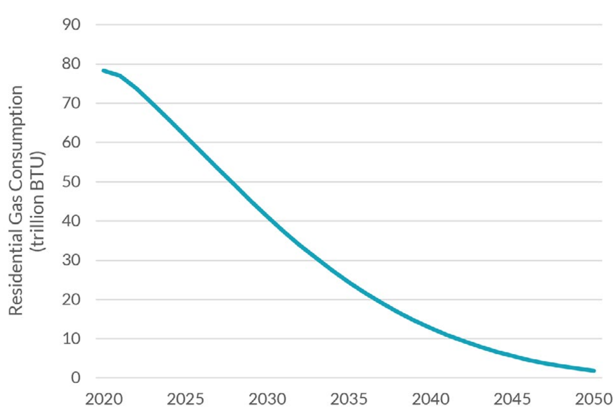
Figure 3. Residential on-site space and water heating GHG emissions, before accounting for use of low- or zero-carbon gas or off-site emissions



Gas consumption

Figure 4 shows SSE's impacts on residential space and water heating gas consumption. The corresponding commercial space and water heating gas consumption chart can be found in Appendix B. To fully decarbonize building energy consumption, remaining gas consumption will need to be displaced with low- and zero-emissions fuels.

Figure 4. Residential consumption of gas for space and water heating



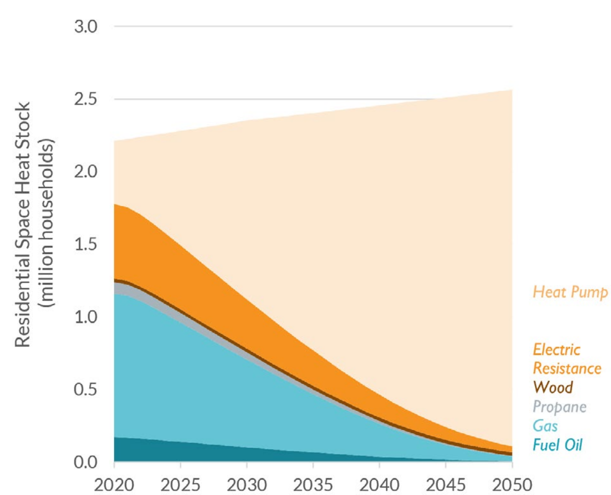
Space heating equipment stock and sales

In this section, we present charts that show the total stock and annual sales of space heating equipment under SSE. We focus on space heating equipment, because it is currently responsible for most on-site emissions from residential buildings.[33] The second largest source of on-site emissions from residential buildings is water heating, which represents a much smaller portion of current total emissions: For residential space and water heating equipment combined, space heating equipment accounts for 74 percent of on-site emissions and water heating equipment accounts for 26 percent of on-site emissions.

Water heating equipment similarly transitions toward heat pump technologies in our analysis but is not separately shown here for simplicity.

Figure 5 shows that SSE results in nearly all buildings, including 96 percent of homes, being fully heated with heat pumps by 2050. Fossil fuel space and water heating is almost entirely eliminated, resulting in the greatest emissions reductions.

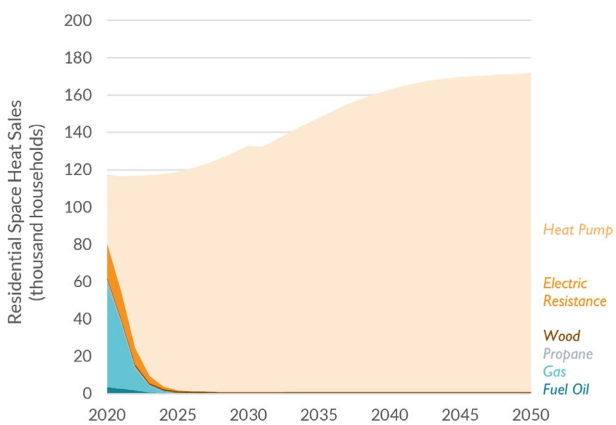
Figure 5. Residential building stock by space heating fuel and technology



33 In 2020, space and water heating equipment were responsible for most fossil gas use from residential buildings. Space and water heating equipment accounted for 91 percent of residential gas consumption, while the remaining 9 percent of gas consumption was attributable to cooking, clothes drying, and other end-uses that were not included in our modeling here. (U.S. Energy Information Administration. 2018. *Residential Energy Consumption Survey*. Available at: https://www.eia.gov/consumption/residential/.)

To achieve this level of electrification, residential space heating equipment sales almost entirely shift to heat pumps by the mid-2020s, as shown in Figure 6.

Figure 6. Residential space heating equipment sales[34]



As Figure 6 shows, gas heating equipment sales drop to near zero under this scenario, allowing for the almost complete removal of the gas system by 2050.[35]

Results for the commercial sector are provided in Appendix B.

4.2. Gas Rate Model

Applying the BDC results, we now model the financial impact on the gas utilities of electrifying the building heating stock.

The GRM allows Synapse to project gas utility rates based on different scenarios for utility investment, sales, and financial models. We use input data from annual utility reports to State regulators, alongside data from the Pipeline and Hazardous Materials Safety Administration[36] (for gas pipeline investment data) and rate cases[37] (such as depreciation and cost-of-service studies) to build a model of the past up to the present. The model tracks utility plant-in-service, depreciation, capital additions and retirements, operations and maintenance, and income taxes. It accounts for capital structure and changes in tax rates.

Looking forward from the present, the model allows us to test scenarios for different levels of investment and customer growth or decline, pipeline replacement programs, early retirements, stranded costs, and changes in depreciation rates. These cases can correspond to electrification, as assumed in the analysis here, or other decarbonization scenarios developed in the BDC. We have developed ways to map changes in customer numbers to changes in miles of pipeline in service and other aspects of capital assets.

The GRM must make assumptions about fuel prices. Here, as described below, we make assumptions for fossil fuel price and for alternative gaseous fuels. For alternative gaseous fuels, we use two fuel cost sensitivities—the Low AGF Price sensitivity and the High AGF Price sensitivity.

The following section details our assumptions for GRM inputs. The assumptions and projections are explained and analyzed in Sections 4.2.1 and 4.2.2, and Section 4.2.3 shows results of the modeling in terms of gas rate base per customer, rates, and bill impacts.

34 The slight decrease in new installations between 2030 and 2031 results from slower expected population growth (and consequently new housing construction) after 2030. (Weldon Cooper Center for Public Service. 2018. Observed and Total Population for the U.S. and the States, 2010-2040. *Demographics Research Group.* Available at: https://demographics.coopercenter.org/national-population-projections.)

35 Apart from replacing gas equipment, heat pumps will replace electric resistance heating stock. Replacing electric resistance heaters with more efficient heat pumps should reduce the electric load from those buildings and partially offset the increased electric load due to replacing the gas heating stock with heat pumps.

36 U.S. Department of Transportation: Pipeline and Hazardous Materials Safety Administration. August 2, 2021. Gas Distribution, Gas Gathering, Gas Transmission, Hazardous Liquids, Liquefied Natural Gas (LNG), and Underground Natural Gas Storage (UNGS) Annual Report Data. Available at: https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids.

37 Maryland Public Service Commission. 2021. *Case Search.* Available at: https://www.psc.state.md.us/.

4.2.1. Assumptions and Analysis

Alternative Gaseous Fuel Pricing: In the Low AGF Price sensitivity, the price of alternative gaseous fuel from 2021 to 2050 ranges from $14.37/MMBtu to $22.92/MMBtu, based on a 2020 ICF report for AltaGas and WGL (in 2020 dollars).[38] In the High AGF Price sensitivity, the price of alternative gaseous fuel from 2021 to 2050 is $69.03/MMBtu, based on a report by E3 on building decarbonization in Maryland (in 2020 dollars).[39] The price of fossil gas is kept the same in both the Low and High AGF Price sensitivities. From 2021 to 2050, the price of fossil gas ranges from $2.94/MMBtu to $4.05/MMBtu, based on the U.S. Energy Information Administration's *Annual Energy Outlook 2022* Henry Hub natural gas spot price projections (in 2020 dollars).[40]

Assumptions about the climate impact of renewable and low-carbon gases: Synapse modeled the SSE scenario such that no fossil gas remains in the system past 2045 and that remaining gas use is provided by alternative gaseous fuels. Our modeling assumes that renewable and low-carbon gases are emissions-free and that the buildings sector will be responsible for emissions reductions proportionate to its current emissions. With this assumption, BGE, WGL, and Columbia Gas's conversion to all low-carbon gases would support the State's compliance with the *Climate Solutions Now Act*. Recent studies show, however, that alternative gaseous fuels have higher emissions rates than previously assumed. For example, a 2022 analysis by Imperial College London found that leakage rates from RNG may be twice as high as previously thought.[41] Though beyond the scope of our work here, such leakage rates would reduce the benefits associated with low-carbon fuels and make *Climate Solutions Now Act* compliance more challenging.

Infrastructure replacement: We assume that the Maryland Public Service Commission continues to approve each utility's current investment approach, as allowed under PUA § 4-210 (the *Strategic Infrastructure Development and Enhancement*, or STRIDE, law) as though electrification and customer departures are not occurring. Under STRIDE, gas utilities currently run programs to replace leak-prone pipes (generally cast-iron and bare-steel pipes) with plastic pipes. The STRIDE program replaces both *mains* (larger pipes that serve many customers) and *services* (the building-specific pipes that connect the mains to customer buildings). STRIDE permits utilities accelerated recovery of the costs of gas infrastructure replacements through a surcharge on customer bills. The surcharge is capped at $2.00/month on residential bills but is reset with each base rate case, when STRIDE investments are moved into base rates.

> Recent studies show that **alternative gaseous fuels have higher emissions rates** than previously assumed.

38 ICF International. April 2020. *Opportunities for Evolving the Natural Gas Distribution Business to Support the District of Columbia's Climate Goals*. Available at: https://sustainability.wglholdings.com/wp-content/uploads/Technical-Study-Report-Opportunities-for-Evolving-the-Natural-Gas-Distribution-Business-to-Support-DCs-Climate-Goals-April-2020.pdf. AltaGas is the Canadian parent company of WGL.

39 Clark, T., D. Aas, C. Li, J. de Villier, M. Levine, J. Landsman. October 20, 2021. *Maryland Building Decarbonization Study*. Energy + Environmental Economics. Available at: https://mde.maryland.gov/programs/Air/ClimateChange/MCCC/Documents/MWG_Buildings%20Ad%20Hoc%20Group/E3%20Maryland%20Building%20Decarbonization%20Study%20-%20Final%20Report.pdf at 13 (showing a conservative alternative gaseous fuel price of $70/MMBtu (in 2021$), which we converted into 2020$ to arrive at the $69.03/MMBtu value).

40 U.S. Energy Information Administration. March 2022. *Annual Energy Outlook 2022: Table 13*. Available at: https://www.eia.gov/outlooks/aeo/data/browser/#/?id=13-AEO2022&region=0-0&cases=ref2022&start=2020&end=2050&f=A&linechart=ref2022-d011222a.31-13-AEO2022&ctype=linechart&sourcekey=0.

41 Imperial College London. 2022. "Biogas and biomethane supply chains leak twice as much methane as first thought." Phys.org. Available at https://phys.org/news/2022-06-biogas-biomethane-chains-leak-methane.html.

The assumption in the SSE scenario that utilities continue under their current investment approach means that the STRIDE program continues as planned and depreciation rates for utility investment continue to be set at today's levels, based on the expected engineering life of assets—as long as 70 years for new plastic pipes, for example. STRIDE cost calculations are imported from analysis by DHInfrastructure for OPC. Although STRIDE investments continue, the GRM scenario assumes that customers are electrifying and departing the system, consistent with the BDC scenario results.

Depreciation: Additionally, Synapse assumed that the utilities do not update their depreciation approach, despite the customer departures. Accordingly, we used recent depreciation studies from each utility to determine their 2020 depreciation rates and used these 2020 values for each specific utility asset from 2021 to 2050 (approximately 100 utility assets per utility).[42]

Capital additions: In the GRM, we calculated capital additions for distribution plant mains, services, meters, meter installations, and house regulators based on net customer additions, pipeline retirement approach, and historical pipe data. All other capital addition line items grow at 2 percent per year. This growth rate corresponds to the 2 percent inflation rate that we used throughout the model.[43]

Operations & Maintenance: We projected operations and maintenance expenses based on the total number of customers, the miles of pipeline, and the number of services for each future year. This projection also used the model-wide inflation rate of 2 percent.

Other costs: We held after-tax return on equity, cost of debt, debt fraction of capital, federal income tax, and state income tax constant at their 2020 levels.

Rate Class Allocations: To determine the rates by class (residential versus commercial and industrial customers), we separated out each utility's revenue requirement based on the proportion of residential customers to commercial and industrial customers and the proportion of residential gas sales to commercial and industrial gas sales. The BDC modeling provided the split between residential and commercial and industrial customers both for customer counts and gas sales. The calculation to determine rates by class also accounts for different drivers of utility revenue requirements. Specifically, some costs (like billing and customer service) scale with the number of customers, while other costs (like maintenance) are more closely related to the miles of mains or number of services. Our methodology is informed by common practice in cost allocation studies.

4.2.2. Customer and Sales Projections

Customers: Using customer projections from the heating stock results of the BDC modeling, we determined that more customers leave the natural gas system than are added to the gas system in each year of the modeling, starting in 2021. Total annual customer additions decrease to zero by 2038 in BGE, by 2037 in WGL, and by 2033 in Columbia. By 2050, the total customers left on each of the three utility systems is just 5 to 7 percent of their total 2020 number of customers.

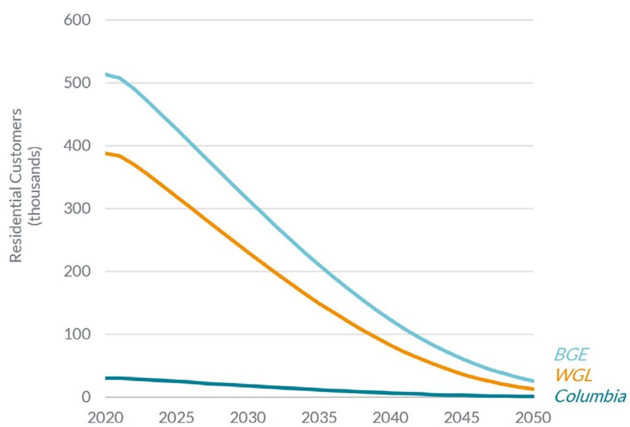
42 DHInfrastructure used total distribution, transmission, and composite non-STRIDE depreciation rates and held the 2022 values constant throughout its analysis. DHInfrastructure did not break out distribution, transmission, and depreciation rate projections by specific utility asset, as Synapse did. The difference between the Synapse and DHInfrastructure depreciation methodologies reflects the difference in granularity needed for each model and the overall projection methodology for each analysis. Relative to DHInfrastructure's analysis, Synapse tracked a greater number of individual data points to allow consideration of alternative futures.

43 In comparison, DHInfrastructure assumed that total non-STRIDE capital expenditures stay constant at their 2022 values and do not increase with inflation. Synapse broke out the non-STRIDE capital expenditure projections by utility asset or utility asset grouping. Synapse further used a separate, more detailed methodology for certain capital additions, preventing us from using just one set rate of change for all capital additions. Since DHInfrastructure was tracking fewer data points, holding the non-STRIDE capital expenditures constant was sufficient to effectively project the results of a status quo approach.

By 2050, the total customers left on each of the three utility systems is just 5 to 7 percent of their total 2020 number of customers.

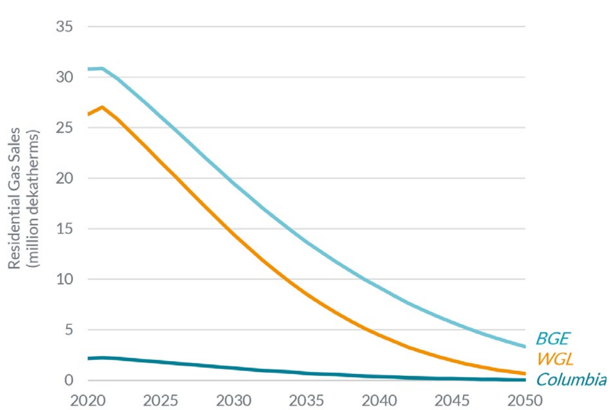
Figure 7 shows detailed residential customer projections by utility.

Figure 7. Residential customers by utility



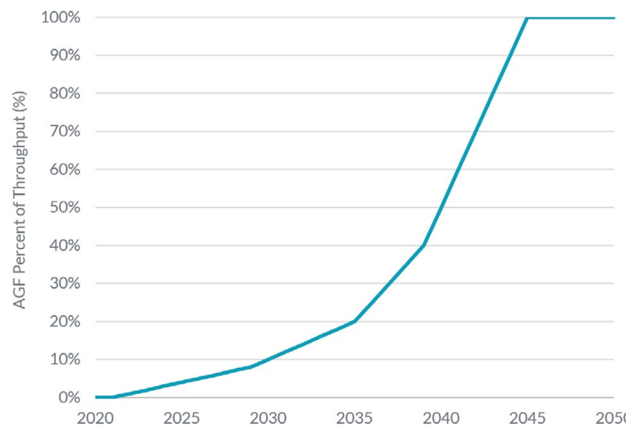
Sales. Using BDC heating stock results and historical utility sales, we determined total gas sales per utility. Our projection shows that total volumetric gas sales decrease from 2020 to 2050, by 89 percent for BGE, 90 percent for WGL, and 84 percent for Columbia. Figure 8 shows residential volumetric gas sales by utility.

Figure 8. Residential gas sales by utility



To meet Maryland's climate goals, all remaining gas throughput in the pipeline system is alternative gaseous fuels by 2045. This is shown in Figure 9.

Figure 9. SSE alternative gaseous fuels percent of throughput



4.2.3. Utility-Specific Modeling Results

Rate base per customer

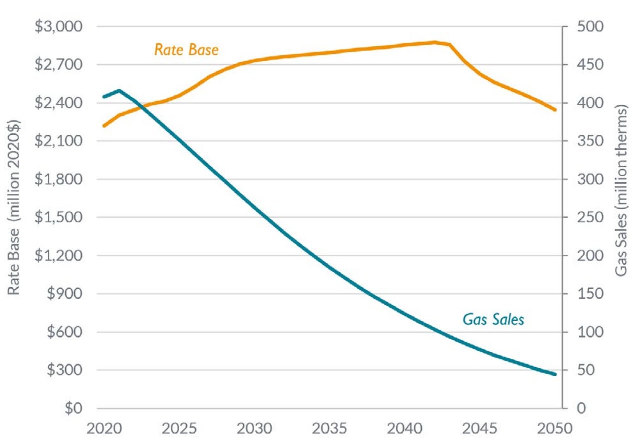
Rate base is the total value of the original cost of assets used and maintained by a utility less accumulated depreciation. Rate base is an identifiable, yet changing, number that has been approved in a regulatory proceeding—generally a rate case in which regulators approve a utility's capital expenditures. The amount of rate base is the cumulation of a utility's capital spending, paid for by customers, and is multiplied by the utility's rate of return (the cost of its debt and equity) to calculate the utility return on its investments. Customers pay down rate base when they pay the utility's depreciation expense that is reflected in the rates on their bills.

To keep rate base (and therefore rates) constant with gas sales continuing at the same level, a utility's approved spending on new capital assets must not exceed the pace at which its existing assets are retired, as customers pay for them through depreciation expense. Rate base—and rates—must increase when regulators approve utilities' capital expenditures (e.g., to replace old infrastructure and for system expansion) faster than existing assets are retired. And if sales are declining, rates must be increased even further to cover the fixed original costs of a utility's previous and ongoing approved capital expenditures. In other words, if utilities invest in pipeline infrastructure faster than existing assets are depreciated and despite decreasing numbers of customers and sales, they will seek substantial rate increases to recover the fixed costs of their rate bases.

Figures 10 through 12 illustrate declines in customers and sales. The figures show that with electrification, the utility's rate base becomes bigger and bigger relative to the utility's fuel throughput (or sales). This drives substantial increases in the utility's rates (the charges per unit measured in a therm of gas throughput) so that the utility can recover its rate-base-related costs across its reduced sales. Rate increases, in turn, will further drive customers off the gas system. **As high levels of customers abandon the gas system over a short period of time, the utility will be forced to strand assets.**

As shown in Figure 10, BGE's STRIDE program increases the utility's rate base and keeps it at roughly that level through the early 2040s. After the completion of its current STRIDE program, rate base falls slightly, assuming customers continue to pay the utility's depreciation expense.

Figure 10. BGE rate base, in real $2020 (left axis) and gas sales (right axis), in the SSE scenario



WGL has a smaller remaining STRIDE program, projected to end in the mid-2030s. Rate base starts to decline gradually around 2028 when annual STRIDE costs decrease about 55 percent compared to the previous year; it decreases faster in 2036 when its current STRIDE program ends, as shown in Figure 11.

Figure 11. WGL rate base, in real $2020 (left axis) and gas sales (right axis), in the SSE scenario

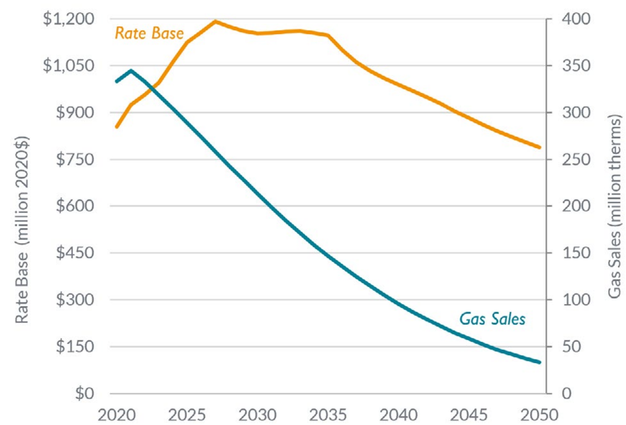
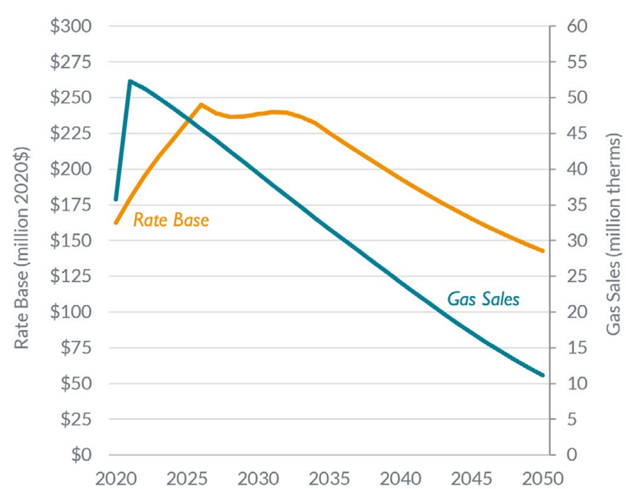


Figure 12 shows that Columbia Gas's rate base begins to flatten out and eventually decline after 2026, when its current STRIDE program ends.

Figure 12. Columbia Gas rate base, in real $2020 (left axis) and gas sales (right axis), in the SSE scenario



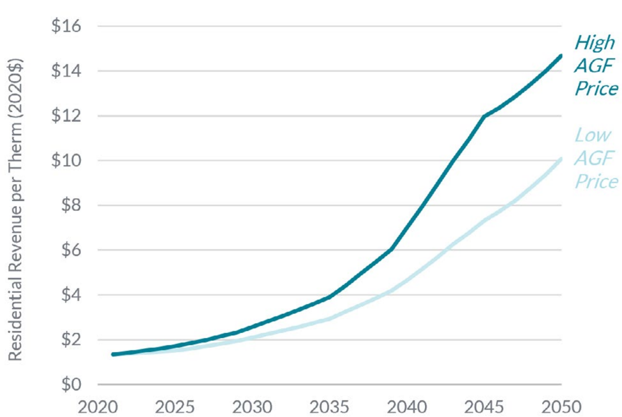
Rates

We approximate utility rates under SSE by taking the utility's annual revenue requirement (including fuel costs, return on rate base, and depreciation and operating expenses) and dividing by the projected amount of gas sold to customers.

We modeled two fuel cost sensitivities to determine the range of potential customer rates. The Low AGF Price ranges from $14.37 per MMBtu to $22.92 per MMBtu and the High AGF Price is set at $69.03 per MMBtu (all in $2020). From 2020 to 2050, utility rate base increases in the near term and stays relatively high (as seen above in Figures 10 through 12). Due to electrification, however, the total therms of gas throughput decreases. At the same time, fuel costs rise as fossil gas is replaced with alternative gaseous fuels. As a result, the revenue the utility must receive per therm sold—i.e., customer rates—must rise for the utility to recover its costs. The effect on customer rates—the required revenue per therm—is illustrated in Figures 13 through 15. The results show that **sector-specific electrification will lead to substantial increases in gas rates**.

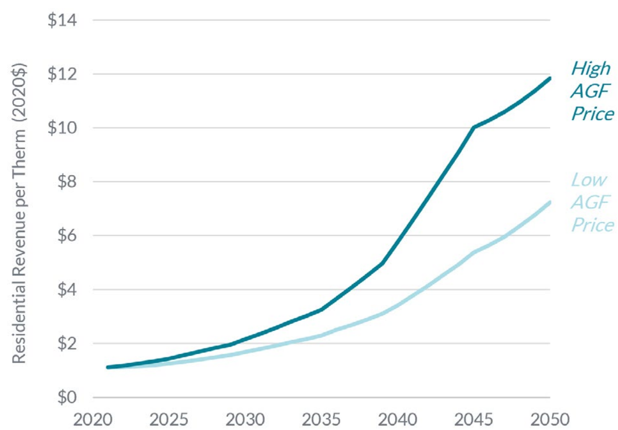
For BGE, our analysis shows that rates increase from $1.34 per therm in 2021 to $2.94 per therm in 2035 and $10.06 per therm by 2050 under the Low AGF Price scenario. In the High AGF Price scenario, the rates increase from $1.34 per therm in 2021 to $3.90 per therm in 2035 and $14.68 per therm in 2050.

Figure 13. BGE residential gas rates



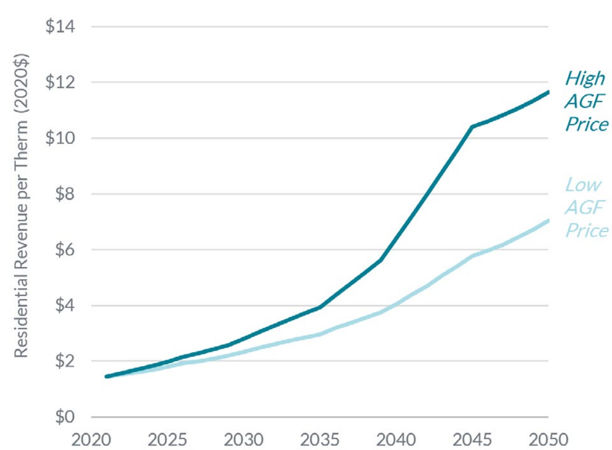
For WGL, our analysis shows that rates increase from $1.11 per therm in 2021 to $2.30 per therm in 2035 and $7.23 per therm by 2050 under the Low AGF Price scenario. Under the High AGF Price scenario, rates increase from $1.11 per therm in 2021 to $3.26 per therm in 2035 and $11.85 per therm in 2050.

Figure 14. WGL residential gas rates



For CMD, our analysis shows that rates increase from $1.44 per therm in 2021 to $2.97 in 2035 and $7.03 per therm by 2050 under the Low AGF Price scenario. In the High AGF Price scenario, rates increase from $1.44 per therm in 2021 to $3.93 per therm in 2035 and $11.65 per therm in 2050.

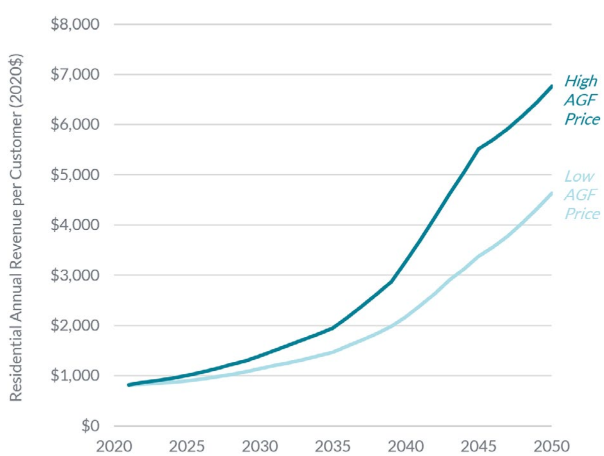
Figure 15. Columbia residential gas rates



Bill impacts of rate increases

Figures 16 through 18 show the annual energy-related operating cost of an average home for space and water heating end-uses under the SSE scenario for BGE.[44] Figure 16 shows the calculation for BGE. In the SSE scenario, building operating costs for residential customers staying on the gas system increase considerably by 2050, from $820 per year in 2021 to $1,464 per year in 2035 and $4,634 per year in 2050 under the Low AGF Price scenario. In the High AGF Price scenario, building operating costs for residential customers increase from $820 per year in 2021 to $1,944 per year in 2035 and $6,759 per year in 2050.

Figure 16. BGE residential building total gas costs (Low and High AGF Price)



As seen in Figure 17, WGL residential building operating costs increase from $780 per year in 2021 to $1,315 per year in 2035 and $3,827 per year in 2050 under the Low AGF Price scenario. In the High AGF Price scenario, building operating costs for residential customers increase from $780 per year in 2021 to $1,868 per year in 2035 and $6,270 per year in 2050.

Figure 17. WGL residential building total gas costs (Low and High AGF Price)

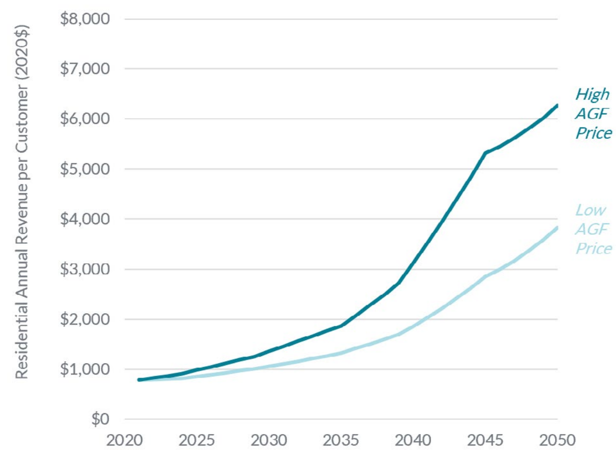
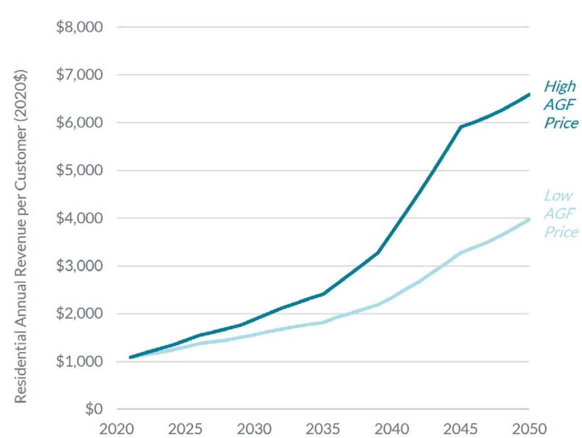


Figure 18 shows residential building operating costs for Columbia Gas. Costs rise from $1,086 per year in 2021 to $1,818 per year in 2035 and $3,979 per year in 2050 under the Low AGF Price scenario. In the High AGF Price scenario, building operating costs for residential customers increase from $1,086 per year in 2021 to $2,408 per year in 2035 and $6,591 per year in 2050.

Figure 18. Columbia residential building total gas costs (Low and High AGF Price)



44 These figures include the cost of fuel in addition to delivery costs.

The following tables provide a summary of the results of our modelling as shown in Figures 13 through 18 and described above.

2035 and 2050 range of residential rate impact depending on cost of alternative gaseous fuels

Rates ($2020/therm)

	2021	2035 AGF range	2050 AGF range
BGE	1.34	2.94 to 3.90	10.06 to 14.68
WGL	1.11	2.3 to 3.26	7.23 to 11.85
CMD	1.44	2.97 to 3.93	7.03 to 11.65

2035 and 2050 range of residential bill impact depending on cost of alternative gaseous fuels

Annual Bill (2020$)

	2021	2035 AGF range	2050 AGF range
BGE	$820	$1,464 to $1,944	$4,634 to $6,759
WGL	$780	$1,315 to $1,868	$3,827 to $6,270
CMD	$1,086	$1,818 to $2,408	$3,979 to $6,591

Importantly, Figures 13 through 18 provide the output for SSE modeling based on the *MWG Policy Scenario* that has heat pumps as the sole source of heating in over 95 percent of residential buildings by 2050. Our modeling achieves the 95 percent goal by gradually increasing heat pumps' share of the Maryland market from 2021 to 2050. As gas rates rise, however, customers will become increasingly likely to electrify their homes to avoid high gas rates. Thus, customer migration away from gas could be faster than the projections we used in modeling SSE. This increase in customer departures would further increase gas rates and perpetuate the cycle of customer departures and increasing rates for customers who remain on the gas system.

Customer migration away from gas could be faster than the projections used.

4.3. Implications of Analysis

The rapid decline in gas sales, together with a flat or increasing rate base (as shown in Figures 10 through 12), cause the dramatic increases in customer rates and bills found in our modeling of SSE in Section 4.2.3. While the overall impact on customer energy bills—across both electric and gas utilities—is beyond the scope of our analysis, our modeling confirms E3's conclusion that *gas* rates for residential customers remaining on the gas system will increase significantly as the State acts to meet its climate goals if the utilities do not alter their practices as a result of customer departures.[45]

Our analysis further holds important implications for the fixed costs that remain in the utilities' rate bases for decades into the future due to ongoing utility capital spending. Electrification will happen gradually as the building stock turns over. Gas rate increases due to electrification will also be gradual. But at some point, it could prove difficult—if not impossible—for gas rates to increase to the levels necessary for gas utilities to recover their fixed rate base costs and remain economically viable. Customers will electrify to avoid the high gas rates, and customers without alternatives nevertheless may not be able to afford continued gas service. If and when this plays out, the utilities will have substantial unrecovered and uneconomic assets remaining in rate base and on their books.

We note that such outcomes can be mitigated. If utilities adapt to electrification, they will be able to update their spending practices to lessen their revenue requirements to slow customer rate increases. In doing so, the utilities can mitigate their stranded assets, and customers who are unable to electrify in the near term will not see costs rise as rapidly.

45 MCCC, *Building Energy Transition Plan: A Roadmap for Decarbonizing the Residential and Commercial Building Sectors in Maryland*, at p. 14.

APPENDIX A

GLOSSARY AND ABBREVIATIONS

Term	Definition	Source
Alternative Gaseous Fuels	Non-conventional fuels such as hydrogen and various forms of natural gas including renewable, synthetic, and biomethane.	Environmental Protection Agency. "Alternative Fuels." Oct. 4, 2021. *Renewable Fuel Standard Program*. Available at: https://www.epa.gov/renewable-fuel-standard-program/alternative-fuels.
Biomethane	Pipeline-quality natural gas substitute produced by purifying biogas, a methane-rich gas produced from organic materials (also known as Renewable Natural Gas).	Natural Gas Vehicles for America. "The Potential of Renewable Natural Gas," 7 Jan. 2009, https://afdc.energy.gov/files/pdfs/biomethane_4.pdf. Accessed 6 July 2022.
Depreciation	The loss in service value not restored by current maintenance and incurred in connection with the consumption or prospective retirement of property in the course of service from causes against which the carrier is not protected by insurance, and the effect of which can be forecast with a reasonable approach to accuracy.	"18 CFR Ch. I, Pt. 352." *Code of Federal Regulations*. Available from: https://www.ferc.gov/sites/default/files/2020-06/18cfr352.pdf. Accessed 6 July 2022.
Fugitive Emissions	Unintended leaks of gas from the processing, transmission, and/or transportation of fossil fuels.	Glossary - U.S. Energy Information Administration (EIA), https://www.eia.gov/tools/glossary/.
Hydrogen (by type)	**Green hydrogen** is made by using clean electricity from surplus renewable energy sources, such as solar or wind power, to electrolyze water. **Blue hydrogen** is created from natural gas using steam methane reformation; the process captures and stores the emitted carbon dioxide underground. **Gray hydrogen** is created from natural gas using steam methane reformation but without capturing the greenhouse gases made in the process.	National Grid. "The Hydrogen Colour Spectrum." Available at: https://www.nationalgrid.com/stories/energy-explained/hydrogen-colour-spectrum.
Rate Base	The net investment of a utility in property that is used to serve the public; this includes the original cost net of depreciation, adjusted by working capital, deferred taxes, and various regulatory assets—the term is often misused to describe the utility revenue requirement.	Lazar, J. (2016). Electricity Regulation in the US: A Guide. Second Edition. Montpelier, VT: The Regulatory Assistance Project. Retrieved from https://www.raponline.org/knowledge-center/electricity-regulation-in-the-us-a-guide-2/.

Term	Definition	Source
Recovered Methane	Methane gas that is captured from landfills, wastewater facilities, and farmland through the use of anaerobic digesters.	Environmental Protection Agency. "Learning About Biogas Recovery." *EPA*. Available at: https://www.epa.gov/agstar/learning-about-biogas-recovery.
Return on Equity	The rate of earnings realized by a utility on its shareholders' assets, calculated by dividing the earnings available for dividends by the equity portion of the rate base.	New York State Public Service Commission. "Glossary of Terms Used by Utilities and Their Regulators." Available at: https://www.dps.ny.gov/glossary.html.
Revenue Requirement	The annual revenues that the utility is entitled to collect (as modified by adjustment clauses). It is the sum of operation and maintenance expenses, depreciation, taxes, and a return on rate base. In most contexts, revenue requirement and cost of service are synonymous.	Lazar, J. (2016). Electricity Regulation in the US: A Guide. Second Edition. Montpelier, VT: The Regulatory Assistance Project. Retrieved from https://www.raponline.org/knowledge-center/electricity-regulation-in-the-us-a-guide-2/.
Stranded Assets	Assets that have suffered from unanticipated or premature write-downs, devaluation or conversion to liabilities.	Lloyd's. 2017."Stranded Assets." Available at: https://www.lloyds.com/strandedassets.
Synthetic Natural Gas	A manufactured product, chemically similar in most respects to natural gas, resulting from the conversion or reforming of hydrocarbons that may easily be substituted for or interchanged with pipeline-quality natural gas.	U.S. Energy Information Administration. *Glossary - U.S. Energy Information Administration (EIA)*, https://www.eia.gov/tools/glossary/.

Abbreviation	Term
AGF	alternative gaseous fuels
BDC	Building Decarbonization Calculator
BGE	Baltimore Gas and Electric
C&I	commercial and industrial
GHG	greenhouse gas
GRM	Gas rate model
MWG	Mitigation Work Group
OPC	Office of People's Counsel
STRIDE	Strategic Infrastructure Development and Enhancement program
SSE	Sector Specific Electrification
WGL	Washington Gas Light

APPENDIX B

DETAILED COMMERCIAL RESULTS

Figure B-1. Commercial on-site space and water heating GHG emissions, before accounting for use of low- or zero-carbon gas or off-site emissions

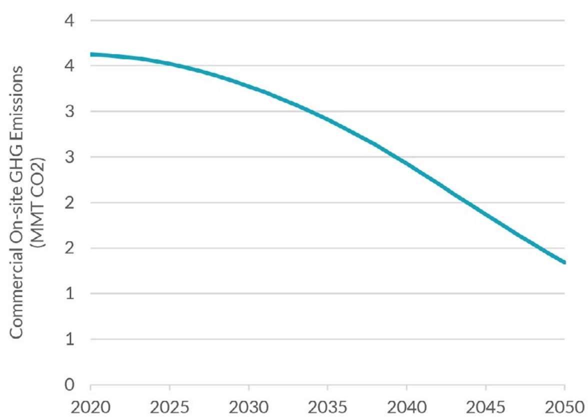


Figure B-2. Commercial gas consumption

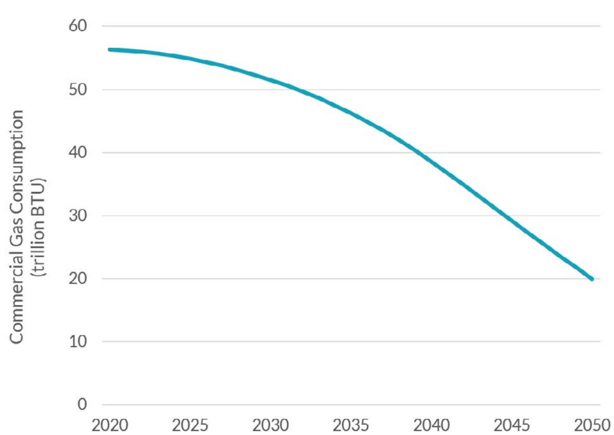


Figure B-3. Commercial building stock by space heating fuel and technology

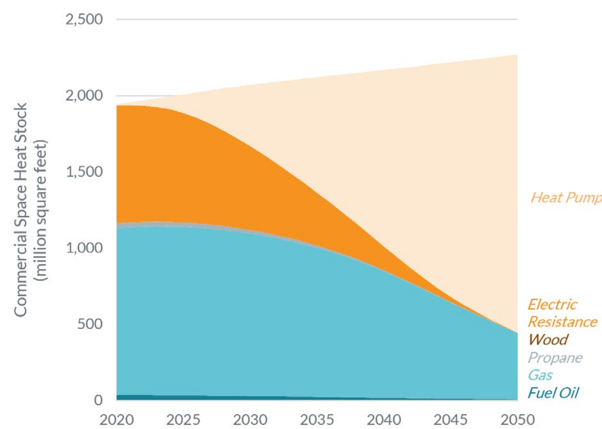


Figure B-4. Commercial and industrial customers by utility

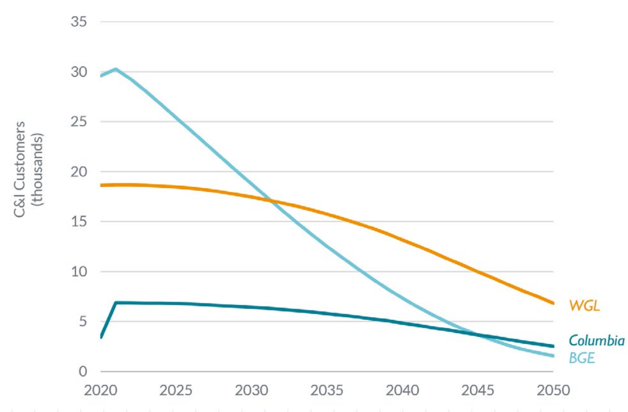


Exhibit ASH-3
Appendix D

B-5. Commercial and industrial gas sales by utility

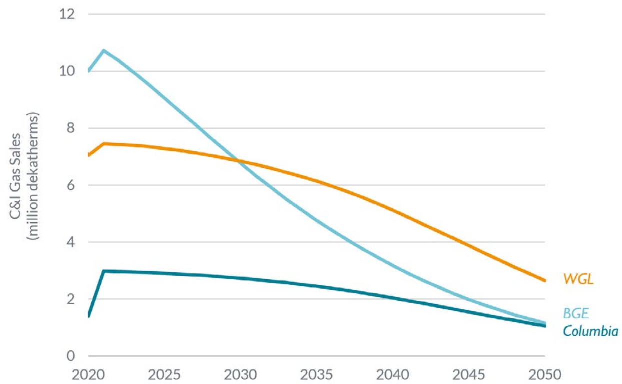


Figure B-6. BGE commercial and industrial building total gas costs (Low and High AGF Price)

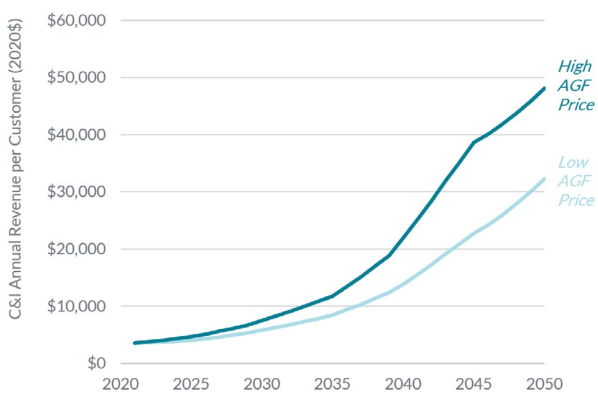


Figure B-7. WGL commercial and industrial building total gas costs (Low and High AGF Price)

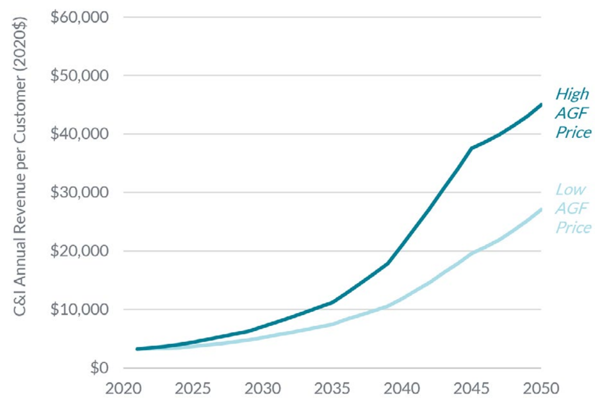
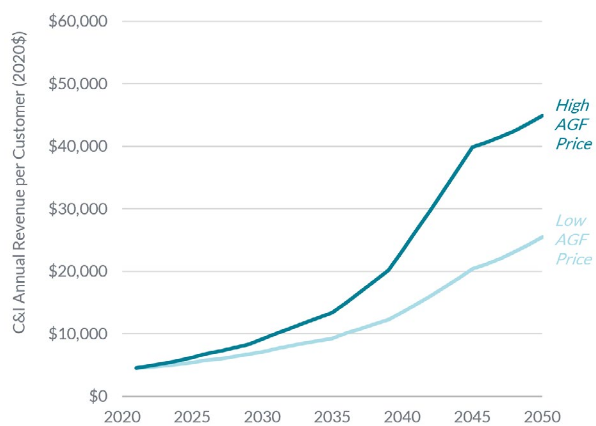


Figure B-8. Columbia Gas commercial and industrial building total gas costs (Low and High AGF Price)



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Appendix E

OPC GAS SPENDING REPORT

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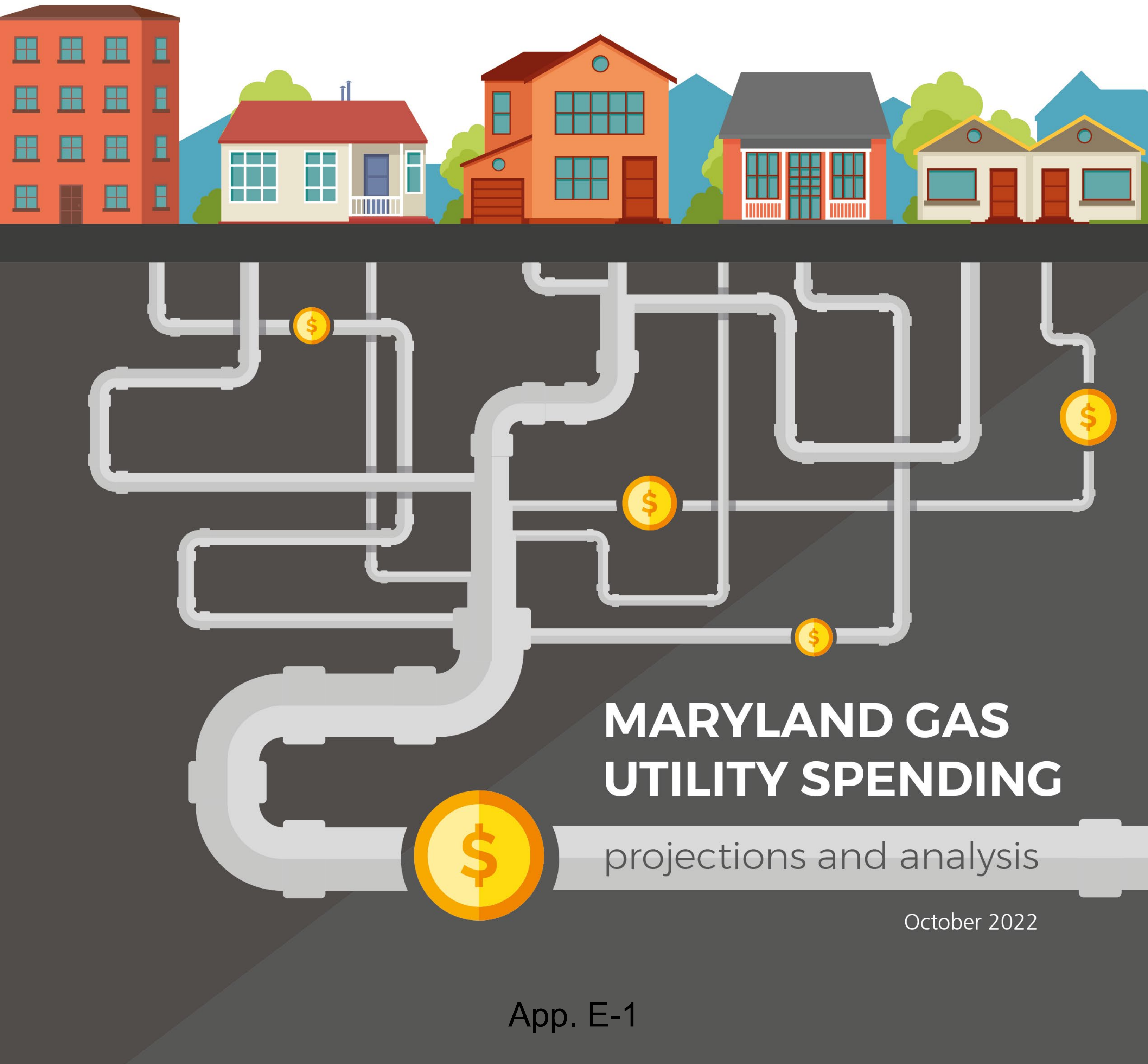
State of Maryland



MARYLAND GAS UTILITY SPENDING

projections and analysis

October 2022

DEAR READERS

Policymakers and customers are making long-term decisions about the future of natural gas. Policymakers are deciding what role—if any—gas will play in the State's effort to meet its climate goals. And every day, customers are deciding what types of appliances will heat their homes, water, and stoves for the next two decades. Making the right decisions depends on access to good information. To make decisions about natural gas, distribution system costs and commodity costs are the two key components of customer gas bills that need to be understood.

This report focuses on the cost impacts of the *distribution system spending*—costs that customers pay utilities for delivering gas—with less emphasis on gas *commodity prices* (which currently are more than double what they were 18 months ago). This focus is appropriate because—unlike gas commodity costs—the cost impact of gas utility distribution system spending is subject to State policies that can control and mitigate those costs.

It should be easy to identify how much gas companies with government-granted franchise monopolies plan to spend on delivering gas; after all, their captive customers pay for it.

But it is not easy.

Utility spending is siloed into different programs and categories of costs, and it is generally subject to regulatory oversight only *after* or shortly before customer dollars are spent. Utilities are also not generally required to publicly disclose their long-term spending plans—much less engage in any sort of transparent comprehensive planning process that invites public input.

This failure of transparency represents a major regulatory gap that leaves customers and policymakers alike in the dark on how utilities will spend billions of customer dollars in the coming decades.

To identify just how many customer dollars the gas utilities are on track to spend, our office engaged DHInfrastructure to analyze utility filings and relevant Public Service Commission orders, and make reasonable assumptions to project future gas utility spending, and assess what that spending means for residential utility customers. We directed DHInfrastructure to make calculations based on business-as-usual spending, without accounting for spending reductions resulting from State climate policy or otherwise. This business-as-usual assessment is important because the utilities are not proposing to scale back any of their spending; in fact, quite the opposite—Maryland's gas utilities are accelerating their capital spending and pushing

This report shows that without significant regulatory action, gas utility customers will see substantial and continuing increases in their gas bills in the coming years to pay for accelerating capital spending.

back against efforts to slow it down. This report shows that without significant regulatory action, gas utility customers will see substantial and continuing increases in their gas bills in the coming years to pay for accelerating capital spending. This problem—creating continuing, long-term, significant upward pressure on gas bills—predates and exacerbates the very large increases in gas bills, during 2022 and anticipated for the winter of 2022/3, due to the dramatic recent increases in the gas commodity portion of gas utility bills.

While the projections contained in the following report represent business-as-usual, they are *conservative* about how high gas utility rates may go. **The utilities' spending and the customer-bill impacts of that spending, combined with gas commodity prices, could be significantly larger than the report shows for at least three reasons.**

1. **Some degree of electrification appears inevitable.** This means the amount of gas moving through the pipes will decline as customers replace their appliances and heating systems with all-electric systems. Since utilities' spending will be recovered among fewer customers and sales, rates for remaining gas customers will increase *more* than reflected in this report.

2. **The pace of gas investments has accelerated in recent years.** But because we do not think the current growth rate can be maintained, as the report explains at Section 2.2, DHInfrastructure modelled slower growth.

3. **The report uses conservative gas commodity prices.** It uses a commodity cost based on the average February gas commodity price for the last five years, which is less than $0.50/therm for each utility. The model thus shows commodity prices *significantly lower* than gas commodity prices are today. For example, Washington Gas Light's commodity price for residential and general service as we head to press (in September 2022), is $ 1.1314/therm, more than double the commodity price we model.

For these three reasons, our projections on spending and rates are conservative; actual gas utility spending and gas utility customer bills could be significantly higher than these projections.

We hope this report helps educate stakeholders and policymakers on the significance of unmitigated gas utility spending for Maryland's gas utility customers.

David S. Lapp
People's Counsel

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SECTION ONE

EXECUTIVE SUMMARY

Maryland's Office of People's Counsel (OPC) engaged DHInfrastructure to prepare various projections and analyses on the current trajectory of gas infrastructure investments and corresponding rate impacts of the projected level of investment at the State's three largest gas distribution companies: Baltimore Gas and Electric (BGE), Washington Gas Light (WGL), and Columbia Gas of Maryland (CMD). Using conservative assumptions, the report's findings show that a continuation of the utilities' spending practices means significantly higher costs for gas delivery, resulting in higher bills for most Maryland residential customers.

This report discusses the approach and assumptions used to develop the projections, presents the results of the projections, and then includes a brief written analysis on the results. It also reports on recent historical trends in natural gas distribution and commodity rates based on actual data. Below we summarize the findings.

Maryland's three largest gas companies are currently undertaking massive capital investment programs through STRIDE...

In 2013, the Maryland General Assembly enacted the Strategic Infrastructure Development and Enhancement (STRIDE) law, section 4-210 of the Public Utilities Article, *Annotated Code of Maryland* (section 4-210 or STRIDE statute). The STRIDE statute authorizes Maryland gas utility companies to file and the Public Service Commission to approve infrastructure investment plans and corresponding project cost-recovery schedules.

The statute requires that companies receive PSC approval of their STRIDE plans on five-year cycles. BGE, WGL, and CMD all requested and received approval for initial five-year plans in 2013 and are currently on their second five-year plans that run from 2019 to 2023. Table 1.1 below shows that the utilities complete their STRIDE plans on file with the PSC at different stages, with BGE's extending to its sixth five-year plan running through 2043. This timeline indicates that for some Maryland utilities, STRIDE is still only in the early stages. Based on each of the three company's STRIDE plans, we find that there is upward of $4,764 million remaining to be invested through STRIDE alone over the next 20-plus years.

Table 1.1: STRIDE Investment Plans of Maryland's Three Largest Gas Utilities (million $)

	BGE	WGL	CMD	THREE-COMPANY TOTAL
Total spent STRIDE I (actual 2014-2018)	$522.73	$218.50	$66.19	
Actual/Authorized budget STRIDE II (2019-2023)	$827.28	$363.07	$87.22	
Estimated STRIDE III (2024-2028) budget	$693.39	$439.44	$57.38	
Estimated STRIDE IV (2029-2033) budget	$803.83	$194.82	$0	
Estimated STRIDE V (2034-2038) budget	$931.86	$86.35	$0	
Estimated STRIDE VI (2039-2043) budget	$1,034.48	$0	$0	
All-time Total STRIDE I – VI	$4,813.58	$1,302.19	$210.79	$6,326 million
Future Total = Remaining STRIDE II + STRIDE III to STRIDE VI	$3,793.70	$877.71	$92.94	$4,764 million

Totals in figures and tables may not add up precisely due to rounding.

...and these companies will continue to make other investments outside of STRIDE well into the future.

Maryland gas utilities are also continuing to invest in other capital asset categories not covered by STRIDE. Our conservative estimate is that if the companies spend on non-STRIDE activities at current levels, there will be another $29,749 million investments outside of STRIDE between 2022 and 2100. As shown in Table 1.2, the combined STRIDE and non-STRIDE investments are $34,513 million.

Our conservative estimate is that if the companies spend on non-STRIDE activities at current levels, there will be **another $29,749 million in investments outside of STRIDE** between 2022 and 2100.

Table 1.2: Maryland Gas Capital Expenditure (CAPEX) Investments, 2022-2100 (million $)

	STRIDE (2022-2043)	Non-STRIDE (2022-2043)	Non-STRIDE (2044-2100)	Total
BGE	$3,793.70	$5,799.14	$15,005.96	$24,598.80
CMD	$92.95	$235.31	$609.67	$937.93
WGL	$877.71	$2,255.34	$5,843.39	$8,976.45
Total	$4,764.36	$8,289.79	$21,459.02	$34,513.18

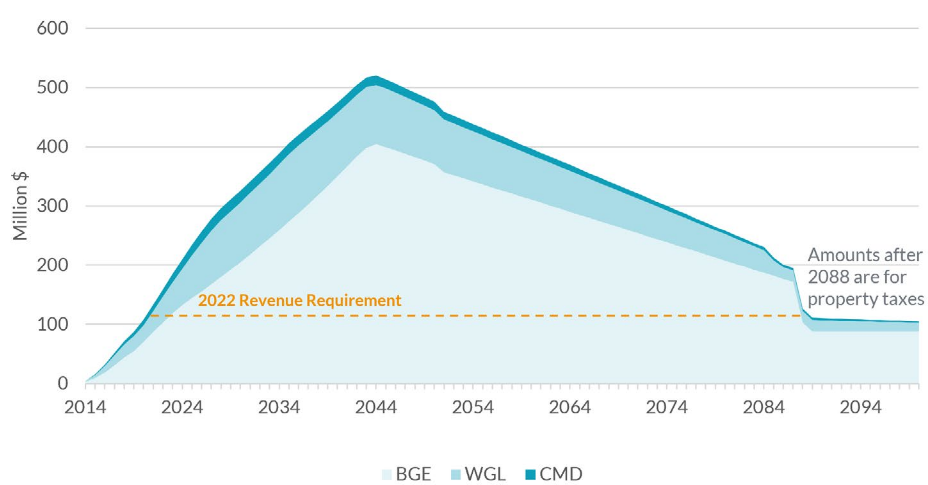
If this pace of investment continues, the capital component of the revenue requirements collected from customers will more than double over the next 25 years...

To understand the impact of our capital investment projections on gas utility rates, we first developed a revenue requirement model that estimated the capital-related components of the revenue requirement. Roughly speaking, the "revenue requirement" consists of the utility's total revenue needs; the annual revenue requirement is divided by anticipated sales to arrive at the per therm rate that customers pay. (The term is defined in the glossary at the end of this report.) Importantly for customers, the capital investment portion of the revenue requirement accounts for only the costs related to the utilities' spending on capital expenditures such as depreciation, return on equity, and property taxes; it does not include (a) the utilities' operational costs nor (b) gas commodity costs that customers pay in their bills.

All utility capital investment enters the utility's rate base. The rate base is the undepreciated value of utility plant-in-service, composed of the utility's prior capital investments less accumulated depreciation. It determines the capital investment-related portion of the utility's revenue requirement (i.e., the annual revenues the utility is authorized to recover from its customers through its rates). Capital investments are recovered from the utility's customers over time—through a depreciation charge, which is often more than 30 years, and as long as 70 years, depending on the expected life of the asset—until it is fully depreciated. Customers pay both a "return of" investments, in the form of depreciation, and a "return on" investments equal to the utility's weighted average cost of capital (WACC), which is expressed as a percentage multiplied by the utility's rate base.[1]

The pyramid figure below was made using the revenue requirement model. What makes this figure informative is that it provides context for where the utilities currently are in their overall STRIDE plans. As identified by the orange dotted line, the combined

Figure 1.1: STRIDE Annual Revenue Requirement Pyramid



If STRIDE plans continue as currently constituted, **customers could eventually be paying more than three times** for STRIDE investments than the amounts they are spending today.

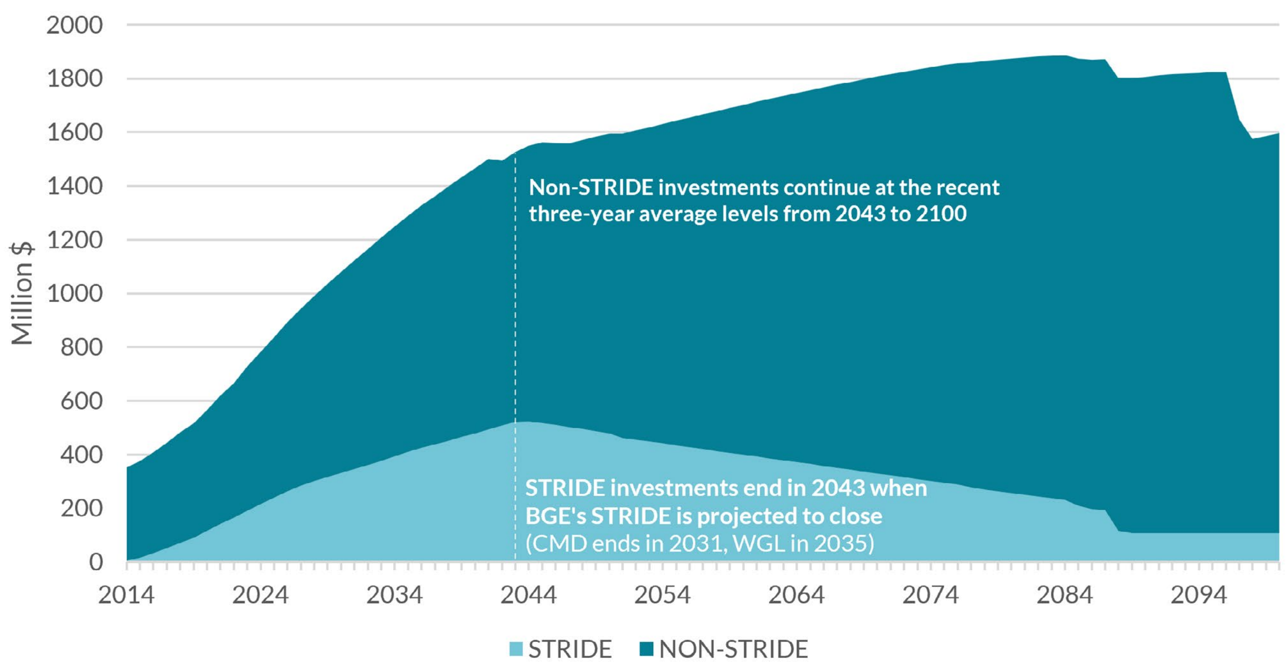
1 The capital-related revenue requirement also includes a tax "gross-up," including the federal and state income taxes owed if the utility earns its WACC, the property taxes related to the capital investment, and certain other miscellaneous fees.

2022 capital investment component of the utilities' revenue requirement of approximately $160 million across the three STRIDE programs represents a fraction—30 percent—of the $524.1 million peak in STRIDE revenue requirements that we project for 2044. In other words, if STRIDE plans continue as currently constituted, then Maryland customers could eventually be paying more than **three times** for STRIDE investments than the amounts customers are paying today.

The STRIDE annual revenue requirement amounts (Figure 1.1) represent only a fraction of the total aggregate capital investment-related revenue requirements customers will need to pay to cover utility capital investments made over the next 80 years. The STRIDE and non-STRIDE capital additions we project through 2100 would result in an annual capital revenue requirement for the three utilities exceeding $1.5 billion by 2043, or **2.3 times** the combined $667 million in capital investment-related revenue requirements customers are paying through rates in 2022. Put another way, customers today are responsible for paying less than half of the capital investment-related costs that customers will be responsible for in 2043. Figure 1.2 provides both a comparison of the combined non-STRIDE (dark teal) and STRIDE (light teal) capital investment-related revenue requirements across the combined three companies and shows how the total capital investment-related revenue requirements (dark teal + light teal) will evolve over time.

Customers today are responsible for paying less than half of the capital investment-related costs that customers will be responsible for in 2043.

Figure 1.2: Combined Three-Company STRIDE and Non-STRIDE CAPEX Annual Revenue Requirement



...which will result in corresponding increases in base rates charged to customers to cover the rise in rate base.

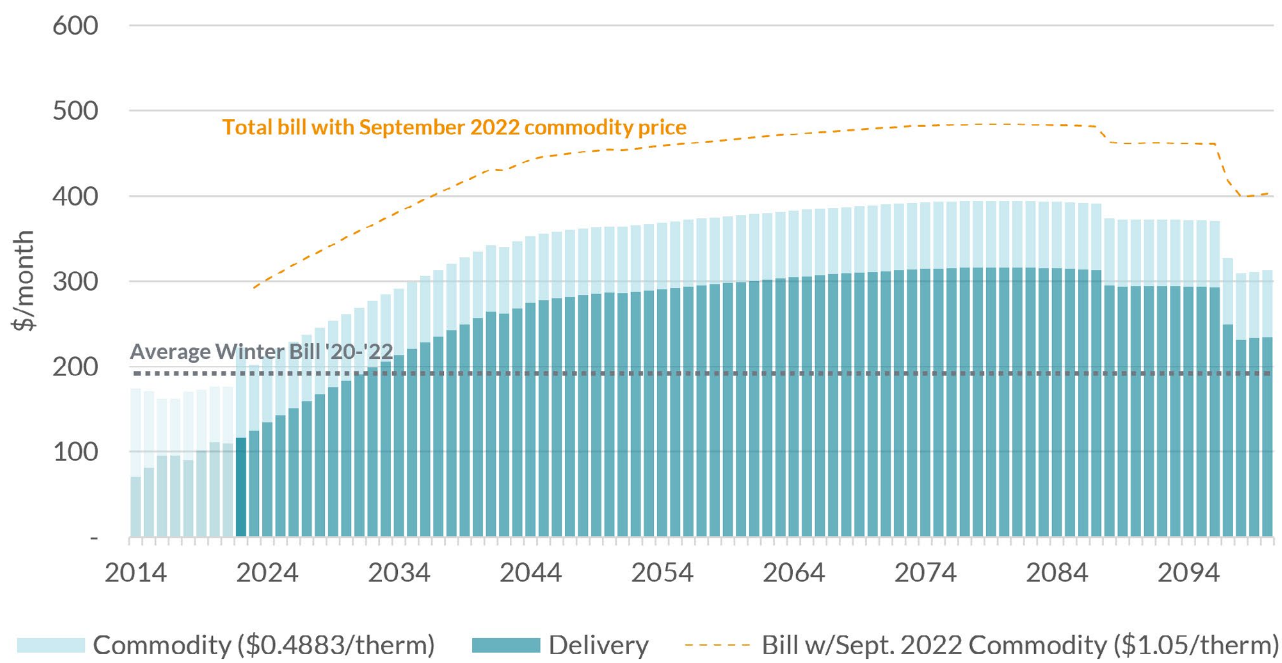
Next, we identified how the capital investments will affect customer rates. This step allocates revenue to the residential heating class of each company using the revenue allocation factors from the most recent STRIDE filings. The billing determinants for customer-months and usage were set based on the revenue calculations in the compliance filing from the most recent rate case for each company. The customer and sales numbers are assumed to remain constant over the evaluation period. Stated otherwise, the projections do *not* account for any migration of gas customers to electric service as a result of electrification policies.

To show the bill impacts over time, we evaluate the typical bill for a winter customer using 160 therms per month in January and February. We use this period because these months tend to be the highest bills for customers.

Figure 1.3 shows that the BGE typical residential customer's bill will grow from an average of $192 in 2020-2022 to $299, a 56 percent increase by 2035, and $364, a 90 percent increase by 2050. This assumes commodity prices revert back to the five-year averages. If gas prices stay near the current September levels ($1.05/therm for BGE), then that would add an additional $90 per month to the typical winter bill.

The BGE typical residential customer's bill will **increase 56% by 2035.**

Figure 1.3: BGE Typical Winter Bill, 2014-2100



BGE rates for 2021 and 2022 include the Rider 18 offset that was adopted to lower bills in the first two years of the MYRP. This offset amount is removed after 2022.

Figure 1.4 shows that the WGL typical residential customer's bill will grow from an average of $160 in 2020-2022 to $224, a 40 percent increase by 2035, and $230, a 44 percent increase by 2050. This, too, assumes commodity prices revert back to the five-year averages. If gas prices stay at the September 2022 level ($1.1314/therm for WGL), then that would add another $102 per month to the typical winter bill.

Figure 1.5 shows that the CMD typical residential customer bill will grow from an average of $186 in 2020-2022 to $270, a 45 percent increase, by 2035 and $276, a 48 percent increase, by 2050. If commodity prices remain at the September 2022 level

Figure 1.4: WGL Typical Winter Bill, 2014-2100

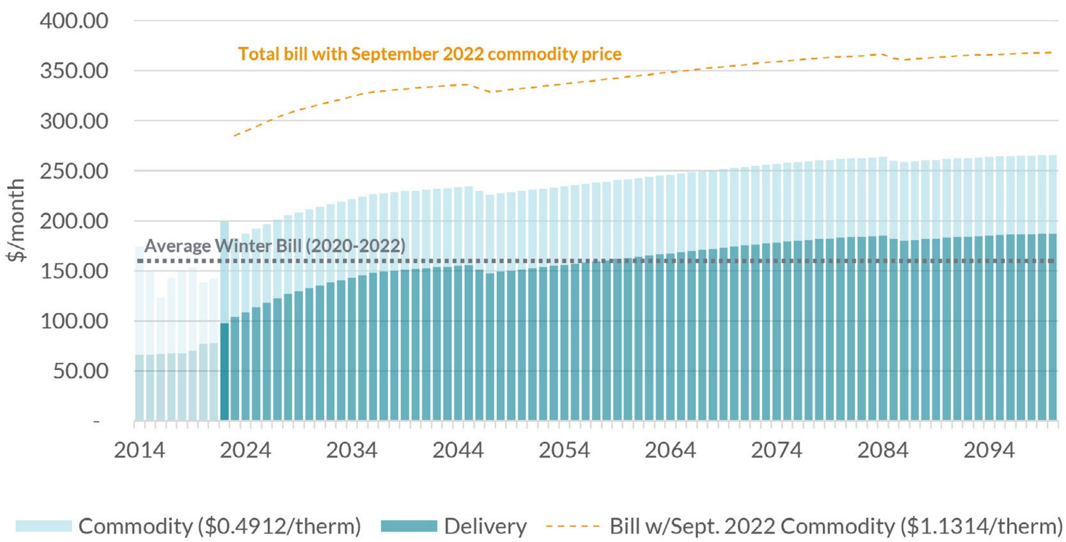
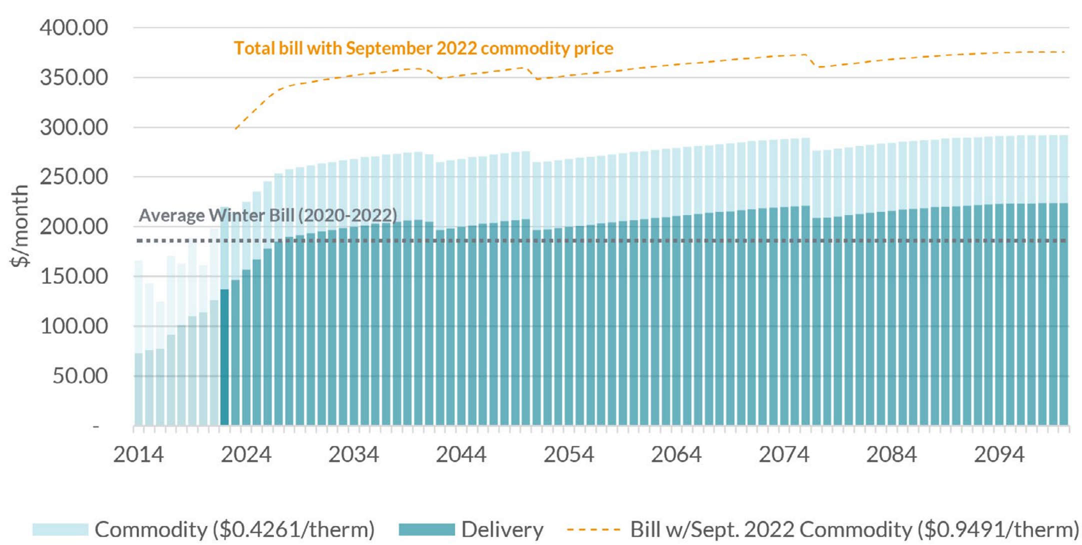


Figure 1.5: CMD Typical Winter Bill, 2014-2100



($0.9491/therm for CMD), that would add another $84 to the typical winter bill.

It is important to recognize that Maryland customers are only at the early stages of paying for STRIDE...

We determined the portion of the total STRIDE costs that have already been recovered through rates and, conversely, what portion of the STRIDE costs remain to be recovered. An investment is being "recovered" through rates until it is fully depreciated. Utilities under rate-of-return regulation receive a "return on" the undepreciated value of an investment in the form of a return on equity and a "return of" the investment in the form of depreciation expenses. Accordingly, we use cumulative STRIDE depreciation to represent the amounts recovered through rates.

We combined the results of the individual companies into Figure 1.6 to provide a wholistic view of the remaining years that STRIDE costs will be recovered through rates in Maryland. What is important to recognize from this figure is that right now, in 2022,

> Right now, in 2022, **only 2.8% of the planned STRIDE costs have been recovered** through rates.

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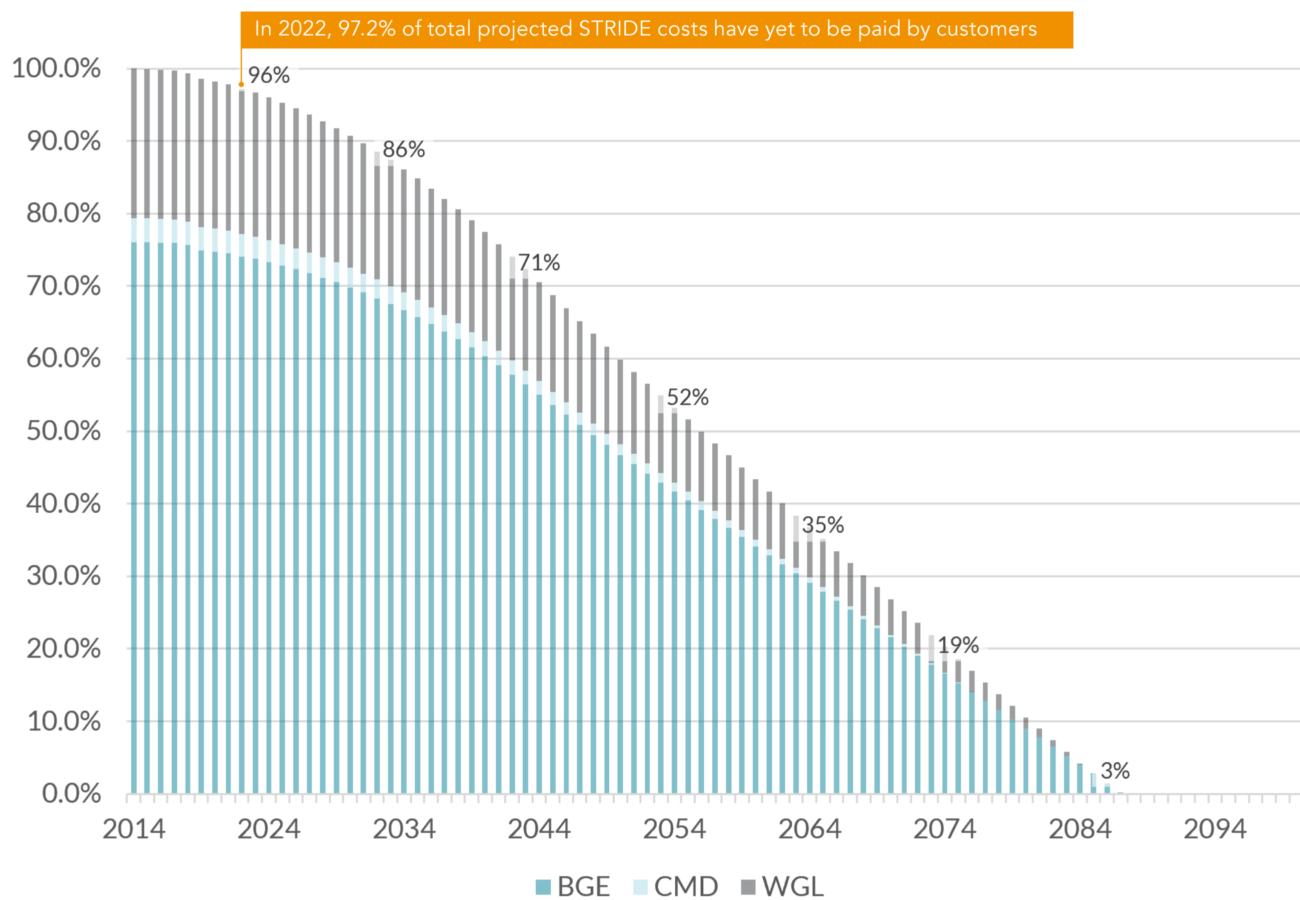
Figure 1.6: Amount of STRIDE Cost Recovery Remaining Across Maryland's 3 Largest Gas Utilities



recovered through rates. STRIDE cost recovery is still at the early stages with Maryland customers expected to be paying off STRIDE costs until 2087.

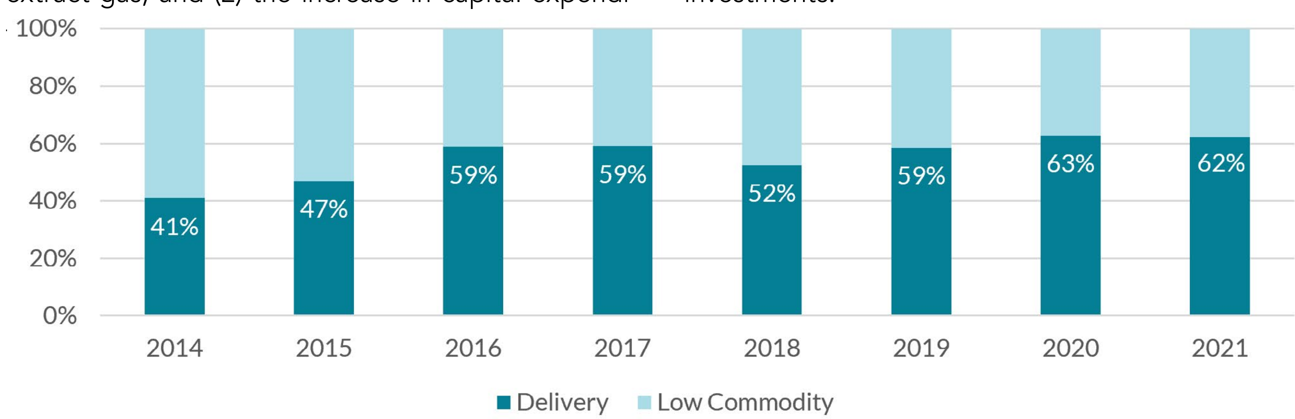
...and the true bill impact of these investments has partially been hidden from customers due to reduced gas prices.

Prior to the increase of gas commodity prices in 2021 and 2022, there had been a trend over the previous decade where the distribution proportion of bills was increasing, while the commodity portion of the bill decreased. This was due to two factors: (1) a drop in commodity prices caused by a large increase in U.S. domestic gas supplies due to the expanded deployment in the U.S. of hydraulic fracking techniques to extract gas, and (2) the increase in capital expenditures, specifically the STRIDE expenditures. The combined effect has been that the drop in commodity prices has offset the increase in base rates. Figure 1.7 shows how a notable flip occurred in 2016: Gas customers began paying more for *delivery* of the gas than for the gas commodity they use, as a proportion of their monthly gas bill.

The drop in commodity prices has offset the increase in base rates.

The increase in gas utilities' distribution prices (or the non-commodity "delivery price") has raised the floor for the total gas bill. When the commodity portion of the gas rate increases, as has happened in 2021 and 2022, customers bear the combined burden of both a return to higher commodity prices and the rise in base rates due to accelerated and increasing capital investments.

Figure 1.7: BGE Typical Winter Bill by Component, 2014-2021 (%)



SECTION TWO

CAPITAL PROJECTIONS

This section describes the approach we used to develop assumptions for the capital investments that BGE, WGL, and CMD will make from 2022 until 2100. The objective was to develop assumptions that approximate the status quo or current trajectory of each company's investments based on recent history and any capital plans that they have presented in regulatory proceedings.

Our assumptions are based on utility filings with the Public Service Commission or Commission orders. Where we have them, we use the utilities' own projections or assumptions.* If further assumptions are required, we use conservative estimates that are based on analysis of recent rate cases and existing utility plans. All assumptions are explained below.[2]

Table 2.1 summarizes the results of these capital projections, both by company in total for Maryland's three largest gas utilities. For perspective, the expenditures over the first eight years of STRIDE (2014-2021) by the three utilities have already been $1,562 million. This table shows that over the remaining duration of STRIDE, the companies anticipate expenditures ($4,764 million) that are triple what has already been spent on STRIDE. These STRIDE amounts will only be a portion of the overall capital expenditures (CAPEX).

*The utility-specific data on which this report is based comes from historical, publicly available information or the utility's projections contained in filings with the Public Service Commission or public reports.

To further ensure the accuracy of the general spending trends and customer impacts observed in this report, OPC provided certain data to the three utilities (BGE, WGL, and CMD) and asked them to confirm its accuracy. OPC informed the utilities that the data would be used in documents shared with the public. Both WGL and BGE responded by identifying where certain numbers in their records differed from the numbers DHInfrastructure identified. DHInfrastructure accordingly updated projections and models used for this report to reflect WGL's and BGE's comments. In other cases, each of which is described in detail in this report, DHInfrastructure made all attempts to use the best available public information. For example, because STRIDE projections are based on expenditures rather than plant-in-service, expenditures were used as a close proxy for plant-in-service; as explained in section 2.2.1, this difference has only a *de minimus* impact on our results. Both WGL and BGE emphasized that their willingness to review the data in no way constituted an endorsement of the numbers for any specific use, because they did not know the context in which the numbers would be used. CMD did not respond to OPC's request.

2 Nominal dollars are used in this report except for STRIDE long-term projections, for which utility filings include an annual 3% increase that may be intended to reflect inflation.

Table 2.1: Maryland Gas CAPEX Investments, 2022-2100 (million $)

	STRIDE (2022-2043)	Non-STRIDE (2022-2043)	Non-STRIDE (2044-2100)	Total
BGE	$3,793.70	$5,799.14	$15,005.96	$24,598.80
CMD	$92.95	$235.31	$609.67	$937.93
WGL	$877.71	$2,255.34	$5,843.39	$8,976.45
Total	$4,764.36	$8,289.79	$21,459.02	$34,513.18

We estimate that if the three companies continue to invest outside of STRIDE at current rates, there will be another $29,749 million in non-STRIDE investments between 2022 through 2100. In total, based on our assumptions about the current trajectory of investments, we estimate that these three utilities are on track to spend $34,513 million on gas CAPEX investment from 2022 through 2100.

The remainder of this section describes how these projections were developed. We begin in Section 2.1 with an overview of the STRIDE investment projections by company and then, in Section 2.2, identify the non-STRIDE capital investment assumptions.

2.1. STRIDE Projections

In 2013, the Maryland General Assembly enacted section 4-210 of the Public Utilities Article, *Annotated Code of Maryland* (section 4-210 or STRIDE statute). The STRIDE statute authorized Maryland gas utility companies to file infrastructure investment plans and corresponding project cost-recovery schedules with the Commission for approval. Eligible investments under STRIDE include infrastructure replacement or improvement projects that meet the following criteria:

- Made on or after June 1, 2013;
- Designed to improve public safety or infrastructure reliability;
- Does not increase the revenue of a gas company by connecting an improvement directly to new customers;
- Reduces or has the potential to reduce greenhouse gas emissions through a reduction in natural gas system leaks; and
- Is not included in the current rate base of the gas company as determined in the gas company's most recent base rate proceeding.[3]

Companies anticipate expenditures that are **triple what has already been spent**.

The statute requires that companies receive approval of their STRIDE plans on five-year cycles. BGE, WGL, and CMD are all on their second five-year plans that run from 2019 to 2023. As part of the filings made to support their second five-year plans, companies also provided updates on their overall STRIDE plans (i.e., the future five-year plans) through either testimony or discovery responses that were used to develop the future STRIDE expenditure projections. These future STRIDE plans continue until the gas utilities have replaced the gas infrastructure targeted by each plan. The subsections below describe each company's STRIDE program and identify the assumptions we used for future STRIDE investments.

3 Md. Code Ann., Public Utilities Article § 4-210 (a)(3).

Section 4-210 permits companies to begin recovering costs of approved STRIDE investments outside of a rate case through the STRIDE surcharge mechanism. Section 4-210 establishes the rate mechanism to be used to recover eligible costs as a "fixed annual surcharge on customer bills." This surcharge is capped at $2 per month for residential customers; for all non-residential customers, the surcharge cap is proportionate to each class's total distribution revenues as determined in the most recent base rate proceeding. When the Commission approves the investments in the utility's subsequent rate case and the previous STRIDE investments are allowed into rate base, the surcharge is reset to zero, subject to increasing again to recover the next round of STRIDE-eligible investments until the next base rate case. Thus, aside from the surcharge, customers are also paying for STRIDE investments through the per therm rates they pay (the "base rates").

Absent the surcharge mechanism, companies would not be able to begin to recover the investment costs of completed projects until these costs are included in rate base in the next base rate proceeding. The time gap between when a project is completed (or "in service") and when it is reflected in base rates is known as "regulatory lag." Cost recovery schedules under the STRIDE statute are initially based on estimated project costs, which are "collectible at the same time the eligible infrastructure replacement is made"[4] and these costs are reconciled annually. This estimate and reconciliation approach effectively eliminates regulatory lag such that companies receive contemporaneous recovery of STRIDE costs as they are incurred. This elimination of "regulatory lag" is the main mechanism by which STRIDE accelerates the replacement of natural gas infrastructure.

The three companies are all currently operating under their second five-year STRIDE plan. With STRIDE plans running until 2026 for CMD, 2035 for WGL, and 2043 for BGE, it is expected that there will be up to four more five-year cycles of STRIDE. Table 2.2 presents each company's future STRIDE plans.

It should be noted that the STRIDE investment amounts presented above are STRIDE expenditures, not "plant-in-service." When utilities invest in capital projects, under traditional rate of return ratemaking, they do not begin to recover these investments until they are "plant-in-service," which literally means that the equipment is operational and providing service to

Table 2.2: STRIDE Investment Plans of Maryland's Three Largest Gas Utilities (million $)

	BGE	WGL	CMD	THREE-COMPANY TOTAL
Total spent STRIDE I (actual 2014-2018)	$522.73	$218.50	$66.19	
Actual/Authorized budget STRIDE II (2019-2023)	$827.28	$363.07	$87.22	
Estimated STRIDE III (2024-2028) budget	$693.39	$439.44	$57.38	
Estimated STRIDE IV (2029-2033) budget	$803.83	$194.82	$0	
Estimated STRIDE V (2034-2038) budget	$931.86	$86.35	$0	
Estimated STRIDE VI (2039-2043) budget	$1,034.48	$0	$0	
All-time Total STRIDE I – VI	$4,813.58	$1,302.19	$210.79	$6,326 million
Future Total = Remaining STRIDE II + STRIDE III to STRIDE VI	$3,793.70	$877.71	$92.94	$4,764 million

4 Md. Code Ann., Public Utilities Article § 4-210 (d)(3)(ii).

customers. The STRIDE surcharge functions differently by permitting utilities to recover costs when they are incurred, even before they are in service. Because of this different treatment, the amounts reported the STRIDE filings that we rely on to make assumptions about future STRIDE investment are technically expenditures on STRIDE, not plant-in-service. Stated otherwise, the expenditure amounts that we use from the STRIDE filings are slightly different from the STRIDE plant-in-service numbers that would be used in a base rate proceeding. Because the timing difference between expenditures on STRIDE projects is usually just days or weeks (instead of months to years for large utility projects) this assumption has only *de minimus* impact on our overall results.

We next describe in more detail the STRIDE plans of each of Maryland's three major gas utilities.

2.1.1. BGE

BGE's STRIDE program is separated into two different sub-programs: Operation Pipeline and Service Replacement Program. The Operation Pipeline program consists of all original asset classes proposed in BGE's initial STRIDE plan: cast iron and bare steel main and bare steel and copper services. In 2016, BGE added the Service Replacement Program to specifically address pre-1970 3/4" high pressure steel services.

Table 2.3 summarizes the current long-term plans for BGE's STRIDE activities based on its most recent public filings. The projected remaining STRIDE expenditures for BGE were forecasted based on a combination of the plans for the remaining two years of the STRIDE II plan (2022 and 2023) and then a steady-state of 48 miles of main replaced each year from 2024 up until 2043, when only 38.2 miles will need to be replaced.[5] The remaining bare steel and copper services targeted through Operation Pipeline are assumed to be replaced as part of this main replacement work because BGE's cost estimates for main replacements include the cost of associated service replacement work.

BGE's estimated cost per mile from its STRIDE II plan is used as the cost basis for the annual budget. We increase the 2023 cost per mile ($2.63 million/mile) by three percent each year—the same assumption

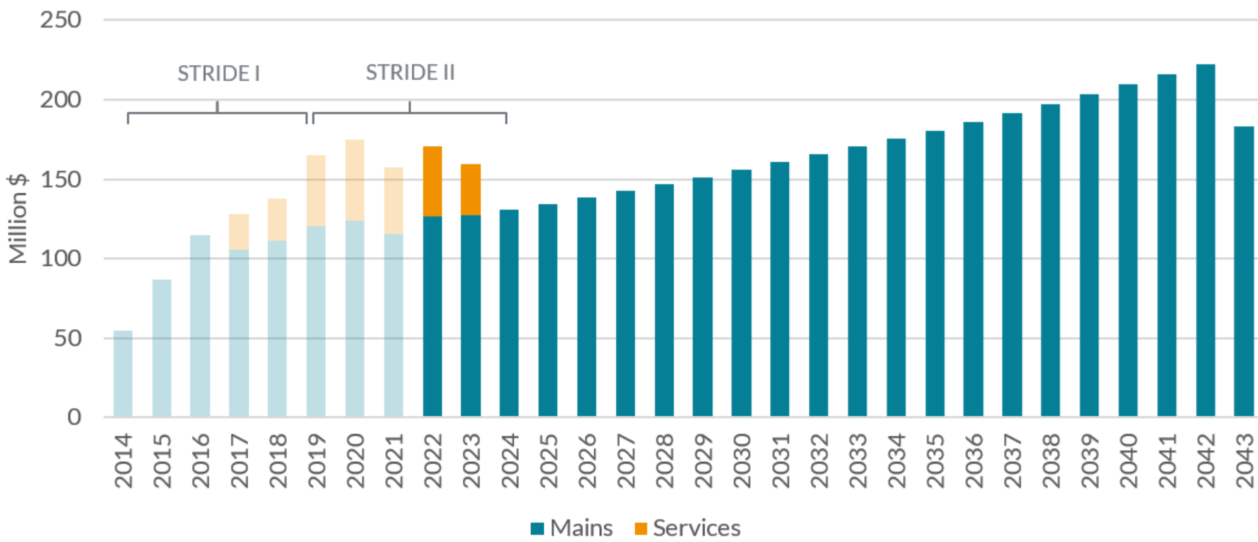
Table 2.3: BGE STRIDE Plans

Program	Asset types	Targeted Infrastructure (STRIDE II plan)	Current Status (2022)	Start Year	End Year
Operation Pipeline	Cast Iron Main	1,216 miles	1,016 miles	2014	2043
	Bare Steel Main	22 miles	14 miles	2014	2028
	Bare Steel Services	63,917 services	53,290 services	2014	2033
	Copper Services	20,251 services	15,600 services	2014	2043
Service Replacement Program	Pre-1970 ¾" High Pressure Steel Services	37,960 services	8,100 services	2016	2023

The "Targeted Infrastructure (STRIDE II)" column represents what was reported as remaining work on the system when BGE submitted its STRIDE II plan. The "Current Status" column provides updated information that accounts for the 2021 PHMSA Annual Report and supplemental information from STRIDE filings.

5 This plan uses a modified version of the projections that BGE presented for its accelerated STRIDE II plan in response to DR OPC 1-4 in CN 9468 that adjusts the number of miles replaced down from BGE's projections to the STRIDE II-approved level of 48 miles per year.

Figure 2.1: BGE STRIDE Investment Actual/Projections



BGE used in its STRIDE II plan—and multiplied by the assumed annual replacement miles to arrive at the estimated STRIDE costs. Figure 2.1 shows the projected STRIDE expenditures (2022–2043) along with STRIDE expenditures already incurred (2014-2021). The light-shaded years are historical (actual) investments while the dark-shaded bars are projections.

2.1.2. WGL

WGL's STRIDE program is unique in that it includes both distribution and transmission sub-programs. The STRIDE I plan was initially approved with a service-only program (Program 1) that was split into three components by service material and three main programs focused on specific pipe materials (Programs 2-4). The Commission subsequently approved another WGL distribution program (Program 5) that focused on three other distribution asset categories and five transmission programs.

WGL's initial plan for STRIDE I was to complete replacement of all targeted asset categories over 22 years—by the end of 2025. Despite the expansion of the programs within STRIDE and regular delays in completing work over the first five years of the program, WGL kept this same overall timeline in its STRIDE II plan. Table 2.4 summarizes the current long-term plans for WGL's STRIDE activities based on its most recent public filings.

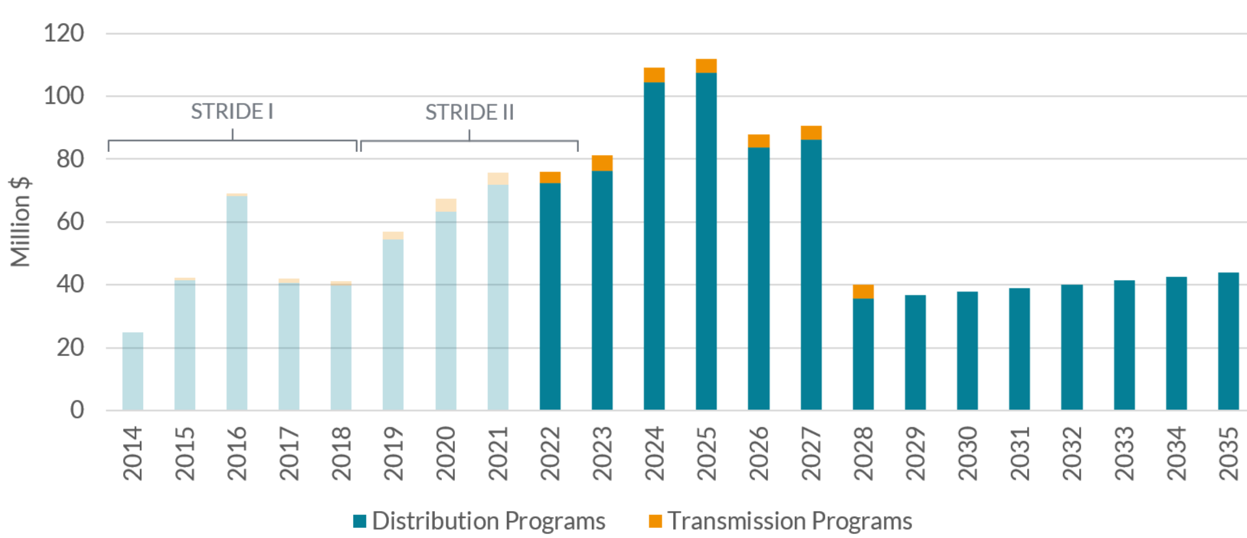
WGL did not provide updated projections of its distribution replacement activities through the end of STRIDE in the STRIDE II docket. Given the complexity created by the number of programs, a more simplistic estimation approach is required. Rather than attempting to develop assumptions for each program, the budget for each distribution program increases by three percent each year until the final year of the program. For example, the budget for Program 2 is $37.08 million in 2023 and is then estimated to be $38.2 million in 2024 (3% higher), and the budget for each year increases accordingly until 2027, the final planned year of the program. This approach effectively assumes that the replacement pace that WGL proposed for the final year of STRIDE II (2023) will continue for the duration of each program. We then added an additional 14.7% to the distribution budgets to account for

Table 2.4: WGL STRIDE Plans

Program	Asset Types	Targeted Infrastructure (STRIDE II plan)	Current Status (2022)	Start Year	End Year
Distribution 1A	Bare Steel / Unprotected Services	8,623 services	6,347 services	2014	2026
Distribution 1B	Copper Services	2,871 services	1,884 services	2014	2026
Distribution 1C	Pre-1975 Plastic Services	1,029 services	371 services	2014	2026
Distribution 2	Bare Steel / Unprotected Mains	124.5 miles	81.95 miles	2014	2028
Distribution 3	VMC Mains	392.7 miles	366.7 miles	2014	2035
	VMC Services	25,345 services	20,397 services	2014	2035
Distribution 4	Cast Iron Mains	56.1 miles	40.04 miles	2014	2035
Distribution 5A	Meter Build Up + Risers	113,000 risers	101,262 risers	2015	2035
Distribution 5B	Shallow Main	0.85 miles	0.24 miles	2015	2035
Distribution 5C	Steel Pressure Gauge Lines	1,725 gauge lines	1,194 gauge lines	2015	2035
Transmission 1	Transmission Mains	0 strips	--	--	--
Transmission 2	Remote Control Valves (RCV)	7 RCVs	Unknown	2015	2023
Transmission 3	Block Valves	10 valves	Unknown	2015	2023
Transmission 4	Valve Risers	7 valve risers	Unknown	2015	2019
Transmission 5	Replacements for Inline Inspection (ILI) Tools	3 strips	Unknown	2019	2025

The "Targeted Infrastructure (STRIDE II)" column represents what was reported as remaining work on the system when WGL submitted its STRIDE II plan. The "Current Status" column provides updated information that accounts for the 2021 PHMSA Annual Report and supplemental information from STRIDE filings.

Figure 2.2: WGL STRIDE Investment Actual/Projections



WGL's recent experience that has shown it has spent on average 14.7% more for the replacements completed over the first three years of STRIDE II.

WGL Witness Stuber provided estimates for the transmission programs through 2028 as part of the STRIDE II transmission plan. WGL has not experienced the same level of delays and cost overruns on its transmission projects, so these estimates were used as presented.

Figure 2.2 shows the projected STRIDE expenditures (2022–2035) along with STRIDE expenditures already incurred (2014-2021).

2.1.3. CMD

The STRIDE program that CMD is currently operating under remains relatively the same as the original program approved by the Public Service Commission in Case Number (CN) 9332. CMD's approved first five-year plan included an average replacement of 7.56 miles of bare steel or cast-iron main per year with an overall target to remove all bare steel and cast-iron main by the end of 2026.[6] For STRIDE II, CMD agreed to a settlement that set the annual replacement rate of bare steel and cast iron mains at eight miles per year. There was no update in CN 9479 on how this slight increase in replacement rate changed the anticipated STRIDE timeline, so the table below assumes that 2026 is still targeted to be the final year. Table 2.5 summarizes the current long-term plans for CMD's STRIDE activities based on its most recent public filings.

As shown in the table above, CMD has only a few years remaining under its current STRIDE program. At its current replacement pace, CMD will have approximately 17.5 miles of bare steel main to replace at the end of STRIDE II. However, we expect that CMD will need to replace more than 17.5 miles of pipe in the next iteration of its STRIDE plan. CMD's STRIDE projects in recent years have included replacement of high levels of non-leak prone material or "contingent" main that was connected to STRIDE targeted pipe.[7] For example, in 2021, CMD reported that it

Table 2.5: CMD STRIDE Plans

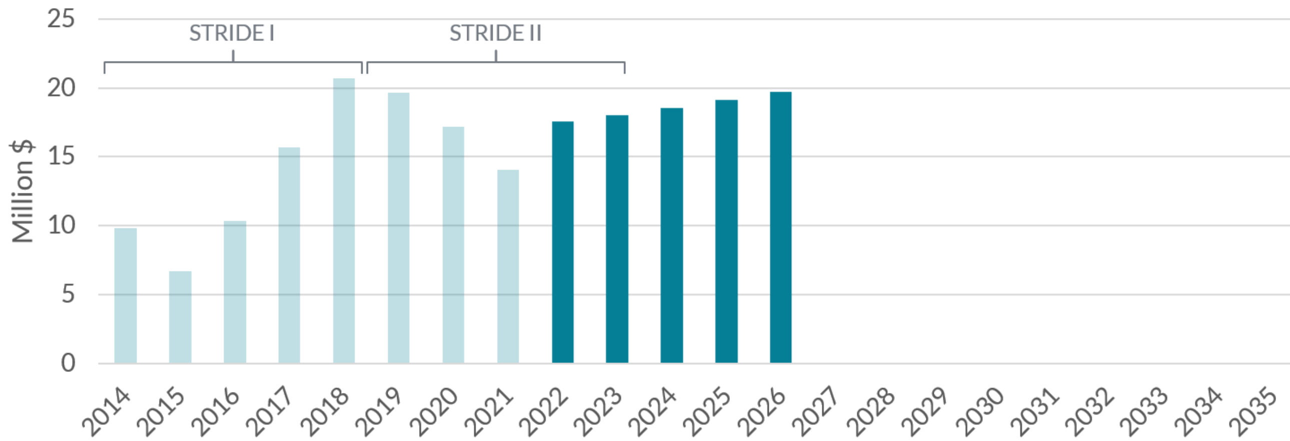
Program	Asset Types	Targeted Infrastructure (STRIDE II plan)	Current Status (2022)	Start Year	End Year
Infrastructure Replacement and Improvement Plan ("IRIS")	Bare Steel Services	3,027 services	1,521 services	2014	2026
	Bare Steel Mains	68.9 miles	33.5 miles	2014	Complete
	Cast/Wrought Iron Mains	2.2 miles	0.0 miles		

The "Targeted Infrastructure (STRIDE II)" column represents what was reported as remaining work on the system when CMD submitted its STRIDE II plan. The "Current Status" column provides updated information that accounts for the 2021 PHMSA Annual Report.

6 The approved plan was CMD's second attempt to receive approval of its first five year STRIDE plan. The Commission denied CMD's initial proposal in CN 9332 to replace 5.9 miles of bare steel and cast-iron mains per year from 2014 to 2018 because it found that the replacement rate did not represent a material acceleration over its current pace.

7 When companies replace materials such as bare steel and cast iron mains that are targeted for removal through STRIDE, there are times when other pipe materials, such as coated steel or plastic mains, are encountered. This other material may be a section of pipe that was previously installed to repair a leak. Companies argue that for efficiency reasons it is more expedient to replace the entire strip of pipe rather than work around the material not targeted for STRIDE. This pipe is commonly called "contingent" main.

Figure 2.3: CMD STRIDE Investment Actual/Projections



had to replace 18.4 miles in total to retire 8.4 miles of bare steel main. Due to the additional costs of removing these 10.1 miles, CMD completed four projects outside of STRIDE (*i.e.*, it is not recovering the costs through the surcharge) in order to complete the eight miles within the budget agreed upon in the CN 9479 settlement. This recent trend of significant "contingent main replacement" led us to assume that the total investment for CMD's final STRIDE years will include more than just the 17.5 miles of bare steel. For the 2024-2026 investment projections, we assume that CMD will continue its same replacement pace of 8 miles per year.[8] At that pace, 17.5 miles of main will be replaced along with 6.5 miles of contingent main. The budget is calculated by using the cost per mile ($2.2 million per mile) used for 2023 grown by three percent each year.

Figure 2.2 shows the projected STRIDE expenditures (2022–2026) along with STRIDE expenditures already incurred (2014-2021).

2.2. Non-STRIDE Capital Projections

We separately analyzed the gas utilities' capital investments made outside of STRIDE (*i.e.*, "non-STRIDE" investments). Unlike STRIDE expenditures for which utilities must file five-year plans, no statute or PSC action requires gas utilities to publicly disclose their long-term capital expenditure plans outside of a rate case.

This analysis thus began by first attempting to understand the amounts of investments each of the utilities have made outside of STRIDE in recent years. The projections for future non-STRIDE investments are based on the recent historical trend. We gathered the most recent data on plant additions available for each company. For WGL and CMD, this includes the three most recent annual reports submitted to the Maryland PSC.[9] For BGE, this includes the capital plans submitted in its three-year MYRP. These numbers were then tied to the annual STRIDE investments made in the same year to arrive at an estimate

8 Note that initial iterations of the CMD projections had assumed CMD's STRIDE plan would operate through 2030.

9 For CMD, we used the annual reports filed for years 2019-2021. For WGL, we used years 2018-2021 as WGL's 2021 annual report was unavailable at the time we conducted our analysis.

Table 2.6: Non-STRIDE Investments of Maryland's Three Largest Gas Utilities, 2022-2100 (million $)

	BGE	WGL	CMD	
Non-STRIDE Year 1	$255.90	$116.00	$8.21	
Non-STRIDE Year 2	$284.89	$107.51	$4.70	
Non-STRIDE Year 3	$249.00	$84.04	$19.18	
Three-Year Average	$263.26	$102.52	$10.70	**THREE-COMPANY FUTURE NON-STRIDE TOTAL**
Estimated Non-STRIDE Spend 2022-2100	$20,805.14	$8,098.74	$844.98	$29,749 million

for non-STRIDE investments.[10] Specifically, for each company, we identified the amount of non-STRIDE investments made as the difference between total plant additions and the STRIDE additions. This is represented by the following formula:

Non-STRIDE Additions =
Total Utility Plant Additions — Stride Additions

Once we identified the historical non-STRIDE additions, the next step was to decide what should be used as the assumed rate of future non-STRIDE additions to capital plant. Two possibilities were considered:

Compound. A recent phenomenon in the gas industry is that utility plant-in-service balances are experiencing compound growth each year. Compound growth means that plant grows at a constant rate. This result requires that plant investment levels increase each year. For example, consider a utility with $1 billion in plant-in-service that makes $100 million in investments. This amount represents a 10 percent increase in plant-in-service. If that utility were then to make a $100 million investment the next year, the annual growth would only be 9.09 percent.[11] To maintain the same 10 percent annual growth in plant-in-service, the amount of additions would instead need to increase to $110 million. One option we considered for estimating non-STRIDE investments was to assume that the level of non-STRIDE investments would be the amount needed to maintain the compound annual growth rate (CAGR) demonstrated over the three-year period between December 31, 2017, and December 31, 2020.

Straight-line. The other approach we considered was to assume that investments outside STRIDE would remain at the same recent levels in perpetuity. We calculated the three-year average level of non-STRIDE additions and then used the result as the constant level of annual future investments. This was called our "straight-line" estimate.

We decided to use the more conservative straight-line assumption for estimating non-STRIDE investments. The compound approach resulted in extremely high levels of investment in the future that did not seem realistic. The straight-line assumptions are likely more realistic but are notably conservative, given that we do not add to the amount each year to account for inflation.

10 As explained earlier, the historical STRIDE amounts relied on in this report are expenditures, not plant-in-service. The utility plant additions reported in the annual reports are plant-in-service numbers. The consequence of this assumption is that our non-STRIDE capital additions here are understated because actual STRIDE plant-in-service is less than STRIDE expenditures.

11 $1.1 billion + $0.1 billion / $1.1 billion -1 = 9.09%

The subsections below describe any unique assumptions that needed to be made for each company and then present the estimate of the non-STRIDE investment amount used in the capital projections.

2.2.1. BGE

BGE is currently operating under a multiyear rate plan (MYRP) from 2021 to 2023. We derived the estimate for non-STRIDE investments by using the capital plan submitted in compliance with the Commission's decision in CN 9645. Table 2.7 presents the derivation of the non-STRIDE capital investment assumption that is used to determine the average annual in the BGE capital projections.

The combined investment projections for BGE, starting after the MYRP in 2024, represent the STRIDE projections through 2045 plus a base level of $263.26 million that we maintain for the entire evaluation period. Figure 2.4 shows the results of our capital investment projections for BGE through 2100.

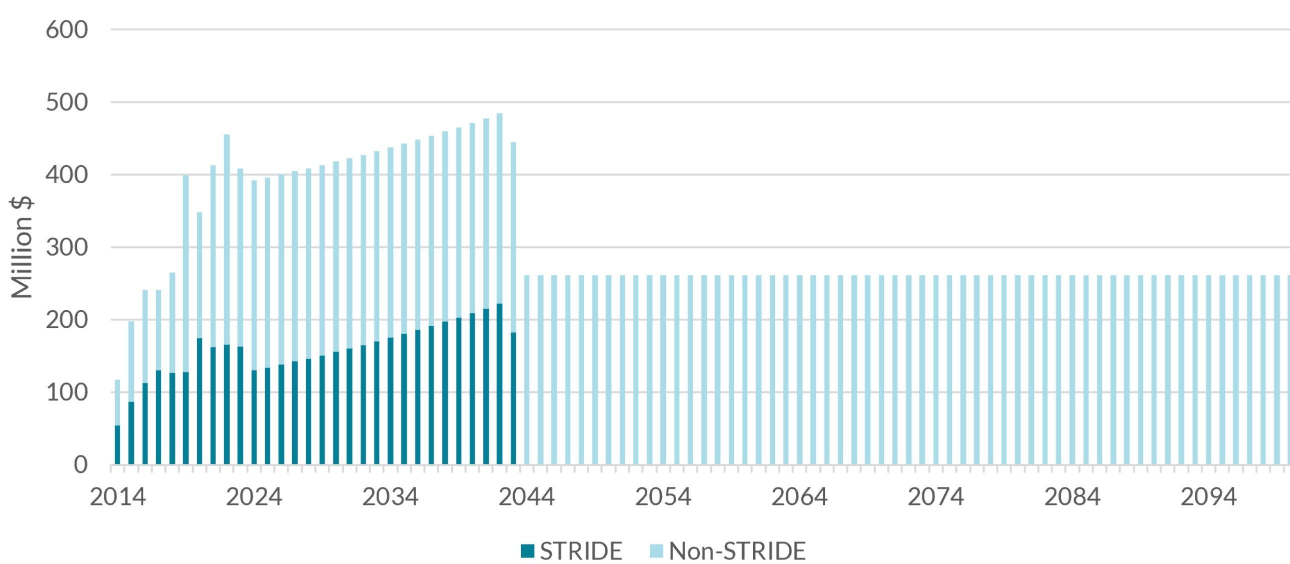
Table 2.7: BGE Non-STRIDE Investment Projections

Line	Description	Source	Projection
1	Plant Additions (2021-2023)	CN 9645, MYRP	$1,277 million
2	STRIDE Plant Addition (2021-2023)	STRIDE filings	$487.4 million
3	Non-STRIDE Plant Additions (2021-2023)	Line 1 – Line 2	$789.8 million
4	Average Annual Non-STRIDE Additions	Line 3 / 3	$263.26 million

2.2.2. WGL

The same approach was used to develop the non-STRIDE capital projections for WGL with two exceptions. First, WGL uses its FERC Form 2 as the basis of its annual report. The problem this reporting creates is that the FERC Form 2 encompasses WGL's operations in Maryland, Virginia, and the District of Columbia, which means that much of the information in WGL's annual report is an aggregate of its three service jurisdictions. While there are Maryland specific entries that identify the number of customers and revenue earned within the Maryland division,

Figure 2.4: BGE Annual Capital Investment Actual/Projections



there is no disaggregation of utility plant or operating expenses by division. This meant that we needed to make assumptions about what amount of utility plant and the utility plant additions were associated with WGL's Maryland division.[12] Second, because WGL is not operating under a MYRP, the beginning of our projections is 2021, the year after the most recently filed annual report.

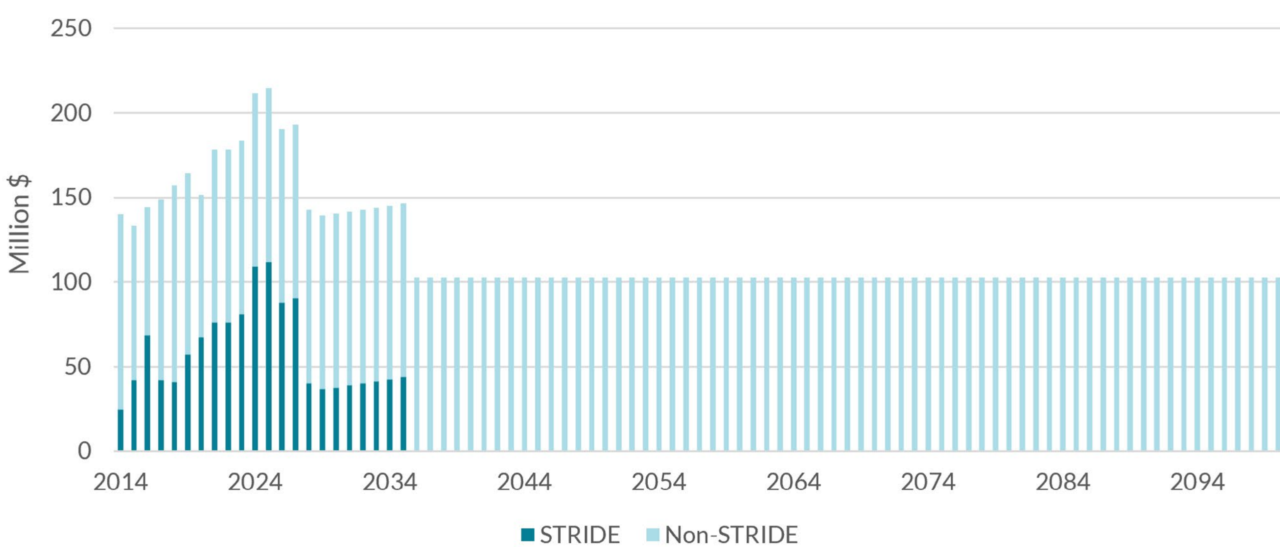
We used WGL's allocated cost-of-service study submitted in its 2020 base rate case (CN 9651) to identify a jurisdictional plant allocation factor to use for assigning a portion of plant additions to Maryland. Table 2.8 presents the derivation of the non-STRIDE capital investment assumption that is used in the WGL capital projections.

The combined investment projections for WGL, starting in 2021, represent the STRIDE projections through 2035 plus a base level of $102.5 million that we maintain for the entire evaluation period. Figure 2.5 shows the results of our capital investment projections for WGL through 2100.

Table 2.8: WGL Non-STRIDE Investment Projections

Line	Description	Note	Projection
1	Total WGL Plant Additions (2018-2020)	Annual Reports	$1,238 million
2	MD Plant Allocator	CN 9651, Exh. RET-6	38.2%
3	Estimated MD Plant Additions	Line 1 * Line 2	$473.1 million
4	STRIDE Plant Addition (2018-2020)	STRIDE filings	$165.6 million
5	Non-STRIDE Plant Additions (2018-2020)	Line 3 – Line 4	$307.5 million
6	Average Annual Non-STRIDE Additions	Line 3 / 3	**$102.5 million**

Figure 2.5: WGL Annual Capital Investment Actual/Projections



12 This decision to use an approximation for the WGL plant in service numbers means that even the historical numbers on revenue requirement and total investments for WGL are estimates.

2.2.3. CMD

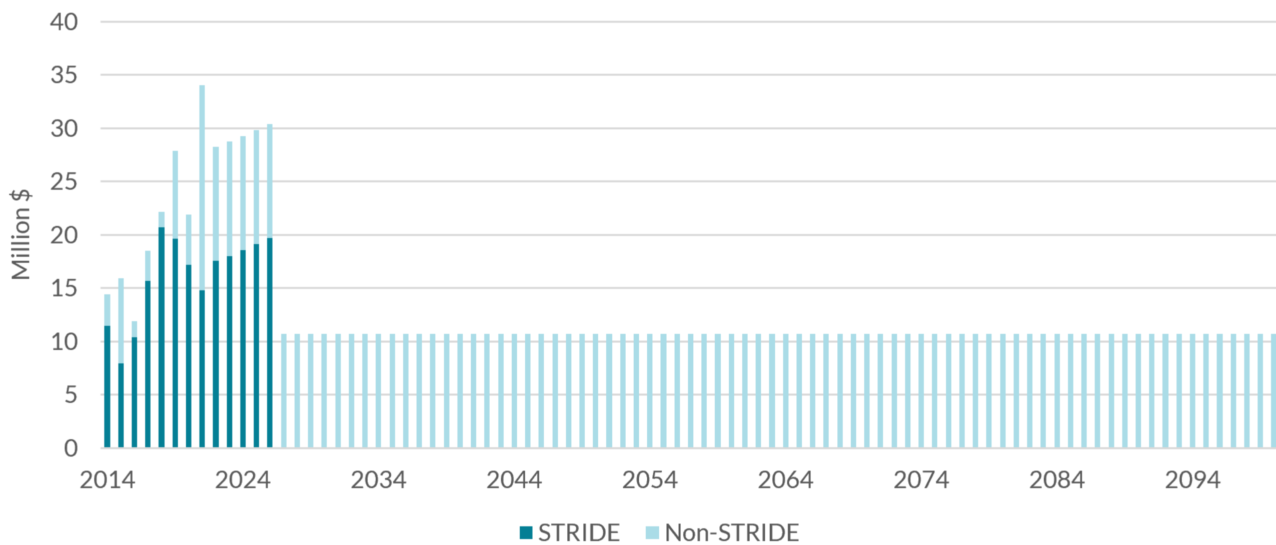
Like we did for WGL, to identify CMD's non-STRIDE investment amounts, we began by looking at its historical investment amounts in the three most recent annual reports. Table 2.9 presents the derivation of the non-STRIDE capital investment assumption that is used in the CMD capital projections.

The combined investment projections for CMD, starting in 2021, represent the STRIDE projections through 2026 plus a base level of $10.7 million that we maintain for the entire evaluation period. Figure 2.5 shows the results of our capital investment projections for CMD through 2100.

Table 2.9: CMD Non-STRIDE Investment Projections

Line	Description	Note	Projection
1	Plant Additions (2019-2021)	Annual Report	$83.75 million
2	STRIDE Plant Addition (2019-2021)	STRIDE filings	$51.66 million
3	Non-STRIDE Plant Additions (2019-2021)	Line 1 – Line 2	$32.09 million
4	Average Annual Non-STRIDE Additions	Line 3 / 3	$10.7 million

Figure 2.6: CMD Annual Capital Investment Actual/Projections



SECTION THREE

ANNUAL REVENUE REQUIREMENT PROJECTIONS

This section both describes the approach we took to estimating the revenue requirements related to our capital investment projections and discusses some of the results of this analysis. We begin, in Section 3.1, with an overview of our revenue requirement modeling approach used to project annual revenue requirements. The remaining four parts of this section include a summary of the annual STRIDE revenue requirements calculated using the revenue requirement model (3.2), a summary of the total STRIDE and non-STRIDE capital revenue requirements calculated using the model (3.3), an explanation of how the operating cost component of the annual revenue requirement was calculated (3.4), and the results of the annual revenue requirement projections for each company (3.5).

3.1. Revenue Requirement Model

To understand the impact of our capital investment projections on rates, we first developed a revenue requirement model that estimated the capital-related components of the annual revenue requirement. This model was a modified version of the model used in the testimony we prepared for OPC on BGE's STRIDE II plan in PSC Case No. 9479.

The revenue requirement for the capital investment components included:

- Return on Rate Base
- Depreciation
- Property Taxes
- Gross-up for income taxes, bad debt, franchise taxes, and PSC assessment.

To calculate the annual revenue requirement in future years, we needed to develop certain assumptions on depreciation, retirements, cost of capital, property taxes, and the gross-conversion factor. We relied on a mix of STRIDE filings and annual reports to develop the assumptions. Table 3.1 presents the various assumptions used to calculate the capital-related revenue requirements for each company.

These assumptions are based on the best information we were able to identify that is publicly available. The assumptions may not represent what BGE's own internal records show today, and actual numbers will differ from those generated using our assumptions. The analysis is solely intended to show the general impact that current capital investment trends will have on future revenue requirements and therefore utility customer rates; it does not identify the precise future revenue requirements that will be developed through the regulatory process.

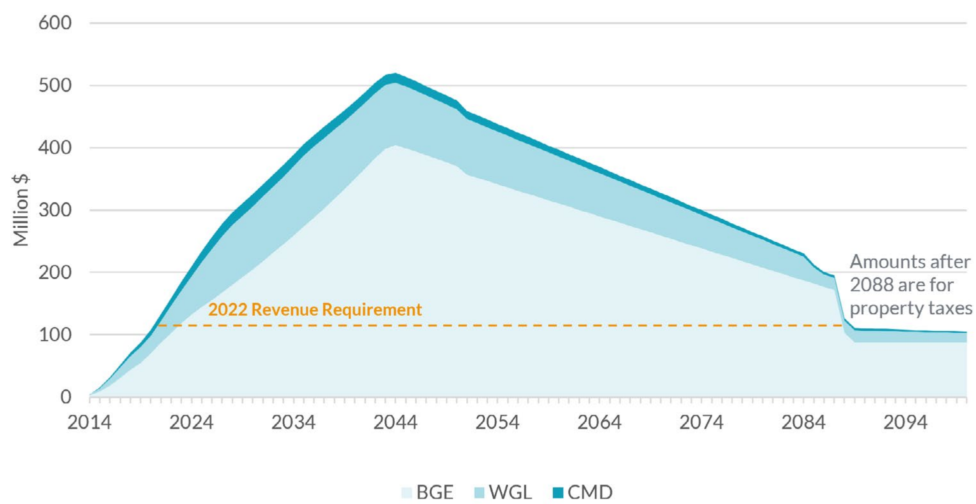
Table 3.1: CAPEX Revenue Requirement Assumptions

	BGE	WGL	CMD
Depreciation Rates	1.76% (mains) 3.54% (services) 2.76% (non-STRIDE)	1.65% (distribution) 1.91% (transmission) 2.42% (non-STRIDE)	1.8% (STRIDE) 2.35% (non-STRIDE)
Retirement Rate	-3.11% (mains) -1.36% (services) -2.50% (non-STRIDE)	-2.5%	-5.0% (STRIDE) -2.5% (non-STRIDE)
Weighted Average Cost of Capital	6.33%	7.09%	7.16%
Gross-Conversion Factor	70.87%	72.48%	70.35%
Property Tax Rate	1.23%	1.12%	1.23%
Tax Treatment of STRIDE Plant Additions	Tax Repairs: 80% MACRS: 20%	Tax Repairs: 80% MACRS: 20%	Tax Repairs: 80% MACRS: 20%

3.2. STRIDE Revenue Requirement

The pyramid figure below was made using the annual revenue requirement approach described in the previous section. What makes this figure informative is that it provides context for where we currently are in the overall STRIDE plans. As identified by the arrow and dotted line, the combined 2022 revenue requirement of approximately $165 million across the three STRIDE programs represents a fraction, 30 percent, of the $524 million peak in annual STRIDE revenue requirements that we project for 2044. In other words, if STRIDE plans continue as currently constituted, then Maryland customers will eventually be paying more than **three times** for STRIDE investments than they are paying today.

Figure 3.1: STRIDE Annual Revenue Requirement Pyramid



Maryland customers will eventually be paying more than **three times** for STRIDE investments than they are paying today.

3.3. Non-STRIDE Revenue Requirement

The STRIDE revenue requirement in Figure 3.1 represents only a fraction of the capital-related annual revenue requirements customers will need to pay to cover for capital investments over the next 80 years. The STRIDE and non-STRIDE capital additions we project through 2100 would result in a combined annual capital revenue requirement for the three utilities exceeding $1.5 billion dollars by 2043 or 2.3 times the combined $667 million in capital revenue requirements customers are paying through rates in 2022. Put another way, customers today are responsible for paying less than half of the capital costs that customers will be responsible for in 2043. Figure 3.2 provides both a comparison of the combined non-STRIDE (dark teal) and STRIDE (light teal) annual capital revenue requirements across the combined three companies and shows how the total annual capital revenue requirements (dark teal + light teal) will evolve over time.

Customers today are responsible for paying **less than half** of the capital costs that customers will be responsible for in 2043.

3.4. Operating Costs Revenue Requirement

Until now, this revenue requirement section has only considered capital-related components. To develop rate projections, we needed to develop assumptions for the level of operating costs included in the annual revenue requirement. Operating cost estimates for the projection period were "reverse-engineered" using a combination of our estimated capital component revenue requirements and the base revenue requirements from the companies' most recent base rate filings. We used the sum of the base distribution revenue requirement and STRIDE revenue requirement from each company's most recent rate

Figure 3.2: Combined Three-Company STRIDE and Non-STRIDE Revenue Requirement

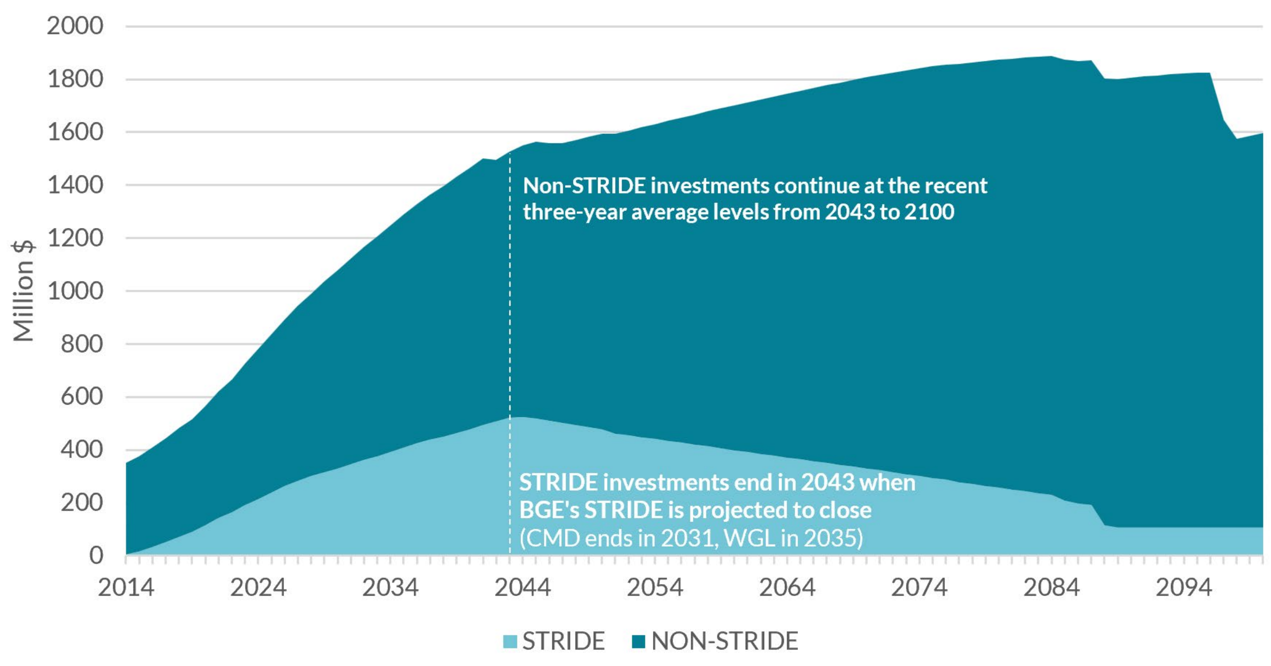


Table 3.2: Operating Cost Revenue Requirement Assumptions

	BGE (CN 9646, Year 3)	WGL (CN 9651)	CMD (CN 9644)
Revenue Requirement	$651.96 million	$377.19 million	$42.30 million
Estimated Capital Revenue Requirement	$423.65 million	$254.08 million	$29.44 million
Operating Revenue Requirement	$228.31 million	$123.11 million	$12.87 million

proceeding and then subtracted our estimated capital revenue requirement to arrive at the estimated operating portion of the revenue requirement. This process is shown in Table 3.2.

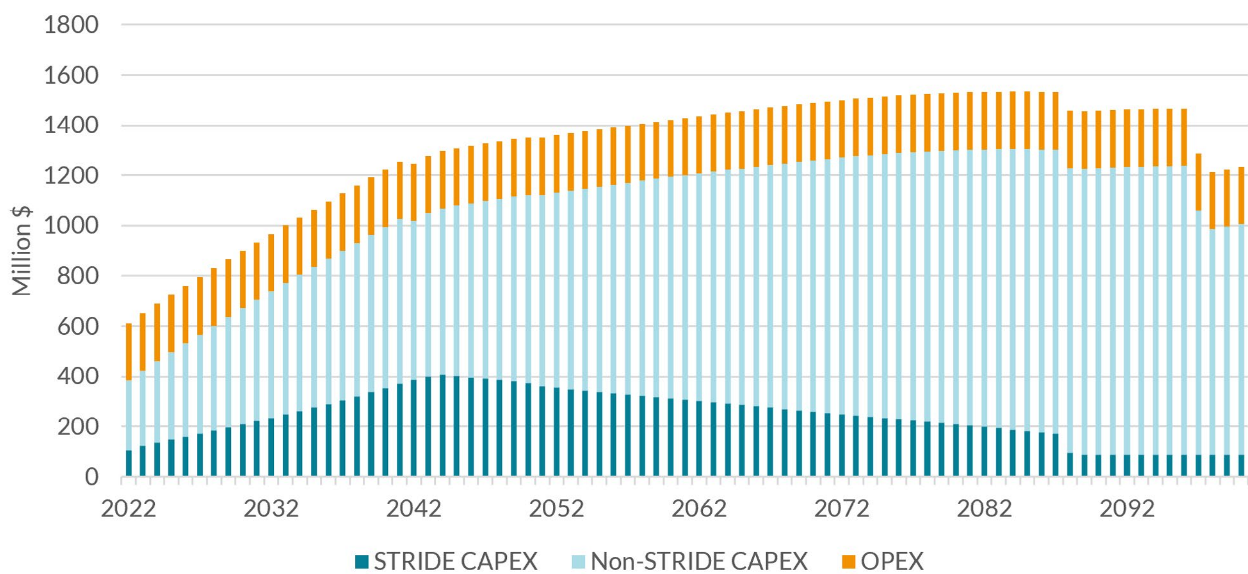
We should emphasize here that we adopt the same operating cost assumptions for every year in the evaluation period; there is no markup for inflation. This approach is consistent with our choice to not grow the non-STRIDE capital investment amounts over time. What this means is that the revenue requirements are in nominal 2022 dollars.[13]

3.5. Annual Revenue Requirement Results

The combination of our STRIDE and non-STRIDE capital revenue requirements and operating expenses represents our annual revenue requirement projections for each company.

Figure 3.3 presents the results of the BGE annual revenue requirement projections. The BGE revenue requirement is projected to peak in 2084 when it reaches $1.532 billion or 2.3 times the revenue requirement of the third year of its current MYRP.

Figure 3.3: BGE Annual Revenue Requirement Projections



13 STRIDE investment assumptions do inherently include inflation to the degree that the companies' cost projections include inflation.

Figure 3.4 presents the results of the WGL annual revenue requirement projections. The WGL annual revenue requirements continue to grow over the evaluation period with no peak and drop like BGE. There is no peak and drop because WGL currently makes more non-STRIDE investments than STRIDE investments. Because WGL's non-STRIDE investments are greater, even when STRIDE ends, WGL is projected to continue making substantial investments. BGE and CMD are currently making a majority of their annual investments through STRIDE such that when STRIDE ends, there is a drop to the baseline non-STRIDE investments. Should WGL's investment follow our assumptions, then rate base would almost double over the next 80 years.

Figure 3.5 presents the results of the CMD revenue requirement projections. CMD's revenue requirements have periodic drops over the evaluation period as STRIDE investments become fully depreciated, but overall the revenue requirement continues to increase over the entire period.

Figure 3.4: WGL Annual Revenue Requirement Projections

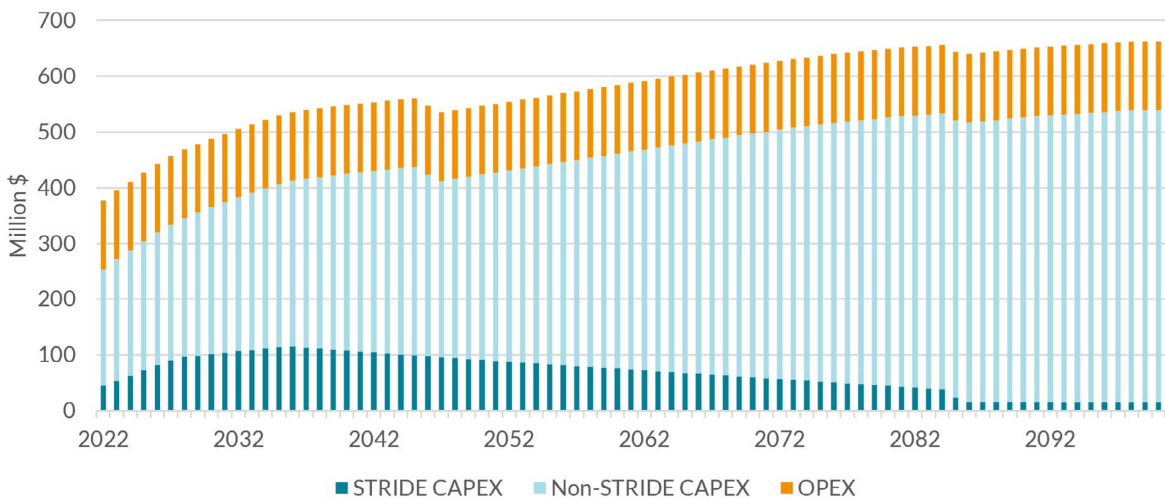
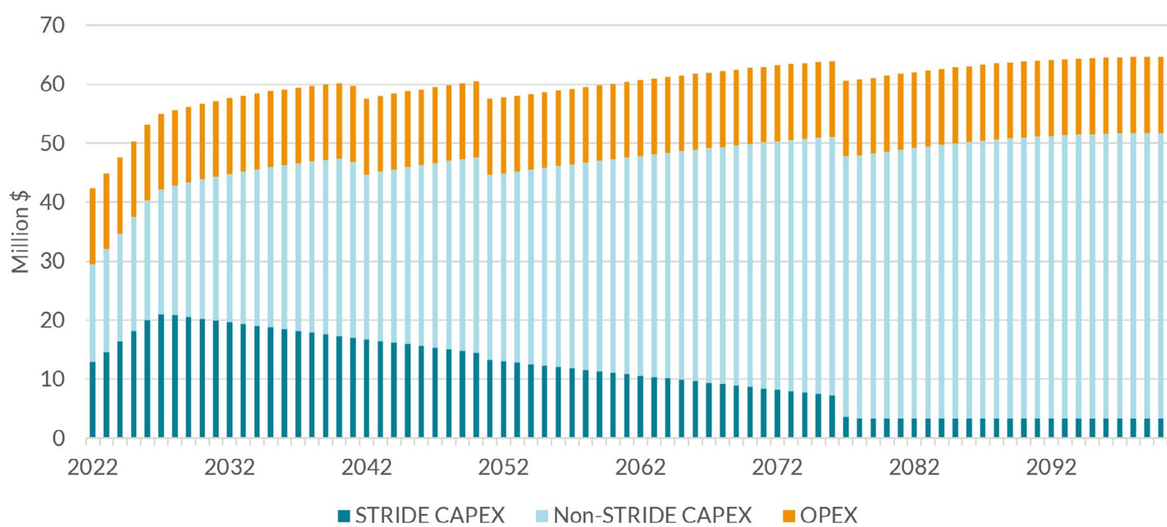


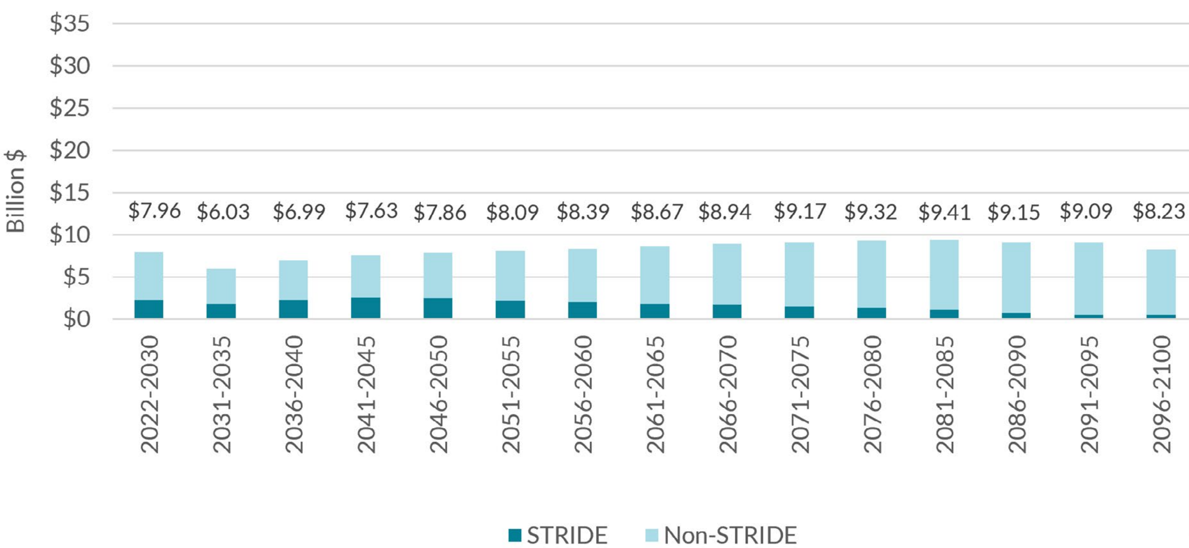
Figure 3.5: CMD Annual Revenue Requirement Projections



The figures above represent the annual amounts that we estimate Maryland's gas customers are expected to be asked to pay from 2022 through 2100. As illustrated in Figure 3.6, total revenues to be collected from customers over this 79-year period across all three companies are estimated to be $125 billion. From 2022-2045, Maryland gas customers will be asked to spend $28.61 billion total.

Total revenues to be collected from customers to pay for capital investments over this 79-year period across all three companies are estimated to be **$125 billion**.

Figure 3.6: Projected Gas Customer Payments toward CAPEX (billion $), 2022-2100



SECTION FOUR

RATE IMPACTS

The annual revenue requirement projections—sum of capital and operating cost estimates—described in Section 3 were used to prepare estimates of typical customer bills. This step was done by allocating revenue to the residential heating class of each company using the revenue allocation factors from the most recent STRIDE filings. The billing determinants for customer-months and usage were set based on the revenue proofs in the compliance filing adopting the rates set in the most recent base rate case for each company. It is assumed that the number of customers and sales remain constant over the evaluation period. Stated otherwise, the projections do *not* account for any migration of gas customers to electric as a result of electrification policies or through endogenous migration.

For each year, we allocate the revenue requirement to the residential heating class and then design rates to recover this revenue target. Rate design follows a three-step process:

- First, the STRIDE surcharge is set as a fixed monthly surcharge to recover the "new" or incremental STRIDE revenue requirement for the year. This distinction is possible because the STRIDE and non-STRIDE capital revenue requirements are calculated separately. Put another way, the target STRIDE revenue for any given year (Year n) is the difference between the cumulative STRIDE revenue requirement for Year n minus the cumulative STRIDE revenue requirement for the previous year (Year n-1). This approach is meant to mimic the "rolling" in of STRIDE into base rates over time.
- Next, a Fixed Charge is set. The Fixed Surcharge starts at current level (or 2023 level for BGE) and is then increased by 1 percent each year.
- Finally, all remaining revenue requirement assigned to the residential classes is collected through the volumetric charge.

Table 4.1: Rate Design and Bill Determinant Assumptions

	BGE (CN 9645)	WGL (CN 9651)	CMD (CN 9644)
Customer Class	Schedule D (Residential)	Residential Heating/Cooling	RS (Residential Service)
Residential Revenue Allocation %	66.5%	69.5%	57.3%
Customer-months	7,886,947	5,470,633	367,106
Sales (therms)	445,102,435	358,972,754	23,750,943
Starting Fixed Charge	$15.25	$11.55	$16.00

Customer-months are the number of bills sent out in a year. This is equal to the number of customers x 12.

We follow the above approach to estimate volumetric and fixed charges for residential customers from 2022 to 2100. To present these results, in the subsections below, we show the monthly bill for a typical customer in winter months. Our typical customer uses 160 therms per month in January or February.[14] The next three subsections provide the results of this typical customer bill analysis for each company.

4.1. BGE

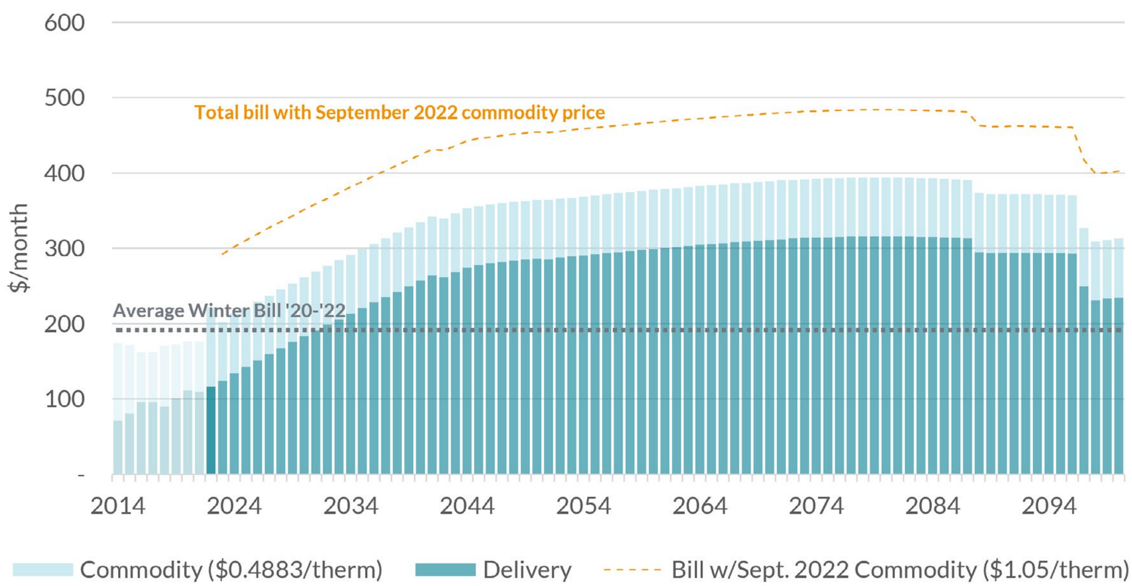
The bill for the typical BGE customer includes both the cost of delivery (fixed base charge, volumetric base charge, STRIDE surcharge) and commodity. Before calculating the typical bill, we needed to develop an assumption for the commodity portion of the bill.

The commodity price we use in the BGE bill analysis is based on the average commodity price charged to BGE's residential customers in the five proceeding Februarys (2018-2022). For reference, and to provide context for the current jump in natural gas prices, we also show what the future BGE bill would be if prices remain at the September 2022 levels.[15] The commodity price assumptions are shown in Table 4.2.

Table 4.2: BGE Commodity Price Assumptions

Scenario	Definition	Price ($/therm)
Base Commodity	5-year February commodity average	0.4884
Current Commodity	September 2022 commodity price	1.0500

Figure 4.1: BGE Typical Winter Bill, 2014-2100



BGE rates for 2021 and 2022 include the Rider 18 offset that was adopted to lower bills in the first two years of the MYRP. This offset amount is removed after 2022.

14 This assumption is based on the average residential gas usage per customer in Maryland for January and February over the last five years. According to the Energy Information Agency (EIA), residential gas consumption in Maryland in the months of January and February has averaged 155.6 million therms for these two months from 2018 to 2022. For the approximately 965,000 residential gas customers in Maryland, this results in an average of 161.17 therms per customer in these two winter months. We round this result to 160 therms for our bill impact analysis.

15 ML#242191 (BGE September 2022 Gas Commodity Price)

The estimated winter bill for a BGE customer from 2022 to 2100 is presented in Figure 4.1. Our projections show that if BGE continues investing in capital at the projected levels, the typical winter bill for a customer using 160 therms/month will grow from an average of $192 in 2020-2022 to $299, a 56 percent increase by 2035, and $364, a 90 percent increase by 2050. These estimates assume commodity prices revert back to the five-year averages. If gas prices stay around the current (2021-2022) levels, then the typical residential customer's winter bill would increase by an additional $89.86 per month.

4.2. WGL

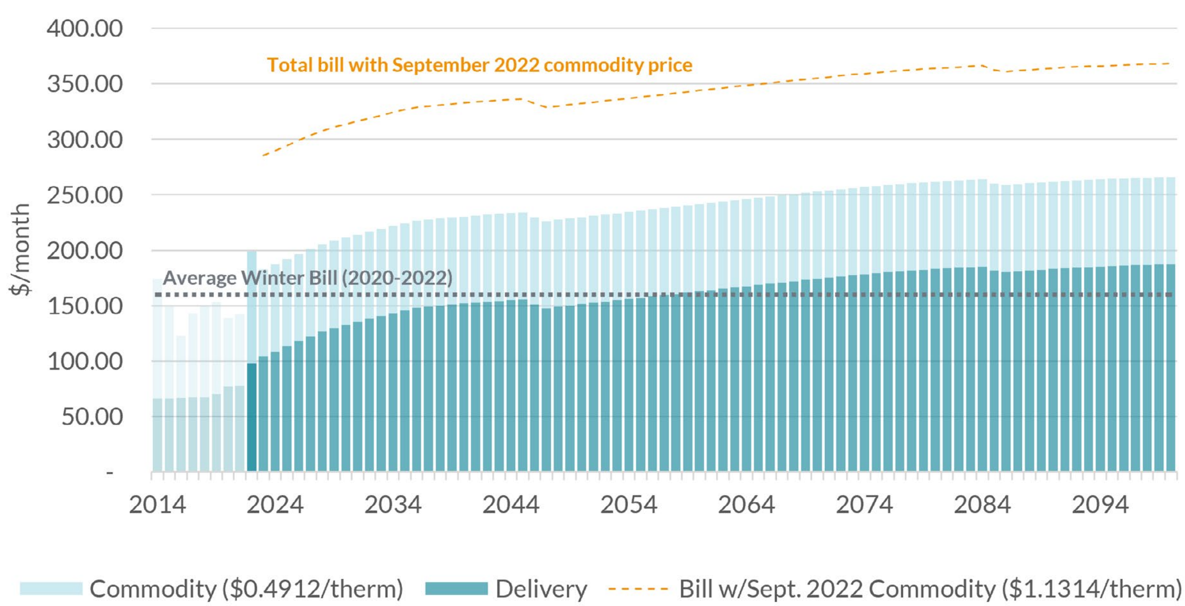
The commodity prices we use in the WGL bill analysis is based on the average commodity price charged to WGL's residential customers in the five proceeding Februarys (2018-2022). For reference, and to provide context for the jump in natural gas prices in 2022, we also show what the future WGL bill would be if prices remain at their current levels. These commodity price assumptions[16] are shown in Table 4.3.

Table 4.3: WGL Commodity Price Assumptions

Scenario	Definition	Price ($/therm)
Base Commodity	5-year February commodity average	0.4912
Current Commodity	September 2022 commodity price	1.1314

The estimated winter bill for a WGL customer from 2022 to 2100 is presented in Figure 4.2. Our projections show that if WGL continues investing in capital at the projected levels, the typical winter bill for a customer using 160 therms/month will grow from an average of $160 in 2020-2022 to $224, a 40 percent increase by 2035, and $230, a 44 percent increase by 2050. If gas commodity prices stay around the September 2022 level, the typical residential customer's winter bill would increase by an additional $102.43 per month.

Figure 4.2: WGL Typical Winter Bill, 2014-2100



16 ML#241971 (WGL September-October 2022 Purchased Gas Charge).

4.3. CMD

The commodity prices we use in the CMD bill analysis is based on the average commodity price charged to CMD's residential customers in the five proceeding Februarys (2018-2022). For reference, to provide context for the jump in natural gas prices in 2022, we also show what the future CMD bill would be if prices remain at their current levels.[17] The commodity price assumptions are shown in Table 4.4.

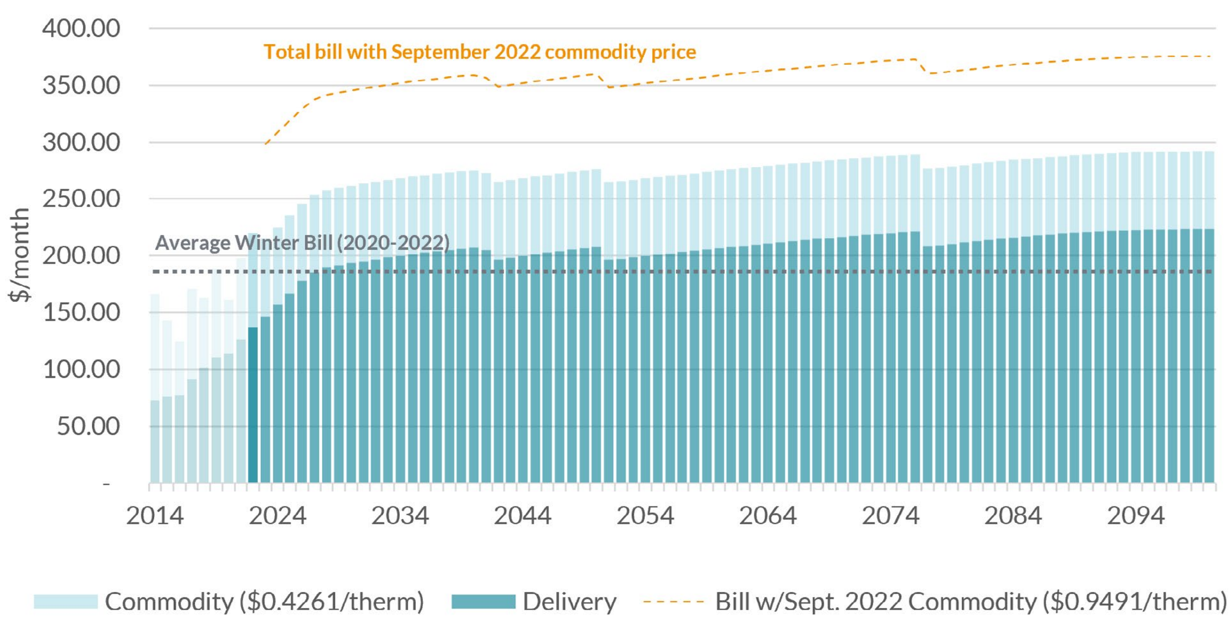
The estimated winter bill for a CMD customer from 2022 to 2100 is presented in Figure 4.1. Our projections show that if CMD continues investing in capital at the projected levels, the typical winter bill for a customer using 160 therms/month will grow from an average of $186 in 2020-2022 to $270, a 45 percent increase by 2035, and $276, a 48 percent increase by 2050. If gas commodity prices stay around the current (September 2022) levels, the typical residential customer's winter bill would increase by an additional $83.69 per month.

Table 4.4: CMD Commodity Price Assumptions

Scenario	Definition	Price ($/therm)
Base Commodity	5-year February commodity average	0.4261
Current Commodity	September 2022 commodity price	0.9491

The average CMD customer's winter bill will increase 45% by 2035.

Figure 4.3: CMD Typical Winter Bill, 2014-2100



17 ML#241226 (CMD September 2022 Gas Commodity Price)

SECTION FIVE

OTHER GAS UTILITY COST ANALYSIS

In addition to the core analysis of developing capital cost projections and estimating the bill impact, we performed other analysis for OPC on STRIDE-related issues. The six subsections below discuss the results.

5.1. Recovery of STRIDE Costs

We determined the portion of the total STRIDE costs that have already been recovered through rates and, conversely, what portion of the STRIDE costs remain to be recovered. An investment is being "recovered" through rates until it is fully depreciated. Utilities under rate-of-return regulation receive a "return on" the undepreciated value of an investment, in the form of a return on equity, and a "return of" the investment, in the form of depreciation expenses. Accordingly, we use cumulative STRIDE depreciation to represent the amounts "recovered" through rates.

The purpose of this exercise is to review the overall rate recovery progress, *i.e.*, progress toward the recovery of all completed and planned STRIDE costs. This meant that we defined the "unrecovered" portion of STRIDE in each year as the sum of the undepreciated completed plant and any remaining STRIDE investment not yet completed.

Figure 5.1: Percentage of STRIDE Costs Remaining to be Recovered by Company

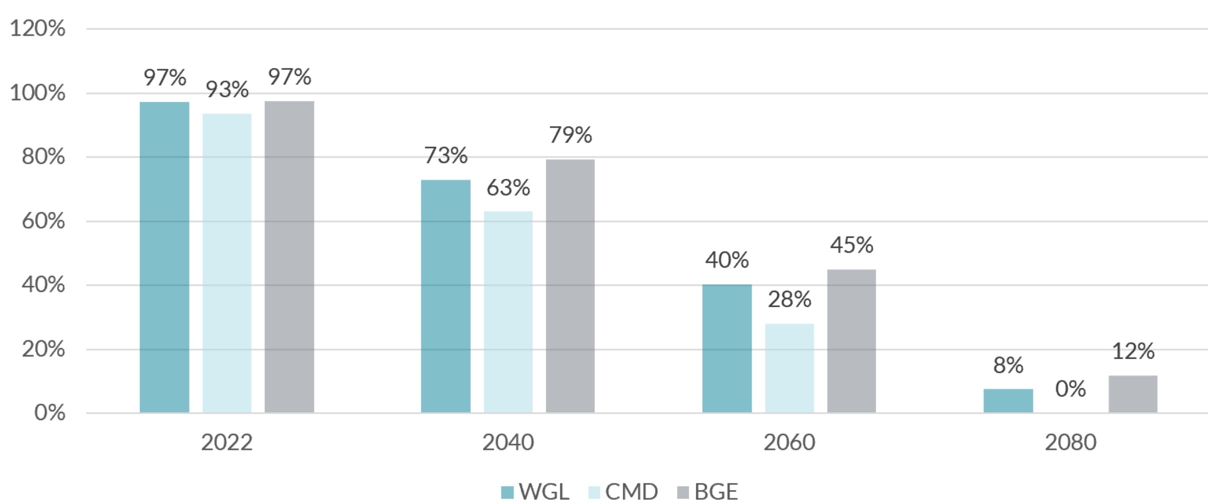


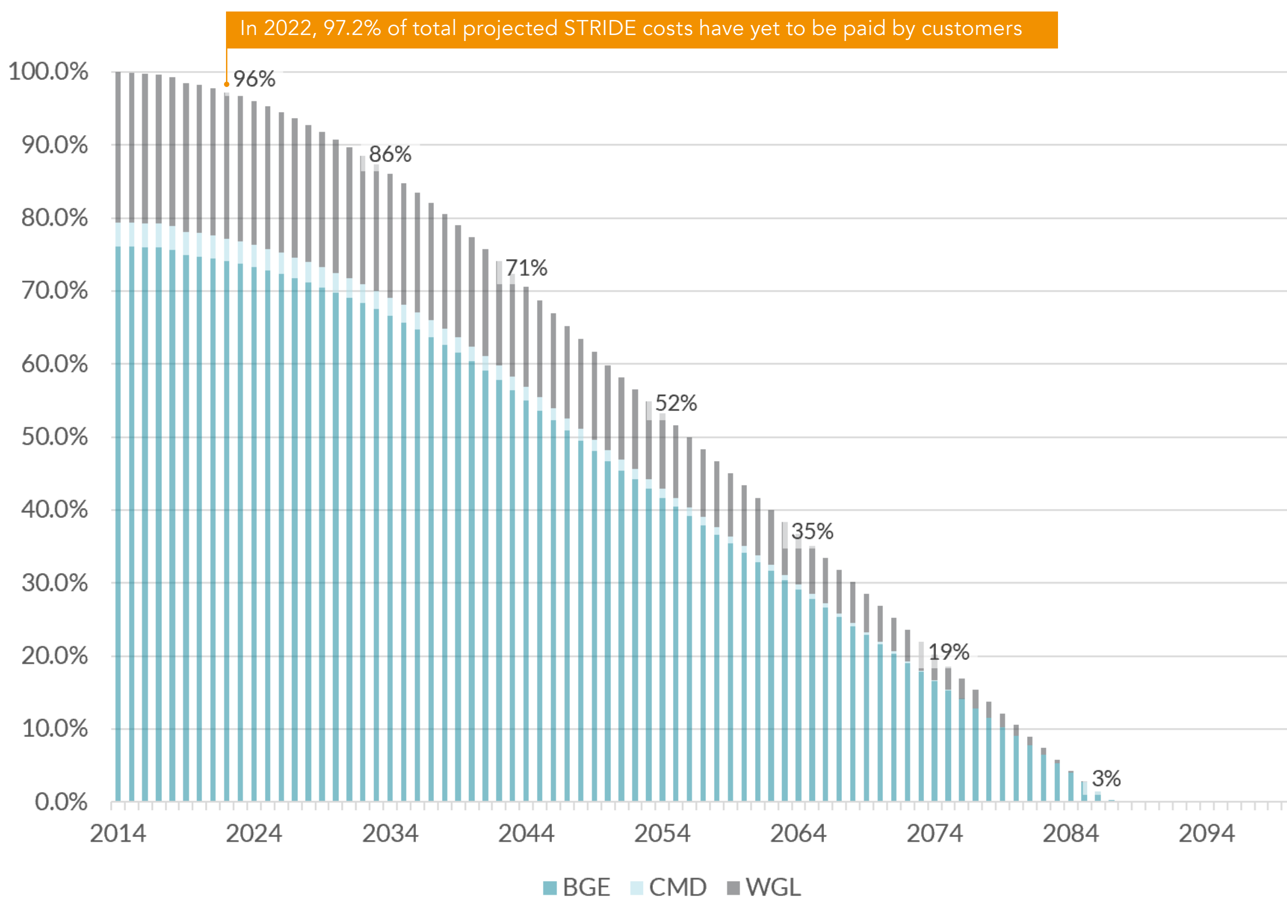
Figure 5.2 shows a snapshot of the progress made periodically by company. Notice that CMD's recovery is faster due to the earlier completion of its STRIDE activities.

We then combined the results of the individual companies into Figure 5.2 to provide a wholistic view of the remaining years that STRIDE costs will be recovered through rates in Maryland. What is important to recognize from this figure is that right now, in 2022, only 2.8% of the planned STRIDE costs have been recovered through rates. STRIDE cost recovery is still at the early stages with Maryland customers expected to be paying off STRIDE costs until 2087.

5.2. Impact of STRIDE on Maintenance Costs

OPC has argued that one of STRIDE's expected benefits should be a reduction in companies' operating costs due to avoided costly leak repairs that no longer need to be addressed. Companies agree that there will be avoided leak repairs but contend this result will not have a corresponding drop in leak repair expenses. BGE has historically made this case in its STRIDE annual audits, where the company notes, "Management does not believe that the STRIDE improvements will result in significant O&M cost savings; however, the infrastructure improvements

Figure 5.2: Percentage of STRIDE Cost Recovery Remaining



are expected to decrease the number of leak repairs that would have otherwise occurred without these improvements."[18] On the other hand, OPC has maintained that if the arguments in favor of STRIDE are that newer, leak-prone pipes will result in lower leaks, then over time there should be a decrease in leak repair expenses.

To assess whether STRIDE has resulted in operating cost reductions, we evaluated the trend in annual maintenance expenditures on main and services since the programs began.

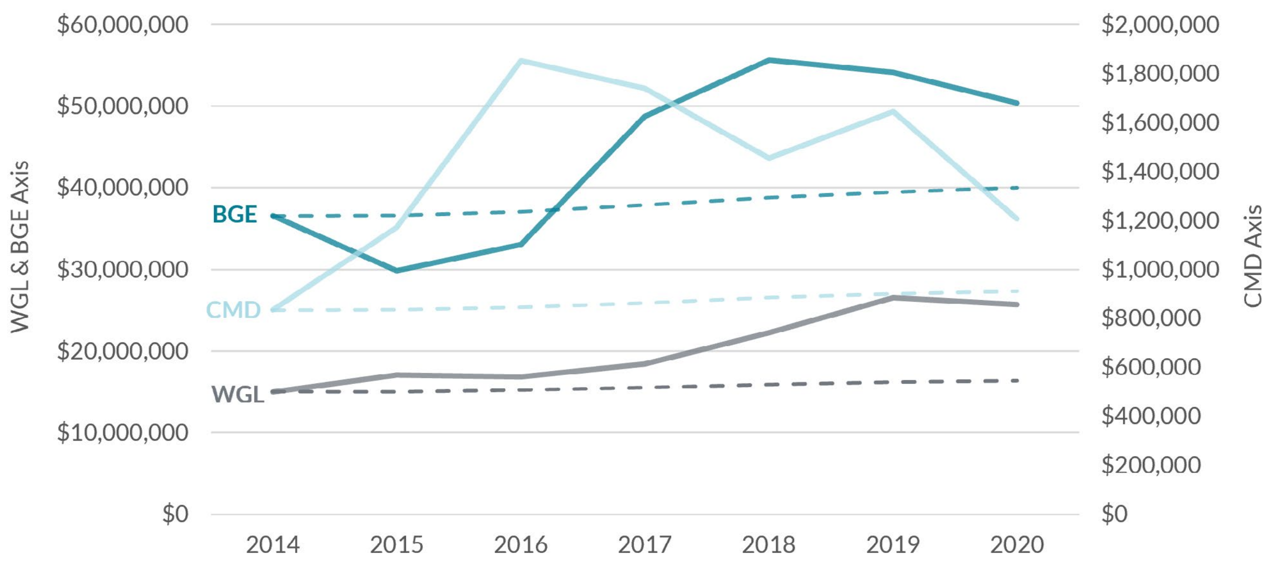
Specifically, we gathered data from each company's annual reports on two FERC operating cost accounts, Account 887 Mains and Account 892 Services. FERC defines those accounts as follows:

- **Account 887 Mains**: This account shall include the cost of labor, materials used, and expenses incurred in the maintenance of distribution mains, the book cost of which is includible in account 376, Mains.
- **Account 892 Services**: This account shall include the cost of labor, materials used, and expenses incurred in the maintenance of services, the book cost of which is includible in account 380, Services.

The annual amounts spent on main and service maintenance by BGE, CMD, and WGL is shown in the figure below. There is no noticeable decrease in operating

All three companies are spending more on operating costs in 2020 than in 2014 when STRIDE began.

Figure 5.3: Historic Main + Service Maintenance Operating Costs



Includes maintance costs in Accounts 887 (Mains) and 892 (Services). Data taken from Annual Reports submitted to MD PSC. WGL costs represent 38.2% of total company costs as an estimate of MD's portion of companywide total.

18 Maillog #214914, Annual STRIDE Plan Agreed-Upon Procedures Report, April 28, 2017, Appendix 3, Management Footnote to Schedule E.

costs for any company since 2014. The dashed line for each company shows what the cost levels would be if the 2014 levels simply increased at the rate of inflation. Because each of these dashed lines in 2020 is below the actual (solid) line, this shows that even after taking inflation into account all three companies are spending more on operating costs in 2020 than in 2014 when STRIDE began.

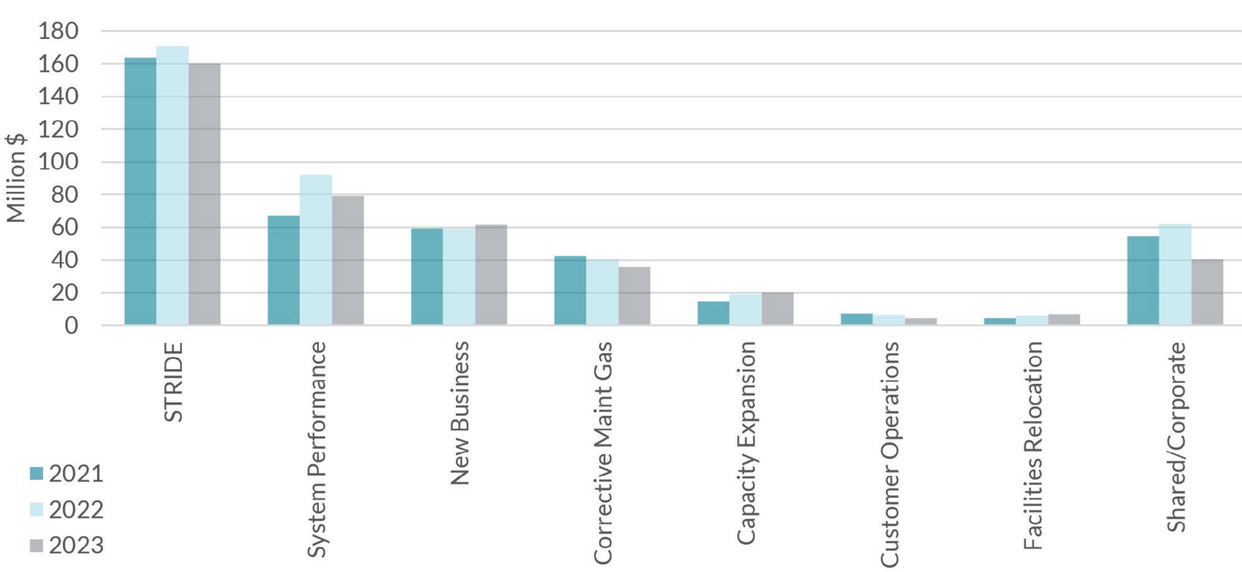
One reasonable interpretation of the results shown above is that the increase in operating costs over inflation from pre-STRIDE levels indicates that customers are not receiving the full benefits intended by STRIDE. The logic is that removing leak-prone or leaking pipes from service results in fewer leak repairs. A more optimistic interpretation of these results is that the operating costs shown here represent a reduction compared to what would have been spent had STRIDE work not been completed. As noted above, this latter interpretation is what the distribution companies contend is correct.

5.3. BGE CAPEX by Category

Within the context of both the gas capital investment discussions and our review of the BGE MYRP capital plans, OPC asked for analysis on the breakdown of BGE's capital plans into different capital categories. We used BGE's three-year gas CAPEX plan submitted as part of the CN 9645 compliance filing to develop Figure 5.4. The figure shows the breakdown of capital investment according to BGE's investment categories. This figure shows that STRIDE (39 percent) continues to be the major focus of BGE's capital investment activities with System Performance (19 percent) and New Business (14 percent) coming in as the second and third highest investment categories. Notably, Shared/Corporate expenses (a combined 12 percent), which includes categories such as real estate and information technology, are higher than some categories, such as corrective maintenance (9 percent) and capacity expansion (4 percent), which directly address safety and reliability problems.

STRIDE continues to be the major focus of BGE's capital investment activities.

Figure 5.4: BGE MYRP CAPEX Plans by Category



This level of information was only available for BGE because it is the only gas utility to submit a multi-year rate plan in Maryland.

5.4. Investments in Distribution System Expansion

This report has focused on gas utility capital expenditures. One aspect of the gas distribution companies' capital spending strategies is their plans for new business and capacity expansion. These categories represent investments being made to grow the gas delivery business beyond its current size. We discuss below trends in investment increases in distribution system expansion. This section summarizes our analysis of capacity expansion and new business for BGE and WGL. Data on new business investments and capacity expansion are not publicly available for CMD.

BGE plans to spend $78.3 million in 2022 on new customer conversions and capacity expansion projects.

5.4.1. BGE

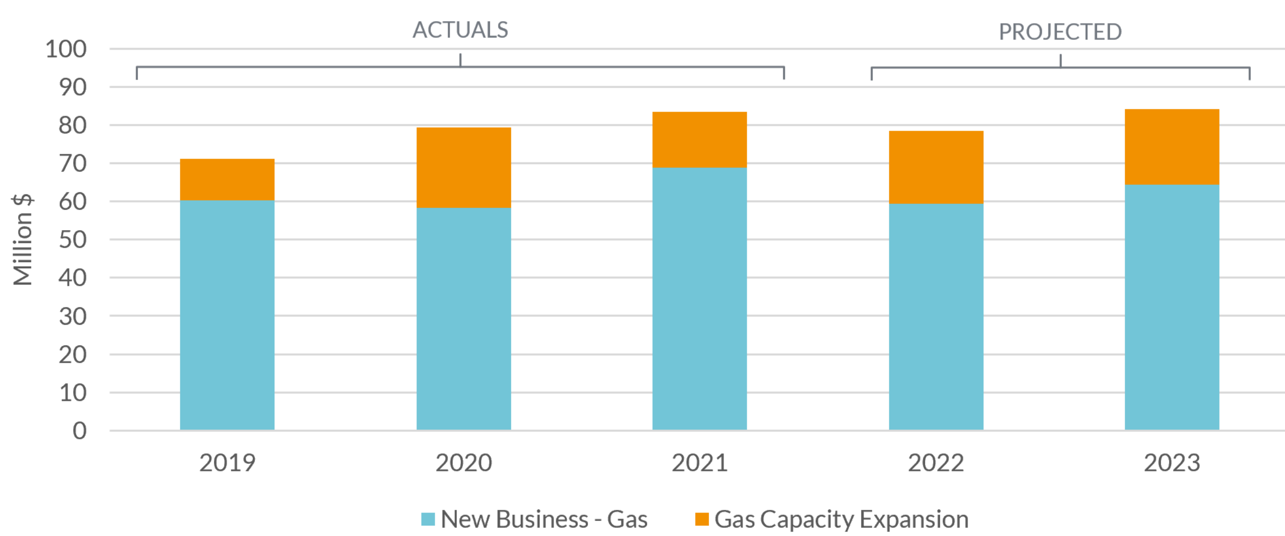
Information on BGE's new business and capacity expansion plans, as well as historical information, was provided as part of the MYRP proceedings in PSC Case No. 9645. BGE plans to spend $78.3 million in 2022 on new customer conversions and capacity expansion projects. This is a slight drop in what has been increasing levels of actual and planned investment in system expansion. As shown in Figure 5.5, the investments pursued through MYRP in 2021 and 2023 on system expansion investment (new business + capacity expansion) represent increases over the historical amounts made in 2019 and 2020.

For context, over the three-year MYRP period, BGE plans to spend 20% ($246 million) of its $1.2 billion capital budget on capacity expansion and new business projects.

5.4.2. WGL

WGL reports its historic expenditures on new business in its annual financial reports. Plans for future new business investments were included in the compliance filing submitted in PSC Case No. 9651.

Figure 5.5: BGE Capital Expenditure on Capacity Expansion and New Business, 2019-2023



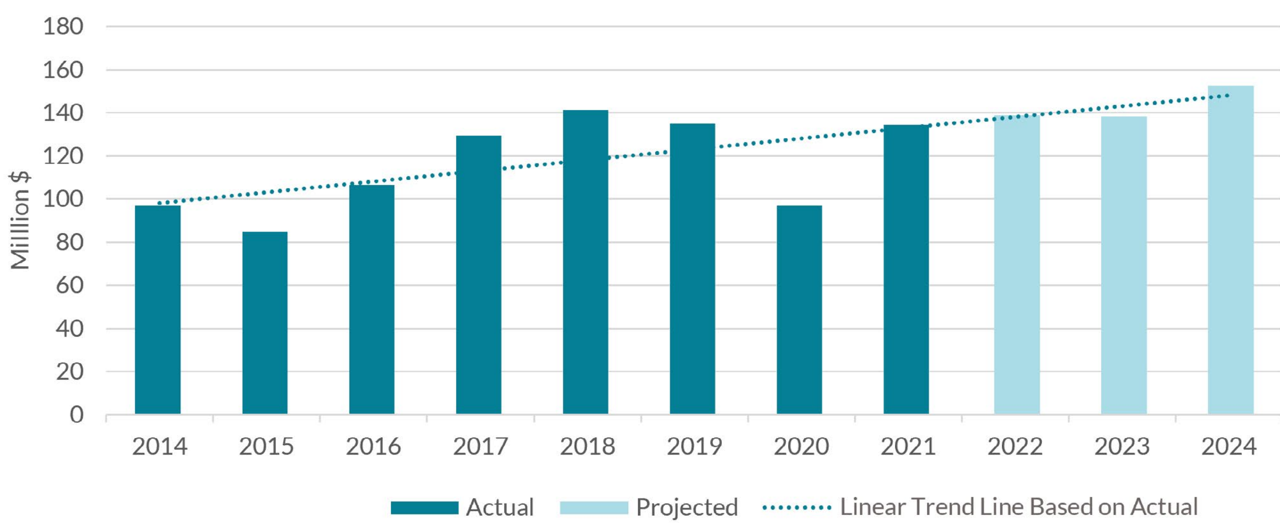
A footnote in these reports notes that the "new business" category also includes "certain projects that support the existing distribution system." We interpret "new business" investments that "support the existing distribution system" to mean expansion of existing system capacity (which BGE's compliance filing calls "capacity expansion").[19] The information on WGL's plans for new business was not available for Maryland alone. Instead, like the information available for total capital investments, the amounts for new business investments are presented in aggregate for all three service jurisdictions. This company-wide information provides insight into WGL's investment efforts being made to expand its gas distribution business.

WGL increased its company-wide capital spending on new business from $97 million in 2014 to $134.4 million in 2021, with a slight dip in expenditures in 2020 ($96.9 million), likely a result due to COVID-19 limitations on entry into customer premises. WGL projections for this category promise an increase in spending in the 2022-2023 period, to $138.3 million for both years, and a further jump in 2024, reaching $152.5 million. Figure 5.6 shows an overall upward trend in spending in the new business category in the decade between 2014 and 2024.

In terms of share of total capital expenditures, spending in this category in 2022 is projected to be 26 percent of all capital expenditures. The share is projected to decrease to 23 percent in the 2023-2024 period.

As stated above, these figures for WGL are company-wide, for service territories in Maryland, Virginia, and the District of Columbia. In rate cases, a cost allocator based on each of WGL's service territory's gas plant-in-service is used to allocate certain shared investment and operating costs. The most recent cost allocator for plant-in-service shows that Maryland's share of gas plant-in-service is 38.2%.[20] Applying this percentage to WGL's 2022-23 projected spending means that WGL's projected Maryland spending on

Figure 5.6: WGL Capital Expenditure on New Business, Actual and Projected (2014-2024)



19 See page 12 of WGL's 2021 Financial report: (*https://www.washingtongas.com/-/media/6b201563983c461c8b-d17a2d50e67af3.pdf*)

20 ML#231646, Case No. 9651, WGL Exhibit ABG-1, Schedule AL, page 2, line 28.

new customers and capacity expansion for 2022 and 2023 is about $52.8 million each year.

5.5. Changes in Bill Composition

Prior to the increase of gas commodity prices in 2020 and 2021, there had been a trend over the previous decade where the distribution portion of bills was increasing, while the commodity portion of the bill decreased or remained relatively constant. We will use BGE as an example to demonstrate this trend. As shown in Figure 5.7, from 2014 to 2020 the overall bill (commodity plus delivery) remained relatively constant from 2014 to 2020 because the decrease in gas commodity prices offset increases in distribution costs.[21]

Over this period a notable flip occurs in 2016: Gas customers begin to pay more to deliver the gas than the gas commodity they use. Figure 5.8 shows the bills from Figure 5.7 broken down into percentage components.

The increase in delivery rates has largely been driven by the capital expenditures, specifically the STRIDE expenditures, addressed in this report. From a customers' perspective, it can be viewed as a positive that improvements in gas extraction have reduced the commodity costs and enabled gas companies to replace leak-prone materials without substantial increases in the total customer bill. The trouble with this perspective is that it ignores the reality that if delivery rates had not increased as rapidly then customers would have paid lower total bills, over this period. Instead of customers saving money from the decrease in commodity costs, gas companies have increased base delivery rates and filled the gap.

Figure 5.7: BGE Typical Winter Bill by Component, 2014-2021 ($/month)

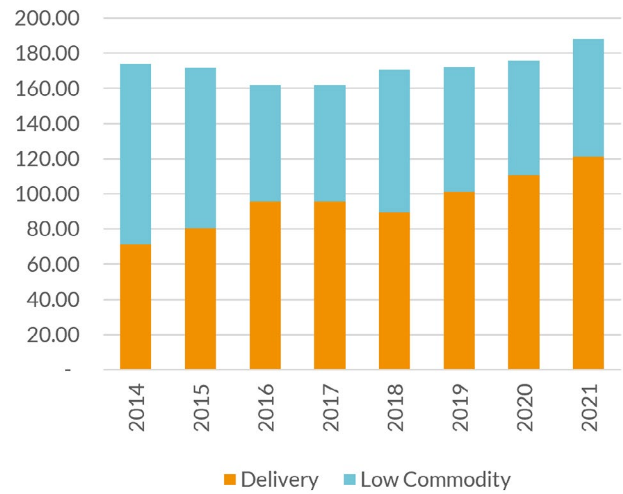
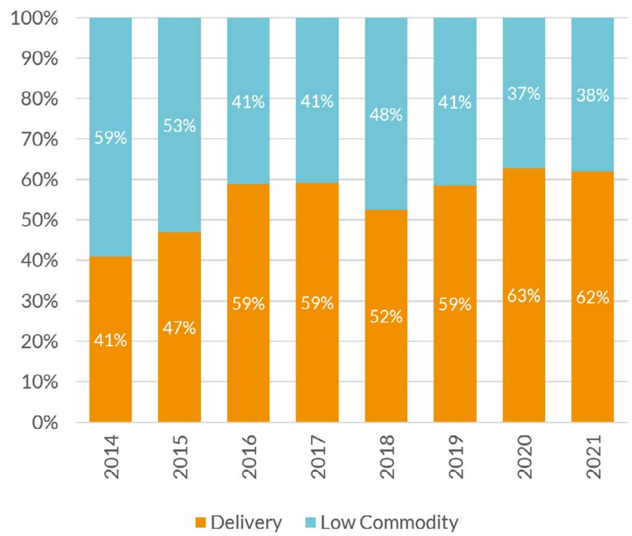


Figure 5.8: BGE Typical Winter Bill by Component, 2014-2021 (%)



If delivery rates had not increased as rapidly, then customers would have paid lower total bills over this period.

21 The delivery portion of the bill impact for 2021 reflects the full offset, i.e., the exclusions, of the rate increase approved by the Commission in Order No. 89678 to address the COVID-19 pandemic; the approved increase in the annual revenue requirement of $54.2 million for 2021 delivery rates will be recovered in future years, with carrying costs.

5.6. Delivery Rates vs. Commodity Prices

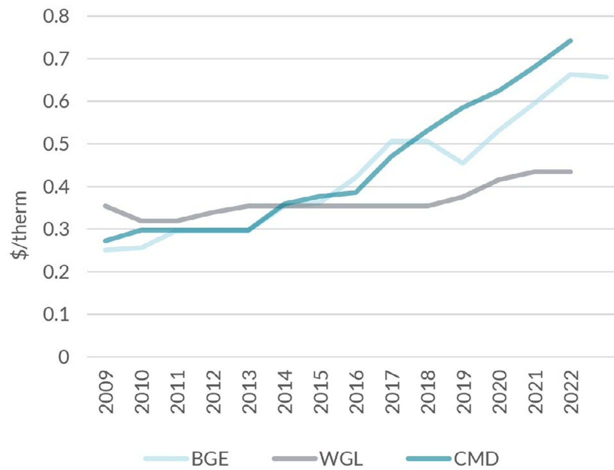
The trend discussed in the previous sections is the result of a period of declining or low-cost gas commodity prices and continued upward pressure from gas utilities on delivery distribution rates. This subsection explores the relationship between the commodity price of gas and the overall costs of gas services.

Delivery charges appear in two separate components of customer rates—a volumetric charge and a demand (or fixed) charge. Steady increases in both the volumetric and fixed portion of delivery rates at the three gas companies from 2009 to 2022 are shown in Figure 5.9 and Figure 5.10.

The steady increase in gas delivery fees has been masked by an unusually prolonged low-price commodity-cost period from 2013 to 2021. Gas prices have historically shown patterns with repeating short (1-2 year) cycles of peaks and troughs in prices. This pattern is evident in the Henry Hub Prices prior to 2013 shown in the figure below where prices routinely dropped but then returned to levels around the previous high mark. This pattern contrasts with the eight-year period between 2013 and 2021 when prices fell and did not return close to the February 2013 levels until February 2021. That gas commodity market now, in 2022, appears to have returned to the era of high price volatility.

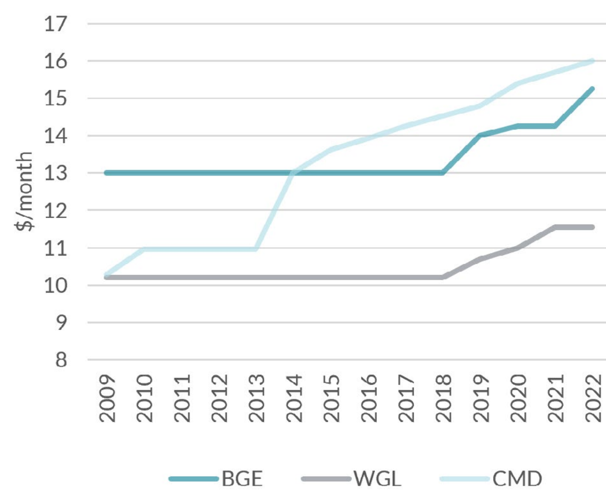
We emphasize this point on gas volatility and the rising cost of gas delivery because price is one of the main factors used by gas companies to promote the continued transition of customers to natural gas away from fuel oil. Versions of the moniker "clean and affordable natural gas" are a common phrase used on gas company websites[22] and regulatory filings.

Figure 5.9: Volumetric Delivery ($/therm) rates, 2009-2022



WGL has a three-block decreasing volumetric rate structure where customers are charged decreasingly lower rates for the first 45 therms, next 135 therms (45-180 therms), and all other usage above 180 therms. The volumetric rate in the figure is a weighted average rate calculated using an assumed 130 therm per month.

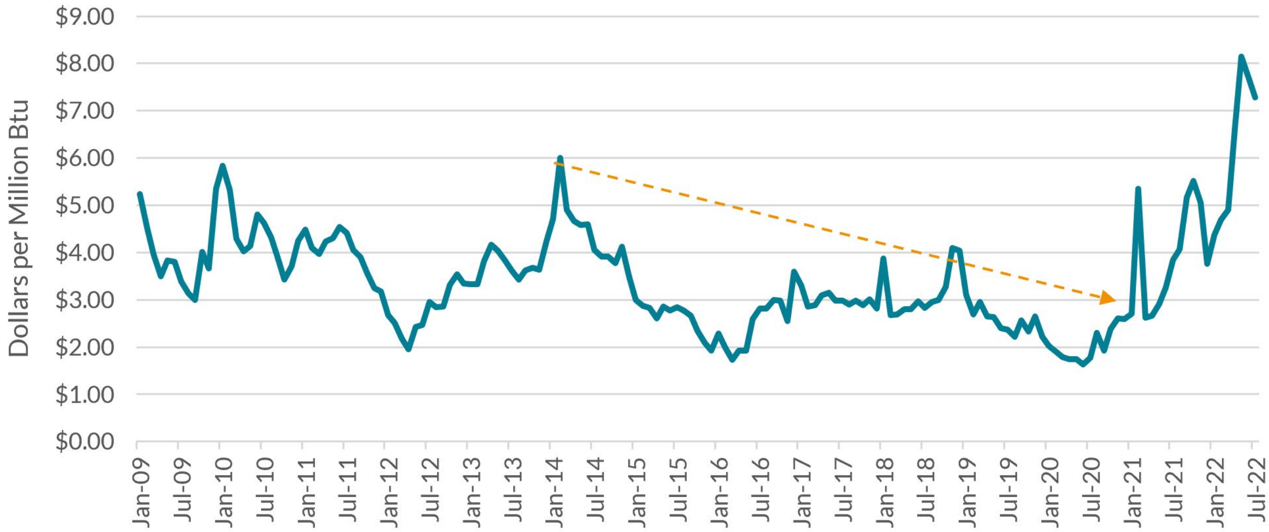
Figure 5.10: Fixed Charges ($/month), 2009-2022



The steady increase in gas delivery fees has been masked by an unusually prolonged low-price commodity-cost period from 2013 to 2021

22 See the websites of BGE (*https://www.bge.com/SafetyCommunity/Education/Pages/BGENaturalGas.aspx*) and WGL (*https://www.washingtongas.com/safety-education/education/about-natural-gas*).

Figure 5.11: Henry Hub Gas Spot Price, January 2009-May 2022



Source: https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm

For example, BGE justified the budget for new business conversions in its MYRP by identifying the "problem statement" intended to be addressed by new business projects—customers wanting to switch from existing electric, propane, or oil to "more cost efficient, natural gas."[23] It is true that drops in commodity prices over the last decade have, at times, made gas a more affordable energy option for some customers. But utility marketing language overlooks the fact that the low commodity prices over this period masked the reality that gas is prone to extremes in price volatility, just like fuel oil.

Gas is prone to extremes in price volatility.

The volatility in prices residential customers paid for gas was around **three times greater** than the volatility in electricity prices over this period.

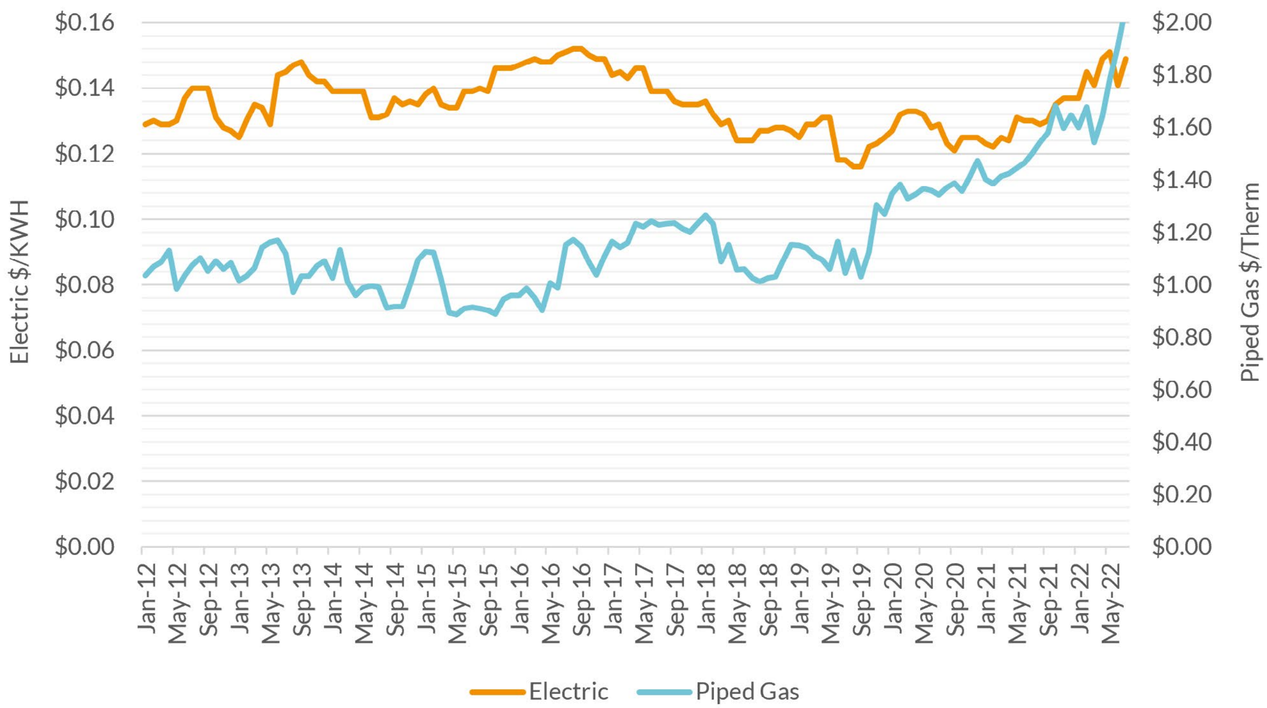
The volatility of gas prices contrasts with electricity, as shown in Figure 5.12. This figure uses data on electricity and gas end-user prices tracked by the Bureau of Labor and Statistics (BLS). Evident in this figure is that between 2009 and 2022, there is greater variability in the price paid by customers for gas than electricity. Statistically, the volatility in prices residential customers paid for gas was around three times greater than the volatility in electricity prices over this period.[24]

Setting aside the issue of volatility, the recent increases in gas prices also show that the proposition that gas is "the more affordable" energy source might be more marketing than reality. To better compare the changes in electricity and gas prices, we indexed the prices using a baseline. In Figure 5.13 below, the January 2012 prices for gas and electricity are used as baselines (January 2012 = 1) and then

23 Case No. 9645, ML# 233739 at page 46.

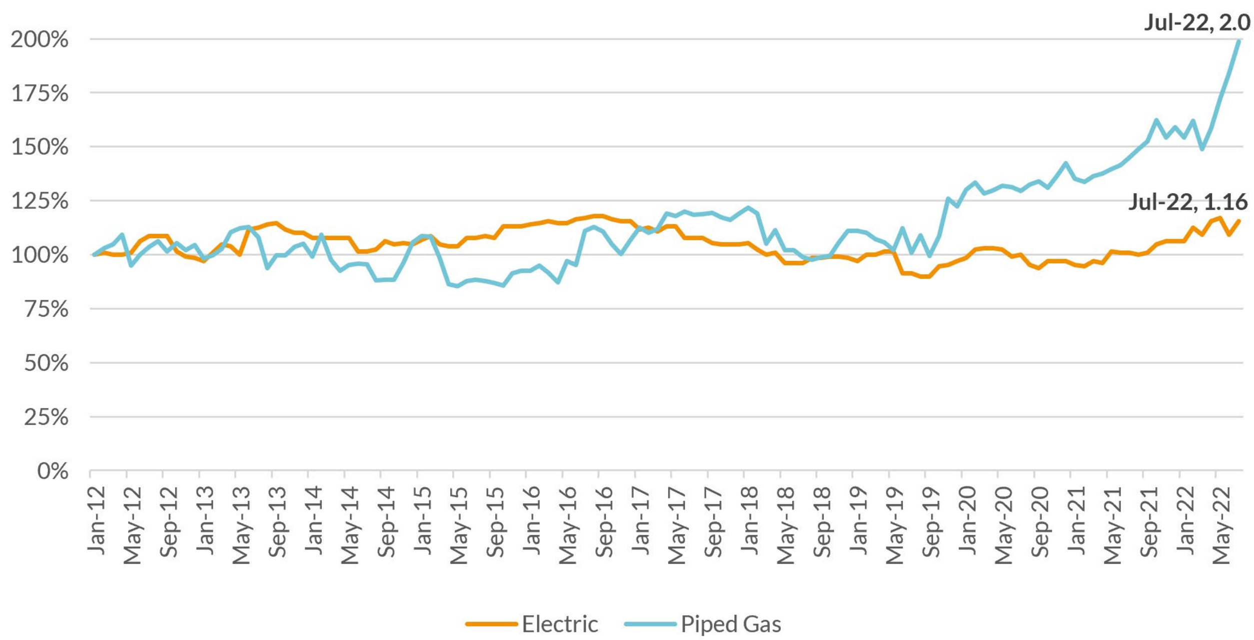
24 Volatility was estimated by calculating the coefficient of variation (CV = standard deviation / mean) of gas and electricity prices over the evaluation period. The CV of gas prices was 0.18 and the CV of electricity prices was 0.06.

Figure 5.12: BGE Residential Electricity and Gas Prices, January 2012-May 2022



Price data on Baltimore electricity and gas prices from Bureau of Labor Statistics (BLS)

Figure 5.13 Indexed BGE Electricity and Gas Prices, January 2012-May 2022 (index = January 2012)



Price data on Baltimore electricity and gas prices from Bureau of Labor Statistics (BLS) every subsequent monthly indicator represents the relationship between that month's price and the base-line price (Monthly price / January 2012 price). What comes across in this figure is that electricity prices have stayed relatively around the same levels since 2012. Prices are 16 percent higher in May 2022 from ten years earlier. On the other hand, gas prices have increased rapidly in the last three years and are now double prices in January 2012. This result exemplifies the combined effect of the end of low-cost gas and the rise in delivery charges over this same period.

Gas companies may argue that it is unfair to use the current high prices as a comparison given the market conditions due to the combined effects of pandemic-driven supply constraints and the war in Ukraine. Regardless of recent gas commodity price spikes, the figure above shows the general trend starting in 2019 of natural gas prices increasing faster than electricity end-user prices.

GLOSSARY AND ACRONYMS

Term	Definition	Source
Commodity rate	The unit rate charged for each unit of gas actually purchased under a contract.	New York State Public Service Commission. "Glossary of Terms Used by Utilities and Their Regulators". Available at: https://www.dps.ny.gov/glossary.html.
Depreciation	The loss in service value not restored by current maintenance and incurred in connection with the consumption or prospective retirement of property in the course of service from causes against which the carrier is not protected by insurance, and the effect of which can be forecast with a reasonable approach to accuracy	"18 CFR Ch. I, Pt. 352." *Code of Federal Regulations*. Available from: https://www.ferc.gov/sites/default/files/2020-06/18cfr352.pdf. Accessed 6 July 2022.
Rate Base	The net investment of a utility in property that is used to serve the public; this includes the original cost net of depreciation, adjusted by working capital, deferred taxes, and various regulatory assets—the term is often misused to describe the utility revenue requirement	Lazar, J. (2016). Electricity Regulation in the US: A Guide. Second Edition. Montpelier, VT: The Regulatory Assistance Project. Retrieved from https://www.raponline.org/knowledge-center/electricity-regulation-in-the-us-a-guide-2/.
Return on Equity	The rate of earnings realized by a utility on its shareholders' assets, calculated by dividing the earnings available for dividends by the equity portion of the rate base.	New York State Public Service Commission. "Glossary of Terms Used by Utilities and Their Regulators". Available at: https://www.dps.ny.gov/glossary.html.
Revenue Requirement	The annual revenues that the utility is entitled to collect (as modified by adjustment clauses). It is the sum of operation and maintenance expenses, depreciation, taxes, and a return on rate base. In most contexts, revenue requirement and cost of service are synonymous.	Lazar, J. (2016). Electricity Regulation in the US: A Guide. Second Edition. Montpelier, VT: The Regulatory Assistance Project. Retrieved from https://www.raponline.org/knowledge-center/electricity-regulation-in-the-us-a-guide-2/.
Stranded Assets	Assets that have suffered from unanticipated or premature write-downs, devaluation or conversion to liabilities.	Lloyd's. 2017."Stranded Assets." Available at: https://www.lloyds.com/strandedassets.

Acronyms

BGE	Baltimore Gas & Electric
CAPEX	capital expenditures
CAGR	compound annual growth rate
CMD	Columbia Gas of Maryland
CN	Case Number
OPC	Office of People's Counsel
MACRS	Modified Accelerated Cost Recovery System
MYRP	Multi-year rate plan
PHMSA	Pipeline and Hazardous Materials Safety Administration
PSC	Public Service Commission
STRIDE	Strategic Infrastructure Development and Enhancement (Public Utilities Article, Ann. Code of Md., § 4-210)
VMC	vintage mechanically coupled
WACC	weighted average cost of capital
WGL	Washington Gas Light

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Exhibit ASH-4

Exhibit ASH-4

OPC
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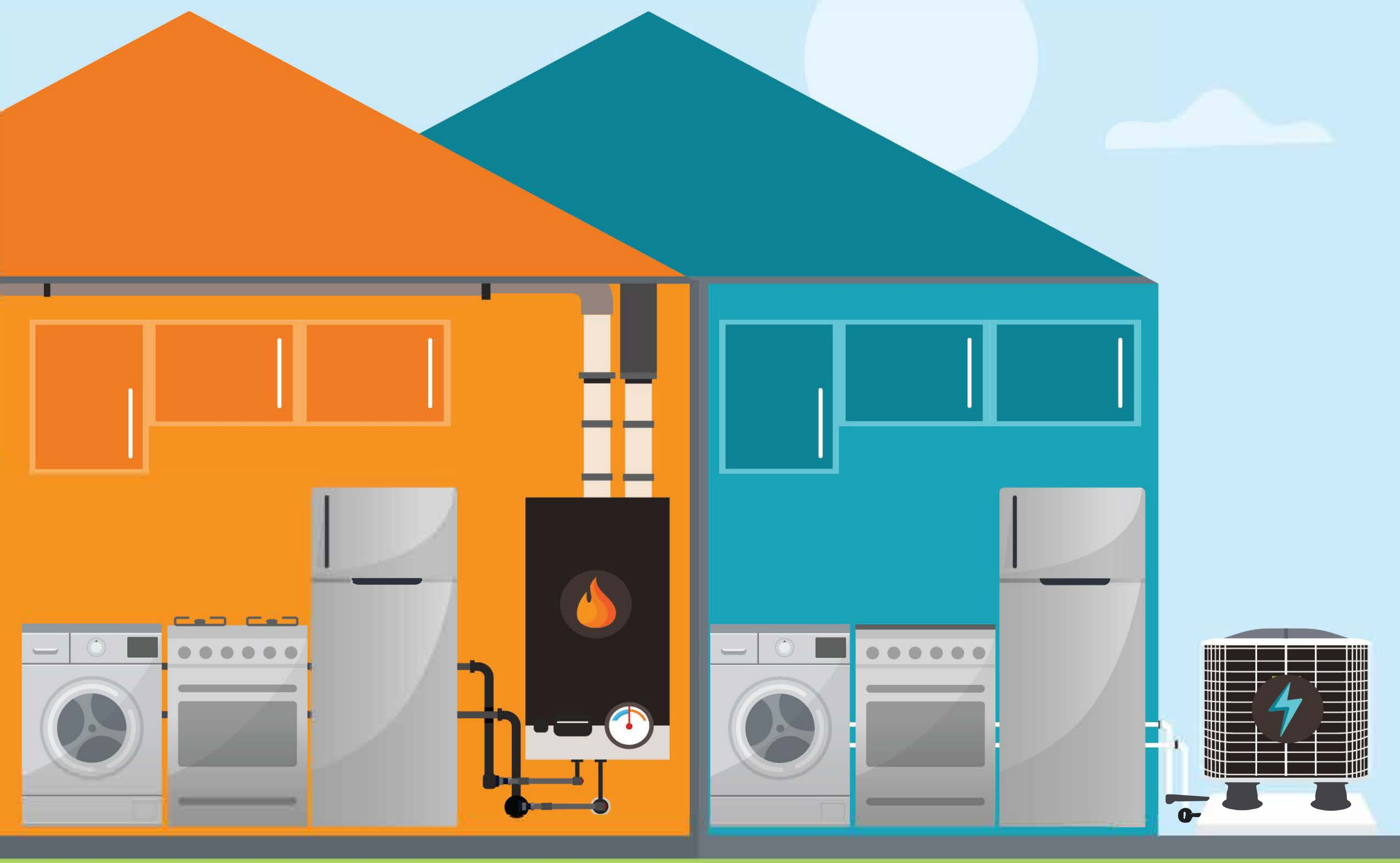
State of Maryland

Climate Policy for Maryland's Gas Utilities

Financial Implications



November 2022

DEAR READERS

The most promising path to transforming Maryland's homes and apartments to meet the State's climate goals involves transitioning to electric heating and cooling systems and appliances. This point is not seriously disputed.

What remains at issue for a decarbonized future is the role of the gas utilities' distribution infrastructure and gas itself. As our recent report, Maryland Gas Utility Spending: Projections and Analysis, shows, despite the State's electrification goals, Maryland's gas utilities are on a business-as-usual path, spending tens of billions of dollars on their delivery systems. Gas utilities hope to recover the costs of this spending over many future decades through higher customer rates. Yet these investments are being made in a declining market—inevitably, the number of gas customers and gas sales will decline with electrification. In fact, electrification already is slowly and steadily eating into gas's market share. Residential customers have been turning more and more to electricity for home heating for more than a decade. These declines in gas use will only accelerate in coming years as federal and State policies favoring electrification take effect.

This dynamic of decreasing gas sales and escalating rates raises a fundamental question: Should Maryland's gas utilities continue to invest heavily in gas distribution infrastructure given the declining market?

How this important question is resolved has significant implications for utility customers in the near and long term. The answer determines whether billions of customer dollars will go toward retaining and enhancing the gas distribution infrastructure or whether those dollars can be used to fund any costs associated with electrification or otherwise reduce customer burdens and help Maryland's economy.

> Should Maryland's gas utilities continue to invest heavily in gas distribution infrastructure given the declining market?

To better understand the scale of the problem, our office engaged a consultant, Synapse Energy Economics, to evaluate what happens to residential utility rates under the current regulatory model and utility spending trajectory as gas sales decline. The results—described in this report—are telling: Replacing fossil gas with lower carbon alternatives causes the rates of the State's largest gas utility, Baltimore Gas & Electric, to increase two to three times 2021 levels by 2035 and seven to 11 times 2021 levels by 2050, with similar ranges of rate increases for Maryland's two other large gas utilities. Such rates are not sustainable. As rates increase to these levels, the resulting high bills will lead many customers—likely most all customers who have options—to leave the gas system, leaving behind customers without alternatives; those remaining gas customers will be unable to afford continued gas service.

No matter the path forward, electrification holds major consequences for gas utilities and their customers. The potential consequences of business-as-usual spending—tens of billions of stranded

Electrification holds major consequences for gas utilities and their customers.

gas infrastructure assets—has huge implications for the State. Who will bear the consequences of the uneconomic investments? Shareholders? Electricity customers? Taxpayers? Indeed, a recent BGE report acknowledges the unsustainability of maintaining its gas distribution system, foreshadowing that it may seek subsidies for its gas business through "transfer payments from the company's electric business."

Similar to our October 2022 report on gas utility business-as-usual capital spending, our estimates are generally conservative. For the price of fossil gas, the report uses prices ranging from \$2.94/MMBtu to \$4.05/MMBtu, based on U.S. Energy Information Administration's Annual Energy Outlook 2022 Henry Hub natural gas spot price projections (in 2020 dollars). These prices are well below the EIA's September 2022 price of \$7.88/MMBtu. For alternative fuel prices, we use a low-price scenario based on a study prepared for Washington Gas Light, and for the high-price scenario we use estimates from E3's 2021 study for the Maryland Commission on Climate Change.

We hope this report helps educate stakeholders and policymakers on the significance of unmitigated gas utility spending for Maryland's gas utility customers as the State electrifies and initiates policies to meet its greenhouse gas reduction goals, with corresponding reductions in gas utility customer base and gas sales.

David S. Lapp
People's Counsel

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SECTION 1

INTRODUCTION

The Maryland Office of People's Counsel (OPC) asked Synapse Energy Economics, Inc. (Synapse) to analyze the gas rates likely to materialize as more Marylanders switch from fossil-fuel-fired building furnaces and appliances to electric ones as part of the effort to meet the State's greenhouse gas (GHG) reduction targets.

Released in 2021, the Maryland Department of Environment's *2030 Greenhouse Gas Emissions Reduction Act (GGRA) Plan* recommends reducing emissions from buildings using energy efficiency and by electrifying building heating systems. Under this plan, the Mitigation Working Group (MWG) of the Maryland Commission on Climate Change (MCCC) developed and issued the *Building Energy Transition Plan*.[1] To inform this plan, Energy + Environmental Economics (E3) analyzed scenarios for achieving reductions in emissions to near net-zero levels for Maryland's residential and commercial buildings by 2045. In total, E3 modeled four scenarios, including the *MWG Policy Scenario*, which was found both to be the lowest-cost scenario and to reduce residential and commercial building emissions by 95 percent. This scenario reflects four core concepts and objectives, including: ensuring an equitable and just transition; shifting to fossil-free space and water heating for new construction; replacing almost all fossil heating systems in homes with heat pumps by 2045; and implementing an emissions standard that provides commercial buildings compliance alternatives.[2]

In 2022, the Maryland State House and Senate passed the *Climate Solutions Now Act*, which requires the State to reduce GHG emissions by 60 percent from a 2006 baseline by 2031 and to achieve net-zero GHG emissions by 2045.[3] On April 8, 2022, Governor Hogan released a letter stating that he would allow the bill to pass without his signature.[4]

To better understand the potential effects of the MCCC Mitigation Working Group's *MWG Policy*

The **MWG Policy Scenario** was found to be the lowest-cost scenario and to reduce residential and commercial building emissions by 95 percent.

1 Maryland Commission on Climate Change. *Building Energy Transition Plan: A Roadmap for Decarbonizing the Residential and Commercial Building Sectors in Maryland.* Approved by the Mitigation Work Group on Oct. 13, 2021.

2 Id., p. 4.

3 Maryland Senate Bill 528. "Chapter 38: an Act Concerning Climate Solutions Now Act of 2022." Available at: https://mgaleg.maryland.gov/2022RS/Chapters_noln/CH_38_sb0528e.pdf.

4 Governor Larry Hogan. April 8, 2022. *Letter from Governor Hogan to State Senate President Ferguson and State House Speaker Jones.* Available at: https://governor.maryland.gov/wp-content/uploads/2022/04/SB-528-CSNA-SB-566-Investment-Climate-Risk-EWS-Letter.pdf.

To achieve net zero GHG emissions by 2045, the vast majority of **buildings will have to either fully electrify their loads or use alternative gaseous fuels for any gas needs**, including backup heating.

Scenario, we modeled the progress of Maryland's electrification to project GHG emissions, trends in gas consumption, and space heating type and space heating equipment sales. Synapse then used these projections to analyze the financial implications of Maryland's climate goals for gas utilities in the State through 2050. Our analysis focuses on the residential sector, consistent with OPC's statutory mission.

To achieve net zero GHG emissions by 2045, the vast majority of buildings will have to either fully electrify their loads or use alternative gaseous fuels[5] for any gas needs, including backup heating. Buildings are relatively low-cost to electrify with commercially available technologies. On the other hand, the most likely candidates for alternative gaseous fuels pose issues related to cost, availability, emissions, safety, and energy use during production. However, certain end-uses would be far more expensive to electrify or have no viable electric alternatives. Given these considerations, it is important to consider how alternative gaseous fuels should be used.

If alternative gaseous fuels are used for building end-uses, the cost of the commodity will increase, and that additional cost will be reflected in customers' bills. Given the availability of cost-competitive electric alternatives, increased gas costs will drive customers off the gas system and decrease gas sales. At the same time, the utilities' investments in pipeline infrastructure, documented in OPC's recent report, Maryland Gas Utility Spending: Projections and Analysis, will also increase gas customers' bills. With more customers leaving the gas system due to electrification, these higher gas commodity and infrastructure costs will have to be recovered through fewer sales. This will mean higher rates for those remaining customers, which will further drive customers off the gas system and increase the risk that the utility will have stranded assets.

In the remainder of this document, we provide context and describe our findings. Section 2 describes how, under traditional ratemaking, gas companies will be affected as customers migrate away from gas use with increasing electrification of their end-uses. In Section 3, we describe technologies available for decarbonizing buildings. In Section 4, we describe our methodology for analyzing decarbonization trajectories and gas utility financials as sales decline. Appendix A features a list of definitions and abbreviations. Appendix B provides figures for the commercial sector.

Given the availability of cost-competitive electric alternatives, **increased gas costs will drive customers off the gas system and decrease gas sales**.

5 Here we assume that Alternative Gaseous Fuels reduce GHG emissions. However, as explained below, recent studies suggest otherwise.

SECTION 2

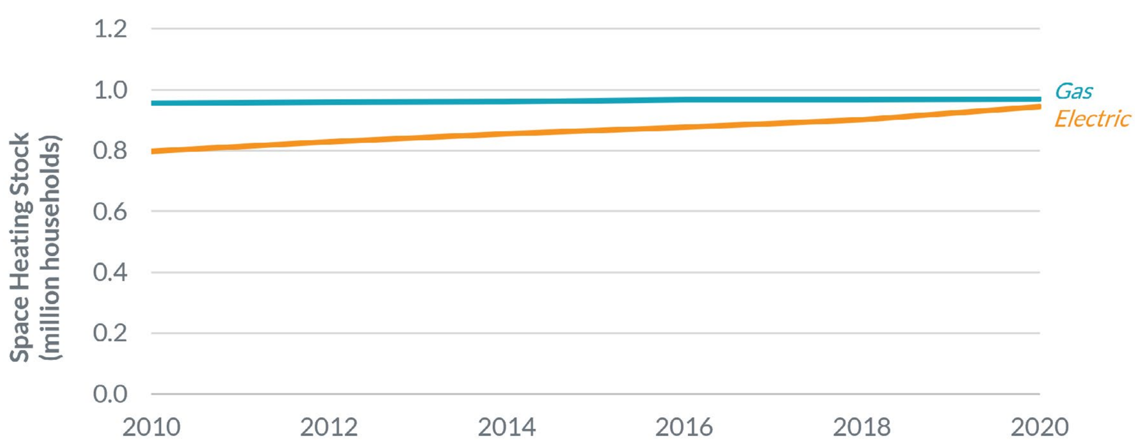
ELECTRIFICATION'S IMPACTS ON GAS RATES

Electric heating stock has been increasing for years now, while gas heating stock has stagnated.

Basic ratemaking principles explain how electrification (the process of switching fossil-fuel-based appliances and other energy end-uses over to electric ones) will affect gas companies by causing customers to migrate away from gas use. The traditional ratemaking model allows utilities to invest in and earn a return on assets such as gas mains and service lines. Utilities recover and earn a return on their investment, typically over the asset's useful lifetime, by including the costs of their investments and the returns on them in the rates they charge customers. This traditional utility business model is designed to ensure utilities can attract shareholders who will put up the money for the investments in exchange for a fair return of—and on—the utility's investments. Without such investments, the thinking goes, utilities would not be able to ensure reliability or meet customers' needs. This model works reasonably well when sales increase over time, but it leads to higher rates when sales are decreasing. Whether occurring as a result of market trends or policy intervention, building electrification will result in declines in gas utility sales, holding all else equal.

Figure 1 shows electric heating stock (mostly heat pumps) has been increasing for years now, while gas heating stock has stagnated. Data from the American Community Survey show that this trend of electrification is occurring across the country. It is notable that

Figure 1. Gas and Electric Space Heating Stock in Maryland Households, 2010-2020



Source: US Census Bureau: American Community Survey. Table DP04: Selected Housing Characteristics for Maryland, 5-year Estimates. June 2, 2022. Available at: https://data.census.gov/cedsci/table?q=DP04&g=0400000US24&tid=ACSDP5Y2020.DP04

this trend toward heating buildings with electricity rather than gas is occurring without significant policy initiatives at the State or local level. While federal and State electrification policies are being discussed (and recently adopted as is the case of the recently enacted *Inflation Reduction Act*, for example), their effects have largely yet to be realized. These policy efforts can be expected to accelerate electrification.

This electrification trend means fewer gas sales. If gas sales decline faster than utilities' asset bases depreciate and faster than the utilities can lower their operating and maintenance costs, gas utilities will seek approval for increasing gas rates to recover the capital invested over fewer unit sales. In turn, higher gas rates are likely to spur more customers to electrify their gas end-uses (furnaces and appliances). As this process goes on, those with the means to electrify—i.e., those who can afford the upfront costs of changing their gas appliances to electric ones and can modify their buildings to accommodate the switch—will do so first. Without changes to regulatory practices or direct assistance, those without access to capital (e.g., low- and moderate-income customers) or the ability to make changes to their dwellings (e.g., renters) will be left on an increasingly costly gas system. Rate escalation will likely hit these groups the hardest.

This trend toward heating buildings with electricity rather than gas is occurring **without significant policy initiatives at the State or local level**.

SECTION 3

TECHNOLOGIES THAT SUPPORT DECARBONIZATION

Achieving net zero by 2045 means that buildings will have to either fully electrify their energy loads or use alternative gaseous fuels for any gas needs, including backup heating. This section discusses key considerations about the available building decarbonization technologies to provide context for the rate analysis in Section 4.

The total cost of installing heat pumps in residential new construction is much less than the cost of installing fossil gas equipment for heat plus central air conditioning (AC) for cooling.

3.1. Electric Space and Water Heating

Heat pumps. Heat pumps provide both energy-efficient cooling and heating. The total cost of installing heat pumps in residential new construction is much less than the cost of installing fossil gas equipment for heat plus central air conditioning (AC) for cooling. For retrofitting an existing building, the cost of installing heat pumps is similar to or less than the combined installed cost of the furnace and central AC. A study by the Lawrence Berkeley National Laboratory (LBNL) found that, on average nationally, a new gas furnace and AC have a combined installed cost of almost $11,000 for residential retrofits. In contrast, the installed cost of heat pumps is substantially less, at just over $8,000.[6] In the absence of extreme price volatility, operating costs, including fuel, are similar for these options.[7] In addition to cheaper up-front costs, heat pumps serve as both the heating and cooling device for a home, requiring a household to only maintain one system. Comparatively, a gas furnace cannot be used for home cooling and requires an additional system for air conditioning.[8]

Electrification will gradually advance as current heating stock reaches the end of its useful life and is increasingly replaced with heat pumps. Moreover, since almost 50 percent of residential buildings in

6 Less, B. D., et al. 2021. *The Cost of Decarbonization and Energy Upgrade Retrofits for US Homes*. Lawrence Berkeley National Laboratory. Available at: https://escholarship.org/uc/item/0818n68p.

7 Energy + Environmental Economics. "Maryland Building Decarbonization Study: Final Report." October 20, 2021.

8 For commercial heating and cooling systems, retrofit costs are harder to compare than for residential ones, because costs vary by building type and data are relatively sparse for the variety of building types in use for commercial applications. Some studies suggest that installed costs for heat pumps are comparable to the cost of gas heating and separate electric AC systems for commercial buildings. (Group 14 Engineering, *Electrification of Commercial and Residential Buildings*, (2020) available at: https://bit.ly/3skNqAp.) For small commercial customers, E3's study for Maryland found that all-electric new construction is cheaper than mixed-fuel new construction due to lower capital and operating costs. (Energy + Environmental Economics. "Maryland Building Decarbonization Study: Final Report." October 20, 2021.)

Maryland are already heated primarily with an electric heating unit (either electric resistance or heat pumps), electrification is already underway in the State.[9]

Hot water heaters. The total equipment and installation costs of electric heat pump water heater (HPWH) retrofits are generally much higher than those of gas storage water heaters.[10] As with space heating, the operating costs of electric and gas appliances are generally similar. Considering fuel costs, electric rate structures such as time-of-use rates can give electric appliances and equipment an edge over gas systems. (Customers billed under a time-of-use rate generally pay more during peak energy-usage hours than during off-peak hours, such as late at night or early in the morning.)

Panel upgrades. Electrification may require upgrades to electrical circuits and panels to accommodate additional load. The cost of upgrading the electrical panel typically ranges from about $500 to $2,000 for most homes, while the costs could be more than $3,000 for others.[11] For some households, these costs can be mitigated. Newer buildings generally have high electrical capacity and thus may not need upgrades. Some customers may upgrade their electrical panels to support electric vehicles and be ready for building electrification measures without additional upgrades. Finally, these costs also can be avoided in the future by using low-amp appliances that are currently in development.

Inflation Reduction Act. The recently enacted federal Inflation Reduction Act (IRA) could substantially reduce the costs of electrification through tax credits. Homeowners can receive a tax credit of up to $2,000 per year to install heat pumps or electric water heaters and up to $600 per year for electrical panel upgrades.[12] The IRA also authorizes rebates for qualifying households for electrification and efficiency measures, including heat pumps, heat pump water heaters, electric stoves, heat pump clothes dryers, circuit panels, wiring, and insulation and air sealing.

3.2. Heat Pumps with Fuel Backup (Hybrid Systems)

Heat pumps can be used in concert with fossil fuel backup or supplemental heating systems. Such backup systems could reduce pressure on the electric system to accommodate higher loads from electrification. However, in a moderate climate like Maryland (with only around 4,000 heating degree days annually)[13] fuel backup is unnecessary. ACEEE found that households in the State would not need fuel backups when using cold-climate heat pumps, which are advanced heat pump systems that provide

Fuel backup systems are unnecessary, and deploying them is costly for consumers.

9 U.S. Energy Information Administration. Residential Energy Consumption Survey: 2020 RECS Survey Data. Available at https://www.eia.gov/consumption/residential/data/2020/index.php?view=state&src=%E2%80%B9%20Consumption%20%20%20%20%20%20Residential%20Energy%20Consumption%20Survey%20(RECS)-f2, accessed October 20, 2022.

10 Less, B. D., et al. 2021. *The Cost of Decarbonization and Energy Upgrade Retrofits for US Homes.* Lawrence Berkeley National Laboratory. Available at: https://escholarship.org/uc/item/0818n68p.

11 HomeAdvisor. July 6, 2022. "Cost to Upgrade an Electrical Panel." Available at: https://www.homeadvisor.com/cost/electrical/upgrade-an-electrical-panel/.

12 Inflation Reduction Act of 2022, §13301. Available at: https://www.congress.gov/bill/117th-congress/house-bill/5376/text.

13 Heating degree days measure how cold the outdoor temperature is relative to a standard temperature, generally 65° Fahrenheit (F), over a period of time. For example, a day with a mean temperature of 40°F would have 25 HDD. (U.S. Energy Information Administration, Units and calculators explained: Degree days. Available at: https://www.eia.gov/energyexplained/units-and-calculators/degree-days.php.) Over the course of a year, Maryland has approximately 4,000 HDD. (Nadel, S. and L. Fadali. 2022. *Analysis of Electric and Gas Decarbonization Options for Homes and Apartments.* Washington, DC. ACEEE. Available at: https://www.aceee.org/sites/default/files/pdfs/b2205.pdf.)

heat down to 5 degrees Fahrenheit or lower.[14] Fuel backup systems are unnecessary, and deploying them is costly for consumers because the gas utilities would need to upgrade old parts of the distribution system and maintain the entire system for use during just a small portion of the year.

3.3. Alternative Gaseous Fuels

Considering that some uses of fossil gas do not currently have electric alternatives, replacing fossil fuel gas with lower carbon alternatives will play an important role for the State's achievement of its climate goals. The most likely alternative gaseous fuels that have potential for replacing fossil gas are biomethane, recovered methane, hydrogen, and synthetic natural gas or synthetic methane.

3.3.1. Biomethane and recovered methane

Recovered methane is methane captured from gas distribution system leaks or other sources. *Biomethane* (also called renewable natural gas, or RNG) is a mixture of carbon dioxide and hydrocarbons released from the decomposition of organic matter. Biomethane must be processed to remove impurities, liquid water, and hydrocarbons, and to attain acceptable heat content.[15] Processing increases costs, consumes energy, and requires investment in processing facilities.

Both biomethane and recovered methane pose collection, processing, and transportation challenges that raise their costs. It may be more economical to use these fuels for some other purpose, in a less-processed form and closer to their sources, rather than using them in distant buildings to replace fossil gas consumption.

Both biomethane and recovered methane pose **collection, processing, and transportation challenges that raise their costs.**

Both biomethane and recovered methane supplies are currently limited and likely to remain constrained well into the future. According to the consulting firm ICF International's 2019 report for the American Gas Foundation, constraints in available biomass feedstocks severely limit biomethane that is potentially carbon-negative, which includes anaerobic digestion of food waste, dairy, and swine manure. (Other feedstocks—gasification of agricultural and forest residue, municipal solid waste, and energy crops—have fewer supply constraints but unfavorable carbon footprints.) The 2019 ICF International report estimates that supplies of the feedstocks that are likely to be carbon negative from Maryland sources will amount to just 5.766 tBtu in 2040 in a high-potential scenario.[16] Relative to current residential gas consumption in Maryland—80.418 tBtu for the residential sector alone in 2020—carbon negative biomethane could displace only a small portion of current gas sales in the State, even assuming

14 One field study in Vermont observed that cold climate heat pumps operated under -20° F at above 1 coefficient of performance (COP) but with reduced capacity. (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.) *See also*, Nadel, S. and L. Fadali. 2022. *Analysis of Electric and Gas Decarbonization Options for Homes and Apartments.* Washington, DC. ACEEE. Available at: https://www.aceee.org/sites/default/files/pdfs/b2205.pdf.

15 Gas quality specifications may vary by pipeline. (Thomson Reuters Practical Law: Pipeline Quality Natural Gas (US). Available at: https://content.next.westlaw.com/practical-law/document/Iee1c892db6ea11eabea4f0dc9fb69570/pipeline-quality-natural-gas?viewType=FullText&originationContext=document&transitionType=DocumentItem&ppcid=b60bf2510cb649d7a374f9f88d3199f5&contextData=(sc.DocLink)&firstPage=true, accessed October 18, 2022.)

16 ICF International. 2019. *Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment. Prepared for the American Gas Foundation.* Available at https://gasfoundation.org/wp-content/uploads/2019/12/AGF-2019-RNG-Study-Full-Report-FINAL-12-18-19.pdf.

Carbon negative biomethane could displace only a **small portion** of current gas sales in the State.

declining gas sales in future years.[17] There also will be competition for the limited biomethane supplies as other states seek to decarbonize their economies.[18]

Because methane is a potent GHG, leaks undercut overall climate efforts. A GHG emissions mitigation strategy that integrates these fuels into the existing distribution system for widespread use should account for fugitive emissions during transport.

Methane leakage also poses safety concerns. Local fire departments in the United States respond to 4,200 home fires caused by ignition of fossil gas per year, most of which involve some type of leak. Each year on average, these fires result in $54 million in direct property damage, 140 civilian injuries, and 40 civilian deaths.[19]

Like fossil gas, in-home use of biomethane and recovered methane poses health and safety concerns due to combustion and leaks.[20] Indoor nitrogen oxide (NO_X) emissions contribute to increased respiratory symptoms and asthma attacks.[21]

3.3.2. Hydrogen

There are different methods of producing hydrogen that impact its carbon footprint. "Gray" hydrogen is produced from fossil gas. As the most common hydrogen production method, gray hydrogen accounts for 6 percent of fossil gas consumption worldwide.[22] "Blue" hydrogen is produced using the same process, but the associated GHG emissions are captured and stored. With both gray and blue hydrogen, emissions result from fossil gas extraction, processing, and use. As a result, gray and blue hydrogen do not provide emissions reductions relative to direct combustion of fossil gas, diesel, or coal for generating heat, as shown in Figure 2.

Gray and blue hydrogen do not provide emissions reductions relative to direct combustion of fossil gas, diesel, or coal for generating heat.

17 Maryland Department of the Environment. 2020. "GHG Emission Inventory." Available at: https://mde.maryland.gov/programs/air/climatechange/pages/greenhousegasinventory.aspx.

18 For example, New York will likely dramatically reduce gas consumption in compliance with its Climate Leadership and Community Protection Act, with likely high demands for RNG for difficult-to-electrify end uses. Current gas consumption in New York, excluding gas for electric power generation, is about 950 Tbtu—far outstripping a recent study's projected statewide potential RNG supply of 47 tBtu/yr. and 147 tBtu/yr. (New York State Energy Research and Development Authority (NYSERDA). 2021. "Potential of Renewable Natural Gas in New York State," NYSERDA Report Number 21-34. Prepared by ICF Resources, L.L.C., Fairfax, VA 22031. nyserda.ny.gov/publications.)

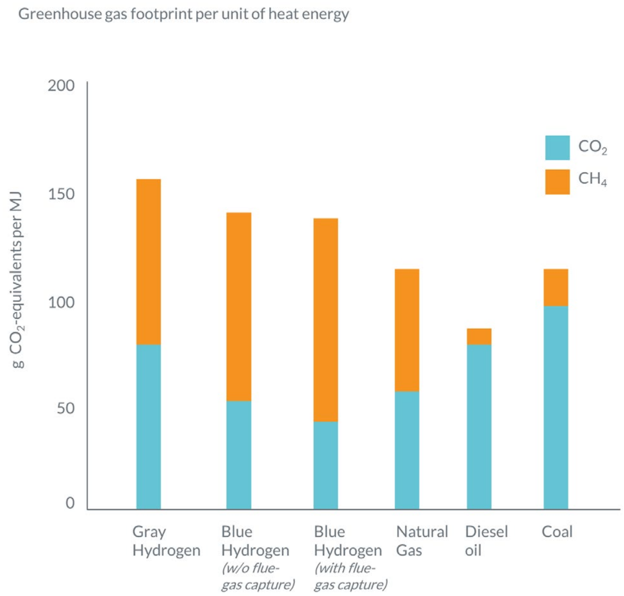
19 The National Fire Protection Association. 2018. "Natural Gas and Propane Fires, Explosions and Leaks: Estimates and Incident Descriptions." Available at https://bit.ly/3vCjxLw.

20 California Energy Commission 2020. *Final Project Report: Air Quality Implications of Using Biogas to Replace Natural Gas in California.* Available at: https://www.energy.ca.gov/sites/default/files/2021-05/CEC-500-2020-034.pdf.

21 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/.

22 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.

Figure 2. Comparison of GHG emissions intensity of gray and blue hydrogen with direct consumption of gas, oil, and coal



Note: Assumes a methane leakage rate of 3.5 percent.

Source: "Greenhouse gas footprint per unit of heat energy" © by Howarth, R., Jacobson, M. 2021. Retrieved from https://onlinelibrary.wiley.com/doi/full/10.1002/ese3.956. Used under Creative Commons Attribution 4.0 International (CC BY 4.0)-Modified to be black and white, remove title, and remove 200 g CO2-equivalents per MJ axis label.

"Green" hydrogen is produced using water as the source of the hydrogen and a carbon-free resource to convert the water to hydrogen. Green hydrogen is not currently cost-competitive with gray hydrogen, although the relative costs may decline as renewable energy costs continue to decrease or policies are enacted that raise the price of fossil fuels.[23]

Hydrogen poses **difficulties for integration** into existing gas infrastructure.

Hydrogen poses difficulties for integration into existing gas infrastructure. Hydrogen can be blended into the gas in the existing pipeline network in small quantities. While some literature has suggested that it may be safe to blend hydrogen into the existing infrastructure up to 20 percent by volume (equivalent to 7 percent by energy content), analysis for the California Public Utilities Commission indicates that only up to 5 percent by volume can be blended in safely.[24] Even if blending hydrogen up to 20 percent by volume (7 percent by energy content) into the existing gas network is safe, doing so would have a limited impact on offsetting fossil fuel use and the corresponding emissions. Higher concentrations of hydrogen would require replacing much of the existing distribution system, since the heat content of hydrogen is lower than methane (requiring larger pipes to accommodate the same energy content) and since some metals (such as those used for pipes) become brittle when exposed to hydrogen.[25]

Hydrogen cannot be interchanged with methane in today's household gas appliances. Beyond relatively low hydrogen blends, consumers would need to purchase new appliances to burn hydrogen safely. As with fossil gas, hydrogen will leak and thereby have reduced carbon benefits. Finally, hydrogen raises safety concerns because it can ignite more easily than natural gas.[26]

23 Howarth, R., Jacobson, M. 2021.

24 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. Penchev, M., T. Lim, M. Todd, O. Lever, E. Lever, S. Mathaudhu, A. Martinez-Morales, and A.S.K. Raju. 2022. *Hydrogen Blending Impacts Study Final Report.* Agreement Number: 19NS1662. California Public Utilities Commission. Available at: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M493/K760/493760600.PDF.

25 U.S. Department of Energy. 2022. "Safe Use of Hydrogen." Available at: https://www.energy.gov/eere/fuelcells/safe-use-hydrogen#:~:text=A%20number%20of%20hydrogen's%20properties,in%20case%20of%20a%20leak.

26 For a technical discussion of the issues discussed here, see Livermore, S., "Exploring the potential for domestic hydrogen appliances," *The Engineer* (2018), available at https://bit.ly/3C2vigD.

3.3.3. Synthetic methane

Synthetic methane can be produced with hydrogen (obtained from electrolysis) and carbon dioxide, (captured either from the ambient air or from exhaust streams before it is released into the air). If renewable energy is used for electrolysis, carbon capture, and other processing, the fuel can have a low-carbon footprint but requires large quantities of energy to produce.[27] Similar to fossil gas, synthetic methane will leak from pipes, and there will be costs associated with fixing leaks, replacing leak-prone pipes, or losses of the fuel. Synthetic methane poses safety risks similar to fossil gas, biomethane, and recovered methane. Leaks of synthetic methane can lead to fires. In addition, synthetic methane combustion causes releases of NOx and other harmful air pollutants, which can lead to serious respiratory health impacts.[28]

3.3.4. Observations about Alternative Gaseous Fuels

The discussion above shows that the most likely candidates for alternative gaseous fuels pose challenges related to cost, emissions, safety, and energy use during production. None of the alternatives that would reduce GHG emissions are available now at scale or at a price similar to natural gas.

The most likely candidates for alternative gaseous fuels pose **challenges related to cost, emissions, safety, and energy use during production.**

Finally, competition for alternative gaseous fuels could be fierce, in Maryland and elsewhere. Other economic sectors—transportation, industrial processes, and electric generation—will compete with buildings for low-carbon alternative fuels. Alternative gaseous fuels will be important for certain of these non-building end-uses because they involve activities that are far more expensive to electrify or for which there are no available electric alternatives. In contrast, buildings are relatively low-cost to electrify and can take advantage of commercially available technologies for space and water heating and for other uses. As a policy matter, it may be important to reserve alternative gaseous fuels for activities that cannot easily be electrified.

27 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.

28 The NOx that is formed when natural gas, biogas, or SNG is combusted comes primarily from nitrogen and oxygen in the air interacting in the high-heat conditions of combustion. Exposure to NOx pollution can aggravate existing respiratory problems and potentially lead to development of respiratory disease. (NRDC 2020. A Pipe Dream or Climate Solution? The Opportunities and Limits of Biogas and Synthetic Gas to Replace Fossil Gas." Available at https://www.nrdc.org/sites/default/files/pipe-dream-climate-solution-bio-synthetic-gas-ib.pdf.)

SECTION 4

MODELING

To better understand the potential effects of the *MWG Policy Scenario*, we modeled the progress of Maryland's electrification under E3's *MWG Policy Scenario*, which we call "Sector Specific Electrification" (SSE). Using our Building Decarbonization Calculator (BDC), we modeled total GHG emissions, trends in gas consumption, and residential and commercial building stock by space heating type and space heating equipment sales under SSE. The model analyzed the turnover of residential and commercial space and water heating systems across Maryland and calculated the corresponding emissions impacts. Our BDC assumptions are detailed in Section 4.1.1, below.

Synapse then applied its Gas Rate Model (GRM) to the BDC modeling results to assess the financial implications for Maryland's three largest gas utilities through 2050. The GRM uses the utilities' historical data and the BDC modeling results to project SSE's impacts on rate base, revenues, and expenses for each of the utilities: Baltimore Gas and Electric (BGE), Washington Gas Light (WGL), and Columbia Gas of Maryland (Columbia or CMD). We also evaluated the residential customer rate impact of using alternative gaseous fuels to offset increasing portions of remaining gas system emissions, culminating in zero remaining fossil gas by 2045.

The BDC modeling, combined with the GRM results, ultimately sheds light on the *MWG Policy Scenario's* effects on gas utilities. It also assesses the scenario's implications for residential customer rates and the stranding of gas utility investments.

4.1. Building Decarbonization Calculator

4.1.1. Assumptions

The BDC uses Maryland-specific data on existing buildings from the U.S. Census Bureau's *American Community Survey*, along with the U.S. Energy Information Administration's *Residential Energy Consumption Survey* and *Commercial Buildings Energy Consumption Survey*, to develop estimates for the characteristics of Maryland's building space and water heating system stock. To determine the current heat pump market share of new installations, we analyzed recent annual increases in the number of homes heated primarily with electricity as reported by the *American Community Survey*.[29]

Residential building electrification target: Consistent with the *MWG Policy Scenario*, under our SSE scenario heat pumps are the sole source of heating in over 95 percent of residential buildings by 2050. To achieve this, we assume that all new construction is all-electric by the late 2020s. In existing buildings, this level of electrification is achieved through steady increases in

29 American Community Survey. 2019. *Table B25040: House Heating Fuel for Maryland, 5-year Estimates*. Available at: https://data.census.gov/cedsci/table?q=house%20heating%20fuel&tid=ACSDT5Y2020.B25040.

We assumed that gas heating will be phased out as **heating units are replaced at the end of their useful lives**.

heat pumps' share of the Maryland market. By 2030, over 95 percent of households that are replacing space heating equipment at the end of the equipment's useful life use heat pumps, increasing to 100 percent by 2035.[30]

Heat pump market share: Based on recent historical data from the *American Community Survey*, we assumed that the number of residential households heating with heat pumps increased by about 8,000 households between 2019 and 2020. We calculated that this level of annual increase implied a heat pump market share (i.e., the percent of space heating equipment sales that are heat pumps) of approximately 10 percent of new heating systems replacing retiring residential fossil fuel systems. We modeled residential heat pump adoption curves starting at these market share values in 2020, and then escalating toward the electrification target over time.[31] While there is no fixed date by which all buildings will be all-electric, the modeling is designed to convert the market to 100 percent heat pumps, such that gas heating will be phased out as heating units are replaced at the end of their useful lives.

Multi-family housing units: Throughout our analysis, we categorized all households in Maryland as being in the residential sector, even though large multifamily residential buildings may require different types of heat pump systems than single-family homes. We measure the sizes of heat pump systems by the number of households they serve. For example, one large heat pump system serving 100 apartments is modeled as 100 individual heat pump systems. Where we were able to break out residential results from total, we present the residential sector here. The results for the commercial sector are provided in Appendix B. Industrial sector gas consumption is not included in this report.

4.1.2. Results

For each year between 2020 and 2050, our modeling shows how SSE impacts the new space and water heating system installations, the total stock of operating space and water heating systems, and the resulting on-site GHG emissions. We discuss these results in the paragraphs below:

- Residential GHG emissions
- Residential gas consumption
- Residential building stock by space heating type and space heating equipment sales

Residential GHG emissions

Figure 3 shows total residential space and water heating emissions. Figure 3 does not account for using low- or zero-carbon gases to reduce emissions. Also, this figure does not include off-site GHG emissions, such as those resulting from the generation of electricity[32] or the upstream methane emissions from

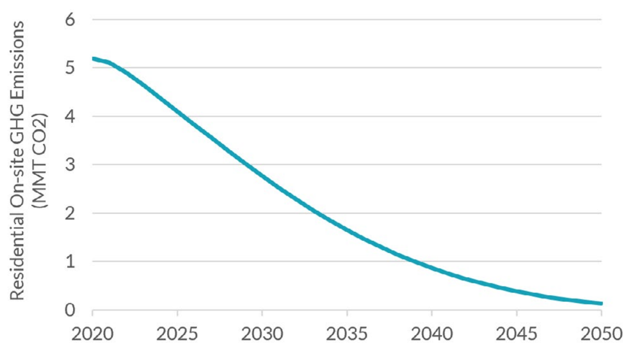
30 In commercial buildings, by 2050, 60 percent of gas-connected buildings switch to heat pumps as the sole source of heating and 40 percent of gas-connected buildings stay on gas for heating. Over 99 percent of all new construction is 100 percent electrified by 2035. Existing buildings with electric resistance heat convert to heat pumps by 2050 and existing buildings with heat pumps continue to use heat pumps.

31 Given that existing commercial buildings would have a harder time switching to heat pumps due to the complexity of their HVAC system configurations, we assumed initial commercial market shares equal to half of the historical residential sales rate. We assumed these market share rates to meet the residential and commercial building electrification targets, described above.

32 While increasing electricity consumption to power heat pumps will lead to some increase in electric generation emissions, that impact is beyond the scope of this report. The emissions increase will be mitigated by Maryland's Renewable Portfolio Standard, which requires 50 percent of electricity to come from renewable resources by 2030, as well as other future policies that may further decarbonize the power sector beyond 2030. Expanded demand-side management and demand response can also reduce electrification's impact on load and emissions.

leaks associated with production, distribution, and transmission of fossil or alternative gaseous fuels.

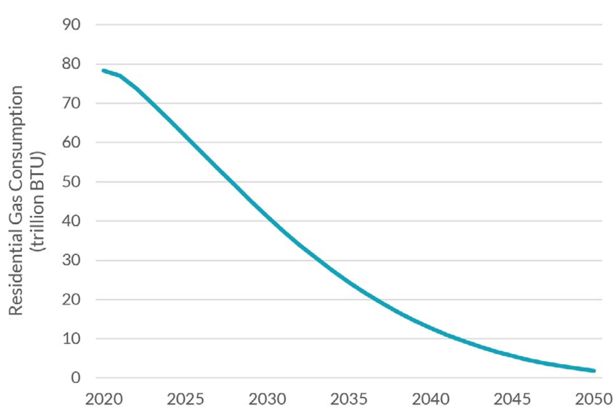
Figure 3. Residential on-site space and water heating GHG emissions, before accounting for use of low- or zero-carbon gas or off-site emissions



Gas consumption

Figure 4 shows SSE's impacts on residential space and water heating gas consumption. The corresponding commercial space and water heating gas consumption chart can be found in Appendix B. To fully decarbonize building energy consumption, remaining gas consumption will need to be displaced with low- and zero-emissions fuels.

Figure 4. Residential consumption of gas for space and water heating



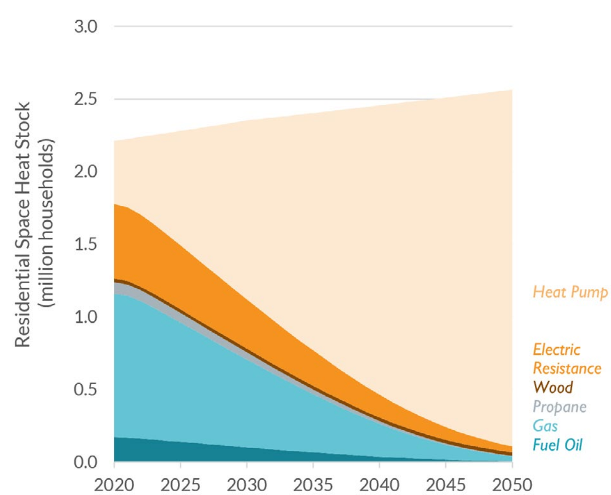
Space heating equipment stock and sales

In this section, we present charts that show the total stock and annual sales of space heating equipment under SSE. We focus on space heating equipment, because it is currently responsible for most on-site emissions from residential buildings.[33] The second largest source of on-site emissions from residential buildings is water heating, which represents a much smaller portion of current total emissions: For residential space and water heating equipment combined, space heating equipment accounts for 74 percent of on-site emissions and water heating equipment accounts for 26 percent of on-site emissions.

Water heating equipment similarly transitions toward heat pump technologies in our analysis but is not separately shown here for simplicity.

Figure 5 shows that SSE results in nearly all buildings, including 96 percent of homes, being fully heated with heat pumps by 2050. Fossil fuel space and water heating is almost entirely eliminated, resulting in the greatest emissions reductions.

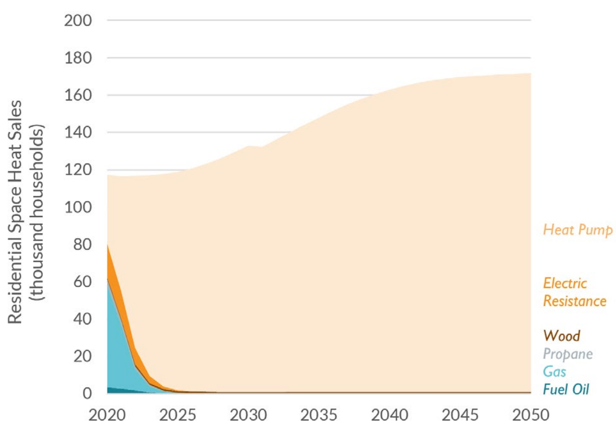
Figure 5. Residential building stock by space heating fuel and technology



33 In 2020, space and water heating equipment were responsible for most fossil gas use from residential buildings. Space and water heating equipment accounted for 91 percent of residential gas consumption, while the remaining 9 percent of gas consumption was attributable to cooking, clothes drying, and other end-uses that were not included in our modeling here. (U.S. Energy Information Administration. 2018. *Residential Energy Consumption Survey*. Available at: https://www.eia.gov/consumption/residential/.)

To achieve this level of electrification, residential space heating equipment sales almost entirely shift to heat pumps by the mid-2020s, as shown in Figure 6.

Figure 6. Residential space heating equipment sales[34]



As Figure 6 shows, gas heating equipment sales drop to near zero under this scenario, allowing for the almost complete removal of the gas system by 2050.[35]

Results for the commercial sector are provided in Appendix B.

4.2. Gas Rate Model

Applying the BDC results, we now model the financial impact on the gas utilities of electrifying the building heating stock.

The GRM allows Synapse to project gas utility rates based on different scenarios for utility investment, sales, and financial models. We use input data from annual utility reports to State regulators, alongside data from the Pipeline and Hazardous Materials Safety Administration[36] (for gas pipeline investment data) and rate cases[37] (such as depreciation and cost-of-service studies) to build a model of the past up to the present. The model tracks utility plant-in-service, depreciation, capital additions and retirements, operations and maintenance, and income taxes. It accounts for capital structure and changes in tax rates.

Looking forward from the present, the model allows us to test scenarios for different levels of investment and customer growth or decline, pipeline replacement programs, early retirements, stranded costs, and changes in depreciation rates. These cases can correspond to electrification, as assumed in the analysis here, or other decarbonization scenarios developed in the BDC. We have developed ways to map changes in customer numbers to changes in miles of pipeline in service and other aspects of capital assets.

The GRM must make assumptions about fuel prices. Here, as described below, we make assumptions for fossil fuel price and for alternative gaseous fuels. For alternative gaseous fuels, we use two fuel cost sensitivities—the Low AGF Price sensitivity and the High AGF Price sensitivity.

The following section details our assumptions for GRM inputs. The assumptions and projections are explained and analyzed in Sections 4.2.1 and 4.2.2, and Section 4.2.3 shows results of the modeling in terms of gas rate base per customer, rates, and bill impacts.

34 The slight decrease in new installations between 2030 and 2031 results from slower expected population growth (and consequently new housing construction) after 2030. (Weldon Cooper Center for Public Service. 2018. Observed and Total Population for the U.S. and the States, 2010-2040. *Demographics Research Group*. Available at: https://demographics.coopercenter.org/national-population-projections.)

35 Apart from replacing gas equipment, heat pumps will replace electric resistance heating stock. Replacing electric resistance heaters with more efficient heat pumps should reduce the electric load from those buildings and partially offset the increased electric load due to replacing the gas heating stock with heat pumps.

36 U.S. Department of Transportation: Pipeline and Hazardous Materials Safety Administration. August 2, 2021. Gas Distribution, Gas Gathering, Gas Transmission, Hazardous Liquids, Liquefied Natural Gas (LNG), and Underground Natural Gas Storage (UNGS) Annual Report Data. Available at: https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids.

37 Maryland Public Service Commission. 2021. *Case Search*. Available at: https://www.psc.state.md.us/.

4.2.1. Assumptions and Analysis

Alternative Gaseous Fuel Pricing: In the Low AGF Price sensitivity, the price of alternative gaseous fuel from 2021 to 2050 ranges from $14.37/MMBtu to $22.92/MMBtu, based on a 2020 ICF report for AltaGas and WGL (in 2020 dollars).[38] In the High AGF Price sensitivity, the price of alternative gaseous fuel from 2021 to 2050 is $69.03/MMBtu, based on a report by E3 on building decarbonization in Maryland (in 2020 dollars).[39] The price of fossil gas is kept the same in both the Low and High AGF Price sensitivities. From 2021 to 2050, the price of fossil gas ranges from $2.94/MMBtu to $4.05/MMBtu, based on the U.S. Energy Information Administration's *Annual Energy Outlook 2022* Henry Hub natural gas spot price projections (in 2020 dollars).[40]

Assumptions about the climate impact of renewable and low-carbon gases: Synapse modeled the SSE scenario such that no fossil gas remains in the system past 2045 and that remaining gas use is provided by alternative gaseous fuels. Our modeling assumes that renewable and low-carbon gases are emissions-free and that the buildings sector will be responsible for emissions reductions proportionate to its current emissions. With this assumption, BGE, WGL, and Columbia Gas's conversion to all low-carbon gases would support the State's compliance with the *Climate Solutions Now Act*. Recent studies show, however, that alternative gaseous fuels have higher emissions rates than previously assumed. For example, a 2022 analysis by Imperial College London found that leakage rates from RNG may be twice as high as previously thought.[41] Though beyond the scope of our work here, such leakage rates would reduce the benefits associated with low-carbon fuels and make *Climate Solutions Now Act* compliance more challenging.

Infrastructure replacement: We assume that the Maryland Public Service Commission continues to approve each utility's current investment approach, as allowed under PUA § 4-210 (the *Strategic Infrastructure Development and Enhancement*, or STRIDE, law) as though electrification and customer departures are not occurring. Under STRIDE, gas utilities currently run programs to replace leak-prone pipes (generally cast-iron and bare-steel pipes) with plastic pipes. The STRIDE program replaces both *mains* (larger pipes that serve many customers) and *services* (the building-specific pipes that connect the mains to customer buildings). STRIDE permits utilities accelerated recovery of the costs of gas infrastructure replacements through a surcharge on customer bills. The surcharge is capped at $2.00/month on residential bills but is reset with each base rate case, when STRIDE investments are moved into base rates.

Recent studies show that **alternative gaseous fuels have higher emissions rates** than previously assumed.

38 ICF International. April 2020. *Opportunities for Evolving the Natural Gas Distribution Business to Support the District of Columbia's Climate Goals*. Available at: https://sustainability.wglholdings.com/wp-content/uploads/Technical-Study-Report-Opportunities-for-Evolving-the-Natural-Gas-Distribution-Business-to-Support-DCs-Climate-Goals-April-2020.pdf. AltaGas is the Canadian parent company of WGL.

39 Clark, T., D. Aas, C. Li, J. de Villier, M. Levine, J. Landsman. October 20, 2021. *Maryland Building Decarbonization Study*. Energy + Environmental Economics. Available at: https://mde.maryland.gov/programs/Air/ClimateChange/MCCC/Documents/MWG_Buildings%20Ad%20Hoc%20Group/E3%20Maryland%20Building%20Decarbonization%20Study%20-%20Final%20Report.pdf at 13 (showing a conservative alternative gaseous fuel price of $70/MMBtu (in 2021$), which we converted into 2020$ to arrive at the $69.03/MMBtu value).

40 U.S. Energy Information Administration. March 2022. *Annual Energy Outlook 2022: Table 13*. Available at: https://www.eia.gov/outlooks/aeo/data/browser/#/?id=13-AEO2022&region=0-0&cases=ref2022&start=2020&end=2050&f=A&linechart=ref2022-d011222a.31-13-AEO2022&ctype=linechart&sourcekey=0.

41 Imperial College London. 2022. "Biogas and biomethane supply chains leak twice as much methane as first thought." Phys.org. Available at https://phys.org/news/2022-06-biogas-biomethane-chains-leak-methane.html.

The assumption in the SSE scenario that utilities continue under their current investment approach means that the STRIDE program continues as planned and depreciation rates for utility investment continue to be set at today's levels, based on the expected engineering life of assets—as long as 70 years for new plastic pipes, for example. STRIDE cost calculations are imported from analysis by DHInfrastructure for OPC. Although STRIDE investments continue, the GRM scenario assumes that customers are electrifying and departing the system, consistent with the BDC scenario results.

Depreciation: Additionally, Synapse assumed that the utilities do not update their depreciation approach, despite the customer departures. Accordingly, we used recent depreciation studies from each utility to determine their 2020 depreciation rates and used these 2020 values for each specific utility asset from 2021 to 2050 (approximately 100 utility assets per utility).[42]

Capital additions: In the GRM, we calculated capital additions for distribution plant mains, services, meters, meter installations, and house regulators based on net customer additions, pipeline retirement approach, and historical pipe data. All other capital addition line items grow at 2 percent per year. This growth rate corresponds to the 2 percent inflation rate that we used throughout the model.[43]

Operations & Maintenance: We projected operations and maintenance expenses based on the total number of customers, the miles of pipeline, and the number of services for each future year. This projection also used the model-wide inflation rate of 2 percent.

Other costs: We held after-tax return on equity, cost of debt, debt fraction of capital, federal income tax, and state income tax constant at their 2020 levels.

Rate Class Allocations: To determine the rates by class (residential versus commercial and industrial customers), we separated out each utility's revenue requirement based on the proportion of residential customers to commercial and industrial customers and the proportion of residential gas sales to commercial and industrial gas sales. The BDC modeling provided the split between residential and commercial and industrial customers both for customer counts and gas sales. The calculation to determine rates by class also accounts for different drivers of utility revenue requirements. Specifically, some costs (like billing and customer service) scale with the number of customers, while other costs (like maintenance) are more closely related to the miles of mains or number of services. Our methodology is informed by common practice in cost allocation studies.

4.2.2. Customer and Sales Projections

Customers: Using customer projections from the heating stock results of the BDC modeling, we determined that more customers leave the natural gas system than are added to the gas system in each year of the modeling, starting in 2021. Total annual customer additions decrease to zero by 2038 in BGE, by 2037 in WGL, and by 2033 in Columbia. By 2050, the total customers left on each of the three utility systems is just 5 to 7 percent of their total 2020 number of customers.

42 DHInfrastructure used total distribution, transmission, and composite non-STRIDE depreciation rates and held the 2022 values constant throughout its analysis. DHInfrastructure did not break out distribution, transmission, and depreciation rate projections by specific utility asset, as Synapse did. The difference between the Synapse and DHInfrastructure depreciation methodologies reflects the difference in granularity needed for each model and the overall projection methodology for each analysis. Relative to DHInfrastructure's analysis, Synapse tracked a greater number of individual data points to allow consideration of alternative futures.

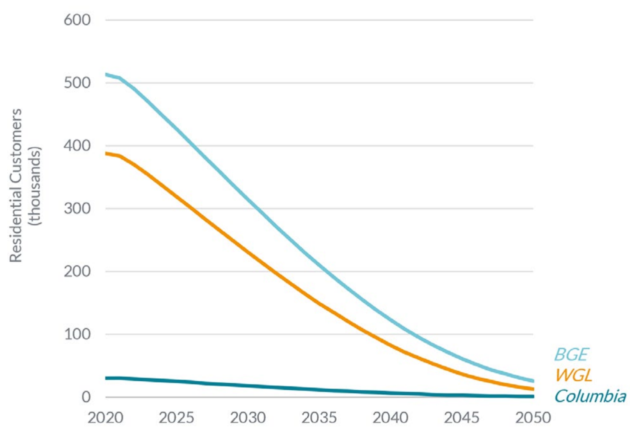
43 In comparison, DHInfrastructure assumed that total non-STRIDE capital expenditures stay constant at their 2022 values and do not increase with inflation. Synapse broke out the non-STRIDE capital expenditure projections by utility asset or utility asset grouping. Synapse further used a separate, more detailed methodology for certain capital additions, preventing us from using just one set rate of change for all capital additions. Since DHInfrastructure was tracking fewer data points, holding the non-STRIDE capital expenditures constant was sufficient to effectively project the results of a status quo approach.

Exhibit ASH-4

By 2050, the total customers left on each of the three utility systems is just **5 to 7 percent of their total 2020 number of customers.**

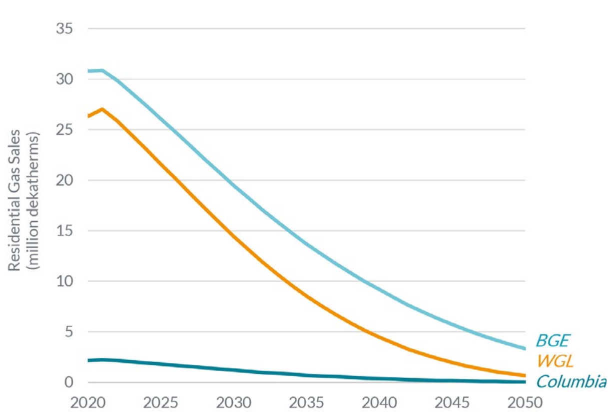
Figure 7 shows detailed residential customer projections by utility.

Figure 7. Residential customers by utility



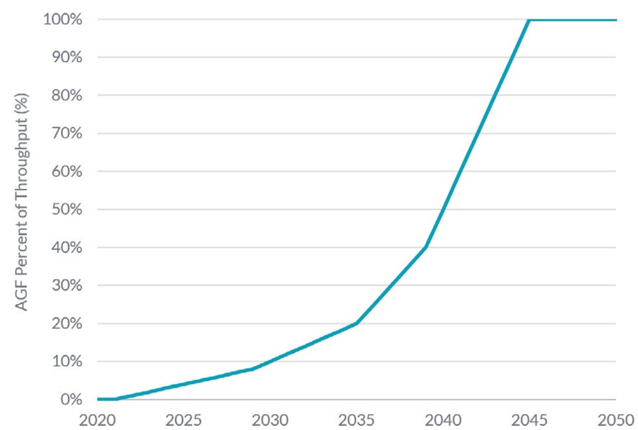
Sales. Using BDC heating stock results and historical utility sales, we determined total gas sales per utility. Our projection shows that total volumetric gas sales decrease from 2020 to 2050, by 89 percent for BGE, 90 percent for WGL, and 84 percent for Columbia. Figure 8 shows residential volumetric gas sales by utility.

Figure 8. Residential gas sales by utility



To meet Maryland's climate goals, all remaining gas throughput in the pipeline system is alternative gaseous fuels by 2045. This is shown in Figure 9.

Figure 9. SSE alternative gaseous fuels percent of throughput



4.2.3. Utility-Specific Modeling Results

Rate base per customer

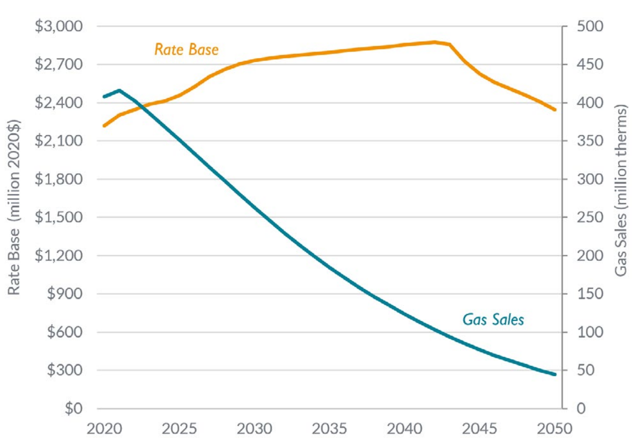
Rate base is the total value of the original cost of assets used and maintained by a utility less accumulated depreciation. Rate base is an identifiable, yet changing, number that has been approved in a regulatory proceeding—generally a rate case in which regulators approve a utility's capital expenditures. The amount of rate base is the cumulation of a utility's capital spending, paid for by customers, and is multiplied by the utility's rate of return (the cost of its debt and equity) to calculate the utility return on its investments. Customers pay down rate base when they pay the utility's depreciation expense that is reflected in the rates on their bills.

To keep rate base (and therefore rates) constant with gas sales continuing at the same level, a utility's approved spending on new capital assets must not exceed the pace at which its existing assets are retired, as customers pay for them through depreciation expense. Rate base—and rates—must increase when regulators approve utilities' capital expenditures (e.g., to replace old infrastructure and for system expansion) faster than existing assets are retired. And if sales are declining, rates must be increased even further to cover the fixed original costs of a utility's previous and ongoing approved capital expenditures. In other words, if utilities invest in pipeline infrastructure faster than existing assets are depreciated and despite decreasing numbers of customers and sales, they will seek substantial rate increases to recover the fixed costs of their rate bases.

Figures 10 through 12 illustrate declines in customers and sales. The figures show that with electrification, the utility's rate base becomes bigger and bigger relative to the utility's fuel throughput (or sales). This drives substantial increases in the utility's rates (the charges per unit measured in a therm of gas throughput) so that the utility can recover its rate-base-related costs across its reduced sales. Rate increases, in turn, will further drive customers off the gas system. **As high levels of customers abandon the gas system over a short period of time, the utility will be forced to strand assets.**

As shown in Figure 10, BGE's STRIDE program increases the utility's rate base and keeps it at roughly that level through the early 2040s. After the completion of its current STRIDE program, rate base falls slightly, assuming customers continue to pay the utility's depreciation expense.

Figure 10. BGE rate base, in real $2020 (left axis) and gas sales (right axis), in the SSE scenario



WGL has a smaller remaining STRIDE program, projected to end in the mid-2030s. Rate base starts to decline gradually around 2028 when annual STRIDE costs decrease about 55 percent compared to the previous year; it decreases faster in 2036 when its current STRIDE program ends, as shown in Figure 11.

Figure 11. WGL rate base, in real $2020 (left axis) and gas sales (right axis), in the SSE scenario

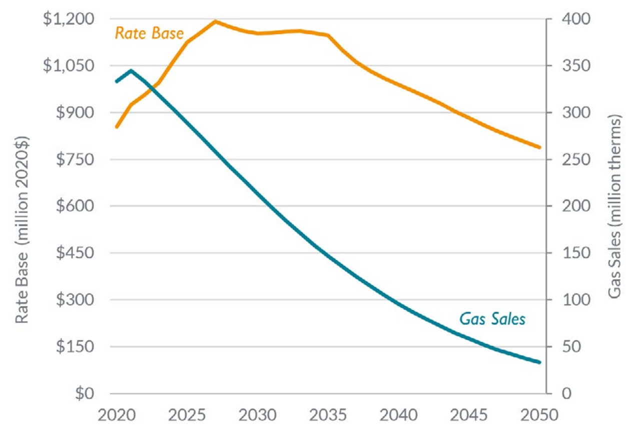


Figure 12 shows that Columbia Gas's rate base begins to flatten out and eventually decline after 2026, when its current STRIDE program ends.

Figure 12. Columbia Gas rate base, in real $2020 (left axis) and gas sales (right axis), in the SSE scenario

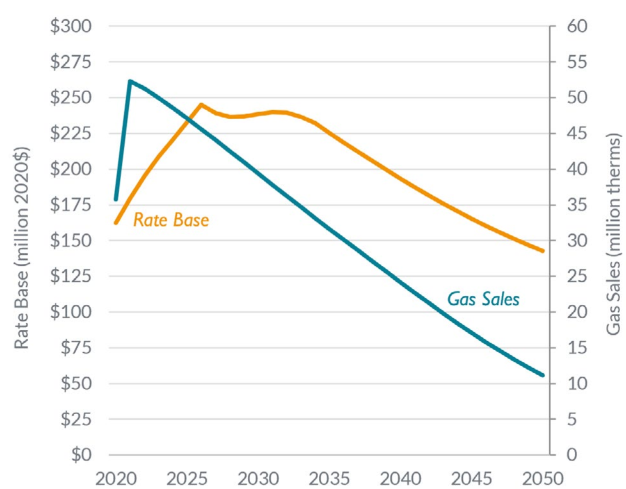


Exhibit ASH-4

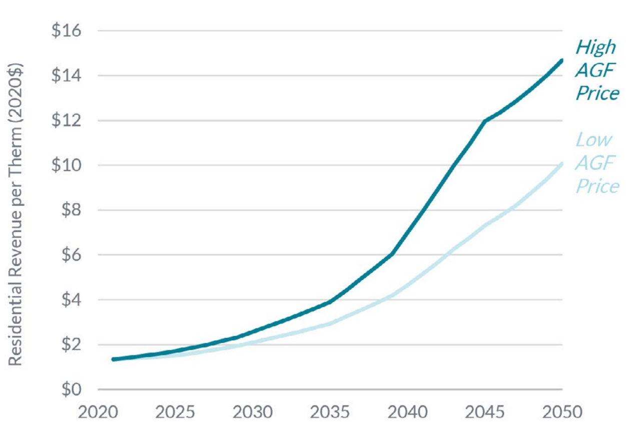
Rates

We approximate utility rates under SSE by taking the utility's annual revenue requirement (including fuel costs, return on rate base, and depreciation and operating expenses) and dividing by the projected amount of gas sold to customers.

We modeled two fuel cost sensitivities to determine the range of potential customer rates. The Low AGF Price ranges from $14.37 per MMBtu to $22.92 per MMBtu and the High AGF Price is set at $69.03 per MMBtu (all in $2020). From 2020 to 2050, utility rate base increases in the near term and stays relatively high (as seen above in Figures 10 through 12). Due to electrification, however, the total therms of gas throughput decreases. At the same time, fuel costs rise as fossil gas is replaced with alternative gaseous fuels. As a result, the revenue the utility must receive per therm sold—i.e., customer rates—must rise for the utility to recover its costs. The effect on customer rates—the required revenue per therm—is illustrated in Figures 13 through 15. The results show that **sector-specific electrification will lead to substantial increases in gas rates**.

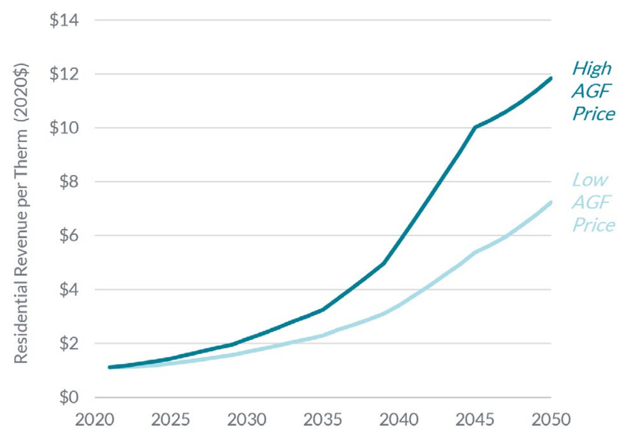
For BGE, our analysis shows that rates increase from $1.34 per therm in 2021 to $2.94 per therm in 2035 and $10.06 per therm by 2050 under the Low AGF Price scenario. In the High AGF Price scenario, the rates increase from $1.34 per therm in 2021 to $3.90 per therm in 2035 and $14.68 per therm in 2050.

Figure 13. BGE residential gas rates



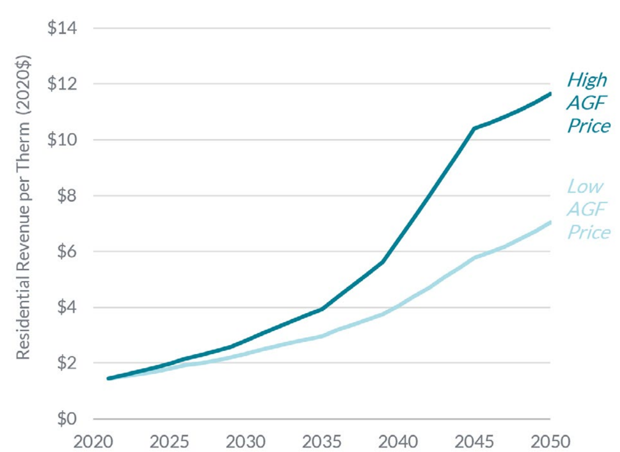
For WGL, our analysis shows that rates increase from $1.11 per therm in 2021 to $2.30 per therm in 2035 and $7.23 per therm by 2050 under the Low AGF Price scenario. Under the High AGF Price scenario, rates increase from $1.11 per therm in 2021 to $3.26 per therm in 2035 and $11.85 per therm in 2050.

Figure 14. WGL residential gas rates



For CMD, our analysis shows that rates increase from $1.44 per therm in 2021 to $2.97 in 2035 and $7.03 per therm by 2050 under the Low AGF Price scenario. In the High AGF Price scenario, rates increase from $1.44 per therm in 2021 to $3.93 per therm in 2035 and $11.65 per therm in 2050.

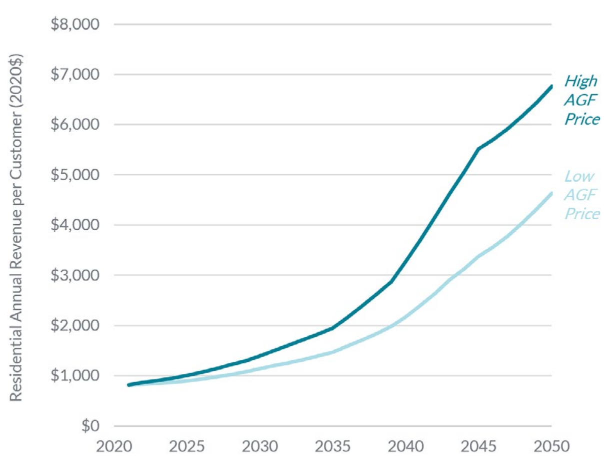
Figure 15. Columbia residential gas rates



Bill impacts of rate increases

Figures 16 through 18 show the annual energy-related operating cost of an average home for space and water heating end-uses under the SSE scenario for BGE.[44] Figure 16 shows the calculation for BGE. In the SSE scenario, building operating costs for residential customers staying on the gas system increase considerably by 2050, from $820 per year in 2021 to $1,464 per year in 2035 and $4,634 per year in 2050 under the Low AGF Price scenario. In the High AGF Price scenario, building operating costs for residential customers increase from $820 per year in 2021 to $1,944 per year in 2035 and $6,759 per year in 2050.

Figure 16. BGE residential building total gas costs (Low and High AGF Price)



As seen in Figure 17, WGL residential building operating costs increase from $780 per year in 2021 to $1,315 per year in 2035 and $3,827 per year in 2050 under the Low AGF Price scenario. In the High AGF Price scenario, building operating costs for residential customers increase from $780 per year in 2021 to $1,868 per year in 2035 and $6,270 per year in 2050.

Figure 17. WGL residential building total gas costs (Low and High AGF Price)

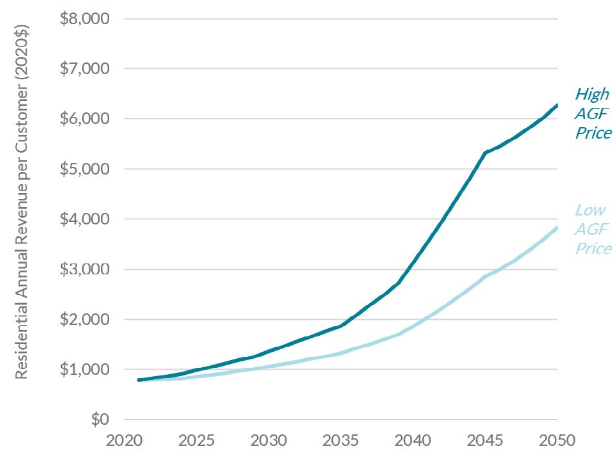
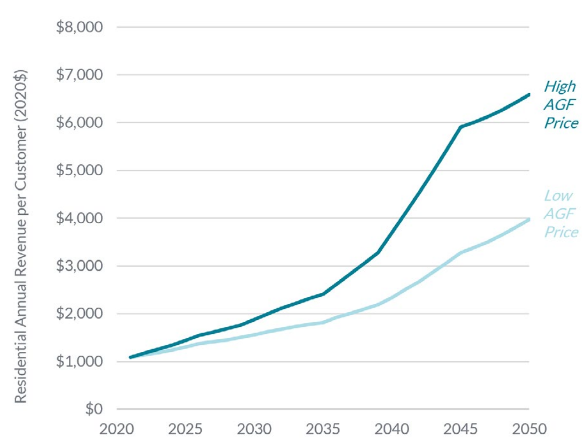


Figure 18 shows residential building operating costs for Columbia Gas. Costs rise from $1,086 per year in 2021 to $1,818 per year in 2035 and $3,979 per year in 2050 under the Low AGF Price scenario. In the High AGF Price scenario, building operating costs for residential customers increase from $1,086 per year in 2021 to $2,408 per year in 2035 and $6,591 per year in 2050.

Figure 18. Columbia residential building total gas costs (Low and High AGF Price)



44 These figures include the cost of fuel in addition to delivery costs.

The following tables provide a summary of the results of our modelling as shown in Figures 13 through 18 and described above.

2035 and 2050 range of residential rate impact depending on cost of alternative gaseous fuels

Rates ($2020/therm)

	2021	2035 AGF range	2050 AGF range
BGE	1.34	2.94 to 3.90	10.06 to 14.68
WGL	1.11	2.3 to 3.26	7.23 to 11.85
CMD	1.44	2.97 to 3.93	7.03 to 11.65

2035 and 2050 range of residential bill impact depending on cost of alternative gaseous fuels

Annual Bill (2020$)

	2021	2035 AGF range	2050 AGF range
BGE	$820	$1,464 to $1,944	$4,634 to $6,759
WGL	$780	$1,315 to $1,868	$3,827 to $6,270
CMD	$1,086	$1,818 to $2,408	$3,979 to $6,591

Importantly, Figures 13 through 18 provide the output for SSE modeling based on the *MWG Policy Scenario* that has heat pumps as the sole source of heating in over 95 percent of residential buildings by 2050. Our modeling achieves the 95 percent goal by gradually increasing heat pumps' share of the Maryland market from 2021 to 2050. As gas rates rise, however, customers will become increasingly likely to electrify their homes to avoid high gas rates. Thus, customer migration away from gas could be faster than the projections we used in modeling SSE. This increase in customer departures would further increase gas rates and perpetuate the cycle of customer departures and increasing rates for customers who remain on the gas system.

Customer migration away from gas could be faster than the projections used.

4.3. Implications of Analysis

The rapid decline in gas sales, together with a flat or increasing rate base (as shown in Figures 10 through 12), cause the dramatic increases in customer rates and bills found in our modeling of SSE in Section 4.2.3. While the overall impact on customer energy bills—across both electric and gas utilities—is beyond the scope of our analysis, our modeling confirms E3's conclusion that *gas* rates for residential customers remaining on the gas system will increase significantly as the State acts to meet its climate goals if the utilities do not alter their practices as a result of customer departures.[45]

Our analysis further holds important implications for the fixed costs that remain in the utilities' rate bases for decades into the future due to ongoing utility capital spending. Electrification will happen gradually as the building stock turns over. Gas rate increases due to electrification will also be gradual. But at some point, it could prove difficult—if not impossible—for gas rates to increase to the levels necessary for gas utilities to recover their fixed rate base costs and remain economically viable. Customers will electrify to avoid the high gas rates, and customers without alternatives nevertheless may not be able to afford continued gas service. If and when this plays out, the utilities will have substantial unrecovered and uneconomic assets remaining in rate base and on their books.

We note that such outcomes can be mitigated. If utilities adapt to electrification, they will be able to update their spending practices to lessen their revenue requirements to slow customer rate increases. In doing so, the utilities can mitigate their stranded assets, and customers who are unable to electrify in the near term will not see costs rise as rapidly.

45 MCCC, *Building Energy Transition Plan: A Roadmap for Decarbonizing the Residential and Commercial Building Sectors in Maryland*, at p. 14.

APPENDIX A

GLOSSARY AND ABBREVIATIONS

Term	Definition	Source
Alternative Gaseous Fuels	Non-conventional fuels such as hydrogen and various forms of natural gas including renewable, synthetic, and biomethane.	Environmental Protection Agency. "Alternative Fuels." Oct. 4, 2021. *Renewable Fuel Standard Program*. Available at: https://www.epa.gov/renewable-fuel-standard-program/alternative-fuels.
Biomethane	Pipeline-quality natural gas substitute produced by purifying biogas, a methane-rich gas produced from organic materials (also known as Renewable Natural Gas).	Natural Gas Vehicles for America. "The Potential of Renewable Natural Gas," 7 Jan. 2009, https://afdc.energy.gov/files/pdfs/biomethane_4.pdf. Accessed 6 July 2022.
Depreciation	The loss in service value not restored by current maintenance and incurred in connection with the consumption or prospective retirement of property in the course of service from causes against which the carrier is not protected by insurance, and the effect of which can be forecast with a reasonable approach to accuracy.	"18 CFR Ch. I, Pt. 352." *Code of Federal Regulations*. Available from: https://www.ferc.gov/sites/default/files/2020-06/18cfr352.pdf. Accessed 6 July 2022.
Fugitive Emissions	Unintended leaks of gas from the processing, transmission, and/or transportation of fossil fuels.	Glossary - U.S. Energy Information Administration (EIA), https://www.eia.gov/tools/glossary/.
Hydrogen (by type)	**Green hydrogen** is made by using clean electricity from surplus renewable energy sources, such as solar or wind power, to electrolyze water. **Blue hydrogen** is created from natural gas using steam methane reformation; the process captures and stores the emitted carbon dioxide underground. **Gray hydrogen** is created from natural gas using steam methane reformation but without capturing the greenhouse gases made in the process.	National Grid. "The Hydrogen Colour Spectrum." Available at: https://www.nationalgrid.com/stories/energy-explained/hydrogen-colour-spectrum.
Rate Base	The net investment of a utility in property that is used to serve the public; this includes the original cost net of depreciation, adjusted by working capital, deferred taxes, and various regulatory assets—the term is often misused to describe the utility revenue requirement.	Lazar, J. (2016). Electricity Regulation in the US: A Guide. Second Edition. Montpelier, VT: The Regulatory Assistance Project. Retrieved from https://www.raponline.org/knowledge-center/electricity-regulation-in-the-us-a-guide-2/.

Exhibit ASH-4

Term	Definition	Source
Recovered Methane	Methane gas that is captured from landfills, wastewater facilities, and farmland through the use of anaerobic digesters.	Environmental Protection Agency. "Learning About Biogas Recovery." *EPA*. Available at: https://www.epa.gov/agstar/learning-about-biogas-recovery.
Return on Equity	The rate of earnings realized by a utility on its shareholders' assets, calculated by dividing the earnings available for dividends by the equity portion of the rate base.	New York State Public Service Commission. "Glossary of Terms Used by Utilities and Their Regulators." Available at: https://www.dps.ny.gov/glossary.html.
Revenue Requirement	The annual revenues that the utility is entitled to collect (as modified by adjustment clauses). It is the sum of operation and maintenance expenses, depreciation, taxes, and a return on rate base. In most contexts, revenue requirement and cost of service are synonymous.	Lazar, J. (2016). Electricity Regulation in the US: A Guide. Second Edition. Montpelier, VT: The Regulatory Assistance Project. Retrieved from https://www.raponline.org/knowledge-center/electricity-regulation-in-the-us-a-guide-2/.
Stranded Assets	Assets that have suffered from unanticipated or premature write-downs, devaluation or conversion to liabilities.	Lloyd's. 2017."Stranded Assets." Available at: https://www.lloyds.com/strandedassets.
Synthetic Natural Gas	A manufactured product, chemically similar in most respects to natural gas, resulting from the conversion or reforming of hydrocarbons that may easily be substituted for or interchanged with pipeline-quality natural gas.	U.S. Energy Information Administration. *Glossary - U.S. Energy Information Administration (EIA)*, https://www.eia.gov/tools/glossary/.

Abbreviation	Term
AGF	alternative gaseous fuels
BDC	Building Decarbonization Calculator
BGE	Baltimore Gas and Electric
C&I	commercial and industrial
GHG	greenhouse gas
GRM	Gas rate model
MWG	Mitigation Work Group
OPC	Office of People's Counsel
STRIDE	Strategic Infrastructure Development and Enhancement program
SSE	Sector Specific Electrification
WGL	Washington Gas Light

APPENDIX B

DETAILED COMMERCIAL RESULTS

Figure B-1. Commercial on-site space and water heating GHG emissions, before accounting for use of low- or zero-carbon gas or off-site emissions

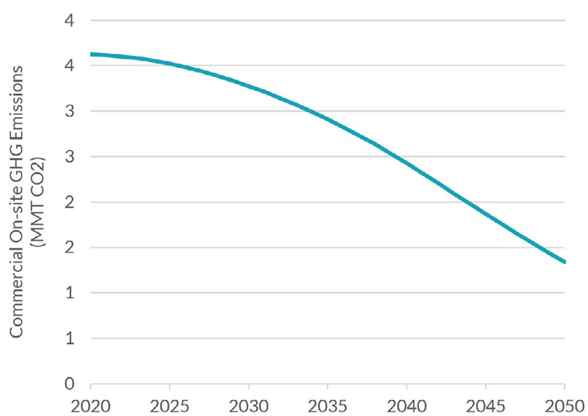


Figure B-2. Commercial gas consumption

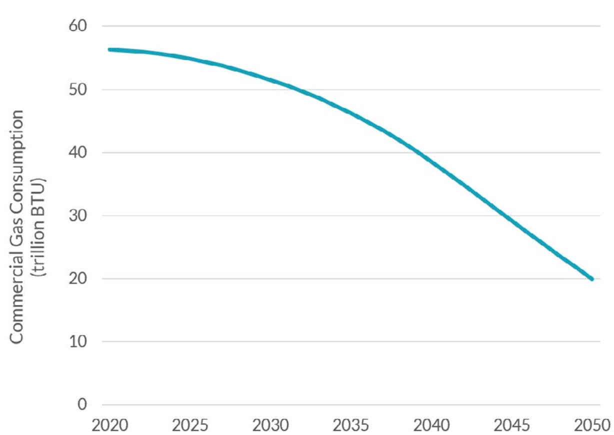


Figure B-3. Commercial building stock by space heating fuel and technology

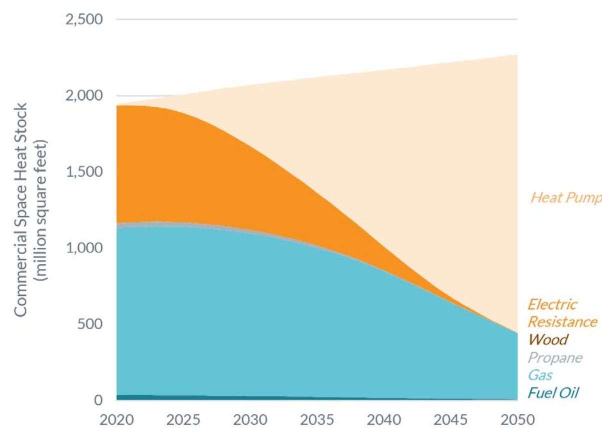


Figure B-4. Commercial and industrial customers by utility

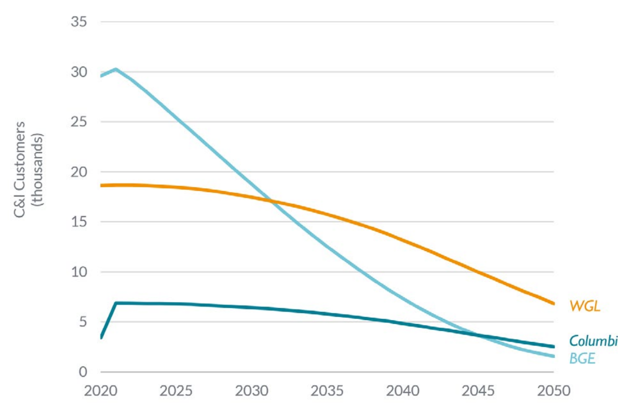


Exhibit ASH-4

B-5. Commercial and industrial gas sales by utility

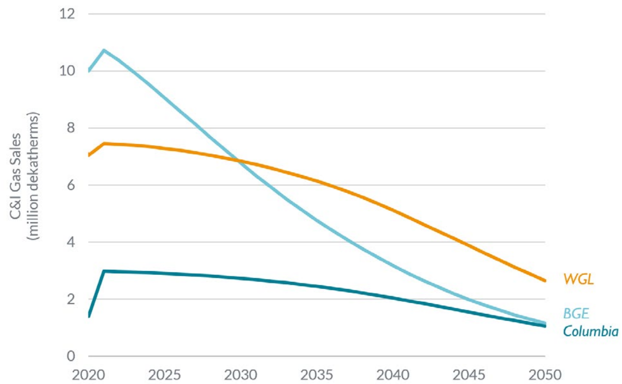


Figure B-6. BGE commercial and industrial building total gas costs (Low and High AGF Price)

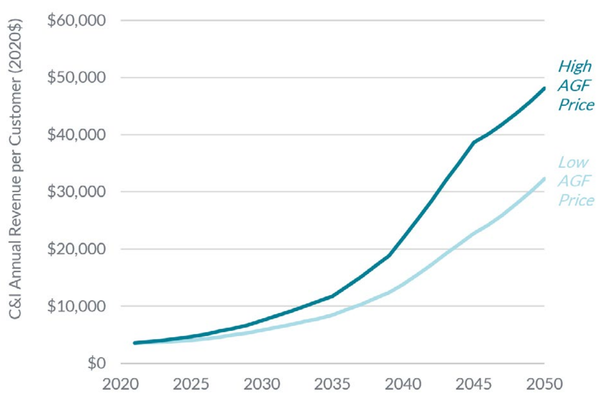


Figure B-7. WGL commercial and industrial building total gas costs (Low and High AGF Price)

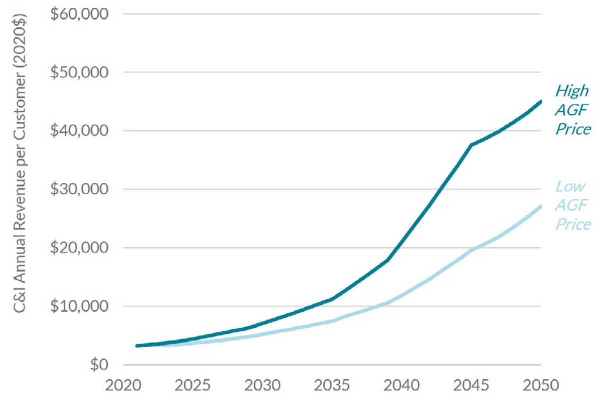


Figure B-8. Columbia Gas commercial and industrial building total gas costs (Low and High AGF Price)

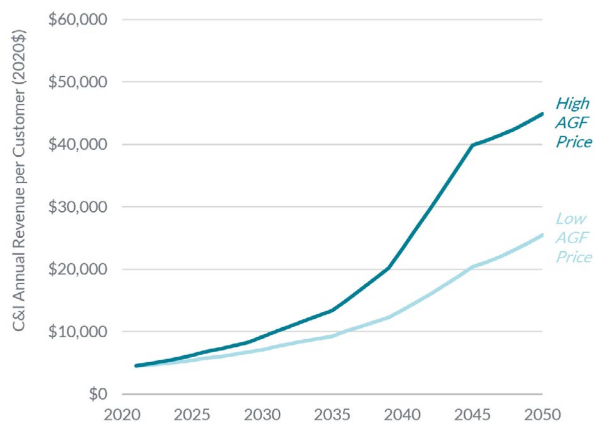


Exhibit ASH-4

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Office of People's Counsel
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Exhibit ASH-5

Exhibit ASH-5

Long-Term Planning to Support the Transition of New York's Gas Utility Industry

Prepared for Natural Resources Defense Council

April 30, 2021

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CONTENTS

EXECUTIVE SUMMARY

Background

New York will need to drastically reduce all fossil fuel use in order to achieve the Climate Leadership and Community Protection Act's (CLCPA) economy-wide goals of achieving 40 percent emissions reductions from 1990 levels by 2030 and net zero emissions by 2050. These goals apply to the entire economy and will have dramatic implications for the conventional natural gas (fossil gas) utilities.

Recognizing that gas utilities need to adjust to new energy and climate policy, the Public Service Commission (PSC or Commission) recently instituted a new proceeding to "establish planning and operational practices that best support customer needs and emissions objectives while minimizing infrastructure investments and ensuring the continuation of reliable, safe, and adequate service to existing customers."[1] The proceeding also aims to improve the transparency and inclusiveness of gas planning, supply and demand analysis, and management of supply constraints. As required by the PSC, the New York Department of Public Service (DPS) filed its Gas System Planning Process Proposal (DPS Proposal) on February 12, 2021.[2] While the proposal recommends important improvements to the current process, the proposal's overall vision for achieving CLCPA and other state policy goals over the long term is far too limited.

This white paper describes the planning practices necessary to guide and support the transition from today's gas industry to one that complies with the CLCPA, maintains essential energy services, manages costs, protects all customers, and promotes energy justice.[3] We recommend two overlapping but different types of plans for this purpose: (a) statewide gas transition plans, and (b) gas utility resource plans. The statewide transition plans should establish a vision for how the industry must evolve over the long-term, and the gas utility resource plans should identify the specific actions, resource investments, and infrastructure investments that each utility will undertake to achieve that long-term vision.

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[1] New York Public Service Commission. Case 20-G-0131 - *Proceeding on Motion of the Commission in Regard to Gas Planning Procedures,* Order Instituting Proceeding, at 4 (Mar. 19, 2020).

[2] Simultaneously with issuing the Staff Gas System Planning Process Proposal, the DPS also filed the Staff Moratorium Management Proposal on February 12, 2021. This paper focuses on the Planning Process Proposal.

[3] We use the term "energy justice" to refer to a concept similar to environmental justice. Energy justice pertains specifically to energy-related benefits and burdens. According to the Initiative for Energy Justice, "[e]nergy justice refers to the goal of achieving equity in both the social and economic participation in the energy system, while also remediating social, economic, and health burdens on those disproportionately harmed by the energy system." Further, "[e]nergy justice aims to make energy accessible, affordable, clean, and democratically managed for all communities." (The Initiative for Energy Justice, https://iejusa.org.) Energy justice analyses should consider the same types of customers and communities as environmental justice analyses; the main difference between the two is the scope of impacts considered.

Long-term gas planning principles and practices

The economic analyses needed to develop statewide gas transition plans will have to be broader and more comprehensive than traditional utility integrated resource plans because of the extent of change required of the gas industry itself. Therefore both statewide transition and utility resource plans should adhere to the following principles and practices:

- Design all scenarios to comply with the CLCPA.
- Integrate gas and electricity planning.
- Assess impacts on gas and electricity sales.
- Use appropriate asset lives and depreciation schedules.
- Articulate greenhouse gas (GHG) constraints.
- Apply a high threshold for approving new gas infrastructure investments.
- Assess multiple gas utility business models.
- Develop comprehensive non-pipeline alternatives (NPA) screening frameworks.
- Adopt practices for strategic asset retirement.
- Update gas load forecasting practices.
- Account for customer actions.
- Account for risk.
- Articulate an action plan.
- Update plans periodically.

The statewide transition plans

These plans should indicate how the state as a whole will achieve New York's long-term industry goals, including emissions reductions as required under the CLCPA and other key regulatory goals. Because of the need for fundamental structural changes in the fossil gas industry, this statewide plan should include considerations of different gas utility business models, as well as enhanced consideration of rate and bill impacts particularly on low-income and moderate-income customers. These statewide transition plans should include the following elements:

- Benefit-cost analyses (BCA) to identify least cost and low risk ways of achieving the statewide transition plan and other regulatory goals.
- Rate and bill analyses of the gas and electricity utilities to identify how different strategies will affect different customer classes.
- Energy justice analyses to identify how low-income and moderate-income customers, captive customers, and disadvantaged communities will be affected by the transition plan.
- Utility financial analyses to identify how different transition scenarios will affect utility financial viability and ability to serve customers.
- Macroeconomic analyses to identify how different transition scenarios will affect economic development in New York state.

The gas utility resource plans

These utility-specific plans should indicate how each gas utility will achieve the vision and the outcomes identified in the statewide gas transition plans. The gas utility resource plans that we recommend here would be consistent with the long-term utility plans described in the DPS Proposal but would be enhanced using the long-term gas planning principles and practices described here.

The statewide transition plans and the gas utility resource plans will have some areas of overlap and some differences. Table 1 compares the two different types of plans.

Table 1. Statewide Transition Plans and Utility Resource Plans

	Statewide Transition Plan	Utility Resource Plan
Geographic scope	New York	each gas utility
Frequency of plan	five years	three years
Study period	2050 or 20 years, whichever is longer	2050 or 20 years, whichever is longer
Long-term gas industry goals	✓	✓
Long-term gas planning principles	✓	✓
Benefit-cost analysis	✓	✓
Rate and bill analysis	✓	✓
Utility financial analysis	✓	✓
Energy justice analysis	✓	✓
Integrate gas and electricity planning	✓	✓
Macroeconomic analysis	✓	–

1. Statewide Gas Transition Plans

1.1. Statewide Planning

The DPS Proposal includes a gas utility resource planning process to meet new and evolving gas industry goals. This proposal represents a significant improvement over current gas planning practices. However, the DPS Proposal lacks a long-term vision for how the New York fossil gas industry will need to evolve over time to ensure that the state can meet the goals of CLCPA, as well as other important goals such as availability of service and customer equity. Further, the DPS Proposal does not recommend a planning process to develop a long-term vision for how the industry should evolve across the entire state.

The importance of statewide planning to develop a vision and roadmap for the gas industry cannot be overstated. The changes that will be required to transform the gas industry are so broad that it would be very inefficient and unwieldy to try to address those changes on a utility-by-utility basis. Some issues, such as coordination with electric utilities, coordination with other industries in complying with the CLCPA, innovative ideas about new business models, and creative proposals for protecting consumers and ensuring energy justice, have important implications across the entire state and should not be addressed in the isolated silos of each utility. In addition to being very inefficient, this approach would likely allow many important issues to fall through the cracks between the different utilities.

Further, the changes required to transform the gas industry are so broad that they will affect many parties throughout the state, including gas and electric utilities, gas and electric utility customers, third-party providers of electric and gas products and services, consumer advocates, environmental advocates, municipalities, gas and electric utility investors, trade allies that provide energy efficiency and demand response services, and state agencies responsible for environmental protection and economic development. These parties' perspectives and interests typically span the entire state and it would be infeasible for all these parties to provide meaningful input into each of the nine utility-specific resource plans that are conducted every three years on a staggered basis, as proposed by the DPS.[4]

Finally, statewide planning is necessary to establish GHG goals for each gas utility, which is a foundational planning criterion for developing each utility's resource plan.

1.2. Long-Term Gas Industry Goals

The DPS, PSC, and the New York State Energy Research and Development Authority (NYSERDA) should lead a stakeholder process to develop a plan for transitioning from today's fossil gas industry to an industry that achieves New York's decarbonization goals, where fossil gas is completely phased out by 2050, which should incorporate sector-specific goals recommended by the Climate Action Council.[5] This statewide transition plan should help define the long-term gas utility industry structure and goals and should outline the actions necessary to achieve those goals. Such goals could include, for example:

- Continue to provide reliable energy services to all electric and gas customers. The fuel types used to provide energy services might change over time, but all customers should have access at least the level of services they have access to today.
- Keep the cost of energy services as low as reasonably possible. This goal can be pursued through sound economic analyses, as described below. It can also be pursued by animating markets and third-party providers of energy services where warranted.
- Achieve the emission reduction goals of the CLPCA.
- Ensure customer equity and energy justice for disadvantaged communities. This should be a key objective embodied in all aspects of the transition plan.
- Manage the financial health of the current electric and gas utilities to ensure that they can continue to provide low-cost reliable services where warranted, can adopt new business models, or can phase out business lines with as little disruption in energy service delivery as possible.

[4] DPS Proposal, p. 7.

[5] The CLCPA creates a Climate Action Council charged with developing a scoping plan of recommendations to meet these targets and place New York on a path toward carbon neutrality. The scoping plan will inform the State Energy Planning Board's adoption of a state energy plan, which will provide official policy guidance for meeting the climate targets.

The DPS Proposal mentions some of these concerns. It states, "[t]he long-term gas system planning process will help the utilities plan where, when, and how to deploy capital to ensure reliability in the future at reasonable cost and in line with State policies."[6] However, it does not clearly lay out all relevant goals. For example, customer equity and energy justice for disadvantaged communities is clearly a goal of the CLCPA but is not mentioned in the DPS Proposal.

1.3. Long-Term Gas Planning Principles and Practices

The economic analyses needed to develop statewide gas transition plans will have to be broader and more comprehensive than traditional utility integrated resource plans because of the extent of change required to the gas utility industry itself. Consequently, the following principles and practices should be adopted to ensure that the statewide gas transition plans will achieve long-term statutory and regulatory goals for the industry.

Design all scenarios to comply with the CLCPA

The GHG emission reduction requirements in the CLCPA should be assumed as a constraint in designing the scenarios to be analyzed in the long-term gas planning process. In other words, all scenarios should comply with the statutory GHG emission requirements. The GHG emissions described in the PSC 2016 BCA Order as "externalities," i.e., costs external to the monetary transactions of the utility, actually become "internal" costs to the extent they are addressed by the CLCPA.[7] They become costs that will be incurred by utilities and ultimately collected from customers. Therefore, these costs of compliance with the CLCPA should be included in all scenarios, and in all elements of the BCA: the Societal Cost test, the Utility Cost test, and the bill impact analysis.[8]

The DPS Proposal notes that the costs and benefits in the BCA should include external costs and benefits (page 22) and should properly account for GHG emissions associated with all solutions (page 26). The gas long-term plans must do more than simply estimate the amount of emissions and put a dollar value on them; they must include reference cases and scenarios that comply with the CLCPA. This approach eliminates the need to monetize GHG emissions because the monetary value of GHG emissions will be implicitly accounted for in the estimates of the costs of the scenarios that comply with the CLCPA.[9] This approach will lead to the most accurate assessment of what is needed to comply with the CLCPA. Using an administratively-determined social cost of carbon, for example, for the value of reducing GHG

[6] DPS Proposal, p. 7.

[7] While the CLCPA internalizes much more of the cost of GHG emissions than previous policy did, some externalities will remain even assuming full compliance with the CLCPA.

[8] Utilities might choose to conduct a sensitivity analysis where they do not comply with the CLCPA, for the purpose of identifying the costs of complying with the CLCPA. But this would be just a sensitivity; it would not be seen as a viable scenario, and it would not be used to determine the optimal long-term mix of gas resources.

[9] There may be additional, external, societal costs of GHG emissions, beyond those required to comply with the CLCPA. If so, then these impacts should be treated as externalities.

emissions will provide a different result than using the actual resources and actions that are required to comply with the CLCPA. If the administratively-determined estimate of the value of GHG emissions is too low, then the gas transition plans will not comply with the CLCPA; if it is too high, then customers will pay too much for compliance with the CLCPA.

Integrate gas and electricity planning

Complying with the provisions of the CLCPA will likely require the electrification of many end-uses, including the conversion of many fossil gas end-uses to electric end-uses. The electric local distribution companies (LDCs), local governments, and state agencies also have programs to support electrification of fossil gas end-uses. Thus, it is critical to consider electric and gas consumption, technology options, prices, and sales in an integrated manner. Each gas utility has a different relationship with the electric utility or utilities that serve its customers. In some cases, the utilities are part of the same corporate entity, in other cases not. The gas utility resource plans should incorporate and reflect each utility's situation and demonstrate how the utilities are working together.

Assess impacts on gas and electricity sales

Achieving the goals of the CLCPA will require a significant reduction in fossil gas sales over time, and perhaps the eventual elimination of fossil gas sales. As fossil gas sales begin to decline, either through electrification or other measures to comply with the CLCPA, it may become necessary for gas utilities to increase prices to recover historical, sunk costs for capital assets. This increase in prices might encourage additional fossil gas customers to switch to alternative sources of energy, creating further upward pressure on fossil gas prices, potentially leading to a death spiral for the fossil gas utilities. Such an outcome obviously has dramatic consequences for fossil gas utilities and their customers, and therefore should be accounted for in long-term planning.

Use appropriate asset lives and depreciation schedules

We agree with the DPS Proposal that asset depreciation schedules are a key input into the economic analyses of gas resources. However, the DPS treatment of depreciation schedules does not go nearly far enough.

The DPS Proposal requires that the long-term gas resource plans should include "a scenario that assumes that the full value of any new gas assets will be depreciated by 2050."[10] Assessing only one scenario, or even a set of scenarios or sensitivities, will not sufficiently capture the requirements of the CLCPA. The CLCPA establishes statutory mandates for reducing GHG emissions, therefore e*very scenario and every sensitivity* should be compliant with the CLCPA. The gas utilities' long-term plans should not include any scenarios where new gas assets are not depreciated by 2050—unless the utilities can demonstrate that such a scenario will comply with the CLCPA.

[10] DPS Proposal, pages 22-23.

Further, there might be scenarios where some gas assets should be phased out or retired before 2050 to achieve the GHG goals in the CLCPA. If this is the case, then depreciation schedules that are longer than the actual operating life of an asset will unduly reduce the cost of that asset and result in a skewed economic analysis in favor of that asset. This might also result in stranded costs that will have to either be recovered from customers (at a time when prices are increasing for other reasons) or by utility shareholders (at a time when they are facing increased pressures due to lower sales).

Appropriate depreciation schedules should be applied to both existing and new gas assets alike.

Articulate annual GHG constraints

Long-term gas plans should articulate all GHG constraints, including goals for 2025, 2030, 2035, 2040, 2045, and 2050. Also including GHG guidelines for each year will help ensure that the 5-year goals will be achieved and will provide clarity for the actions that need to be taken in the short- and medium-term to achieve those 5-year goals.

Apply a higher threshold for approving new gas infrastructure

Where the gas utility resource plan includes specific infrastructure investments, the plan should fully document how those investments meet the standards set in the statewide transition plan. Such documentation should include quantitative analysis of benefits, costs, and risks associated with alternatives; should demonstrate that NPAs were considered before proposing fossil gas assets; and should show that any new gas asset's useful life will end by 2050 at the latest. The higher threshold for approving gas infrastructure should reflect the risk of failing to meet the requirements of the CLCPA, as well as the cost associated with locking into large conventional investments (a negative option value).

Assess multiple gas utility business models

Compliance with the CLCPA might require fundamental shifts in gas utility business models. Therefore, long-term gas plans should assess a variety of different gas utility business models, including establishing district heating systems. Other options, such as the use of biomethane, renewably produced hydrogen, and/or synthetic natural gas could also be assessed; but these studies should be grounded in realistic assumptions about potential feedstock constraints, reflect how these fuels will be used, consider impacts to health and the environment, and properly account for the risk of perpetuating fossil gas use and increasing stranded costs associated with system infrastructure.[11] Also, it should consider the relationship between electric and gas utility business models, an assessment of gas utilities' obligation

[11] Alternative forms of fossil gas are sometimes supported with tradable emission credits or renewable credits that represent the positive environmental attributes associated with the alternative gas supply. If such alternative forms of gas are used by the utility to lower the carbon intensity of its operations to comply with the CLCPA, then the utility must demonstrate that any such credits are retained for the benefit of its customers and in no way "double-counted" by another entity. If the credits are not retained by the utility, then the alternative forms of fossil gas should be treated the same as fossil gas for the purpose of the BCA because the environmental attributes are not being used to lower the carbon intensity of the utility's operations.

to serve customers, and the level of return on equity that should be applied to new business models given a potentially different risk profile.[12]

Develop a comprehensive NPA screening framework

Per the DPS Proposal, NPAs should be evaluated for cost-effectiveness consistent with the PSC 2016 BCA Order,[13] which requires assessment from the societal perspective and at the portfolio level. We agree and recommend that the NPA screening framework account for impacts from NPAs and demand-side measures over their useful measure lives, accounting for the potential need to retire some fossil gas assets prior to 2050. In addition, the framework should consider option value (e.g., value of the flexibility to make smaller investments until more is known about the extent of the need). Further, gas utilities should periodically update their assessments of the capacity shortfalls and the evaluations on the status and performance of each NPA project.[14]

Adopt practices for strategic asset retirement

Each utility resource plan should identify where the utility plans to retire assets, and its specific plans for customer transition. In order to keep gas rates low enough to avoid mass, unmanaged defection away from gas service, the gas LDCs should adopt a strategic gas asset retirement approach under which the LDCs would geographically target customers served by a particular distribution line, and then develop a plan to retire that line by offering electrification or other alternative energy services. This approach is particularly needed for the gas lines that are aging, leaking, are due to be replaced, or have other characteristics that make retirement more cost-effective, feasible, or desirable (e.g., lines with clusters of non-heating gas customers or areas vulnerable to climate change). Although the DPS Proposal considers this strategy, more detail is needed on how it would be implemented.[15]

Update gas load forecasting practices

Each utility resource plan should include utility-specific load forecasts developed consistent with modernized statewide forecasting principles, with the necessary level of location-specific and customer class-specific forecasts required to understand geographic and financial analyses. Gas load forecasting should be aligned with and incorporate the impacts of state and local climate policies. To this end, the modeling should use the most up-to-date assumptions (e.g., on fuel-switching) and provide sufficient

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[12] For more information, see Synapse Energy Economics, *Gas Regulation for a Decarbonized New York*, prepared for Natural Resources Defense Council, June 2020, Section 8.

[13] New York Public Service Commission. 2016 (January 21). *Order Establishing the Benefit Cost Analysis Framework*. Case 14-M-0101 (2016 BCA Order).

[14] Synapse Energy Economics, *Gas Regulation for a Decarbonized New York*, prepared for Natural Resources Defense Council, June 2020, Section 4.

[15] DPS Proposal, p. 19.

granularity and lead time to allow implementation of NPAs.[16] Gas load forecasting should also develop long-term load forecasts leading to the long-term GHG reduction targets, which will enable the state and utilities to find policy and program gaps that they need to address for meeting the emission targets.[17]

Account for customer actions

Electricity and gas customer decisions are likely to play a critical role in the transition of the gas utility industry, especially as gas and electricity prices increase and technologies for substituting gas with electricity become more available and more economic. The long-term gas plans should consider the customer-facing economics in each scenario, differentiating customer classes as necessary, and explicitly identify policies or programs to make the adoption of efficient end-use technologies more economic for customers.

Account for risk

There are many uncertainties and unknowns about how the gas utility industry should evolve over time to comply with the CLCPA. This introduces even more risk and uncertainty than is typically addressed in utility planning processes. Long-term gas plans should acknowledge and, wherever possible, model risk of failure along different pathways. They should also account for the option value of different decisions, i.e., the path dependence that limits the ability to change course in the event of failure.[18]

Articulate an action plan

The transition of the gas utility industry will likely require multiple actions by multiple parties. It is therefore especially important that long-term gas plans articulate the major steps needed to transition from the current fossil gas utility industry to a new industry that meets the requirements of the CLCPA and other regulatory goals.

Update plans periodically

There are still many unknowns about how the gas utility industry transition will unfold, and there will likely be important new developments and information regarding technology options, fuel options, customer preferences, financial issues, customer protection issues, and more. Therefore, long-term gas plans should be updated periodically to address changing circumstances. We recommend that the statewide gas transition plans be developed every five years and the utility resource plans be developed every three years.

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[16] Likewise, DPS Staff recommends inclusion of NPAs in load forecasts and a geographical analysis with enough granularity to clearly identify locations of anticipated localized demand growth to allow for adequate planning. (Id., p. 15).

[17] Synapse Energy Economics, *Gas Regulation for a Decarbonized New York*, prepared for Natural Resources Defense Council, June 2020, Section 4.

[18] Many of these recommendation in this section draw upon a similar analysis conducted by Synapse Energy Economics for the Conservation Law Foundation, filed in Massachusetts Department of Public Utilities Docket 20-80, and available at https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/13118067.

1.4. Comprehensive Economic Assessments

The statewide gas transition plan should be grounded in a comprehensive economic assessment using the same economic principles and concepts that would be applied in similar regulatory contexts. The economic assessment should be used to identify the lowest-cost path for decarbonizing each fossil gas utility's system, while meeting other policy goals such as provision of energy services, compliance with CLPCA, customer equity, and energy justice.

BCA should be the core of the economic assessment but is not the only component. There are several important factors that cannot or should not be included in a BCA but should nonetheless be considered as part of the economic assessment using separate analyses. These include rate and bill analysis, energy justice analysis, utility financial analysis, macroeconomic analysis, and consideration of other qualitative factors.

These different analyses are necessary because they serve different purposes, provide different outputs, and consider impacts on different parties. The outputs of different analyses cannot simply be added together into a single formulaic decision-making metric. Instead, the outputs of each of the analyses need to be considered to identify the best transition plan for all parties involved.

These different types of analyses are presented in Table 2 and discussed in more detail below.

Table 2. Overview of comprehensive economic assessment

Type of Analysis	Purpose	Parties Considered	Key Outputs
Benefit-Cost Analysis	To assess cost-effectiveness by indicating whether the benefits of the transition pathway exceed the costs	All customers on average	Present value (PV) of costs, PV of benefits, PV of net benefits, benefit-cost ratios
Rate and Bill Analysis	To assess customer equity by indicating the impact on customers' rates and bills	All customers, by customer class	change in ¢/kWh and $ per therm, change in $/month and year, by customer class
Energy Justice Analysis	To assess energy justice issues by focusing on specific customer segments and community-level impacts	Vulnerable customers[19] and disadvantaged communities	bills, energy burden, distributed energy resource participation rates, environmental and health impacts
Financial Analysis	To assess the financial viability of current and proposed utility business models	Utility management and investors	retail sales, customers, earned ROE, gross profit, net profit, earnings per share
Macroeconomic Analysis	To assess impacts on state's economy	Workforce in the state	number of jobs, state gross domestic product
Other Considerations	To account for factors that are not addressed in the other analyses	Customers, utilities, society	metrics for factors not considered above

[19] Vulnerable customers may include low-income customers, moderate-income customers, customers who are medically dependent on heating, cooling, electricity for equipment, and customers vulnerable to climate change.

The DPS Proposal discusses some of these elements, including BCA and rate and bill impact analysis. In these cases, we offer recommendations for enhancing these analyses. Other elements, such as the energy justice, financial, and macroeconomic analyses, are not included in the DPS Proposal but should be incorporated into statewide gas transition plans.

Benefit-Cost Analysis

We agree with the DPS Proposal's requirement that utilities should continue to use the practices required in the PSC 2016 BCA order and the utilities' BCA Handbooks. Further, we agree with the DPS Proposal's recommendation to improve upon current practices by (a) providing better estimates of upstream fixed and variable costs, (b) including avoided gas distribution costs, and (c) investigating the costs of renewable gas alternatives to fossil gas. Below we provide several additional enhancements to current BCA practices.

Costs and Benefits to Include

We recommend adding several items to the list of costs and benefits presented in the DPS Proposal.[20] First, the costs and benefits should include the wholesale market price suppression effects for both the electricity markets and the gas markets. In light of the potential for significantly declining fossil gas sales for compliance with the CLCPA, demand-side gas resources and electrification practices could have a substantial dampening effect on wholesale fossil gas prices.[21] Reduced gas demand could also depress the cost of increased electrification, if electricity production costs decline due to the gas price suppression effects.

We recognize that the PSC BCA order concluded that the wholesale price suppression effect should not be accounted for in the Societal Cost test because the changes in prices are essentially a transfer payment between electricity generators and customers.[22] We do not agree with this determination. The wholesale market price effects are not transfer payments; they are utility system impacts, and they should be included in the Utility Cost test and the Societal Cost test.[23]

[20] DPS Proposal, page 22.

[21] There are several components of fossil gas price suppression effects, sometimes called Demand Reduction Induced Price Effects (DRIPE). Basis DRIPE (how changes in fossil gas consumption in New York changes local basis), and cross-DRIPE (how change in consumption affects changes in electricity prices) may be sizable. Supply DRIPE (how a change in fossil gas consumption in New York affects Henry Hub) may be smaller. The components of fossil gas DRIPE are described in Synapse Energy Economics 2018, AESC, chapter 9, available at: https://www.synapse-energy.com/sites/default/files/AESC-2018-17-080-Oct-ReRelease.pdf.

[22] PSC 2016 BCA Order, 2016, page 24.

[23] For more discussion on these points, see *The National Standard Practice Manual for Assessing the Cost-Effectiveness of Distributed Energy Resources*, 2020, Appendix F, Section F.6.

Second, the costs and benefits of methane leaks should be accounted for in the BCA. These leaks have important implications for (a) the cost of delivering gas, and (b) the ability to comply with the CLCPA, and (c) environmental impacts even after the utilities comply with the CLCPA.

Third, the costs and benefits of indoor air quality should be accounted for in the BCA. There is increasing evidence that indoor combustion of fossil gas can have negative health impacts on the building occupants, and these impacts should be accounted for in the Societal Cost test.

Utility Cost Test

The DPS Proposal reiterates the requirement from the 2016 BCA Order that the Utility Cost test and Bill Impact analysis be used as secondary checks on the Societal Cost test, which should be the primary test for assessing cost-effectiveness. We fully support this requirement.

To the extent that the Utility Cost test is used in long-term gas plans, it is important that a societal discount rate is used rather than a discount rate based on the utilities' weighted average cost of capital.[24] A societal discount rate is consistent with the goals of the long-term gas plans. A societal discount rate also reflects the regulatory perspective, which is more appropriate in this context than the utility investors' perspective.[25] The utility investors' perspective is addressed in the utility financial analysis discussed below. Further, since the Utility Cost test will be used as a check on the Societal Cost test, using the same discount rate is necessary in order to make meaningful comparisons across the two tests.

Rate Impact Measure Test

The 2016 BCA Order directs the utilities to use the Ratepayer Impact Measure (RIM) test as a secondary check to indicate the implications of utility plans on customer rates. The DPS Proposal, however, notes that a full bill impact analysis provides better information to assess the implications on customers rates and bills.[26] We agree with this conclusion of the DPS Proposal and recommend that the rate and bill impact analysis be used instead of the RIM test. This means that utilities should no longer conduct or present the results of the RIM test in their BCAs.

Bill Impact Analyses

We agree with the DPS Proposal's framing of the use and the design of the bill impact analyses. These analyses will clearly be an important complement to the BCA because the gas and electricity bill impacts

[24] Note that the discount rate used in a BCA has no bearing on the utility's ability to recover its capital costs. The recovery of capital costs should be included in the costs and the benefits included in the BCA. The only impact that the discount rate has is to give different weight to the short-term versus long-term costs and benefits in the BCA.

[25] See National Energy Screening Project, *The National Standard Practice Manual for Assessing the Cost-Effectiveness of Distributed Energy Resources*, Appendix G, 2020 for more detail.

[26] DPS Proposal, page 22.

of the fossil gas transition are likely to be significant and therefore should inform some of the key decisions.

All the inputs and assumptions that are common to both the BCA and the rate and bill analyses should be the same in both analyses. For example, all scenarios in the bill impact analyses should be consistent with the scenarios in the BCA. As noted above, all of these scenarios should comply with the GHG requirements of the CLCPA.

In addition, the bill impact analyses should account for the reduction in fossil gas sales as a result of electrification of gas end-uses and other means of fuel switching. These changes in the fossil gas market will have critical implications for bill impacts. The bill impact analysis should also account for the electricity bill impacts for those customers that switch from gas to electric end-uses.

Further, the bill impact analyses should explicitly identify any changes in the number and type of fossil gas customers, as well as the number of customers who decide to switch out their gas space or water heating end-uses for other fuels. This information will be critical to understanding how the gas utility industry is transforming over time in light of CLCPA and other industry trends.

Finally, the rate and bill impact analysis should account for the number and types of customers that participate in distributed energy resource programs or otherwise install distributed energy resources. This is important to indicate the extent to which customers will experience lower bills as a result of distributed energy resources and industry changes.

Energy Justice Analysis

The energy justice analysis should build off of the rate and bill impact analysis but with a focus on low-income, moderate-income,[27] disadvantaged communities, and Environmental Justice areas.[28] This analysis should identify and quantify, to the extent possible, impacts on these groups. Metrics could include: energy efficiency and distributed energy resource participation rates for residential customers, low-income customers, moderate-income customers, and customers in disadvantaged communities and Environmental Justice Areas; energy burden for residential customers by census block; capital costs for

[27] Low-income and moderate-income customers both face barriers to managing energy bills and energy burdens that call for policy intervention; however, combining these segments into one group may result in policies that effectively address the needs of moderate-income customers but do not go far enough to lower barriers faced by low-income customers. Thus, we list both groups to emphasize that policies should be designed to address both groups distinctly.

[28] Per the CLCPA, the Climate Justice Working Group is to establish criteria for defining disadvantaged communities; however, the criteria have not been set yet. Interim criteria for disadvantaged communities include those located within New York State Opportunity Zones or communities located within census block groups that meet the HUD 50% AMI threshold and that are also located within the DEC Potential Environmental Justice Areas (NYSERDA, "Disadvantaged Communities." https://www.nyserda.ny.gov/ny/disadvantaged-communities). New York City's environmental justice law, enacted in 2017, requires city government to conduct a comprehensive study that determines which neighborhoods are considered "Environmental Justice Areas". (NYC Climate Policy & Programs. "Environmental Justice: New York City's Environmental Justice for All Report." https://www1.nyc.gov/site/cpp/our-programs/environmental-justice-study.page).

space and water heating equipment; and outdoor and indoor environmental quality impacts affecting disadvantaged communities and Environmental Justice areas.

This analysis should begin with a comprehensive assessment of current energy justice conditions in New York, using the metrics developed. It should then project these metrics into the future under different gas transition scenarios to see how they will improve upon today's conditions and make progress towards New York's energy affordability policy.[29]

Utility Financial Analysis

The utility financial analysis should forecast the fundamental financial metrics of the electric and gas utilities to monitor how well they fare under different scenarios and utility business models. A variety of different gas utility business models should be considered, including district heating systems. To the extent that other options are considered, such as the use of biomethane, renewably produced hydrogen, and/or synthetic natural gas, there should first be assessment of their potential, cost, and environmental and health impacts.

This analysis should be as quantitative as possible, using metrics such as: retail sales, number of customers, allowed return on equity (ROE), earned ROE, earnings per share, gross profit margin, net profit margin, working capital, and operating cashflow. All the inputs and assumptions that are common to both the BCA and the Utility Financial Analysis should be the same in both analyses. For example, the depreciation rates used in the BCA should be the same as those used in the Utility Financial Analysis.[30]

This assessment should consider declining fossil gas sales and increased gas prices necessary to keep utilities financially viable, and the implications this has for the business model. The new and evolving business models must be able to support the gas transition goals outlined above, including net zero carbon emissions, reliability of services, customer equity, and energy justice.

Macroeconomic Analysis

A macroeconomic analysis of gas transition scenarios should assess the job impacts of the expected increases or decreases in the investments in and operations of all energy infrastructure and energy-consuming equipment, as well as re-spending effects of potential changes in customer bills.

Macroeconomic impacts should be presented separately from the monetary values in the BCA. This is primarily because there is a great deal of overlap between the costs and benefits in the macroeconomic impact analysis and the BCA, so adding the two monetary results together can be misleading. In

[29] New York State's Energy Affordability Policy limits energy costs for low-income New Yorkers to no more than 6 percent of household income. (Governor Andrew M. Cuomo. "Governor Cuomo Announces New Energy Affordability Policy to Deliver Relief to Nearly 2 Million Low-Income New Yorkers" https://www.governor.ny.gov/news/governor-cuomo-announces-new-energy-affordability-policy-deliver-relief-nearly-2-million-low).

[30] If a discount rate is used in the utility financial analysis, it may be appropriate to use the utility weighted average cost of capital for that purpose, while the BCA should use a societal discount rate.

addition, there is no single monetary value for macroeconomic impacts that can represent economic development goals.[31] Therefore, the best indication of macroeconomic impacts from different energy scenarios is the number of job-years created in each scenario. These job-years should be presented alongside the BCA results but cannot be added onto them.

Other Qualitative Considerations

Any other non-monetary or qualitative considerations should be fully described so that they can be incorporated into the gas transition plan decisions as warranted. These might include, for example, market animation and customer satisfaction.

1.5. Process to Develop the Statewide Gas Transition Plan

In the proposal, DPS Staff have described a gas system planning process that includes substantial opportunities for stakeholder engagement and education.[32] We appreciate and support this approach. Below we make some additional process-related recommendations for the development of the more comprehensive analyses for the statewide gas transition plan.

The gas transition has substantial implications for many stakeholders, including utilities, regulators, policymakers, residents, businesses, and advocates of different varieties. The plan should therefore be developed transparently and with full participation of these different perspectives. The DPS, however, sits in a unique and central role, and should be the guide for this process with assistance from NYSERDA. We therefore frame these recommendations to the DPS to establish a process for developing the plan that solicits input, maintains transparency, and ensures that all stakeholders have access to the data and analysis they require to inform and understand the plan and how it evolves over time.

In order to reduce barriers to participation, we first recommend that the DPS establish and announce that the process will be open and collaborative. The process should include both written comments and live workshops (virtual and in person, preferably at different locations statewide and at different times of the day, to allow different modes of participation for different communities). The DPS can set the frame and tone for this process by formalizing shared principles to guide the process. These principles should include equity, transparency, open-mindedness, and dependence on evidence and analytical rigor.

The process for developing the gas transition plan should be iterative, with early stakeholder input on goals (as discussed in Section 1.2) to select or refine the specific set of analyses to be conducted. In a joint effort, the DPS, NYSERDA, and the utilities should develop and propose an open, transparent set of methodologies and assumptions, to be provided to stakeholders for review and feedback. The resulting analyses would support the DPS and stakeholders in identifying the critical choices to make in shaping

[31] Some studies use the state gross domestic product as a monetary value to indicate economic development goals. This metric is problematic for several reasons and should be used only with caution.

[32] DPS Proposal p. 10.

the transition plan, making those decisions, and beginning plan implementation. The DPS should be explicit, and all stakeholders should be aware, that it will likely be necessary to select a path forward and begin implementation even in the face of uncertainty, since there are clear economy-wide goals that provide adequate direction to guide decision-making in the near term. The limited timeline between now and 2050 does not allow indefinite study prior to action.

2. GAS UTILITY RESOURCE PLANS

2.1. Gas Utility Resource Planning Process

As noted above, the DPS Proposal includes a gas utility resource planning process that represents a significant improvement over current gas planning practices. However, there are several ways that the DPS Proposal can be enhanced to be consistent with the statewide planning process and ensure that gas utility resource plans meet New York's CLCPA and other regulatory goals.

First and foremost, the gas utility resource plans should be designed to follow the vision and roadmap outlined in the statewide gas transition plans. Further, the analytical practices, including methodologies, assumptions, and inputs, used in the statewide transition plans should be applied in the gas utility resource plans as well. This means that the long-term gas planning principles and practices recommended above in Section 1 should be applied to the gas utility resource plans as well. This will help ensure coordination and consistency across the state.

The gas utility resource plans should be explicitly designed to achieve the state's short-, medium-, and long-term emission reduction requirements of the CLCPA. There are several ways that the DPS Proposal can be enhanced to achieve this outcome. Several of the principles for the statewide gas transition planning process are especially important to translate to the utility-specific plans, as summarized below.

2.2. Gas Utility Resource Plan Contents

Both LDC-specific and statewide long-term gas plans should include the following elements.

- The long-range vision for the industry as a whole
- Load forecasts
- Supply resource forecasts
- Resource and capacity gap analysis for system constraints and meeting the long-term GHG targets
- Assessment of impacts of switching to electricity on electric load, in conjunction with electric utilities
- Options for meeting system capacity constraints
- Long-term scenario analysis:

- Options for achieving the long-term vision, including gas supply options, gas alternative options, electricity alternative options, and demand-side options
- Scenarios for using the options to achieve the long-term vision, including scenarios with fossil gas completely replaced by non-fossil gas alternatives or electricity
- Description of how the different scenarios are evaluated and optimized
- A preferred scenario
- An assessment of customer impacts, including bill impacts, customer fuel-switching, and customer equity

- An action plan for meeting system capacity constraints and the long-term state GHG targets

The DPS Proposal has a section on filing requirements, which appears to address many of the items above.[33] However, it does not go far enough to articulate a long-range vision, or to standardize the specific elements that LDCs need to include in their filings.

2.3. Gas Utility Resource Plans Compared to Statewide Transition Plans

The statewide transition plans and the gas utility resource plans will have some overlap and some differences. Table 3 compares the two different types of plans.

Table 3. Statewide Transition Plans and Utility Resource Plans

	Statewide Transition Plan	Utility Resource Plan
Geographic scope	New York	each gas utility
Frequency of plan	five years	three years
Study period	2050 or 20 years, whichever is longer	2050 or 20 years, whichever is longer
Long-term gas utility industry goals	✓	✓
Long-term gas planning principles	✓	✓
Benefit-cost analysis	✓	✓
Rate and bill analysis	✓	✓
Utility financial analysis	✓	✓
Energy justice analysis	✓	✓
Integrate gas and electricity planning	✓	✓
Macroeconomic analysis	✓	-

3. RELATED REGULATORY POLICIES

In addition to the gas planning practices described above, the DPS should adopt several related policies regarding gas connection rules and cost recovery of gas assets. These policy changes will be critical for informing the state transition plans and the utility resource plans. These related regulatory policies

[33] DPS Proposal, p. 13.

should be adopted as soon as practical because they can have immediate implications for gas utility decision-making.

3.1. Gas Connection Rules

New York's obligation to serve dictates that customers can be asked to pay for new gas service connections only if the connection is over 100 feet long.[34] This burdens other customers with the risk that the cost of the connection will not be fully recovered through the new customer's rates. The State should reconsider the obligation to serve in light of gas's high costs to health and the environment, as well as the socialized costs to customers. We recommend the following:

- Require statewide, standard definitions and consistent reporting on interconnections.
- Remove incentives to gas connections by minimizing socialized costs of new connections.
- Remove or reduce the allowance of "free" line extension costs to new customers.
- Consider shifting the risk of under-collection of the line costs from customers as a whole to the new customer.
- Weigh the obligation to serve in light of socialized costs to customers, health impacts, and policy goals.

3.2. Cost Recovery

Providing regulatory guidance on cost recovery will allow utilities to take steps immediately to address this long-term issue. To this end, the PSC should:

- Provide guidance as soon as possible about how gas asset depreciation schedules should be consistent with the requirements of the CLPCA,[35] and
- Provide guidance as soon as possible about how stranded costs from gas assets will be treated for cost recovery purposes.[36]

[34] PSL Section 31.

[35] Synapse Energy Economics, *Gas Regulation for a Decarbonized New York*, prepared for Natural Resources Defense Council, June 2020, Section 7.

[36] Ibid.

EXHIBIT ASH-6

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NRRI-84-16

THE PRUDENT INVESTMENT TEST IN THE 1980s

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EXECUTIVE SUMMARY

Prudence is an old regulatory concept being put to new use. The frequency of use of the concept by state utility regulatory commissions has increased greatly in the last 10 years. Under one way of counting, there were forty-two state commission cases that made significant use of the concept in the 1974-83 period and nine such cases in the 30-year period before that. The immediate occasion for most recent uses of prudence has been the turmoil in the electric utility industry: construction cost overruns in completed plants, abandonment of plants, and excess capacity.

Recent public discussions of prudence have often loosely referred to "the prudence of a nuclear power plant" or the "prudence of a cost overrun," as if an object or a cost were prudent or imprudent. In our view, prudence always relates to a decision--or the absence of a decision where one is needed--such as a decision to construct a nuclear unit, to abandon a coal unit, or to use certain construction management practices.

For a state commission judging the prudence of a utility investment decision, it is useful to understand the concept of a prudent investment decision not only in public utility law, but also in related areas of law and in finance and management science. Investment decision rules in finance and management science determine a generally accepted mode of behavior for managers making large capital investment decisions in any industry. For competitive companies, investment decisions are intended to maximize profits for investors. All financial authorities agree that the best way to determine whether a capital investment in a project is prudent from the stockholders' point of view is on the basis of the discounted after-tax cash flows to be expected. For an unregulated company, investment decisions are simply a matter of calculating such cash flows.

For a regulated utility, investment decisions must also take into account the franchise obligations to provide all the service demanded, to ensure adequate and reliable service, and to provide service at a reasonable price. Utility decision makers evaluating probable future cash flows must assess the probable regulatory treatment of their investment decisions, a treatment now frequently determined on the basis of prudence.

The concept of prudence is used throughout the law as a standard of conduct owed to others. It seems likely that the concept of prudence in public utility law was borrowed from other areas of law that use the concept. The "prudent man" concept is well known as a standard of care expected in avoiding injury to another person or damage to his property. Other areas of law use the concept of prudence as a standard of care in the conduct of business, particularly where the economic use of property is involved and a legal duty of care is owed to other persons. Here the legal obligations are analogous to the obligations of public utilities for prudent investment decisions. These include the legal obligations associated with mineral development leases and trust and estate management. In these areas of law, the concept of prudence protects the rights of individuals not in control of investment decision making. It does not require perfection in decision making but does require, for example, avoidance of deliberate exposure to substantial risk where the individuals not in control could suffer financially.

The concept of a prudent investment in public utility law is a regulatory oversight standard that attempts to serve as a legal basis for judging whether utilities meet their public interest obligations. It was used as early as 1914 by the public service commission in Massachusetts. The concept first achieved wide recognition in public utility law after it was used by U.S. Supreme Court Justice Brandeis in a concurring opinion in 1923. Brandeis introduced the concept of a prudent investment as a rate base valuation method in an ongoing constitutional debate about utility valuation. While the prudence method did not achieve the status of the only constitutionally correct valuation method, it became a judicially developed concept useful for determining what facility costs should be allowed in rate base. Federal and state legislation rarely apply the concept of prudence explicitly to public utilities. A notable exception is the recent Congressional consideration of prudence as a regulatory standard governing the natural gas acquisition practices of interstate pipelines. However, the concept of a prudent utility decision has been abstractly articulated by the courts, leaving broad discretion for the application of the prudent investment standard by state commissions.

Review of the many recent state commission applications of the standard suggests four guidelines for successful use of the prudent investment test. These are, <u>first</u>, that there should exist a presumption that the investment decisions of utilities are prudent. The presumption of prudence can be overcome, however, by an allegation of imprudence that is backed up by substantive evidence creating a serious doubt about the prudence of the investment decision. Once the presumption of prudence is overcome, a commission needs to decide on the legal standard for judging prudence. The <u>second</u> guideline is to use the standard of reasonableness under the circumstances. That is, to be prudent, a utility decision must have been reasonable under the circumstances that were known or could have been known at the time the decision was made. A corollary to the standard of reasonableness under the circumstance is a proscription against the use of hindsight in determining prudence. Observing this proscription is the <u>third</u> guideline. The proscription against hindsight makes it unwise for a commission to supplement the reasonableness standard for prudence with other standards that look at the final outcome of a utility's decision, though consideration of outcome may legitimately have been used to overcome the presumption of prudence. The <u>fourth</u> guideline is to determine prudence in a retrospective, factual inquiry. The evidence needs to be retrospective in that it must be concerned with the time at which the decision was made. Testimony must present facts, not merely opinion, about the elements that did or could have entered into the decision at the time. Often the evidence for a state commission's retrospective, factual inquiry is developed through a staff investigation. Such a staff investigation can look at the past in great detail and therefore can be time consuming and expensive.

Following these guidelines is likely to be useful, perhaps necessary, for having a court sustain a commission decision regarding prudence.

However, because the prudence test is an emerging area of regulatory law, following these guidelines may not be sufficient to guarantee that a commission's decision based on prudence will be upheld.

Review of recent state commission prudence inquiries involving electric and gas utilities reveals that in only a few cases do commissions rely clearly and solely on the concept of prudence for reaching a judgment. Rather, in most cases commissions also reference the used-and-useful test or some other test when deciding if questionable costs should be included in rates. The review also shows that there have been many electric utility applications but few gas ones. The two principal areas of electric utility application have been construction cost overruns and plant abandonments, with capacity additions running a distant third.

Prudence inquiries involving construction cost overruns often depend on the results of a detailed staff investigation. Also, in cost overruns cases, use of the prudent investment test tends to work against utility interests in that the used-and-useful test alone, depending on how it is interpreted, is more likely to result in full cost recovery for an operational generating station.

The opposite is usually the case when the prudence test is applied to abandoned plant. Here, utilities introduce the prudent investment test in defense of their construction and abandonment decisions. In fact, the most frequent area of application of prudence in recent years has been where a utility plant has been abandoned or cancelled. Unlike construction cost inquiries, these prudence inquiries are usually not preceded by extensive staff investigations. In most cases, the presumption of prudence operates to allow recovery of most or all of the costs. However, a few cases have gone the other way.

Most state commissions have been reluctant to use the prudence test against decisions to add capacity. For many commissions, the mere existence of excess capacity is not necessarily indicative of an imprudent capacity planning decision, and, as long as state-of-the-art demand forecasting methods are used, there would be no finding of imprudence. Many commissions have dealt with cases where utilities defended excess capacity as resulting from prudent decision making. But several state commissions have held that the question of prudence applies not only to the initial investment decision but also to decisions made (or not made) during construction about the ongoing need for additional power. Thus, a failure to cancel a project that was prudently initiated, after it is no longer prudent to continue the project, can result in a finding of imprudence.

The recent emergence of the prudent investment test is mainly due to the higher risks and higher stakes faced by energy utilities, particularly by electric utilities, over the last 10 to 15 years. The higher risks relate primarily to uncertainties about costs, demand growth rates, and the supply of generation capacity needed for the future. Because the environment is riskier, the chance of error in utility planning is greater, and the opportunity for making an imprudent decision is greater than in the past. The consequences of an imprudent decision are also greater--both in absolute and relative terms. Today's direct costs of construction and costs of capital are much higher than in the past. Further, electric construction work in progress for privately owned utilities in the United States as a percentage of net electric plant has increased continuously from 1967 through 1983, from 8 percent to 36 percent, so that the effect on the average company of excluding a large construction project from rates is much greater today than in the past.

Who suffers the consequences of an error--utility customers or utility investors--has become an increasingly important question for commissions as the stakes involved in utility investment decision making grow. State commissioners today are pulled between the obligation to keep utilities financially sound and able to provide reliable service to customers and the obligation to set rates at a level reasonably related to the costs of providing service. They have been forced to choose between these two obligations where large investment values are at stake and where commission action exposes either stockholders or ratepayers to severe financial losses.

The concept of prudence provides commissions with a principle that does not necessarily require an "all or nothing" decision in favor of one side, but can allow some sharing of the risks between investors and ratepayers. The prudent investment test is a tool that regulators are using to provide an answer to the question of who should bear which risks and associated costs. In practice, it seems that many regulators choose not to hold utilities responsible for risks affecting the electric industry as a whole. Instead, state commissions often apply the prudent investment test so as to hold utilities harmless, except for the consequences of decisions that were unreasonable at the time they were made. The test is used principally to hold utilities responsible for the risks over which management has substantial control.

Regular and strict use of the prudence test by state commissions to disallow major portions of large expenditures by utilities is intended to protect utility customers and to compel responsible and efficient utility decision making, but such regular and strict use may have other, unintended consequences. One consequence could be a utility policy of minimal future investment in service capacity. This seems likely to occur unless commissions also provide positive investment incentives or underinvestment penalties. Another possible consequence of strict prudence application is utility bankruptcy. Recent studies suggest that a likely effect of utility debt reorganization would be to increase capital costs and utility rates above the levels that would exist with a limited prudence penalty that did not cause bankruptcy. However, this finding depends heavily on several factors, including the overlapping authorities of the bankruptcy court and the state commission and the extent to which the commission is allowed to participate in the bankruptcy proceedings.

Between the extremes of utility underinvestment and utility bankruptcy are other possible consequences of strict prudence application that represent permanent alterations of the relationships among the parties to a major utility construction project: utility management, the financial community, equipment vendors, architect-engineers, and construction firms. Altering these relationships could raise the costs of utility service because of increased capital costs, more formal "arm's length" dealings, higher construction contract bids, increased litigation among the parties, more detailed record keeping, and less technical innovation. But it is not possible to generalize about the net effect on utility rates of protecting customers from imprudently incurred costs in the short run, compelling utility managers and contractors to be more efficient in the long run, and altering relationships so as to increase long run costs.

Numerous issues about prudence need to be resolved as this area of regulatory law continues to emerge. One set of issues concerns articulating more fully in the hearing room both the nature of a prudent investment decision in the utility business and the regulatory procedures for judging the prudence of a utility decision. In particular, the relationship of the prudence standard to the used-and-useful standard must be clarified. Concerns about the decision-making process for major utility investments have led some utility representatives and some regulators to call for greater commission involvement in this process. A second set of issues concerns the appropriateness of such involvement. Still another group of issues relates to the consequences of regular and strict prudence application and what limitations, if any, ought to be imposed on such application. Of particular concern is the issue of when regulatory disallowance of cost recovery becomes confiscation.

Despite these uncertainties, the extensive contemporary use of the judicially developed prudent investment concept by state commissions demonstrates the vitality and usefulness of the concept. It is not confined to the capital cost component of ratemaking, but has been used to assess the reasonableness of decisions involving operating expenses as well. Under the existing regulatory framework, a utility's rate case is the only occasion for providing accountability to the consuming public and the investing public. Within this framework, the prudent investment test is emerging as a necessary and flexible regulatory tool for identifying types of risk and for placing the risk of utility mismanagement on utility owners.

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FOREWORD

The bylaws of The National Regulatory Research Institute state that among the purposes of the Institute are:

> ...to carry out research and related activities directed to the needs of state regulatory commissioners, to assist the state commissions with developing innovative solutions to state regulatory problems, and to address regulatory issues of national concern.

This report helps meet those purposes, since the subject matter presented here is believed to be of timely interest to regulatory agencies and to others concerned with electric and gas utility regulation.

Douglas N. Jones
Director
March 8, 1985

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CHAPTER 1

PRUDENCE AS AN EMERGING AREA OF REGULATORY LAW

Recently, the concept of prudence has been increasingly used by state utility regulatory commissions. This report contains an examination of the concept of prudence in public utility decision making and of the use of the "prudent investment test" in commission proceedings. The principal objective of this study is to provide useful information and analyses about the prudence concept to commissioners and their staffs who are faced with a judgment about what constitutes a prudent investment decision by a regulated company.

The immediate occasion for most recent applications of the prudence concept has been the turmoil in the electric utility industry. Many large generating units, particularly nuclear power plants, have been cancelled or abandoned. Other nuclear power plants under construction have experienced substantial construction cost overruns. And completed plants have often resulted in excess capacity because electric utility demand forecasts overestimated demand growth.

Recent public discussion of prudence has often loosely referred to "the prudence of a nuclear power plant" or the "prudence of a demand forecast," as if an object or a set of numbers were prudent or imprudent. In our view, prudence always relates to a decision--or the absence of a decision where one is needed. Hence, one can examine the prudence of a decision to construct a generating unit of a particular type and size. One can examine the prudence of a decision to continue or discontinue construction of a partially completed plant. One can examine the prudence of a decision to employ a certain system for managing a construction program and for controlling its costs. Also, one can examine the failure to make any one of these decisions in a case where deliberate choice appears to be required; this could be thought of as a decision to avoid deciding. The point here, of course, is that it is the decision itself that is prudent or imprudent--not the generating unit or its cost or the demand forecast that motivated the decision to build the plant. Thus, recent electric utility applications of the prudence concept have, for the most part, related to decisions involving capacity planning. Commissions have considered the prudence of decisions that relied on overly optimistic demand forecasts and that resulted in either plant abandonment or excess capacity. Prudence has been considered for decisions regarding construction management practices that have led to excessive cost overruns and, in some nuclear cases, plants of questionable safety licensability.

The concept of prudence is, of course, applicable to the decisions of all regulated industries. The recent emergence of important electric utility applications of this concept, in what has come to be called the prudent investment test, has given it new prominence in public utility regulation. (Here, we refer to a significant application of the concept of prudence as a use of the prudent investment test.[1]) While most of the examples in this report deal with the recent application of the prudent investment test to electric utility decisions, examples of applications to gas utility decisions are also provided where appropriate.

The concept of prudence has existed for a long time in state utility regulation to ensure that only prudently decided capital expenditures are allowed in the rate base of a utility. For example, the concept of prudence was used as early as 1914 by the public service commission in Massachusetts.[2] While the concept has existed for a long time, it was not widely used by state commissions until after two decisions by the U.S. Supreme Court (the Natural Gas Pipeline case of 1942 and the Hope Natural Gas Co. case of 1944) which, taken together, provided a firmer legal basis

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[1]According to Black's Law Dictionary Revised 4th ed. (St. Paul: West Publishing Co., 1968), p. 1643, a test is "something by which to ascertain the truth respecting another thing; a criterion, guage, standard, or norm."

[2]See Middlesex & Boston Rate Case, 2 Ann. Rep. Mass. P.S.C. 99, 111-12 (1914).

for the use of the prudence concept.[3] Even then, the frequency of use of the concept by state commissions was relatively low for the next 30 years, compared to the recent frequency of application. Table 1-1 shows the number of times, according to the P.U.R. Digest, that the prudent investment test was used in some significant manner by a state commission during each of the 4 decades since the Hope case. There are five such cases reported in the first decade, only one in the next, three in the third, and then forty-two cases reported in the last.

Use of the prudent investment test by state commissions requires an understanding of the concept of prudence. Just what constitutes a prudent investment decision is addressed in chapter 2 of this report. It contains a review of the finance and management science literatures and discusses what constitutes a prudent investment decision for managers and financial professionals. The chapter then traces the historical judicial development of the concept of prudence in public utility law. It shows also how prudence is used in other areas of law dealing with fiduciary duties, including the law of bailments, the law of trusts, the law relating to corporate responsibilities, and the law of oil and gas leasing. The idea here is that some new perspective about the prudence of public utility decisions can be obtained by examining these ancillary fields where prudence is a central concept.

Chapter 3 contains a discussion of some recent state applications of the prudent investment test. The chapter begins with some guidelines to follow in a successful prudence application. The remainder of the chapter contains a discussion of recent state prudence cases by type of case. The types of cases discussed are those dealing with (1) construction cost overruns, (2) abandonment and cancellation of electric facilities, (3) capacity additions, and (4) abandonment and cancellation of gas facilities.

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[3]See Rose, "The Hope case and Public Utility Valuation," 54 Columbia Law Review 188, 212 (1954).

TABLE 1-1

STATE ELECTRIC AND GAS UTILITY CASES IN THE P.U.R. DIGEST THAT MAKE SIGNIFICANT USE OF THE PRUDENT INVESTMENT TEST, BY DECADE, FROM 1944 THROUGH 1983

Decade	Number of Cases	Case Citations	Prudence Applications
1944-1953	5	Re Arkansas Power & Light Co., 55 PUR (NS) 129 (Ark. PSC, 1944)	Uses the prudent investment standard to determine rate base
		Public Service Commission v. Louisiana Power & Light Co., 65 PUR (NS) 18 (La. PSC, 1946)	Adopts the prudent investment test as a valuation method
		Re Georgia Power Co., File No. 19314, Docket No. 8948-A (Ga. PSC, Nov. 22, 1948)	Uses the prudent investment test to determine rate base
		Mayor of Everett v. Malden and Melrose Gas Light Co., 78 PUR (NS) 129 (Mass. DPU, 1949)	Allows a plant in rate base as a prudent investment
		Re Consolidated Edison Co. of New York, 96 PUR 195, 231 (NYPSC, 1952)	Concerns construction cost overruns
1954-1963	1	Re Central Maine Power Co., 29 PUR3d 113 (Me. PUC, 1959)	Uses the prudent investment test to determine the portion of plant acquisition costs to be included in rate base
1964-1973	3	Re Consolidated Edison Co. of New York, 54 PUR3d 43, 112 (NYPSC, 1964)	Uses the prudent investment test to determine the plant acquisition costs to be included in rate base
		Re Consolidated Edison Co., 41 PUR3d 138 (NYPSC, 1968)	Uses the prudent investment test to determine the prudence of the initial decision to construct the facility and the construction contracting practices

TABLE 1-1--Continued

Decade	Number of Cases	Case Citations	Prudence Applications
		Re Consolidated Edison Co. of New York, 85 PUR3d (NYPSC, 1970)	Uses the prudent investment test on construction cost overruns
1974-1983	42	Re Consumers Power Co., 14 PUR4th 370 (Mich. PSC, 1976)	Uses the prudence test in the case of a plant cancellation
		Re Iowa Power & Light Co., 13 PUR4th 164 (Ia. SCC, 1976)	Concerns the Iowa SCC's authority to investigate the prudence of a utility investment
		Re the Detroit Edison Co., 20 PUR4th, 1, 13 (Mich. PSC, 1977)	Uses the prudence test in the case of a plant cancellation
		Re Virginia Electric Co., 44 PUR4th 46,49 (VSCC, 1977)	Uses the prudence test in the case of a plant cancellation
		In Re Detroit Edison Co., 24 PUR4th 362, 368 (Mich. PSC, 1978)	Uses the prudence test in the case of construction cost overruns
		Re Potomac Electric Power Co., 29 PUR4th 517 (D.C. PSC, 1979)	Uses the prudence test in the case of a plant cancellation
		Re Virginia Electric Co., PUR4th 65 (VSCC, 1979)	Uses the prudence test in the case of a plant cancellation
		Gulf State Utilities, 40 PUR4th 593 (La. PSC, 1980)	Uses the prudence test in the case of a plant cancellation
		Re Carolina Power & Light Co., Dkt. No. E-2 Sub 366 (NCUC, 1980)	Uses the prudence test in the case of a plant cancellation

TABLE 1-1--Continued

Decade	Number of Cases	Case Citations	Prudence Applications
1974-1983 (cont.)		Re Virginia Electric & Power Co., Case No. 9322 (WVPSC, February 1, 1980)	Uses the prudence test in the case of a plant cancellation
		Re Central Maine Power Co., Docket Nos. 80-25 & 80-66 (Me. PUC, Oct. 31, 1980)	Uses the prudence test in the case of a plant cancellation
		Re Potomac Electric Power Co., 36 PUR4th 139, 165-166 (D.C. PSC, 1980)	Recognizes the use of the prudent investment test for rate base determination
		Re Rochester Gas & Electric Corp., 41 PUR4th 438, 444 (NYPSC, 1981)	Concerns a failure to cancel plant
		Re Maine Public Service Co., 44 PUR4th 104 (Me. PUC, 1981)	Uses the prudence test in the case of a plant cancellation
		Re Northern States Power Co., 42 PUR4th 339 (Minn. PUC, 1981)	Uses the prudence test in the case of a plant cancellation
		Re Rochester Gas & Electric Co., 41 PUR4th 438 (NYPSC, 1981)	Uses the prudence test in the case of a plant cancellation
		Re Virginia Electric & Power Co., 44 PUR4th 46 (VSCC, 1981)	Uses the prudence test in the case of a plant cancellation
		Re Iowa Public Service Co., 46 PUR4th 339, 368 (Iowa SCC, 1982)	Concerns load fore-casts and a failure to cancel
		In re Commonwealth Electric Co., 47 PUR4th 229 (Mass. DPU, 1982)	Concerns a failure to cancel plant
		In re Houston Lighting & Power Co., 50 PUR4th 157 (1982)	Concerns a failure to cancel plant

TABLE 1-1--Continued

Decade	Number of Cases	Case Citations	Prudence Applications
1974-1983 (cont.)		Re Potomac Electric Power Co., 50 PUR4th 500 (D.C. PSC, 1982)	Uses the prudence test in the case of a plant cancellation
		Re Bangor Hydro-Electric Co., 46 PUR4th 503 (Me. PUC, 1982)	Uses the prudence test in the case of a plant cancellation
		Re Rochester Gas & Electric Co., 45 PUR4th 386 (NYPSC, 1982)	Uses the prudence test in the case of a plant cancellation
		Re Duke Power Co., 49 PUR4th 483 (NCUC, 1982)	Uses the prudence test in the case of a plant cancellation
		Re Houston Lighting & Power Co., 50 PUR4th 157 (Tex. PUC, 1982)	Uses the prudence test in the case of a plant cancellation
		Re Central Vermont Public Service Corp., 49 PUR4th 372 (Vt. PSB, 1982)	Uses the prudence test in the case of a plant cancellation
		Wisconsin Public Service Corp. v. PSC, 325 N.W.2d 867 (Wis., 1982)	Overturns state commission decision that denied utility recovery of prudently incurred plant cancellation cost
		Re Carolina Power & Light Co., 49 PUR4th 188 (NCUC, 1982), reversed in part, 55 PUR4th 582 (NCUC, 1983)	Uses the prudence test in the case of a plant cancellation
		Re Boston Edison Co., 46 PUR4th 431 (Mass. DPU, 1982) affirmed 455 N.E.2d 414 (Mass., 1983)	Concerns a failure to cancel plant

TABLE 1-1--Continued

Decade	Number of Cases	Case Citations	Prudence Applications
1974-1983 (cont.)		Re Iowa Power & Light Co., 51 PUR4th 405, 411 (Ia. SCC, 1983)	Concerns load forecasts
		Re Consumers Power Company, 52 PUR4th 536 (Mich. PSC, 1983)	Uses the prudence test in a temporary abandonment
		Re United Illuminating Co., 55 PUR4th 252 (Conn. DPU, 1983)	Uses the prudence test in the case of a plant cancellation
		Re Commonwealth Electric Co., 47 PUR4th 229 (Mass. DPU, 1983)	Uses the prudence test in the case of a plant cancellation
		Re Detroit Edison Co., 52 PUR4th 318 (Mich. PSC, 1983)	Uses the prudence test in the case of a plant cancellation
		Re Atlantic City Electric Co., 51 PUR4th 109 (NJBPU, 1983)	Uses the prudence test in the case of a plant cancellation
		Pennsylvania Public Utility Commission v. Duquesne Light Co., 52 PUR4th 644 (PaPUC, 1983), affirming 51 PUR4th 198 (PaPUC, 1983)	Uses the prudence test in the case of a plant cancellation
		Re Central Illinois Light Co., 57 PUR4th 351 (Ill. CC, 1983)	Uses the prudence test in the case of a plant cancellation
		Re Carolina Power & Light Co., 55 PUR4th 582 (NCUC, 1983)	Uses the prudence test in the case of a plant cancellation
		Re Virginia Electric & Power Co., 54 PUR4th 1 (WVPSC, 1983)	Uses the prudence test in the case of a plant cancellation

TABLE 1-1--Continued

Decade	Number of Cases	Case Citations	Prudence Applications
1974-1983 (cont.)		Re Union Electric Co., 53 PUR4th 565 (Ill. CC, 1983)	Uses the prudence test in the case of a plant cancellation
		Re Wisc. Pub. Serv. Corp., 52 PUR4th 389 (Wis. PSC, 1983)	Uses the prudence test in the case of a plant cancellation
		Pa. Pub. Util. Comm'n v. Pa. Power & Light Co., 55 PUR4th 185 (PaPUC, 1983)	Uses the prudence test in the case of a plant cancellation

Source: Public Utilities Report Digests.

Chapter 4 develops the theme that a riskier utility environment is the cause of the recent prominence of the prudence test. For electric and gas utilities, the environment for investment decision making has been riskier over the last 10 years than previously. Because of the higher risks, the chance of error in decision making is greater and the consequences of error are greater than before. The prudent investment test is evolving into a regulatory tool for allocating the risks associated with utility decision making.

Chapters 5 and 6 look toward future applications of the concept of prudence. Chapter 5 contains a discussion of the possible utility strategies and financial consequences that could result from the use of the prudence test, and chapter 6 deals with issues yet to be resolved. Included in chapter 6 is a discussion of the relationship of the prudence test to the used-and-useful test, the emerging issues that the courts must ultimately resolve, and the authors' considerations about the possible future of the concept of prudence as a regulatory tool.

CHAPTER 2

THE PRUDENT INVESTMENT DECISION

The recent evolution of the application of the concept of prudent investment as a requirement governing public utility financial decision making reflects concern over the soundness of such utility investment decision making. But what constitutes a prudent investment decision?

To answer this question, we reviewed the finance and management science literatures and reviewed the relevant legal history to understand the roots of the concept of a prudent investment, particularly as it relates to public utilities. The review of the management science and finance literature with respect to prudence was undertaken to determine a generally accepted mode of behavior for managers making large capital investment decisions. As a major part of this effort the authors searched cases, commission orders, law journals, and restatements of law to find examples of how the concept of prudence has been used in public utility law and other related areas of law.

Prudent Investment Decisions in Finance and Management Science

Investment decision rules in finance and management science were developed to guide the decisions of managers, principally of unregulated firms. These rules may not fully apply to the decisions of utility managers. Regulators may expect managers to provide service at the lowest reasonable cost. Stockholders expect managers to maximize profits, subject to the constraints set down by regulators. At times these expectations may be in conflict. The finance and management science rules discussed here relate more to stockholder expectations. The legal history discussed next treats the obligations of utilities to customers and hence relates more to the expectations of regulators.

nuclear power plant should be ignored. The NPV of completing the plant and generating revenues should be compared to the NPV of abandoning the plant and taking a tax write-off. The plan with the higher NPV should be chosen.

For an unregulated company, such a decision is then a matter of doing the calculation. For a regulated company, the decision involves an assessment of the probable regulatory treatment of cancelled plant on the one hand versus treatment of possible cost overruns or excess capacity on the other hand. The effect of commission policy on utility investment strategy is examined further in chapter 5.

The finance literature agrees that investment decisions depend on expected incremental after-tax cash flows and that those cash flows should be valued using the NPV method. The NPV method requires discounting cash flows at a discount rate commensurate with the risk of the project. Disagreement in finance literature arises about what risk is relevant and how the discount rate should be adjusted for relevant risk.

For regulated companies, these are not only the usual risks relating to costs, demand, and supply, but also risks related to the uncertainty of regulatory treatment. The latter may be particularly hard to quantify in decision models.

Most textbooks advocate the use of the Capital Asset Pricing Model (CAPM), or, in special circumstances, the Certainty Equivalent method (CEQ). As mentioned, some authors advocate use of a newer model, the Arbitrage Pricing Theory (APT). Still other authors argue that ignoring individual risk, as is done in the CAPM and the APM, is wrong and advocate using overall risk as one factor when making investment decisions. The most theoretically precise model seems to be the Time-State Preference model, but this model does not seem to be ready for practical decision making yet.[2]

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[2]See Stewart C. Myers, "A Time-State Preference Model of Security Valuation," Journal of Financial and Quantitative Analysis 3 (March 1968): 1-34. Also see Charles W. Haley and Lawrence D. Schall, The Theory of Financial Decision, 2d ed. (New York: McGraw-Hill, 1979).

By the beginning of 1984, approximately thirty-five public utility commissions used the CAPM to determine cost of capital. It is an elegant theory that describes risk/return tradeoffs in perfect capital markets.[3] This theory argues that with perfect capital markets all investors would own perfectly diversified portfolios. The only risk that matters to such investors is undiversifiable risk, sometimes called market risk. This market risk can be measured somewhat imprecisely for individual companies, but reasonably accurately for industries. A standardized measure of this risk is called "beta," and finance textbooks and stockbrokers often refer to a company's beta risk. By knowing a company's beta, the company's cost of capital can be estimated using something called the "Security's Market Line," and this cost of capital is the discount rate that should be used in the NPV method when evaluating projects.

The CAPM is strictly valid, for technical reasons, only when risk increases at a uniform rate through the life of a project. Some projects, such as building nuclear power plants, may be more risky during the construction phase than during the operating phase of the project. Other projects, such as drilling an oil well, may have the greatest risk at the end of the project. When risk does not grow linearly through the project, the CAPM must be modified to the Certainty Equivalent method (CEQ).[4] The CEQ involves calculating the certain equivalent cash flow that an executive would trade for a given risky cash flow and then discounting that certain equivalent cash flow back to the present at the riskless interest rate. In other words, the CEQ method adjusts the cash flow for risk, not the

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[3]See William F. Sharpe, "Capital Asset Prices: A Theory of Market Equilibrium under Conditions of Risk," Journal of Finance 19 (September 1964): 425-447; John Litner, "Security Prices, Risk, and Maximal Gains from Diversification," Journal of Finance 20 (December 1965): 587-615; and Jan Mossin, "Equilibrium Prices in a Capital Asset Market," Econometrica 34 (October 1966): 768-783.

[4]Alexander A. Robichek and Stewart C. Myers, "Conceptual Problems in the Use of Risk-Adjusted Discount Rates," Journal of Finance 21 (December 1966): 727-730.

discount rate. A method of calculating certain equivalent cash flows that is consistent with the CAPM is explained in some textbooks.[5]

Some authors claim that the CAPM is misspecified and produces biased estimates of the cost of capital.[6] Evidence for the misspecification is the consistently positive intercepts (alphas) obtained when estimating betas for the electric utility industry. Two authors, Meyer and Roll, propose using an alpha adjustment to the cost of capital obtained from the CAPM.[7] A more recent theory of asset valuation is the Arbitrage Pricing Theory (APT) by Ross.[8] Roll and Ross argue that the APT, by using several market risk factors, avoids the one-dimensional errors caused by using only one measure of risk in the CAPM.[9] They show that the APT produces cost of capital estimates for the electric utility industry that are nearly 100 basis points higher than those produced by the CAPM and have alphas that average zero, as predicted by theory. The Roll and Ross cost of capital estimate appears to be virtually identical to cost of capital estimates produced through the alpha-adjustment methods mentioned above.

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[5]For example, see Richard Brealey and Stewart Myers, Principles of Corporate Finance (New York: McGraw-Hill Co., 1982).

[6]See Chartoff et al., "The Case Against the Use of the Capital Asset Pricing Model in Public Utility Ratemaking," 3 Energy Law Journal 67 (1983).

[7]See Testimony of Dr. Richard F. Meyer (Jan. 30, 1980) at 58-61, In the Matter of the Valuation Proceedings under Section 303(c) and 306 of the Regional Railroad Reorganization Act of 1973, Special Court Misc. No. 76-1; and Testimony of Dr. Richard W. Roll at 74-80 (Jan. 30, 1980), In the Matter of the Valuation Proceedings under Section 303(c) and 306 of the Regional Railroad Reorganization Act of 1973, Special Court Misc. No. 76-1; These transcripts are available from the Special Court for the Regional Rail Reorganization Act, U.S. Court House #1820A, 3rd St. and Constitution Avenue, N.W., Washington, D.C. 20001.

[8]Stephen A. Ross, "The Arbitrage Theory of Capital Asset Pricing," Journal of Economic Theory 13 (December 1976): 341-360.

[9]Richard W. Roll and Stephen A. Ross, "Regulation, the Capital Asset Pricing Model, and the Arbitrage Pricing Theory," Public Utilities Fortnightly, May 26, 1983, pp. 22-28.

Nearly all the finance textbooks advocate the use of sensitivity analysis and computer simulations to estimate the overall risk of major projects. Few textbooks seem to realize that analyzing risk in these ways is inconsistent with the CAPM conclusion that only market risk matters, and no textbook describes how to make a decision given a project's sensitivity and simulation results. Brigham points out that there is no quantitative rule available for using simulations and sensitivity results and advocates using "judgment."[10]

All projects involve a risk of failure, and large projects involve a risk of bankruptcy. In finance literature, bankruptcy costs are defined as the "cost of the funeral." In a perfect capital market, when a company defaults on a debt obligation, the company's assets are assumed to be costlessly turned over to the bondholders. In practice, bankruptcy results in a substantial amount of the assets being sold to pay for attorneys' fees and bankruptcy court costs instead of being paid to the bondholders. Bondholders know this and charge in advance an interest premium on their bonds equal in value to the expected bankruptcy costs.

Van Horne points out that bankruptcy costs violate the CAPM perfect capital market assumption and are reason enough to consider overall risk in making investment decisions.[11] He advocates ranking projects both by NPV and by overall risk, using judgment when the project with the highest NPV also has the highest overall risk.

Petty gives plausible but, we believe, erroneous advice.[12] He advocates using sensitivity analysis and computer simulations to estimate the probability of bankruptcy and then adjusting the expected cash flows by the expected cost of bankruptcy. He overlooks the fact that stockholders

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[10]Eugene F. Brigham, Financial Management Theory and Practice, 3d ed. (Chicago: Dryden Press, 1982).

[11]James C. Van Horne, Financial Management and Policy, 6th ed. (Englewood Cliffs, N.J.: Prentice-Hall, 1983).

[12]William J. Petty et al., Basic Financial Management, 2d ed. (Englewood Cliffs, N.J.: Prentice-Hall, 1982).

do not pay bankruptcy costs directly. Instead, as the probability of bankruptcy increases, the interest expense of debt financing increases. The amount of this increase is difficult to compute.

Regulated utilities seek to reduce the risk to stockholders, particularly the risk of bankruptcy, by obtaining regulatory approval for ratepayer sharing of risks. This gives regulators and ratepayers a stake in the prudence of utility investment decisions--a theme developed further in chapters 4 and 5.

Management Science Literature

Management science literature discusses investment decisions as part of a topic called "decision theory." A typical introduction to decision theory discusses decisions under three circumstances: certainty, risk, and uncertainty.[13]

Decision making under certainty is trivial: the decision maker simply chooses the largest payoff. Decision making with risk means decision making with a known probability distribution, usually for a decision to be made repeatedly, such as an inventory stocking problem. Again the decision is easy: choose the largest expected payoff, or equivalently, the minimum expected loss. Uncertainty is defined as an unknown probability distribution, usually for a unique decision. Lee, among others, gives a list of proposed decision rules for uncertainty, such as Minimax, Maximin, and Minimize Regret.[14] Hillier and Lieberman point out that these rules are not accepted by most management science practitioners, that the rules ignore probabilities, and that the rules usually assume malevolent opponents rather than nature, which is assumed to be neutral.[15]

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[13]Robert J. Thierauf, An Introductory Approach to Operations Research (Santa Barbara: John Wiley and Sons, Inc., 1978).

[14]Sang M. Lee, Introduction to Management Science (Chicago: Dryden Press, 1983).

[15]Frederick S. Hiller and Gerald J. Lieberman, Operations Research, 2d ed. (San Francisco: Holden-Day Inc., 1974).

One rule that does enjoy general acceptance is Baysian analysis, which uses subjective probability estimates when objective estimates are unavailable.[16] The Baysian rule then advocates maximizing expected profits. Sometimes an investor can purchase more information before making a decision. Baysian analysis allows an investor to estimate the expected value of the new information. The investor can then decide whether to purchase the new information by comparing its cost to its expected value.

Some management science textbooks acknowledge that maximizing expected profits may not be the best objective function.[17] Maximizing utility seems to be as close to calculating a risk/return tradeoff as management science comes. In none of this literature is there a discussion about comparing payoffs coming in different years. Siemans, Marting, and Greenwood is the only management science book that was found that discussed the Net Present Value rule, so common in the finance literature, and it did not discuss how to adjust the discount rate for risk.[18]

In sum, management science literature has developed sophisticated techniques such as Baysian analysis and linear programming for maximizing an expected payoff function, but has little to say about the payoff function itself. From the finance literature, however, we know that the expected payoff functions must be discounted cash flows, and that the discount rate must be commensurate with the relevant risk of the investment.

However, while these rules for making prudent investment decisions are useful for utility managers as they seek the greatest return for utility investors, they must be tempered by the legal obligation of the utility to invest prudently from the viewpoint of serving the public interest.

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[16]For example, see Fadil H. Zuwaylif et al., Management Science: An Introduction (Santa Barbara: John Wiley and Sons Inc., 1979).

[17]For a discussion on maximizing utility, see Michael Q. Anderson, Quantitative Managment Decision Making (Montery: Brooke/Cole Publishing Co., 1982); Robert E. Markland, Topics in Management Science (New York: John Wiley and Sons Inc., 1979); and Bernard W. Taylor, Introduction to Management Science (Dubuque: Wm. C. Brown Co. Publishers, 1982).

[18]Nicolai Siemans et al., Operations Research (New York: The Free Press, 1973).

Prudent Investment Decisions and the Law: Obligations of Public Utilities

The concept of a prudent investment is a regulatory oversight standard that attempts to serve as a legal basis for adjudging the meeting of utilities' public interest obligations, specifically in regard to rate proceedings.

The purpose of the remainder of this chapter is to analyze the history and judicial application of the legal concept of prudent investment as it relates to the obligations of public utilities. As part of this analysis, the concept of prudence is explored as a legal standard of business conduct in relation to analogous regulated business activities other than the operation of public utilities: activities including the operation of trusts, oil and gas development, and others. The examination of these analogous activities may provide additional insights appropriate for state commission application to the public utilities.

Although much has been written recently about the various elements of the concept of public utility prudent investment obligations, no apparent comprehensive treatment of the subject and related legal areas has emerged. For this reason, a thorough technical discussion of the subject matter is needed and may advance the public discussion. This analysis attempts to develop a legal framework within which the concept of prudent investment can be legally defined as it applies to public utilities and its usefulness as a regulatory standard can be evaluated.

An appropriate starting point in the discussion of the legal concept of prudence is to provide a general legal definition of the term for use throughout this analysis. The term "prudence" is broadly defined as:

> Carefulness, precaution, attentiveness, and good judgment, as applied to action or conduct. That degree of care required by the exigencies or circumstances under which it is to be exercised....This term in the language of the law, is commonly associated with "care" and "diligence" and contrasted with "negligence."[19]

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[19] Black's Law Dictionary, p. 1392.

In a similar fashion, the term "prudent" is generally defined as:

> Sagacious in adapting means to an end, circumspect in action or in determining any line of conduct, practically wise, judicious, careful, discreet, circumspect, sensible.[20]

Several judicial decisions have also provided general definitions of the terms. For example, it has been held that "prudent" and "cautious" are synonyms.[21]

"Prudent" has also been held to mean exercising sound judgment or being recognized by practical wisdom.[22]

Although these general definitions give some guidance as to the legal usage of the terms in a variety of contexts, they are at best only a meager beginning point in the legal analysis of the concept of public utility prudent investment requirements.

The concept of prudence is used throughout the law as a description of a standard of conduct owed to others. In the law of torts, the "ordinary reasonably prudent man" is well known for the careful conduct of his own actions in avoiding personal injury to others, both with respect to his actions and with respect to the foreseeability of their consequences.[23]

Beyond the law of torts, other areas of law have found use for the concept of prudence as a standard of care in the conduct of business affairs. The economic use of property where the legal duty of care is owed

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[20] Id.

[21] See, State v. Norton, 286 N.W. 476, 479, 227 Iowa 13 (1939).

[22] See, Westbrook v. Watts, 268 S.W.2d 694, 698 (Tex. Ct. App. 1954).

[23] See, Prosser on Torts (4th ed., 1971) Section 32, entitled "Negligence: Standard of Conduct," p. 150.

to persons other than the manager is most analogous to the concept of prudent investment obligations of utilities. These areas include the legal obligations arising in the context of mineral development leases, trust management, and estate management--all activities where legal obligations were developed at Common Law and all predating the use of the concept of prudence in the context of utility management.

It seems likely that the concept of prudence was borrowed from other areas of law and made to apply to public utility regulation. In fact, the historical analysis in the next section offers one piece of evidence demonstrating this.

It is appropriate to mention at the outset that the law does not generally intrude into the managerial decision process, except in the area of regulated activities. In the arena of general corporate law, for example, a broad range of business discretion is vested with management, which is deliberately insulated from legal recourse under the so-called "business judgment rule." As one corporate law treatise puts it:

> The "business judgment" rule sustains corporate transactions and immunizes management from liability where the transaction is within the power of the corporation (intra vires) and the authority of management, and involves the exercise of due care and compliance with applicable fiduciary duties.
>
> Corporate management is vested in the board of directors. If in the course of management, directors arrive at a decision, within the corporation's powers (intra vires) and their authority, for which there is a reasonable basis, and they act in good faith, as the result of their independent discretion and judgment, and uninfluenced by any consideration other than what they honestly believe to be the best interests of the corporation, a court will not interfere with internal management and substitute its judgment for that of the directors to enjoin or set aside the transaction or to surcharge the directors for any resulting loss.
>
> Business judgment thus, by definition, presupposes an honest, unbiased judgment (compliance with fiduciary duty) reasonably exercised (due care), and compliance with other applicable requirements.
>
> Although the business judgment rule is usually stated in terms of director functions, it is no less applicable to officers in the

> exercise of their authority and may be applicable to controlling shareholders when they exercise their more extraordinary management functions.[24]

Thus, there is no general legal obligation that imposes rigorous standards of conduct in the ordinary course of business. However, many areas of law, because of the peculiar legal relationships that arise, have developed standards to protect the rights of individuals not in control of decision making or business planning. The prudent investment concept is such a standard.

For all these reasons a detailed recapitulation of the historical development and analysis of prudent investment obligations of public utilities provides a significant insight into the contemporary use of prudence as a regulatory tool.

Historical Judicial Development

The starting point in most analyses of the concept of prudent investment obligations of public utilities is a footnote in the separate opinion of Mr. Justice Brandeis in 1923 in Missouri ex. rel. Southwestern Bell Telephone Co. v. Public Service Commission, in which he noted:

> The term prudent investment is not used in a critical sense. There should not be excluded from the finding of the base, investments which, under ordinary circumstances, would be deemed reasonable. The term is applied for the purpose of excluding what might be found to be dishonest or obviously wasteful or imprudent expenditures. Every investment may be assumed to have been made in the exercise of reasonable judgment, unless the contrary is shown.[25]

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[24]Harry G. Henn, Corporations (St. Paul: West Publishing Co., 1961) at Sec. 233, entitled "Business Judgment Rule," pp. 364-364.

[25]Missouri ex. rel. Southwestern Bell Telephone Co. v. Public Service Commission, 262 U.S. 276 (1923), p. 289, note 1.

The footnote was a reference to Brandeis' discussion of utility rates:

> The thing devoted by the investor to the public use is not specific property, tangible and intangible, but capital embarked in the enterprise....The compensation which the Constitution guarantees an opportunity to earn is the reasonable cost of conducting the business Cost includes not only operating expenses, but also capital charges. Capital charges cover the allowance, by way of interest, for the use of the capital,...the allowance for the risk incurred; and enough more to attract capital....Where the financing has been proper, the cost to the utility of the capital, required to construct, equip and operate its plant, should measure the rate of return which the Constitution guarantees opportunity to earn.[26]

Brandeis used the concept of prudent investment in this context:

> ...adoption of the amount prudently invested as the rate base and the amount of the capital charge as the measure of the rate of return [would provide a]...basis for decision which is certain and stable. The rate base would be ascertained as a fact, not determined as a matter of opinion. It would not fluctuate with the market price of labor, or materials, or money...[27]

Although the Southwestern Bell case appears to be the first Supreme Court case in which the concept of prudent investment gained recognition, it is obvious from Justice Brandeis' references that he relied upon both earlier state case law and various law reviews dealing with utility rates in the formulation of his now famous articulation of prudent investment.

Among the authorities relied upon by Justice Brandeis were two law review articles published in the Michigan Law Review in 1917 and 1923 that were written by Edwin C. Goddard, who served as a professor of law at the University of Michigan for several years shortly after the turn of the century. One of Goddard's early works was a case book entitled Cases on the Law of Bailments and Carriers and of Service by Public Utilities, which

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[26] Id., pp. 290-292, and 306.

[27] Id., pp. 306-307.

was originally copyrighted in 1904 and updated and published again in 1928.[28]

What is interesting about the 1928 version of the bailment and utility case book is the juxtaposition of the two seemingly unrelated and diverse topics. The law of bailments deals with the obligations and liability of custodians of goods and is generally not regarded as related to public utility law. Goddard, however, saw a relationship between the two topics that is revealed in his preface:

> The reasons for treating these subjects in one book are mainly two, the exigencies of the law school curriculum and an interrelation that permits a natural development of these subjects in one course... The bailment relation is one of the fundamental concepts of the law, and deserves more than the incidental and fragmentary reference it receives in the property law courses. Better than any other subject of the law it provides material for the study of care and negligence, and here it is vitally related to the most important feature of common carrier law, viz. the liability of the common carrier. And here we are entering the whole field of public utilities, of which the common carrier is easily foremost in extent and importance. Incidentally, the pledge and the innkeeping relation, the telegraph and the telephone, take their places in a natural way.[29]

Thus, it would seem that Goddard saw an important relationship between the obligations of care in the management of property for others under bailment law and public utility law, a fact that is demonstrably corroborated by his inclusion of then contemporary cases dealing with the concept of prudence. For example, one of the bailment cases of the period that

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[28]Edwin C. Goddard, Cases on the Law of Bailments and Carriers of Service by Public Utilities (Chicago: Callagan and Company, 1928). Between the two versions of this case book, Goddard published another case book entitled Cases on Principal and Agent (St. Paul: West Publishing Co., 1914).

[29]Goddard, Cases on the Law of Bailments, p. iv.

Goddard chose to include in the book was Hanes v. Shapiro,[30] a case that extensively cited Judge Story on the concept of prudence. Because it may be assumed that Goddard saw the relationship of diverse areas of law, the references to his law reviews on prudence take on an added significance in terms of the historical antecedents to the use of prudence in relation to utilities and are worthy of extended consideration.

The first Goddard article relied upon by Brandeis was an attempt to develop a regulatory construct of utility valuation to which Goddard referred as the "efficient investment theory." The article proposed the efficient investment theory as a solution to the dilemma of whether to use actual cost or reproduction cost as the basis for setting utility rates:

> In this connection the use of the terms "value" and "valuation" is unfortunate. It is not value in any ordinary sense that is being sought, as has often been noticed. The basis for all dealings involving purchase and rate making should be, not actual cost, not reproduction cost, not market value, not stock and bond issue. It should be what has been well called the "efficient investment," i.e., the actual amount honestly and prudently invested in the utility, under normal conditions; no more, no less. The "efficient investment" theory eliminates all consideration of losses due to mismanagement. Those must be charged to stockholders. "The company is held to the same standard of honesty and prudence in the management and maintenance as in the original acquisition of its properties." It takes no account of bad property investments, it eliminates all the objectionable elements that have been urged against the actual cost theory. As it has been stated in a recent case by the Washington Commission, "it would seem equitable, just and fair that the public should be required to furnish fair, just, and reasonable compensation for the reasonable and necessary detriment a utility has suffered by reason of its service to the public....
>
> It cannot be urged that the adoption of the "efficient investment" as the valuation base would not be attended with difficulties.

30Hanes v. Shapiro, 168 N.C. 24, 84 S.E. 33 (1915), cited by Goddard in his Cases on the Law of Bailment, p. 187.

> But they are no greater than have attended all fair value computation on the indefinite rule of the past, even when the cost-of-reproduction-less-depreciation, and plus some uncertain, but considerable, other items has been adopted. And once the initial difficulties are past, what was before all uncertainty and matter of dispute becomes a certain as ledger balances.... [Footnotes deleted and emphasis added.][31]
>
> To secure a good service it is to the public interest to make investment in public utilities attractive, and to give a return on such investment not merely equal to, but somewhat higher than, returns in kindred private enterpries. Returns should not be too high, however, or they will attract not the investing public, but speculators and manipulators, to the detriment alike of the public and of honest investors. It is also to the public interest to assure, as far as possible, to the investor in public utilities, a return on what is really put into the utility <u>in good faith and with prudence and good judgment.</u> Such a condition would do much to substitute for the antagonism and often unreasonable suspicion now existing between the public and public service companies that harmonious and understanding relation based upon mutual respect for rights and observance of duties that is so needed to make public service satisfactory. Once past the initial difficulties, which are not at all insurmountable, the "efficient investment" theory will insure between the public and public utilities a relationship which is fair to both, which will attract the necessary capital by making the investment almost as safe as governmental securities, and which will make possible and probable an adequate and efficient service. [Emphasis added.][32]

In the second article, Goddard more specifically embraced the use of a prudent investment standard and retreated from defining the notion as "efficient investment." His conclusion clearly indicates that the concept was intended to reconcile the continuing legal debate about ratemaking valuation by defining a more practical approach. It is also evident that he was concerned about the constitutional implications of the prudent investment standard in light of earlier Supreme Court rate decisions:

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[31]Goddard, "Public Utility Valuation," 15 <u>Michigan Law Review</u> 203, 223-224 (1917).

[32]<u>Id</u>., p. 227.

> The conclusion of this review of recent cases is that the Commissions, working at first hand with the practical problems of valuation, generally lean more and more decidely toward fixing value--so called--of public utilities on prudent investment, largely, and in not a few cases wholly. The courts, on the other hand, still wallow in the uncertainties of the rule, which is scarcely a rule at all, of Smyth v. Ames, making value a question of judgment. In the cases, judgments continue to vary as widely as ever. The courts are probably too firmly committed to a consideration of various elements to expect them to adopt the definite rule of fixing base values on prudent investment. Whether legislatures will step in here, and whether a legislative act making prudent investment the basis would be held to be constitutional is for the future to reveal. [Emphasis added.][33]

Thus we see that, in principal reliance upon the Goddard articles, Justice Brandeis introduced the concept of prudent investment into what was already an ongoing legal debate over methods of utility valuation for the purposes of ratemaking. Two observations may be made about Goddard's proffer of the prudent investment concept to reconcile the valuation debate. First, his formulation itself is rather abstract in that it did not articulate specific examples of application of the concept. And, second, he offered no analysis of the constitutionality of the concept. In essence, his approach was pragmatic and suggested merely what ought to be done.

An important refinement in the Goddard approach, upon which Justice Brandeis obviously relied in his Southwestern Bell opinion, was advanced in a 1922 Yale Law Journal article:

> The essential theory which seems more just is that investment in public utility securities, whether denominated as stock or bonds, should be regarded practically as an investment in bonds bearing a fixed return with the principal protected against impairment through appropriate depreciation and maintenance charges. It would seem a sound principle to regard the operators of public utilities as trustees of the service for the public and of the capital invested for the security holders. It should be their obligations to keep costs as low as consistent with efficient service and to do all in their power to insure investors of capital a safe non-speculative rate of return.

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[33]Goddard, "Public Utility Valuations and Rates," note and comment, 19 Michigan Law Review 849, 852-853 (1921).

> Public utility operators who recognize these obligations cannot support theories of public utility regulation which make public utility securities a speculative investment and subject public utility service to the hazards of speculative enterprise.
>
> Public utility operators and public officials alike, who are not financial or political demagogues, should join in a demand for the establishment in the courts and commissions of the doctrine that a reasonable rate for public utility service should be ascertained by the addition to current operating expenses of the amount of interest required to recompense at market rates the capital actually and <u>prudently</u> employed in producing the service and to induce the further investment of capital needed for desirable extensions and improvements....
>
> If the courts can be brought to realize that the word "value" means nothing except a resultant of earning power and that the value of a property cannot be ascertained until after its earning power is fixed, then figures showing the <u>prudent investment in a property can be presented, not as evidence of the value of the property, but as evidence of the cost to the owners of the property of providing public service</u>. The courts viewing the operators of the property as trustees who must obtain from the public reimbursement for outgoes, will find the evidence of the prudent investment in the property relevant and essential to determine the amount of capital upon which the operators must pay the market rate in order to continue to furnish service. In this investigation there is no inquiry whatsoever as to the value of the property. In fact, the question of the value of the property is entirely irrevelant. [Emphasis added.][34]

This description of prudent investment obligations drew on the concept of prudence in trust law in its characterization of public utilities as enterprises being conducted as trusts for the benefit of the public. Thus, through his general reference to the concept of prudent investment in <u>Southwestern Bell</u>, Justice Brandeis introduced into the middle of a constitutional debate about utility valuation an alternative approach.

Without digressing too far, it is helpful to examine the status of the constitutional debate at the time of the Brandeis opinion. In 1898, the

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[34]Richberg, "A Permanent Basis for Rate Regulation," 31 <u>Yale Law Journal</u> 263, 278-279 (1922).

U.S. Supreme Court confronted the first major constitutional issue concerning utility ratemaking in the context of challenge against commission set utility rates based upon alleged violations of the injunction of the Fourteenth Amendment against taking without just compensation. In Smyth v. Ames,[35] the Supreme Court faced the question of whether a state's regulatory establishment of inadequate rates for a railroad constituted an unconstitutional take of property. The Court held that no constitutional violation occurred so long as the ratemaking process assured that utilities received a fair rate of return on capital investment. Almost immediately the question moved to what constituted capital investment upon which the return was to be gauged.

In 1920 the Supreme Court held in Ohio Valley Co. v. Ben Avon Burrough[36] that the nature of the constitutional issues involved in utility ratemaking was such as to require judicial scrutiny. Finally, in 1923 in a case decided just before Southwestern Bell, the Supreme Court addressed more specifically the entitlement of utilities to reasonable rates of return in the landmark Bluefield decision:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.[37]

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[35]Smyth v. Ames, 169 U.S. 466 (1898).

[36]Ohio Valley Co. v. Ben Avon Burrough, 253 U.S. 287 (1920).

[37]Bluefield Water Works & Improvement Company v. Public Service Commission, 262 U.S. 679, 692-693 (1923).

Justice Brandeis' reference to prudent investment in Southwestern Bell takes on added significance in light of the fact that the same Court had just decided Bluefield without characterizing valuation determination there in terms of prudent investment. It may be fairly concluded, as subsequent events corroborate, that Brandeis introduced the concept without either consensus among his colleagues on the Court or a very clear articulation of its legal definition.

Subsequent utility cases before the Supreme Court reveal that the Brandeis approach did not gain immediate acceptance. Indeed the use of reproduction valuation in utility rate cases continued. In 1927 in McCardle v. Indianapolis Water Co.,[38] the Supreme Court laid down a rule that seeingly mandated the use of reproduction under the Smyth case.

However, in Los Angeles Gas Co. v. Railroad,[39] the Court upheld a valuation from which reproduction cost had been excluded, thereby leaving the status of reproduction cost as the basis for utility ratemaking in doubt. Prudent investment, however, was not a concept utilized in rate analysis by the Court.

In 1935 in the West Ohio Gas case, the Court talked around the concept of prudence without actually mentioning it:

> A public utility will not be permitted to include negligent or wasteful losses among its operating charges. The waste or negligence, however, must be established by evidence of one kind or another, either direct or circumstantial. In all the pages of this record, there is neither a word nor a circumstance to charge the management with fault....There is not even the shadow of a warning to the company that fault was imputed and that it must give evidence of care. Without anything to suggest that there was such an issue in the case, the commission struck off 2%, it might with as as much reason have struck off 4 or 6. This was wholly arbitrary.[40]

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[38]McCardle v. Indianapolis Water Co., 272 U.S. 400 (1927).

[39]Los Angeles Gas Co. v. Railroad Commission, 289 U.S. 287 (1933).

[40]West Ohio Gas Co. v. Public Utilities Commission of Ohio (No. 1), 294 U.S. 63, 68 (1935).

And, in a case decided a year later in which important issues concerning managerial judgment, perhaps appropriate for reference to prudent decision making in the context of permissible rates, the Court again avoided reference to prudence:

> The contention is that the amount to be expended for these purposes is purely a question of managerial judgment [under the Packers and Stockyards Act]. But this overlooks the consideration that the charge is for a public service, and regulation cannot be frustrated by a requirement that the rate be made to compensate extravagant or unnecessary costs for these [salesmen's salaries] or any purposes. We are not persuaded that the conclusions as to proper allowances on this head were without substantial support in the record.[41]

Not only was the concept of prudent investment not readily acceptable or used by the majority of the Supreme Court, but the matter of utility valuation remained in flux. In 1938, for example, the Supreme Court allowed to stand the use of historical cost as a measure of valuation for rate determination.[42]

A specific reference to prudent investment was not made by the Court until 1942 in the <u>Natural Gas Pipeline</u> case, and then only in a minority concurring opinion of Justices Black, Douglas, and Murphy:

> As we read the opinion of the Court, the [Federal Power] Commission is now freed from the compulsion of admitting evidence on reproduction cost or of giving any weight to that element of "fair value." The Commission may now adopt, if it chooses, prudent investment as a rate base--the base long advocated by Mr. Justice Brandeis. And for the reasons stated by Mr. Justice Brandeis in the Southwestern Bell Telephone case, there could be no constitutional objection if the Commission adhered to that formula and rejected all others.[43]

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[41]Acker v. United States, 298 U.S. 426, 431 (1936).

[42]Railroad Commission v. Pacific Gas Co., 302 U.S. 288 (1938).

[43]Federal Power Commission v. Natural Gas Pipeline Co., 315 U.S. 575, 606 (1942).

As the immediate comments on the Natural Gas Pipeline case demonstrated, the injection of Brandeis' prudent investment concept back into the rate debate after a period of dormancy caused great confusion among judicial scholars.

> Should a company operating at a loss even on the prudent-investment basis be denied permission to discontinue service, so that in effect its property is actually being confiscated for the public use without just compensation, the minority [in FPC v. Natural Gas Pipeline (1942)], in refusing to discuss the question, would be hard put to avoid the explicit language of the Fifth Admendment. Of course, the minority answer would probably be that the Commission would not make such an order unless based upon appropriate findings, for which there would be the safeguard of adequate review.[44]

However, as the subsequent decision in the Hope case revealed, a majority of the Court was not yet ready to articulate a valuation method of any specific sort--prudent investment included:

> ...it is the result reached not the method employed which is controlling....[i]t is not the theory but the impact of the rate order which counts,....[i]f the total effect of the rate order cannot be said to be unjust and unreasonable, judicial inquiry under the [Natural Gas] Act is at an end.[45]

The uncertainty of valuation and the status of the prudent investment concept during this period have been discussed extensively in light of the many state court cases decided then.[46]

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[44]"Public Utilities--Constitutional Law-Scope of Judicial Review of 'Confiscatory' Rate Orders," Note, 42 Columbia Gas Review 870, 873-874 (1942). See also, "Does the Ghost of Smyth v. Ames Still Walk?" Note, 55 Harvard Law Review 1116 (1942), for a review of rate cases in light of the then recent decision by the Supreme Court in FPC v. Natural Gas Pipeline, supra.

[45]Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591, 602 (1944).

[46]Mendelson, "Smyth v. Ames in State Courts, 1942 to 1952," 37 Minnesota Law Review 159, 164-165 (1953).

One assessment of the valuation rules and the status of the concept of prudent investment demonstrated the interpretative difficulty encountered by the state of Wisconsin:

> [One Wisconsin Court concluded that its state commission in a rate case]...found nothing except that a certain amount of dollars represent a reasonable profit.
>
> ...Reasonable profit ON WHAT? That is the trouble with the commission's decision. It has no bottom. It has a numerator but no denominator. For a long time, Wisconsin believed in the "prudent investment" theory of rate making. A utility was entitled to a fair return on the amount of money prudently invested in the enterprise, it was said. That sounded fair. That is the universal standard. Every businessman expects to receive a fair return on the money which he has put into his business whether he runs a hardware store or an apartment building or a bowling alley. Our Supreme Court of Wisconsin approved the prudent investment theory.
>
> ...Apparently many other Commissions and jurists interpreted the Hope case as [returning to the prudent investment theory]...for there was a great swing throughout the country to the investment cost theory in the years immediately following.[47]

There is little doubt that the concept of prudent investment has figured significantly in the Supreme Court's historical efforts to come to grips with the constitutionally controlling scheme of valuation for the purposes of utility ratemaking. But despite the fact that the prudent investment concept has received explicit minority approval as a possible regulatory approach under today's result-oriented constitutional standards of confiscation, the fact remains that the concept has never been given express majority approval by the U.S. Supreme Court. Prudent investment has not achieved the status of definitively resolving the conflict between historical costs and reproduction costs for which it was originally intended. This is because it never really spoke clearly to the issues surrounding that conflict. Instead, it has become, in a modern sense, exactly what it was originally: a concept useful in determining <u>what</u> facility costs should be allowed, rather than <u>how</u> costs for specific

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[47] Demet and Demet, "Legal Aspects of Rate Base and Rate of Return in Public Utility Regulation," 42 <u>Marquette Law Review</u> 331, 335-336 (1959).

facilities should be calculated. Viewed as a measurement of the inclusion of certain costs in the rate calculation because of the soundness of their incurrence, the concept has flourished as a regulatory oversight tool helpful to ratemaking regulators.

The status of prudent investment as a valuation methodology different from historical or reproduction costs is often inaccurately characterized. For example, in the widely read textbook on Public Utility Economics, by Paul J. Garfield and Wallace F. Lovejoy, it is observed that:

> [An]...actual cost method, called prudent investment, may be taken as historical cost, as defined, less any amounts found to be dishonest or obviously wasteful. Under the prudent investment standard every investment is assumed to be prudent unless the contrary is shown.[48]

While this characterization is generally true, it inflates prudent investment to the status of a rate methodology, rather than more accurately describing it as a test of what costs to include in the rate calculation.

But even as a criterion for the determination of what costs, whether actual or reproduction costs, of utility investment to include in rate-making decisions, the concept of prudent investment continues to be articulated abstractly by lower courts, leaving broad discretion for the application of the concept by regulators to specific investment decisions.

Current Legal Use of Prudence

The concept of prudence has found current application in several diverse areas of law. There are several recent lower court decisions that have referred in one fashion or another to obligations of the prudence of management decisions in regulated industries. It might be observed that in these cases the use of the concept of prudent investment or prudence

[48]Paul J. Garfield and Wallace F. Lovejoy, Public Utility Economics (Eastcliff, N.J.: Prentice-Hall, 1964), p. 57.

generally is not encumbered by the baggage of the Brandeis valuation concept. Instead, the idea of prudent activities takes on an evaluative aspect concerning the propriety of decisions and their regulatory consequences.

For example, in a case involving the disallowance of various costs in airline rates relating to an employee strike, one court made this observation:

> But the issue is not whether the company acted lawfully but whether it acted prudently--a higher standard. The contract and the Railway Labor Act, also invoked by TWA, may well have given TWA the right to spend its won funds without limit in implementation of the attitudes of management. But they do not give TWA a right to a subsidy to cover losses in a strike prolonged by its imprudent intransigence, and that is the critical finding before us....
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> ...The [Civil Aeronautics] Board in no way assumed that prudence in taking account of human emotions required abject submission to labor demands.
>
> TWA charges that the Board was invading the sphere of management and was taking advantage of hindsight to hold management to an exceptional standard of conduct....In this respect the standard is not fundamentally different from that applicable in conventional utility rate regulation where the commission may disregard waste and improvidence but must not usurp the role of management....We seek to conjoin the spark of private profit and the drive of private enterprise with some surveillance by Government officials devoted to the public interest....That a conclusion of imprudence reflects a view of how business should be conducted is no reason for a court's withholding deference from permissible findings of the commissioners whose presumptively broad gauge warranted their appointment by the President, with the advice and consent of the Senate, to undertake the delicate task of surveillance of the regulated industry....
>
> ...We are not unaware that the difficulties may be greater in practice than in philosophy in avoiding an improper usurpation of managerial discretion while conducting a proper review of abuse of that discretion, and that the difficulties are not lessened when Government officials have the 20-20 vision of hindsight. The greater risk of disallowances is doubtless noticeable even in conventional rate-making when the period under consideration is past and the commission proceeds by reference to actual operating figures rather than nunc pro tunc estimates.

> The other side of the coin is that in some instances utilities may gain the benefit of pointing to an adverse change in conditions more readily sensed by management than Government officials.[49]

The TWA case is important, not only for the principles set forth in evaluating managerial decision making, but also because it constitutes the only obvious example of judicial acknowledgement of the fact that the regulatory evaluation of prudence is retrospective. Yet the Court in TWA concluded that even as a retrospective regulatory tool, the evaluation of prudence served a valuable purpose.

Similarly, one U.S. Court of Appeals, in the context of reviewing the regulatory treatment to be accorded tax decisions made by regulated companies under the Natural Gas Act, assessed managerial discretion in relation to regulatory objectives in the following fashion:

> We freely recognize, as does the Commission, that there are many areas and many situations which must remain within the jurisdiction of management. However, it has long been recognized that establishment of public utility charges involves the assessment of costs for a public service. Basic to the purpose of the Natural Gas Act is a design of regulation concerned with final adoption of rate charges fairly intended to protect the public interest.
>
> Necessarily, the area of tax policies embraces managerial decisions directly reflected in the cost of natural gas supplies for the use of the ultimate customer. Here it seems to us quite reasonable and logical to recognize as inherent in the Commission the duty and requirement to exercise its expertise in evaluating the entire tax effect of managerial judgment. If such elected tax policies do not fairly indicate a reasonable and prudent business expense, which the consuming public may reasonably be required to bear, following the required hearing and review procedures, then federal regulatory intervention is required.[50]

The concept of prudence has even been used in evaluating the propriety of conduct relating to the environment. In Wayne County Dept. of Health,

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[49]Trans World Airlines, Inc. v. Civil Aeronautics Board, 385 F.2d 648, 655-657 (D.C. Cir. 1967), cert. denied 390 U.S. 944 (1967).

[50]Midwestern Gas Transmission Company v. Federal Power Commission, 388 F.2d 444, 448 (7th Cir. 1968), cert. denied 392 U.S. 928 (1968).

Air Pollution Control Division v. Olsonite Corp.,[51] a state court recently held that, for the purposes of an environmental protection statute, a provision that a defendant against whom action is brought pursuant to the statute may raise affirmative defense that there was no feasible and prudent alternative to the defendant's conduct, the words "prudent alternative" did not require that there be a comprehensive balancing of competing interests.

Thus the concept of prudence as a standard against which regulated activities can be evaluated has been used in a variety of contexts. In the broadest of legal uses, the adjective "prudent" is used so often in connection with judgment that it has become a regular term of legal art. But its use as an adjective does not necessarily invoke the definitional attempts of Brandeis in the context of utility ratemaking.

Law Relating to Oil and Gas Leases

The frequent use of prudence in connection with various judgmental legal evaluations occurs in several major areas of business conduct. One of the areas in which the concept has gained extensive use, and in which it has taken on major definitional significance, is the area of oil and gas leasing.[52]

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[51]Wayne County Dept. of Health, Air Pollution Control Division v. Olsonite Corp., 263 N.W.2d 778, 797, 79 Mich. App. 668 (1977).

[52]See generally Lopez and Parsley, "Microbes, Simulators, and Satellites: The Prudent Operator Pursues Enhanced Recovery under the Implied Covenants," 58 North Dakota Law Review 501 (1982); Williams, "Implied Covenants in Oil and Gas Leases: Some General Principles," 29 University of Kansas Law Review 153 (1981); Williams, "Implied Covenants for Development and Exploration in Oil and Gas Leases--The Determination of Profitability," 27 University of Kansas Law Review 443 (1979); Merrill, "The Modern Image of the Prudent Operator," 10 Rocky Mountain Mineral Law Institute 107 (1965); Meyers, "The Covenant of Further Exploration: A Comment," 37 Texas Law Review 179 (1958); Meyers, "The Implied Covenant of Further Exploration," 34 Texas Law Review 553 (1956); Merrill, "Implied Covenants and Secondary Recovery," 4 Oklahoma Law Review 177 (1951); and Merrill, "Implied Covenants, Conservation and Unitization," 2 Oklahoma Law Review 469 (1949).

The concept of the prudent operator requirement with respect to oil and gas leasehold development obligations was recently summarized in a legal treatise as follows:

> All jurisdictions impose a prudent operator rule to determine whether lease development satisfies the implied covenant of further development. This rule requires that operations be mutually profitable to both lessor and lessee and be diligently prosecuted in relation to the circumstances in each case. Within such relationship the lessee has an implied duty, after production is acquired, to develop the lease to its fullest extent.
>
> By prevailing view, in Oklahoma, Texas, and several other jurisdictions, it is not a breach of the prudent operator standard when the lessee holds portions of a lease for long periods of time without development, where profitability of further development cannot be shown.[53]

This summary of the prudent operator test is based upon numerous state court decisions which have applied the rule in various specific disputes over the propriety of development decisions. The prudent operator rule as it is applied has squarely placed in courts the position of interpreting lease obligations by evaluating the factual circumstances relating to development, exploration, and recovery opportunities and decisions concerning specific leaseholds.

For example, in Trust Company of Chicago v. Samedan Oil Corp.,[54] the Tenth Circuit defined the prudent operator test as follows:

> ...the prudent operator [of oil and gas leases] test as the term suggests...imposes upon the lessee the implied duty to do whatever in the circumstances would be reasonably expected of a prudent operator of a particular lease, having a rightful regard for the interest of both the lessor and the lessee....[T]he implied covenants of the lease impose no obligation upon the lessee to develop the lease beyond the point where it would be profitable to him, even if some benefit to the

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53Richard W. Hemingway, The Law of Oil and Gas (St. Paul: West Publishing Co., 1983), Sec. 8.3., p. 414.

54Trust Company of Chicago v. Samedan Oil Corp., 192 F.2d 282, 284 (10th Cir. 1951).

lessor would result therefrom. And, that the one seeking cancellation has the burden of proving that the drilling of additional wells would probably result in profitable production.

The prudent development rule is clearly one of reasonableness. The Texas Supreme Court concluded in Clifton v. Koontz[55] that the lessee's obligation as to the development is measured by the rule of reasonable diligence or what an ordinarily prudent and diligent operator would do and does not require the continuation in the performance of these duties unless there is a reasonable expectation of profit, not only to the lessor, but also to the lessee.

Similarly, in Harris v. Morris Plan Co.,[56] it was held that a breach of the covenant to develop occurred when a well was abandoned and others were willing to enter and drill and there were several surrounding productive wells. In contrast, the decision in Baker v. Collins,[57] that a covenant to develop further was not breached when the existing well involved the expenditure of large sums of money and other wells that had been drilled were dry or not producing, again demonstrates the balanced judicial application of the rule.

And finally a pair of cases demonstrates an outer boundary on the requirements that will be imposed in the name of prudent development obligations. The cases held that where a lessee had made a substantial investment in exploration of the area and in drilling other wells to determine the advisability of further drilling on the leases or of drilling to deeper formations, there was no breach of the covenant of reasonable development.[58]

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[55]Clifton v. Koontz, 160 Tex. 82, 325 S.W.2d 684 (1959).

[56]Harris v. Morris Plan Co., 144 Kan. 501, 61 P.2d 901 (1936).

[57]Baker v. Collins, 29 Ill.2d 410, 194 N.E.2d 353 (1963).

[58]See, Frazier v. Justiss Mears Oil Co., 391 So.2d 485 (La. App. 1950), writ refused 395 So.2d 340 (La. 1950); and West v. Sun Oil Co. 490 P.2d 1073 (1971).

Recently in Mitchell v. Amerada Hess Corp., the Oklahoma Supreme Court made the important observation that profit can not be ignored as a component of the prudent operator requirement in a decision to add an additional well to a productive formation by holding:

> We thus hold there is no implied covenant to further explore after paying production is obtained, as distinguished from the implied covenant to further develop. In addition to the speculative burden the offered covenant would place on lessees, the covenant as tendered is substantially served by the covenant for further development as it is interpreted in this jurisidiction while limiting the duty to drill additional wells to those instances where a prudent operator would expect a probability of potential profit from the well contemplated.[59]

In U.S. v. City of Pawhuska,[60] the Tenth Circuit held that the prudent operator rule, as applied in Oklahoma, imposes an implied duty on a lessee to do whatever in the circumstances would be reasonably expected of a prudent operator of a particular mineral lease, having a rightful regard for interest of both the lessor and lessee.

The Kansas high court found in Rush v. King Oil Co.[61] that under the prudent operator test, which determines the scope of duties of oil and gas lessees, a lessee must continue reasonable development of leased premises to secure oil for common advantage of both lessor and lessee and the lessee may be expected and required to do that which an operator of ordinary prudence would do to develop and protect the interests of parties.

The prudent operator test provides a legal standard that requires continued examination of factual circumstances in order to assess prudence. New recovery and exploration techniques may create development and exploration obligations that did not exist in the past. In this respect, the

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[59]Mitchell v. Amerada Hess Corp., 638 P.2d 441, 449-450 (Okla. 1982).

[60]U.S. v. City of Pawhuska, 502 F.2d 821 (10th Cir. 1974).

[61]Rush v. King Oil Co., 556 P.2d 431, 220 Kan. 616 (1977).

prudent operator standard is sufficiently flexible to permit adaptation to changing circumstances.[62]

Finally, the obligation of prudent development has been applied as a standard governing mineral leases other than oil and gas. With respect to coal, one court has held that the rule that mining and selling coal be conducted in an ordinarily "prudent and businesslike manner" required merely whatever would be reasonably expected of operators of ordinary prudence, having regard to interests of lessor and lessee. Under such provision, no obligation rests on lessee to carry operations beyond the point where they will be profitable to them, even if some benefit to lessor will result therefrom. It is only to the end that minerals be extracted with benefit to both that reasonable diligence is required. Whether in any particular instance such diligence is exercised depends upon a variety of circumstances, such as quantity of coal capable of being produced from premises, local market or demand therefore, means of transporting it to market, and usages of business.[63]

Thus, the judicial development and use of the prudent operator rule as it is applied to the development, exploration, and recovery obligations attaching to oil and gas leaseholds bear direct analogy to the usage of the prudent investment concept as it relates to public utilities. One significant difference that is worthy of note, however, is that the concept of prudent development obligations gives rise to affirmative injunctive relief by the courts. If prudent development is not occurring and it should be, it can be directed by the courts or penalties extinguishing leasehold rights may be imposed. Viewed from the perspective that a failure to undertake additional development of a leasehold is a continuing negative

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[62]See Lopez and Parsley, "Microbes, Simulators, and Satellites," p. 501.

[63]See, Mendota Coal & Coke Co. v. Eastern Ry. & Lumber Co., 53 F.2d 77 (9th Cir. 1931).

development decision, the prudent operator test may contain the same retrospective component as the prudent investment requirement applied to public utilities.

Law Relating to Trusts

There is at least one other major area of law in which the use of the prudent investment concept bears a striking similarity to the use of that concept in connection with public utilities. Although there does not appear to be a traceable origin of the use of the concept of prudent investment respecting public utilities from the concept of prudent investment pertaining to trust obligations, it does seem fair to assume that the long standing use of the concept in trust law would have been known to, and could have been borrowed by, legal scholars--including Brandeis--who played a role in the early articulation of prudent investment theory for public utilities.

As the trust concept of the prudent investment was described in one leading case, decided by the Massachusetts Supreme Court in 1890:

> The rule in general terms is that a trustee must in the investment of the trust fund act with good faith and sound discretion, and must "observe how men of prudence, discretion, and intelligence manage their own affairs, not in regard to speculation, but in regard to the permanent disposition of their funds, considering the probable income, as well as the probable safety of the capital invested...."
> A prudent man possessed of considerable wealth, in investing a small part of his property, may wisely enough take risks which a trustee would not be justified in taking. A trustee, whose duty it is to keep the trust fund safely invested in productive property, ought not to hazard the safety of the property under any temptation to make extraordinary profits. Our cases, however, show that trustees in this Commonwealth are permitted to invest portions of trust funds in dividend paying stocks and interest bearing bonds of private business corporations, when the corporations have been acquired, by reason of the amount of their property and the prudent management of their affairs, such a reputation that cautious and intelligent persons commonly invest their own money in such stocks and bonds as permanent investments.[64]

[64]Appeal of Dickinson, 152 Mass. 184, 25 N.E. 99, 99-100 (1890).

Similarly, in another case, St. Louis Union Trust Co. v. Toberman, the court provided a broad description of the duties of a trustee:

> As a fundamental proposition, it is the duty of a trustee, in the investment of trust funds committed to his care and keeping, to exercise such care and diligence as men of ordinary prudence, intelligence, and discretion would employ, not with a view to speculation, but rather with a view to the permanency of the investment, considering both the probable income and the probable safety of the capital invested. This does not mean, however, that a trustee shall invariably have the unlimited authority to invest trust funds as an ordinarily prudent and diligent man might invest his own funds, since an ordinarily prudent man may, and frequently does, invest his own funds with the idea and hope of accumulation, and at the risk which such intent imposes. A trustee, on the contrary, may take only such risks as an ordinarily prudent man would take in the investment of the funds of others, bearing ever in mind that it is the preservation of the estate, and not an accumulation to it, which is the chief object and purpose of his trusteeship.[65]

In fact the very nature of a trust is almost completely dependent upon the judicial oversight provided by the concept of prudent investment decisions made by the trustees acting on behalf of beneficiaries.

Clearly, the risks of concentration and benefits of diversification are accepted rules of prudent trust management under the prudent investment rule.[66] It has been held, for example, that trustees failed to follow the prudent investor standard with respect to administration of a testamentary trust of which the plantiffs were beneficiaries where they invested two-thirds of trust principal in a single investment, invested in real property secured only by a second deed of trust, and made that investment without adequate investigation of either borrowers or collateral.[67]

But as broadly articulated in Jackson v. Conland,[68] the prudent

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[65]St. Louis Union Trust Co. v. Toberman, 235 Mo. App. 559, 140 S.W2d 68,72 (1940).

[66]See, Dowsett v. Hawaiian Trust Co., 393 P.2d 89, 95, 47 Haw. 577 (1964).

[67]Matter of Collins' Estate, 139 Cal. Rptr. 644, 72 C.A.3d 663 (1977).

[68]Jackson v. Conland, 420 A.2d 898, 178 Conn. 52 (1979).

investor rule, which is the usual touchstone for evaluating the propriety of trust investments, requires that the trustee observe how men of prudence, discretion, and intelligence manage their own affairs, not in regard to speculation, but in regard to permanent disposition of their funds, considering the probable income, as well as the probable safety of the capital to be invested.

Legal obligations of prudence similar to those employed in relation to the duties of trustee are also used in law relating to the administration of estates. The obligation in estate administration has been summarized this way:

> A fiduciary is required to exercise reasonable care and skill and to act prudently in the performance of his functions. The standard of care and skill is expressed in various ways....Modern cases often quote the language of Professor Scott and the Restatement, which provide that a trustee is to exercise "such care and skill as a man of ordinary prudence would exercise in dealing with his own property." 1 Restatement of Trusts Second Sec. 174; 2 Scott, Trusts Sec. 174 (2d ed. 1956). The element of prudence--the caution implicit in this standard--is frequently emphasized by stating that the test is not how a prudent man would act with regard to his <u>own</u> property but how a prudent trustee would act in administering <u>the</u> property of <u>others</u> or how he would act in conserving property.
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> <u>In re Mild's Estate,</u> 25 N.J. 467, 136 A.2d 875 (1957), involved the surcharge of an administratrix for delegation of duties and failure to supervise the activities of her attorney. To the assertion that the administratrix was not capable of adhering to the usual standard of care and skill, the court responded: "This standard does not admit of variation to take into account the differing degrees of education or intellect possessed by a fiduciary. The standard of the ordinary prudent person is of necessity an ideal one and is not tailored to the imperfections of any particular person." Mr. Justice Holmes aptly stated the rule as follows:
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> "The standards of the law are standards of general application. The law takes no account of the infinite varieties of temperament, intellect and education which make the internal character of an act so different in different men. It does not attempt to see men as God sees them, for more than one sufficient reason...." Holmes, The Common Law, p. 1089 (1881)....
>
> On the other hand, a fiduciary possessing greater than ordinary skill and more than ordinary facilities is under a duty to exercise the skill and to utilize the facilities at his disposal. Thus in Liberty Title & Trust Co. v. Plews, 142 N.J.Eq. 493, 509, 60 A.2d 630, 642 (1948), it is stated:

> "In the present case, the corporate trustee held itself out as an expert in the handling of estates and trust accounts. It also held itself out as having particular departments for investments and statistical information, and especially skill in this respect. It had so advertised for a number of years....It therefore represented itself as being possessed of greater knowledge and skill than the average man and, '...if the trustee possesses greater skill than a man of ordinary prudence, he is under a duty to exercise such skill as he has.'...The manner in which investments were handled must be viewed and assayed in the light of such superior skill and ability."[69]

There are several ways in which the courts have expressed the concept of prudent action in regard to the administration of trusts and wills. For example, the case of In re McCafferty's Will[70] held that executors must "be faithful," "diligent," and "prudent" and exercise industry and care as intelligent men exercise in the conduct of their own affairs of equal importance.

The broad legal principles imposing prudence in the managment of trusts and estates necessarily draw courts into the examination of specific investments.[71] Although the prudent man rule requires in each case the assessment of the prudence of managerial actions, over the years courts have come to identify certain types of investments as inherently imprudent because of the high degree of risk associated with them. However, the legal test for prudence continues to provide the flexibility for a continuing reassessment of the soundness of various investment options. For example, one commentator recently observed that the historical legal view of trust investment in common stocks as being imprudent might be changing:

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[69]Eugene F. Scoles and Edward Halbach, Jr., Decedents Estates and Trusts (Boston: Little, Brown and Co., 1965), pp. 473-474.

[70]In re McCafferty's Will, 264 N.Y.S. 38, 147 Misc. 179 (1933).

[71]See generally, Shattuck, "The Development of the Prudent Man Rule for Fiduciary Investment in the United States in the Twentieth Century," 12 Ohio State Law Journal 491 (1951); and Bines, "Modern Portfolio Theory and Investment Management Law: Refinement of Legal Doctrine," 76 Columbia Law Review 721 (1976).

> Regarding the prudent man rule, the investment strategy suggested by modern theory appears to run afoul of many of the established principles of trust investment law. Yet, the market portfolio [of common stocks] has been recommended by some of the most skilled experts in the field of trust investments. When the market portfolio is finally tested under the prudent man rule, courts should adopt a position consonant with modern theory. The beauty of the prudent man rule is that "[i]t is susceptible of being adapted to whatever conditions may arise in the evolution of society and the progress of civilization." [Footnote deleted.][72]

Like the area of oil and gas leasehold developmental obligations under the prudent operator rule, the prudence legally required in the operation of a trust is directly analogous to the concept of prudent investment requirements in the area of utility regulation. In trust law, the concept of prudence has both prospective and retrospective significance. It can be used to impose subsequent liability for imprudent decisions of the past, as well as impose an injunctive remedy to force decisions to be made in the future.

Implicit in both the areas of oil and gas leasing and trusts is the notion that appropriate conduct is governed by a high duty of management care because the legal control of management decisions has been vested with those other than the direct beneficiaries. What is prudent is deemed to be ascertainable through the reasonable efforts of competent managers with sound and reasonable judgment. That risk is involved in managerial decison making is judicially acknowledged. But, the deliberate exposure to substantial risk in the exercise of managerial discretion is by its very nature imprudent, for risk is to be avoided, if not altogether, at least insofar as possible under the circumstances.

Federal Natural Gas Legislation

In the debate over federal natural gas regulation, the 98th Congress (1984) recently focused on the concept of prudence in an effort to address concerns over the natural gas acquisition practices of interstate natural

[72]Weil, "Common Stock: The Forbidden Trust Investment," 33 Alabama Law Review 407, 435 (1982).

gas pipelines. Although no action was taken by the Congress, the debate over these practices is likely to continue. The focus of debate is the provision contained in Section 601(c) of the Natural Gas Policy Act of 1978,[73] which permits the automatic pass-through of gas acquisition costs by pipelines to distribution companies unless the Federal Energy Regulatory Commission finds "...the amount paid was excessive due to fraud, abuse, or other similar grounds."

Shortly after the enactment of the NGPA, pipelines entered into new gas purchase contracts which often contained so-called "take-or-pay" provisions.[74] Take-or-pay provisions have often been identified as one of the reasons that delivered prices to consumers remain high, despite excessive supplies and diminishing demand. But one rate proceeding in particular had the effect of focusing attention on the "fraud, abuse, or other similar grounds" provision of the NGPA.

On December 30, 1982, Federal Energy Regulatory Commission Administrative Law Judge Levant announced a decision concerning the purchased gas adjustment rate--the pass-through rate--for Columbia Gas Transmission Corporation, a pipeline with production and distribution subsidiaries serving Ohio, Kentucky, West Virginia, and Washington, D.C., among other states. Judge Levant made two key findings: first, that Columbia's contracting practices prevented it from discharging its legal obligation to sell gas at the lowest reasonable rate, and second, that Columbia had reduced "takes" of lower cost gas in order to continue "takes" of high cost gas, frequently from its own subsidiaries. These two findings, along with others, formed the basis for concluding that Columbia's purchasing practices constituted an "abuse" under Section 601 and that the pass-through should be denied.[75]

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[73]15 U.S. Code Section 3301, et seq.

[74]See Poling, "The Natural Gas Dilemma: Decontrol or Recontrol?" 30 Federal Bar News & Journal 206 (April 1983).

[75]See, Columbia Gas Transmission Corp., F.E.R.C. Docket Nos. TA 81-1-21-001 and 81-2-21-001, Decision of the Administrative Law Judge (Dec. 30, 1982); and F.E.R.C. Opinion No. 204 (Jan. 16, 1984).

While the Levant decision was pending for final decision by the Commission, the Congress began to debate in earnest proposed natural gas legislation. FERC's review of the Columbia case rejected the conclusion that an "abuse" under the NGPA had occurred, even though the Commission found without apparent legal significance that Columbia "recklessly disregarded" its legal mandate to provide gas at the lowest possible cost to its customers.[76]

Hearings and studies available to the Congress had identified take-or-pay contracts as one impediment to effective market signalling between producers and ultimate consumers.[77]. Among various legislative proposals were specific proposals which would have modified the Section 601 "fraud and abuse" provision by adding the concept of prudence. As the legislation developed, first, by the Senate Energy Committee and later by the House Energy and Commerce Committee, both versions contained prudence modifications of Section 601 (among many other elements).

The Senate Energy Committee adopted a "prudent purchase rule," which allowed pass-through of certain gas acquisition costs in relation to the formulated "free market price indicator." This approach was summarized as follows:

> Section 301 would amend section 601(c) of the NGPA by adding three new paragraphs. Section 601(c) currently provides, in part, that the Federal Energy Regulatory Commission may not prohibit an interstate pipeline from recovering from its customers the ful [sic] cost of the gas it has purchased, unless the Commission determines that the pipeline paid an excessive amount for such gas due to fraud, abuse, or similar grounds. In the absence of such a finding, the Commission is required to permit each pipeline to pass through to its customers its purchase gas costs, if such costs are deemed to be just and reasonable under section 601(b).

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[76]See Poling, "Natural Gas: 1983 Events," 31 Federal Bar News & Journal 82 (February 1984)

[77]See, "Natural Gas Regulation Study," (Committee Print 97-GG), Subcommittee on Fossil and Synthetic Fuels of the House Committee on Energy and Commerce, 97th Cong., 2d Sess. (1982).

Section 301 would add a "prudent purchase" test to the requirements of section 601(c). The test would apply only to gas purchased under contracts for the first sale of natural gas entered into or renegotiated during a three-year period after the date on which the free market price indicator goes into effect. That date would be the first day of the eighth full month after enactment of the bill.

In general, the prudent purchase test would establish new standards to be applied by the Commission in determining whether interstate pipelines would be permitted to pass through to their customers certain increases in purchased gas costs.

New paragraph (3) of section 601(c) would permit the passthrough of purchased gas costs if the amounts paid are "prudent" as defined in subparagraph (A). However, the Commission would have the authority to prohibit a pipeline from recovering purchased gas costs that do not meet the prudency test. Passthroughs could not be denied if such purchases are "prudent" as defined in subparagraph (A). Purchases would be deemed to be prudent if they meet one of three criteria: (1) the weighted average amount paid during any month for gas purchased under new and renegotiated contracts does not exceed 110 percent of the free market price indicator in effect during that month; (2) the purchase is the result of a pipeline's exercise of right of first refusal pursuant to section 318(a); or (3) the amount was paid pursuant to a right of first offer under section 318(b).[78]

In his "Minority Views," Senator Metzenbaum put it more simply:

> To summarize, the problem the Senate should address is the failure of pipelines to minimize their gas costs. Pipelines have not only passed up cheap supplies in favor of expensive supplies, and agreed to prices and price formulas which are exorbitant, but they have entered into long-term contractual arrangements which have impaired their ability to respond to market changes. At a minimum, effective consumer legislation would not only require that pipelines engage in prudent purchase gas practices and be held accountable to the customers for their imprudence, but would also void the over-bearing contractual provisions, which prevent pipelines from lowering their gas costs. Ceilings must be placed on take-or-pay obligations, and price escalation clauses must be defused.[79]

The House Committee on Energy and Commerce took a very different approach from the Senate Energy Committee in its adoption of a prudence

[78]Senate Report 98-205, 98th Congress, 1st Session (1983), at p. 32.

[79]*Id.*, at p. 154.

standard as a part of the existing section 601 of the NGPA:

> Section 301(a) amends section 601(c) of the NGPA by adding paragraphs (3) and (4) thereto. The new NGPA section 601(c)(3) defines the term "similar grounds," thereby amplifying this basis for denying the "passthrough of pipelines" purchase gas costs to consumers. "Similar grounds" includes misrepresentation (by the pipeline purchaser); imprudence by a pipeline in its gas purchasing practices, including any purchasing or operating practice which does not result in the lowest reasonable rate; and failure by a pipeline to bargain at arm's-length with any natural gas seller. In determining whether a rate is the lowest reasonable rate, the Commission should look not only at the level of prices paid producers for gas but should also consider other factors relevant to maintenance of adequate service, such as reliability and location of supply, the need for long-term commitments of reserves, and the operating characteristics of the pipeline, all of which affect the value to the pipeline of particular supplies.[80]

In the "Additional Views," subscribed to by twenty members of the Committee, this characterization was also given of the Committee approach:

> Section 302 of H.R. 4277 would direct FERC to deny recovery of natural gas purchase costs incurred by interstate pipelines in cases of misrepresentation, imprudence, "including any purchasing or operating practice which does not result in the lowest reasonable rates," or a failure to bargain at arm's length. Pipelines are also prohibited from providing "any undue preference or advantage to any affiliate." The Commission may not, however, use this authority to establish natural gas ceiling prices or set forth any price ("or method of determining such a price") as a dividing line between prudent and imprudent prices.
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> If the FERC finds that a pipeline has been imprudents [sic], has unreasonably refused to provide transportation services, or has discriminated in favor of an affiliate in providing transportation services, FERC shall make "an appropriate reduction" in the pipeline's rate of return.[81]

Thus, it can be seen that the approaches taken by the House Committee and the Senate Committee were quite different. The Senate approach was one

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[80]House Report 98-814, 98th Congress, 2d Session (1984), at p. 40.

[81]*Id.*, at 139.

wholly of statutory construct. The use and definition of "prudent" was undertaken in specific and limited reference to a statutory scheme of rate formulation and is clearly not an effort to incorporate judicial uses of the concept of prudence for the discretionary use of ratemakers. The rates would have been set by formula, with little or no regulatory application of standards of prudence as a review of the soundness of utility management investment decisions.

The House approach appears to have been an effort, in part, to vest regulatory discretion by lifting the usage of prudence from the law generally without the imposition of a strict statutory definition.

The possible renewal and ultimate outcome of the recent Congressional debate over modifications to the Natural Gas Policy Act is in doubt. There is substantial public concern over the many aspects of the natural gas industry. The proposed legislation had the effect of focusing attention on, and renewing the discussion of, the concept of prudent business practices by natural gas companies.

It is fair to observe that, although federal regulation of natural gas under the Natural Gas Act and the Natural Gas Policy Act has not extensively utilized heretofore the concept of prudence (as it is summarized here), the concept is not foreign to federal regulation and has been used from time to time. For example, in a Court of Appeals decision in one of the Permian Area Rate Base cases, it was observed that the return of a public utility should assure confidence in the financial soundness of the utility and be adequate under prudent management to maintain and support its credit and enable it to raise money necessary for proper discharge of its public duties.[82]

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[82]See Skelly Oil Co. v. Federal Power Commission, 375 F.2d 6 (10th Cir. 1967), affirmed in part, reversed in part, Permian Basin Area Rate Cases, 390 U.S. 747 (1968), rehearing denied Bass v. Federal Power Commission, 392 U.S. 917 (1968).

On the other hand, the Federal Power Commission, predecessor of the Federal Energy Regulatory Commission, held that regulated utilities had extensive management discretion in the conduct of business affairs:

> The Commission has no authority either to conduct or supervise the day-to-day operations involved in the production and transportation of natural gas in interstate commerce. Those functions are left to management for decision and the managers exercise a broad area of discretion in the conduct of business.[83]

Still, the Court of Appeals in the Midwestern Transmission case, supra, did refer to "prudent business expenses." Thus, the references to prudent action under federal natural gas regulation have been made, although the regulatory concept has not received specific endorsement as a method of disqualifying investments from eligibility for inclusion in the rate base.

In fact, one effort by the FERC to establish a rule requiring producers to act as prudent operators in developing and maintaining deliverability from natural gas reserves was found to be beyond the statutory authority of FERC under the Natural Gas Act. In Shell Oil Co. v. Federal Energy Regulatory Commission,[84] the Fifth Circuit held that the imposition of a prudent operator rule as an implied condition of natural gas company sales and transportation certificates was contrary to the prohibitions against the regulation of production and gathering under the Natural Gas Act. Shell only determined that the statute would not allow for the proposed regulation and did not attempt to assess the efficacy of the FERC proposed use of the prudent operator test. Although the current Congressional proposals concerning prudent operational activities by pipelines

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[83]Midwestern Gas Transmission, 36 F.P.C. 61, 70 (1966).

[84]Shell Oil Co. v. Federal Energy Regulatory Commission 566 F.2d 536 (5th Cir. 1978). See also, note, "Gas Law--The Federal Energy Regulatory Commission under Authority Conferred by the Natural Gas Act of 1938 is Exceeding Its Jurisdiction by Issuing Order No. 539B which Would Establish a Regulation Requiring a Producer to Act as 'Prudent Operator' in Developing and Maintaining Deliverability from Natural Gas Reserves," 6 Texas Southern University Law Review 481 (1981).

have a somewhat different focus from the FERC proposal dealt with in Shell, both attempted the use of prudence as a regulatory standard.

Congressional consideration of the use of prudence as a method to establish a regulatory standard of scrutiny over gas purchasing practices is significant. Under the current relaxed regulatory framework of the NGPA, where wellhead rate ceilings are set by statutory formula, the current pass-through provisions provide only modest regulatory flexibility in terms of "fraud or abuse." These terms, like prudence, are concepts of legal art. But their narrowness has limited the authority, or perhaps willingness, of the FERC to use them effectively. The statutory expansion of FERC discretion through the use of prudence is viewed as increasing the degree of regulatory scrutiny which may be exercised. Without an express statutory definition, the pending legislative proposals introducing prudence into the NGPA framework would seem to incorporate many of the views of prudence reviewed here.

CHAPTER 3

RECENT STATE APPLICATIONS OF THE PRUDENCE TEST

As indicated in chapter 1, there have been many state commission applications of the prudence test in recent years. In this chapter, we review the major cases by type of case. Before this, however, we offer certain guidelines for successful applications of the prudent investment test.

Guidelines for a Successful Prudence Application

In reviewing the many state utility commission inquiries that use the concept of prudence, we noticed certain themes that are common to many of the proceedings that treat this concept with special care. From these themes are derived four guidelines for proper use of the prudent investment test. These guidelines are not necessarily all explicitly delineated in any particular case.

In our view, the principal guidelines for a successful prudence inquiry are (1) a rebuttal of the presumption of prudence, (2) a rule of reasonableness under the circumstances, (3) a proscription against hindsight, and (4) a retrospective, factual inquiry. Following these guidelines is likely to be useful, perhaps necessary, for having a court sustain commission findings. However, because prudence is an evolving regulatory tool, following these guidelines may not be sufficient to guarantee that a commission's findings will be upheld. This is because regulatory tests other than prudence must also be considered.

The Presumption of Prudence

When applying the prudent investment test, state commissions have taken seriously Justice Brandeis' admonition regarding prudent investments: "Every investment may be assumed to have been made in the exercise of reasonable judgment, unless the contrary is shown."[1] Commissions have interpreted this as requiring a rebuttable presumption of prudence. It has been held that without "affirmative evidence showing mismanagement, inefficiency, or bad faith,"[2] an investment decision is presumed to be prudent. In the absence of such an affirmative showing, at least one court has stated that a commission cannot disallow a utility's expenses.[3] Thus, for example, unless a particular management decision associated with the planning or construction of a power plant is challenged, the full original cost of the investment in the power plant is presumed to be prudent and includable in rate base.[4] The presumption of prudence makes for efficient regulation in that commissions are not required, or allowed, to review the prudence of all utility decisions regardless of their number, importance, or result.

A mere allegation of imprudence may not be sufficient to rebut the presumption of prudence; rather, an allegation of imprudence must be backed up by evidence that is substantive and that creates a serious doubt about the prudence of the investment decision.[5] A serious doubt as to the prudence of management decision making might be created, for example, by a Nuclear Regulatory Commission decision denying an operating license to a nuclear unit because of inadequate quality assurance or by a large, unexplained construction cost overrun.[6] In one state the mere existence

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[1]State of Missouri ex rel. Southwestern Bell Telephone Co. v. Public Service Commission, 262 U.S. 276, 289 (1923) Brandeis, J. concurring.

[2]Re Chesapeake & Potomac Telephone Co., 57 PUR3rd 1, 7 (D.C.P.S.C., 1964).

[3]State ex rel. Utilities Commission v. North Carolina Textile Manufacturers Association, Inc., 296 S.E.2d 487, 498 (N.C.Ct. App., 1982).

[4]Of course, in fair value states the investment is included in rate base at its fair value, which may or may not be its original costs.

[5]Minnesota Power and Light Co., 11 FERC Para. 61,312 (1980).

[6]See Randall L. Speck, "Proving Imprudent Management in Nuclear Power Plant Construction," a paper presented to the Seventh Annual Conference of Regulatory Attorneys (Madison, Wisconsin, June 4, 1984), p. 4.

of a construction cost overrun was considered enough to rebut the presumption of prudence.[7] However, another state commission rejected evidence challenging the presumption of prudence in a case where the construction costs of a nuclear power plant were claimed to be excessive on the basis of the costs for comparable units constructed elsewhere.[8] This indicates that one is more likely to create a serious doubt that serves to rebut the presumption of prudence if the evidence is closely related to the decisions about the plant in question.

Once the presumption of prudence has been rebutted, the utility has the burden of proving that the investment decision alleged to be imprudent was in fact prudent. Whether the utility actually meets its burden of proving that its decision was prudent depends on the test used for determining prudence and on the evidence presented for and against prudence.

Reasonableness under the Circumstances

When the rate base treatment of an investment is challenged on the basis of prudence, the test applied to determine if the investment decision is prudent becomes critical. Most commissions applying the prudent investment test use the standard developed in the Brandeis opinion of the Southwestern Bell case; namely, the prudence of a decision is based on its reasonableness under the circumstances.[9] From this starting point, state commissions have developed the prudent investment test as it is currently applied to public utilities. This test requires a standard of care (a fiduciary duty) owed by the utility to its customers. The standard of care is one of "reasonableness under the circumstances which were known at the

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[7]See In Re Detroit Edison Co., 24 PUR4th 326 (Mich. P.S.C., 1978).

[8]See In Petition of Florida Power Corp., [1979-81 Transfer Binders] Util. L. Rep. (CCH) Para. 23,318 FlaPSC, (1981). See also, Re Consolidated Edison Co. of New York 96 PUR 195, 231 (NYPSC, 1952), in which there was no exclusion from rate base where there was no specific proof of excessive costs for the plant in question, even though the construction costs of the plant were higher than those of comparable plants.

[9]See footnote 1, supra.

time."[10] This test was elaborated in a recent case before the Massachusetts Department of Public Utilities as follows:

> [A utility's] actions should be judged by asking whether they were prudent at the time, under all the circumstances, considering that the Company had to operate at each step of the way prospectively rather than in reliance on hindsight. Accordingly, the department will base its findings on how reasonable individuals would have responded to the particular circumstances and whether the Company's actions were prudent in light of all conditions and circumstances which were known or which reasonably should have been known at the time the decisions were made.[11]

Other tests for prudence have been considered. Some other tests look at the final outcome of a utility's decision in judging prudence. A utility may construct an inoperable generating station, may exceed its construction budget severalfold, or may incur costs much greater than the costs of another utility for constructing a similar plant. Under the guidelines we suggest here, these final outcomes may serve to overcome the presumption of prudence, but do not necessarily address the question of reasonableness under circumstances. In some instances, state commissions use some form of final outcome test for determining prudence, either as the only test or as a test that supplements the test of reasonableness under the circumstances.

Other tests for prudence have been proposed, but have been rejected by several commissions. The more lax "rational basis standard" would hold an investment to be prudent provided the manager's decision had some rational basis.[12] The only investment decisions that are likely to be rejected

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[10]Re Boston Edison Co., 46 PUR4th 431 (Mass. DPU, 1982).

[11]<u>Id</u>., p. 438.

[12]The rational basis standard was approved of in Re Consolidated Edison Co. of New York, 54 PUR3d 43, 112 (N.Y. PSC, 1964), <u>aff'd</u> 260 N.Y.S.2d 340 (1965), <u>modified on other grounds</u> 217 N.E.2d 140 (1960) (<u>per curiam</u>), but was later rejected in Re Consolidated Edison of New York, Inc., 45 PUR4th 325 (NYPSC, 1982).

under the rational basis test would be those that are either made with the intent of fraud or are totally irrational. Commissions also have rejected the "abuse of discretion" test[13] and the "normal business judgment" test, because these tests are inappropriate in that

> [W]e are not dealing...with suits against corporate officials for individual liability. We are concerned with the extent to which ratepayers should bear [the costs of an imprudent action, which cannot] be equated with the rules defining director's obligation to a corporation.[14]

In applying the standard of reasonableness under the circumstances, commissions, in some instances of high risk projects, have required a higher than normal standard of care to compensate for the high risks associated with project decisions. For example, in one FERC case involving a multi-billion dollar nuclear project, the administrative law judge held that no industry can be permitted to set its own standards by universally adopting careless and slipshod methods. In applying the reasonableness standard, it is thus no excuse that a utility did no worse than its peers; rather, the public has the right to demand the use of superior tools and techniques to build nuclear generating facilities at the lowest reasonable costs. When the risk of harm to the ratepayer is greater, the standard of care expected from a reasonable person is higher.[15] Because of the amount of skill, expertise, and experience necessary to complete a nuclear plant successfully, state commissions have sometimes held utilities to a very high standard of care when applying the test of reasonableness under the circumstances. For example, the New York

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[13]Used in Re Midwestern Gas Transmission Co., 36 F.P.C. 61, 70-71 (1966), aff'd 388 F.2d 444 (7th Cir.), cert. denied 392 U.S. 928 (1968).

[14]Re Consolidated Edison Co. of New York, Opinion 79-1 (NYPSC, January 16, 1979), p. 5.

[15]See New England Power Company, Docket No. ER8L-703-000 (FERC, per Nacy, A.L.J. May 4, 1984); see also Speck, "Proving Imprudent Management," p. 5.

Public Service Commission emphasized the high degree of care in planning, supervision, and control required in the construction of nuclear power plants due to the health risks associated with nuclear materials and the high cost that can result from error and delay.[16]

Proscription Against Hindsight

A proscription against the use of hindsight in applying the prudence standard is a corollary to the "reasonableness under the circumstances" test. The decisions of the utility are not subject to "Monday-morning quarterbacking." Instead, they are to be judged in light of the conditions and circumstances that were or should have been known to the utility at the time of its decision. In our view, the proscription against hindsight makes it unwise for a commission to supplement the reasonableness test with some form of final outcome test unless the final outcome test is used solely to overcome the presumption of prudence.

If a state commission engages in hindsight, any finding of imprudence is subject to reversal. One example of such a reversal involves a recent case before the Florida Supreme Court. The court reversed a decision by the Florida Public Service Commission that the Florida Power Corporation was imprudent in its management of its Crystal River-3 nuclear plant because the utility failed to check a hook, which failed, resulting in a 2,000 pound test weight falling onto some nuclear fuel assemblies. The court stated that the Commission had used hindsight in its decision.[17]

Retrospective, Factual Inquiry

Once the presumption of prudence is overcome, there is a need to

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[16]See Re Consolidated Edison Co. of New York, Opinion No. 79-1 (NYPSC, January 16, 1979).

[17]"State High Court Again Nixs PSC Order for $11-Million Florida Power Refund," Electric Utility Week, October 8, 1984, pp. 4-5.

develop evidence about whether the investment decision was prudent or imprudent. To accomplish this, state commissions engage in retrospective, factual inquiries.

Evidence for prudence or imprudence needs to be retrospective, or backward looking, in that it must be concerned with the time at which the decision was made. It must present facts, not merely opinion. These facts should cover all the elements that did or could have entered into the decision, including all relevant data, information, decision-making tools, and the circumstances at the time. For example, it would be improper to use past data in a current computer model to review a past decision if this type of model were not available in the past or if use of such a model could not reasonably be expected of the decision maker.

The evidence is presented in an inquiry before the commission. This may be a rate case that takes up the rate base treatment of a utility investment or a special prudence inquiry. In either case, the commission inquiry may be preceded by a staff investigation, which ought to be retrospective and factual, with a view toward developing the evidence for use in the inquiry. Such staff investigations can look at the past in great detail and therefore can be time-consuming and expensive, especially if much of the work is done by consultants.

Recent staff prudence investigations are similar in many ways to the prospective management audits that have been conducted in the 1970s and 1980s. A restrospective prudence investigation is different, however, from a management audit in one key aspect. The prudence investigation is backward looking without applying hindsight to decisions made in the past. A management audit, on the other hand, looks at the decisions of a utility, given contemporary management standards. Because it suggests changes in the utility's managerial practices to be made prospectively, the use of hindsight is not only allowed, it is encouraged.

Areas of Recent State Application

We have reviewed recent state commission prudence inquiries involving electric and gas utilities. Many electric applications were discovered but few gas applications. The two principal areas of application involving electric utilities were construction costs overruns and plant abandonments with capacity additions running a distant third.

Few of these cases rely solely on the prudence test for reaching a judgment. In most, the commission references the "used-and-useful" test or a "balancing of interests" test (that is, balancing the legitimate interests of customers and investors) to decide if certain costs should be included in rates. The cases described here in detail are those that rely most strongly on the prudence test. Those merely mentioned here all refer to the concept of prudence, but the degree to which the commission relied on this concept in reaching its decision was sometimes unclear. Also, some of the cases here rely on extensive staff prudence investigations for evidence.

Construction Cost Overruns

The prudence inquiries that rely most heavily on staff investigations are those involving generating plant construction cost overruns. This is so because the purpose is not simply to decide whether or not imprudent decisions were made, but also to determine the consequences of any imprudent decisions in terms of additional costs. Several state regulatory commissions have recently begun inquiries regarding the prudence of a utility in managing construction costs.

Because construction cost overruns rarely occurred before the 1970s, and when they did occur the overruns were of small magnitude, the authors found few cases explicitly applying the prudence test to construction cost overruns before the 1970s. Rather, the presumption of prudence applied. However, since the 1970s, state commissions have been more active in challenging the value of investments about to go into rate base on the basis of prudence. Such a challenge usually must be preceded by a staff prudence investigation to develop evidence of imprudence.

Some key areas into which a staff investigation of cost overruns is likely to inquire are (1) whether decisions relating to costs were made at the appropriate levels within the corporate hierarchy and whether the senior officers received adequate information to allow them to make responsible decisions; (2) whether the utility was adequately involved in the planning of the project; (3) whether the utility selected an architect/ engineer who could handle the project in a cost-effective manner; (4) whether the utility monitored the engineering effort; (5) whether procurement was based on competitive bids; (6) whether the contracts were all cost-plus, or whether there were incentive mechanisms included; (7) whether the utility monitored the work force utilization; (8) whether time schedules were established for construction tasks and whether there were adequate reporting systems in place to identify deviations from the schedule; (9) whether the scheduling was realistic and whether management used the reporting systems as a tool to prevent future delays; (10) whether delivery of materials and equipment were effectively scheduled, controlled, and monitored; (11) whether the construction manager was effectively monitored; (12) whether the utility took steps (especially in nuclear construction) to improve the interaction between construction and engineering; (13) whether there was adequate monitoring of the project budget and whether variances from the budget were brought to the attention of project management; and (14) whether the utility arranged its financial planning so that financing would not adversely affect scheduling, and hence cost. In addition, one could investigate key technical issues that deal with the competence of the design, engineering, and construction of the plant.[18]

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[18]Edward Berlin and Steven Agresta, "Prudence Investigation of Nuclear Construction Projects," a paper presented to the Twenty-Second Annual Iowa State Regulatory Conference on Public Utility Valuation and Rate Making Process (Ames, Iowa, May 18-20, 1983), pp. 7-14.

Three major state prudence investigations of cost overruns are described next. In addition, we report other state actions for dealing with cost overruns that rely on the concept of prudence to varying degrees.

Enrico Fermi-2

An excellent example of a construction cost overrun investigation by a state commission staff is the Staff Investigation of Enrico Fermi-2 Nuclear Power Project. The Michigan staff began its investigation by looking into the "ground rules" concerning the inclusion of a major utility investment in rate base in Michigan. Included in this was a cursory review of how the used-and-useful test and the prudence test have been applied in Michigan and other states. In Michigan, according to Bhatia and Fielek, the used-and-useful test is applied in a straightforward fashion: if a facility is in service, it is used and useful and includable in rate base; if not in service, it is not.[19] Because Michigan does not have construction certification authority for electric plants, the issue of need can first arise subsequent to the completion of the facility.

The Michigan Public Service Commission initiated an Enrico Fermi-2 prudence inquiry with two concerns. The first concern was the original decision to construct the plant; the second was the reasonableness of the expenditures during the construction of the plant.[20]

The Michigan staff therefore conducted a prudence investigation in three stages. The first stage dealt with the need for the project, including the need at the time of the initial decision, the continued need as established by periodic reviews, and the final need for the project, that is, whether the project represented excess capacity.

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[19]Hasso Bhatia and Michael A. Fielek, "A Plan for Investigation into the Prudency (sic) of Power Plant Expenditures," The Proceedings of the Fourth NARUC Biennial Regulatory Conference (Columbus: The National Regulatory Research Institute, 1984).

[20]Ibid.

In the second stage, staff conducted an investigation to establish a rough range of costs for the Enrico Fermi project, which could be considered reasonable compared with similar nuclear projects. This comparable cost study was conducted for the purpose of determining whether the presumption of prudence could be rebutted, in other words, whether there existed enough evidence for a prima facie case of management imprudence. If the results of this second stage showed that the construction costs of Enrico Fermi-2 fell close to or below the mean costs of comparable plants, then the prudence investigation would have stopped at this stage.

The third stage of the prudence investigation involved a detailed evaluation of the project management and decision-making process to determine which factors resulting in plant cost overruns were themselves the result of imprudent management and which were not. Throughout the third stage of the investigation, care was taken that all the decisions were evaluated in light of the circumstances, conditions, and information available at the time. If the decision resulted from a management evaluation reasonably based on cost-benefit analysis, risk analysis, technical feasibility, practicality, experience, and good judgment, then the decision was judged to be prudent. Even if the decision turned out to be wrong because of unforeseen future events, the decision was still deemed to be prudent. However, the staff recognized the fact that nuclear safety regulations were frequently changing, so that some degree of anticipatory judgment about this by utility management was required.[21]

The staff's Fermi-2 project investigatory team consisted of seven members. Also, a twelve-member Rate Base Advisory Committee was set up to define the scope of the investigation, to establish guidelines, evaluate criteria, to oversee the progress of the investigation, and to decide generic issues such as treatment of rework, effects of delay, regulatory impacts, and inflation adjustments.[22]

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[21]Ibid.

[22]Ibid.

The prudence investigation involved over 440 information requests and on-site personal interviews with key personnel including the senior utility management; the utility's project management team; contractors; vendors; suppliers; foremen from the site; and managers and auditors responsible for reporting, accounting, and financial control.

The Michigan Public Service Commission staff concentrated its investigation on only a handful of actions and decisions, based on their significance to the overall project. The actions and decisions that were examined for possible imprudence included (1) any action or decision causing significant project delays, (2) any major modifications in construction resulting from design or construction deficiency, (3) management deficiencies in project labor or control, (4) management deficiencies in quality assessment and quality control, (5) any action or decision subject to Nuclear Regulatory Commission citation, and (6) management deficiencies in vendor control.

The critical, but most difficult analysis was the determination of the cost of project delay due to imprudence. The investigators were aided by the state-of-the-art scheduling tools that the utility was utilizing. To determine if a decision caused project delay the prudence investigator had to determine whether the action was on the construction project's critical path, since only those items on the critical path add to the final project time. Even when a delay along the critical path was identified, the staff investigators were still left with the difficult task of deciding whether the delay was beyond the control of the utility and, if not, how much delay occurred. Once a delay was determined to have occurred as a result of imprudence, then the cost of the delay had to be determined and adjusted for inflation.

As a result of this retrospective prudence investigation, the Michigan Public Service Commission staff recommended that $365.48 million be disallowed from the estimated total project cost of $3.075 billion for Enrico Fermi-2. Of that total, approximately $122 million were disallowances due to project delays along the critical path, and the remainder of the recommended disallowances represented an accumulation of many specific items of unnecessary cost incurrence resulting from poor supervision and management decisions.

This staff recommendation was made in testimony during a prudence inquiry conducted by the Michigan Public Service Commission. As of this writing, all the evidence has been presented to an administrative law judge who has not yet rendered a decision.[23]

Shoreham

Another significant retrospective prudence investigation was conducted by the State of New York Department of Public Service, initially with the assistance of a consulting firm and its subcontractor. The prudence investigation was ordered as Phase II of Commission Case 27563 to investigate the cost incurred by the Long Island Lighting Company (LILCO) in the construction of the Shoreham Nuclear Power Station.

An initial investigation determined that there were serious problems with LILCO's management of the Shoreham project. Based on the initial findings, the Department of Public Service dramatically increased the resources devoted to the investigation, and in February 1983 a second consulting firm was hired to assist the staff in conducting a "full-blown" retrospective investigation of LILCO's management of the Shoreham project. In conjunction with the consulting firm, the New York Department of Public Service formed a Shoreham Task Force consisting of eighteen full-time staff members, as well as fifteen part-time Task Force members who were called upon as necessary. The Task Force consisted of lawyers, engineers, accountants, and computer and clerical support staff.[24]

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[23]Personal communication with Dr. Hasso Bhatia, Michigan Public Service Commission Staff, January 23, 1985.

[24]See Executive Summary Testimony of Thomas G. Dvorsky, Shoreham Project Technical Coordinator, State of New York Department of Public Service (February 1984), Investigation of the Shoreham Nuclear Power Station, New York Public Service Commission Case 27563 - Phase II - Shoreham Prudence Investigation.

The Shoreham Task Force conducted its investigation by using on-site investigations at the LILCO home offices and at the Shoreham site. The Task Force reviewed files of 66 LILCO departments and offices and examined the files of 58 of LILCO's managers, including the President and Chairman of the LILCO Board. As a part of its investigation, the Task Force obtained approximately 10,000 documents relevant to the Shoreham construction. The Task Force also obtained LILCO's computerized accounting information system for Shoreham. The Task Force also obtained and reviewed copies of the project files of the architect/engineer, the construction manager, and the main piping and structural contractors. The Task Force then organized and placed all the documents and information received into a computerized record retrieval system, which ultimately contained over 1.5 million pages of information on microfilm. Finally, the Task Force interviewed 49 individuals including LILCO employees, contractors, and consultants involved in the Shoreham project.[25]

The Task Force reported finding serious mismanagement and inefficiencies throughout the project in each of the areas of project management, construction management, regulatory relations, engineering management, and quality control.[26] The factor identified by the Task Force to have caused the longest delay in the plant's completion was the procurement, fabrication, testing, and installation of the emergency diesel generators for the Shoreham plant. According to the Task Force, this failure resulted in delays that are estimated to have increased the cost of the Shoreham unit by $500 million.

Based on its findings, the State of New York Department of Public Service recommended that $1.55 billion of the cost of Shoreham should be excluded from rate base out of the then current total cost estimate of $3.85 billion. The staff's recommended adjustment was based on the assumption that the Shoreham unit would become operational in January 1985.

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[25]Ibid.

[26]Ibid.

The staff took the position that any additional costs that resulted from further delays should be borne by the stockholders. Thus, the New York Department of Public Service staff proposed that no more than $2.3 billion of the $3.85 billion construction expenditure in the Shoreham project should be allowed in rate base. The balance of the expenditure would be disallowed for being imprudently incurred.[27]

Since then, the management of LILCO has proposed a plan to phase the Shoreham investment into rate base over a 13-year period beginning July 1, 1984, 18 months before the plant's in-service date. The plan calls for LILCO stockholders to pay a $250 million "contribution to rate reduction" to settle the question of the prudence of the Shoreham investment. LILCO, nonetheless, maintains that all of its construction expenditure decisions in Shoreham were prudent.[28]

The New York Public Service Commission, instead, recently approved an agreement providing LILCO with emergency financing to pay $90 million for bonds maturing September 1, 1984. The agreement also gave the lending institution a third-mortgage of $1.2 billion as security for loans made by LILCO in the past. However, the Commission made it clear that its regulatory authority, pursuant to the provisions of the New York Public Service law, is not constrained by the agreement, leaving unconstrained the Commission's authority to make a prudence adjustment to the value of the Shoreham investment going into rate base.[29]

Zimmer

Another example of a state commission undertaking a retrospective prudence investigation is the investigation of the possible mismanagement

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[27]Ibid.

[28]"LILCO Outlines Plan to Recoup Shoreham Costs," The Wall Street Journal, 1 June 1984, p. 6.

[29]"New York PSC Approve LILCO Loan Agreement with Banks, Eliminates Any Limits on Future PSC Actions," NARUC Bulletin, No. 38-1984, September 17, 1984, p. 13.

and related costs involved in the construction of the M. H. Zimmer Nuclear Power Station. In this case, the investigation was conducted by a consultant under contract to the Public Utilities Commission of Ohio (PUCO). Zimmer construction was managed by the Cincinnati Gas and Electric Company on behalf of itself and two co-owners. The PUCO issued a request for a proposal on November 11, 1983 for a consulting firm to do three things: (1) develop a definition of mismanagement in a nuclear power project, (2) identify any mismanagement at the Zimmer project, and (3) quantify the cost of mismanagement associated with the Zimmer project. The PUCO hired a consulting firm, with a subconsultant, on December 20, 1983 to complete the study.[30]

The consultants performing the Zimmer prudence investigation relied on eleven books and ninety-nine articles to develop their definitions of management and mismanagement. Their view of management and mismanagement can be summed up as follows:

> ...[R]isk-taking [is] a normal part of management, and competent management must take risks. These risks, however, must be within an appropriate context, and not be a challenge to society or a danger to the public or the employees. However, a mistake made as a result of actions which were clearly predictable is, indeed, mismanagement. Further, failure to adjust or correct actions after a mistake has been identified is, also, mismanagement.[31]

The consultants then identified instances of possible mismanagement. Of these, two of the more important concern cost management: cost management after the 1981 NRC "immediate-action" letter and cost management for the Mark II pressure suppression containment. The NRC letter directed

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[30]O'Brien-Kreitzeng & Associates, M. H. Zimmer Nuclear Power Station: Analysis of Possible Mismanagement and Correlated Cost, prepared for the Public Utilities Commission of Ohio, June 15, 1984, p. 1-1.

[31]Ibid., p. 2-16.

that the utility take corrective measures for construction quality concerns. The NRC letter required, among other things, (1) an immediate increase in the size and technical expertise of the Cincinnati Gas and Electric Quality Assurance organization; (2) that action be taken by April 15, 1981 to assure the independence of the quality assurance/quality control function; (3) a complete reinspection of all quality control inspections; (4) a review and revision of all quality control inspection procedures by qualified design engineers and quality assurance personnel, and a temporary suspension of associated construction activities; and (5) training on new quality assurance/quality control (QA/QC) procedures and practices by all QA/QC personnel. The consultants also identified the high costs of the Mark II pressure suppression containment as possibly being the result of mismanagement. Two events in the early 1970s suggested that the design of the Mark II containment system was not adequate, and as a result the system was redesigned and suffered associated cost increases.

In order to quantify the incidence of mismanagement at the Zimmer project, the consultants grouped instances of possible mismanagement into three levels of significance. The first level, the policy level, represents the highest level of management responsibilities, including moral and ethical conduct, performance in good faith with the laws, competence, a dedication to quality and safety, and verification that the aforementioned policies are implemented. The second level, the control and performance level, reflects operations carried out by middle management within the broader policies of upper management. These areas of management include scheduling, quality, cost, and budget control; controlling craft productivity; documentation; planning and design control; personnel training; and developing organizational procedures. The third level of management relates to specific incidents, which are merely symptomatic representations of management policy and its implementation.

The first two levels, top management and middle management, were rated according to a point system. The consultants determined that mismanagement in a nuclear project could consist of a failure to manage any of the following five functions: (1) responsible performance, (2) planning, (3) implementation, (4) maintenance of control, and (5) achievement of meaningful results. The consultants rated, on a subjective basis, each of these five functions of management as follows: a failure of management, 3; inadequate management, 2; adequate management, 1; and good management, 0. The following seven activities of middle management were rated: (1) planning; (2) project management and control; (3) scheduling; (4) engineering; (5) construction management; (6) procurement and contract management; and (7) quality assessment, quality control, and regulatory compliance. The overall rating for each of the seven activities was the average of the ratings for that activity in each of the five managerial functions. For example, the scheduling activity of middle management received the following functional ratings: responsible performance, 2; planning, 3; implementation, 2; maintenance of control, 2; and achievement of meaningful results, 2. An average scheduling rating of 2.2 resulted. According to the consultants a rating of 2.0 or more is indicative of mismanagment. The ratings by the consultants resulted in a finding of mismanagement (a score of 2.0 or more) for each of the seven activities at the middle management level.[32]

The consultants rated three activities of top management. They were (1) quality assurance/quality control, (2) cost management after the 1981 NRC immediate-action letter, and (3) cost management for the General Electric Mark II pressure suppression containment. The consultants rated top management decisions as inadequate or a failure in two of these categories, the exception being the utility's management of the Mark II containment costs, which the consultants rated as good.

In assessing the cost of mismanagement associated with the Zimmer project, the consultants found that, of the estimated $3.3 billion required to complete the facility as a nuclear unit, $1.7 billion would be the result of mismanagement. The consultants also concluded that if the utility

[32]Ibid., pp. 2-18 to 2-22A.

were to cancel the plant the entire cost--$1.7 billion at that time--would be the result of mismanagement. Further, if the utility were to convert the nuclear plant to a coal-burning plant, $1.3 billion would be the result of mismanagement.

The consultants' report has been criticized by officials of the lead utility, the Cincinnati Gas and Electric Company, as being "simplistic," because it

> appears that the consultants could not quantify costs specifically related to mismanagement, as they were assigned to do by the commission. As a result...the consultants...concluded that everything they believed cannot be used in the conversion of the Zimmer plant to a coal-fired facility is attributable to mismanagement.[33]

The utility also disputed the consultants' conclusions that (1) $1.3 billion of the plant cannot be used in the coal conversion, (2) the utility should have suspended construction of Zimmer after the immediate-action letter from the NRC in April 1981, and (3) $326 million should be assessed against the utility because of the necessity to redesign the Mark II containment, when the report gave the company's own managerial and engineering effort a high rating.[34]

It should be remembered that the conclusions reached in the consultant's study do not necessarily reflect the views of the Commission or its staff, but the study is likely to be important evidence in a PUCO inquiry regarding the prudence of utility decisions about the Zimmer plant. Recently the Commission found reasonable cause to believe that there had

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[33]"Ohio Utility Criticizes Zimmer Study," Public Utilities Fortnightly, July 19, 1984, p. 52.

[34]Ibid. It should be noted that the utilities that are co-owners of the Zimmer plant have jointly filed suit against the General Electric Company and the Sargent & Lundy Engineers to recover damages associated with the nuclear steam supply system and the Mark II containment. See "Ohio, Zimmer Owners Seek Recovery of Damages," Public Utilities Fortnightly, August 16, 1984, p. 53.

been "imprudence or mismanagement"[35] in connection with the Zimmer plant. As a result of this finding, the Commission ordered an investigation in two phases. In the first phase of the investigation, the Commission will determine what portion of the Zimmer project that was specifically nuclear will never become used and useful as part of a coal plant. In the second phase of the investigation, the Commission will examine whether any imprudence or mismanagement occurred and whether any such imprudence or mismanagement caused the owners to convert the unit from nuclear to coal.

Final Outcome Test for Prudence in Cost Overrun Cases

As mentioned, in our view the concept of prudence applies only to decisions, and the appropriate test for prudence is one of reasonableness under the circumstances. Because application of the concept is an emerging area of regulatory law, the prudent investment test is rarely, if ever, used in strict conformance with the guidelines set out at the beginning of this chapter. Indeed, only time and the courts will tell if these guidelines or some other guidelines evolve into established elements of a prudence inquiry. Concerning construction costs, several states have judged the reasonableness of the final costs resulting from management decisions rather than the decisions themselves. Sometimes this "final outcome" test of whether ratepayers should bear the cost has been linked to the concept of prudence. Other times it has not: investment costs may be excluded from rate base on the basis of "usefulness," for example.

The Enrico Fermi-2, Shoreham, and Zimmer investigations just discussed are among the state applications that best conform to our guidelines, but even in these investigations some features of a final outcome test may appear together with the test of reasonableness under the circumstances. Certainly, it would be hard to prove that a decision that led to a good

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[35]"Ohio: Commission Initiates Zimmer Prudence Investigation," Public Utilities Fortnightly, December 6, 1984, p. 59.

final outcome was unreasonable under the circumstances (even though it is easy to imagine such a case). Consequently, investigators are likely to consider the final outcome of a decision along with the quality of the decision making. For example, in the Zimmer investigation the consultants found that the management associated with the Zimmer plant was, by and large, inadequate. This finding was based in part on "achievement of meaningful results."

Further, when is expert testimony about reasonableness objective or subjective, and to what degree does it always implicitly, if not explicitly, rely on knowing the final outcome? The use of expert opinion, presumably based on factual evidence, cannot be avoided in a retrospective prudence inquiry. In the Zimmer investigation, it is unclear whether the consultants used an objective or subjective rating to derive their findings. Hence, it is not always clear from their documentation whether the consultants' rating of the utility's failure or success in managing the project could be used with the prudence test under the guidelines set out above. It is questionable whether a consultants' average numerical rating of several activities, including achievement of results, applies the test of reasonableness under the circumstances to utility decisions. Further, choice of a particular average rating as a borderline between good and bad management may appear too subjective. While any opinion, including an expert opinion, is inherently subjective, that opinion must be sure to focus on the quality, not the outcome, of the decisions made.

In one state, the use of a final outcome test for judging the prudence or imprudence of construction cost overruns is the method set out in recent legislation. The Kansas legislature enacted a law that specifically empowers the Kansas State Corporation Commission to exclude from rate base construction costs that are a result of imprudence or inefficiency. The statute enumerates several tests to judge imprudence, including (1) a comparison of the final cost of the plant to the final costs of other comparable facilities, (2) a comparison of the cost overruns at the plant to the cost overruns at other comparable facilities, (3) a comparison of the rates resulting from the new plant as opposed to prior rates, and (4) an assessment of the impact of the new rates on the state's economy. The statute also provides that the burden of proving costs to be prudent is automatically shifted to the utility if the construction cost overruns are more than 200 percent of the utility's original cost estimate.[36] It is interesting that many of the tests set forth in the Kansas statute are similar to the comparable cost method used by the Michigan Public Service Commission staff in its investigation to overcome the presumption of prudence. The Kansas statute, however, appears to allow a comparable cost test to be used actually to find those costs that are imprudent.

Some state commissions have developed a final outcome test that either implements or supplements the prudent investment test for the purpose of controlling the inclusion of excessive construction costs in rates. One example is the test applied by the Connecticut Public Utilities Control Authority (PUCA) at the behest of the state legislature. It sets a "cap," or a maximum final cost for which Connecticut ratepayers could be charged, for the Seabrook-1 nuclear unit.[37] Legislation provides that the cap could be exceeded to account for (1) an increase in the costs of labor and materials to the extent that such increase is due to an inflation rate above 10 percent per year, (2) an increase in financing costs related to an increase in the weighted average rate for allowance for funds used during construction above 10.25 percent per year, (3) any costs directly attributable to new regulations adopted by the Nuclear Regulatory Commission, and (4) any costs due to unforeseen and unavoidable labor

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[36]See KAN. STAT. ANNO. 66-128 (1984).

[37]"UI Proposal Would Restrict Return on Seabrook-1 Costs Topping $4.5 Billion," Electric Utility Week, September 24, 1984, pp. 6-7; and "UI Explains Proposal to Limit Return on Seabrook-1 Costs Topping $4.5 Billion," Electric Utility Week, October 1, 1984, p. 4.

stoppages.[38] The PUCA set the cap at $4.7 billion in direct construction costs.[39]

One year earlier, the Connecticut legislature had set a $3.54 billion cap on the recoverable investment in the Millstone-3 nuclear unit.[40] The PUCA, however, recently selected a consulting firm to conduct a retrospective prudence audit of the Millstone-3 nuclear plant. Thus, while it is not yet clear whether the cap is meant to supplement or supplant the prudent investment test in the Seabrook-1 case, it is clear that the PUCA views the construction cap as a supplement to the prudent investment test in the Millstone-3 case.[41]

The New York Public Service Commission set a cap on the Nine-Mile Point-2 nuclear plant. In this case, the Commission has made it quite clear that the cap and the rate-of-return incentive supplement (rather than supplant) the prudent investment test. The Commission indicated that any portion of the cost of the plant that is attributable to mismanagement will not be recoverable by the utility. The Commission has also indicated that it intends to have the staff conduct a comprehensive, retrospective prudence investigation of the Nine-Mile Point nuclear plant, similar in most respects to the Shoreham prudence investigation.[42]

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[38]"Conn. Legislature Triggers CWIP Law, Directs Limits on Seabrook-1 Cost," Electric Utility Week, May 7, 1984, pp. 1-2.

[39]See Re Construction Costs of Seabrook Unit No. 1, Docket No. 84-06-17, (Conn. DPUC, Sept. 27, 1984).

[40]Connecticut Public Act No. 83-99.

[41]See "Connecticut Commission Endorses Seabrook Unit Completion," Public Utilities Fortnightly, January 10, 1985, p. 52 and "Connecticut DPUC to Have Prudency Audit Conducted on Millstone Nuclear Plant," NARUC Bulletin, No. 50-1984, December 10, 1984, p. 24.

[42]"Gioia of New York Comments on New Niagara Mohawk Estimate of $5.1 Billion Cost of 9-Mile 2 Plant," NARUC Bulletin, No. 16-1984, April 16, 1984, p. 20.

The New York Public Service Commission's cap for the Nine-Mile Point-2 nuclear plant operates in conjunction with an incentive rate of return, imposed in 1982. The incentive rate of return requires that stockholders of the owner-utilities share 20 percent of all costs of Nine-Mile Point-2 in excess of $4.6 billion. Under the cap imposed by the Commission, the cost sharing ceases at $5.4 billion, and 100 percent of any additional costs is to be borne by the utility stockholders. The New York Commission held that the cap is neither unfair nor unlawful, because it is based on the utilities' own current cost estimate, which the Commission held to be reasonable, and includes an allowance for a 6-month delay in the currently estimated October 1986 operation date. The Commission explicitly recognized that, with a cap, the owner-utilities could bear a penalty for some potential cost overruns that are not within the control of the management (and hence could not be said to be imprudent). The Commission stated that, given (1) the advanced stage of the project, (2) the reasonableness of the cap figure, and (3) the public interest in having certainty about the maximum cost of the project, the imposition of such a risk on the utilities is reasonable. Nevertheless, the Commission would consider a petition from any party to increase or decrease the cap as a result of extraordinary events beyond the control of the utilities.[43]

New Jersey has also adopted a similar cap in its proceedings.[44] But, the reliance on the concept of prudence is unclear.

Final outcome tests for disallowance of utility investments may be justified on some basis other than prudence. Commissions have placed a cap

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[43]"New York PSC Agrees to Set Cap of $5.4 Billion on Costs Owners of 9-Mile Point 2 Can Pass to Customers," NARUC Bulletin, No. 28-1984, pp. 5-6.

[44]Gerald Charnoff, "Why Management Did It All Right: Overregulation and Other Acts of God," a paper presented to the Seventh Annual National Conference of Regulatory Attorneys (Madison, June 4, 1984).

on project costs without any reference to the prudence test. For instance, the California Public Utilities Commission has approved an 80-mile 500-kV line for the Southern California Edison Company, subject to a cap on its cost. Construction costs above the cap will not be recovered from ratepayers. The cap will be based on a cost estimate to be filed by the utility with the Commission, subject, of course, to Commission approval. The Commission will approve future adjustments in the cap only if the utility can show that (1) changes are needed, (2) the changes are cost effective, and (3) the changes are required by circumstances that were unforeseen at the time of the original estimate.[45]

Plant Abandonments

The most frequent application of the prudent investment test in recent years has been in the situation where a utility plant has been abandoned or cancelled. In this situation, commissions must decide whether to allow the utility to recover all, part, or none of its investment in cancelled plant. Unlike the cost overruns inquiries, these inquiries are usually not preceded by very extensive staff investigations.

Many cases involving abandoned or cancelled electric plants have been decided by state and federal commissions. Examples of recent commission actions in such cases appear in table 3-1. These examples, while not a comprehensive list, show the wide variety of regulatory treatments for abandoned or cancelled plant costs by state and federal commissions. The table contains information about thirty-one state commissions, the District of Columbia Commission, and the Federal Energy Regulatory Commission. It shows whether each commission typically allows any recovery of the costs of abandoned or cancelled electric plants and the number of years over which utilities have been allowed to amortize these costs. Also shown are whether rate base treatment of the unamortized balance is permitted and

[45]"PUC Okays 80-Mile-Long, 500-kV Line for Southern California Edison," Electric Utility Week, October 15, 1984, p. 11.

TABLE 3-1

EXAMPLES OF FEDERAL AND STATE COMMISSION ACTIONS
IN RECENT ABANDONED OR CANCELLED ELECTRIC PLANT CASES

State Agency by State	Whether Any Cost Recovery Is Allowed	Amortization Period in years	Treatment of Unamortized Balance	Treatment of AFUDC
Arizona	No	-----	-----	-----
California	Yes	4,5	No Return	Amortized, Disallowed
Connecticut	Yes	10	Return Allowed, No Return	Amortized
District of Columbia	Yes	10	Return Allowed	Amortized
FERC	Yes	5,10	No Return	Amortized
Idaho	No	-----	-----	-----
Indiana	Yes	15	No Return	Amortized
Iowa	Yes	5	Return Allowed	-----
Maine	Yes	-----	No Return	-----
Maryland	Yes	7,10	No Return	Amortized
Massachusetts	Yes	2,3,13	No Return, Levelized Carrying Charge on Non-AFUDC	Amortized only for Debt and Preferred Equity
Michigan	Yes	3,10	No Return	Amortized
Missouri	No	-----	-----	-----
Minnesota	Yes	-----	No Return	-----
Montana	No	-----	-----	-----
Nevada	Yes	-----	No Return	-----
New Hampshire	No	-----	-----	-----
New Jersey	Yes	15,20	No Return	Amortized
New York	Yes	3,5,10,15	Return Allowed	Amortized
North Carolina	Yes	5,10	No Return	Amortized
North Dakota	Yes	-----	No Return	-----
Ohio	No	-----	-----	-----
Oklahoma	Yes	10	Return on Debt and Preferred Equity	Amortized
Oregon	Yes	-----	No Return	Amortized, No Amortization
Pennsylvania	Yes	10	No Return	Amortized
South Dakota	Yes	5,--	No Return	Amortized
Texas	Yes	10	No Return	Amortized
Vermont	Yes	10	No Return	Amortized
Virginia	Yes	10,15	No Return	Amortized

TABLE 3-1--Continued

State Agency by State	Whether Any Cost Recovery Is Allowed	Amortization Period in years	Treatment of Unamortized Balance	Treatment of AFUDC
Washington	Yes	10	No Return	Amortized, No Amortization
West Virginia	Yes	10,20	No Return	Amortized
Wisconsin	Yes	5	No Return, Return Allowed	Amortized
Wyoming	No	-----	-----	-----

Sources: "DOE Sees Investors Shielded from 70% of Nuclear Unit Cancellation Costs," Electric Utility Week, May 30, 1983, pp. 8-9; Shippen Howe, "A Survey of Regulatory Treatment of Plant Cancellation Costs," Public Utilities Fortnightly, March 31, 1983, pp. 52-58; David Wagman, "NRRI Report: Many Commissions Deny Recovery Through Ratepayers of Investment in Cancelled Nuclear Plants," NRRI Quarterly Bulletin: No. 17, ed. Vivian Witkind Davis (Columbus: NRRI, 1984), at pp. 9-17; and updates from Electric Utility Week and Public Utilities Fortnightly.

whether allowance for funds used during construction (AFUDC) is includable in the cost to be recovered. The entries represent the results of one or more cases in each state listed. Hence, multiple entries can appear for a state, one for each case. Dashed lines indicate cases where the information is not applicable or not available. Actions for any one state tend to be uniform with respect to cost recovery, return on unamortized balance, and AFUDC, but vary considerably for the amortization period.

In most cases, the presumption of prudence operates to allow the recovery of costs sunk into an abandoned or cancelled plant. In general, state commissions have allowed recovery of the prudently incurred costs of an abandoned or cancelled plant, but have often divided the costs between the investor and the ratepayer by means of the treatment of amortization.

Many of the state commissions do not allow the unamortized balance of the investment in rate base, and some do not allow any cost recovery of the allowance for funds used during construction.

Most state commissions have permitted at least partial recovery of the costs of an abandoned or cancelled utility plant. For example, the Virginia State Corporation Commission found that the timing of a decision by the Virginia Electric and Power Company to cancel its North Anna-3 unit was not imprudent and that a recovery of some of the construction and cancellation costs should be allowed. While the utility had requested that it be allowed to amortize its investment of $481.7 million, the Commission only allowed a recovery of $258 million in costs. The company had also requested that a 10-year amortization period be used and that the company be allowed to earn a debt and equity return on the unamortized balance. The Commission was unable to find that the utility's actions were imprudent so as to disallow cost recovery for the cancelled plant. The Commission found, however, based on its own independent investigation, that the 1980 North Anna feasibility study was sufficiently flawed so that the Commission decided to increase the amortization period to shift more of the total cancellation costs onto the stockholders. Instead of the 10-year amortization period that the utility requested, the Commission imposed a 15-year amortization period and denied any return on the unamortized balance. The 15-year period almost equally divided the cancellation costs between ratepayers and stockholders.[46] Thus, although no imprudence was explicitly found, the shareholders were required to bear at least part of the cancellation costs of North Anna-3.

The New Jersey Board of Public Utilities (NJBPU) has also recently allowed recovery of a cancelled plant based on its finding that the expenditures in the plant were prudently incurred. In 1982 the NJBPU

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[46]See Virginia State Corp. Commission v. Virginia Electric & Power Co., Case No. PUE830041 (March 27, 1984); see also, "Recovery of Nuclear Plant Cancellation Costs Allowed," Public Utilities Fortnightly, May 24, 1984, pp. 58-59, and Electric Utility Week, April 18, 1983.

approved the recovery of $12.5 million for the abandonment costs associated with the Sterling nuclear plant, amortized over a 20-year period, in keeping with the NJBPU's policy that the prudently incurred investments in an abandoned plant should be recoverable. In a recent case, the NJBPU refused to shorten the amortization period, but did add $1.5 million to the amount recoverable to reflect the additional abandonment costs incurred since its initial decision in 1982.[47]

The NJBPU also found that the decisions to start and then to abandon the construction of the Hope Creek-2 nuclear unit were prudently made. The NJBPU allowed the abandonment costs to be recovered over a 15-year period, with no return allowed on the unamortized balance. The investors, in being denied further returns on the unamortized balance of their investment after the plant was abandoned, are thus required to share the loss with ratepayers.[48]

However, in other cases, state commissions disallowed the recovery of part or all of the costs of an abandoned or cancelled plant because of imprudence in the timing of the decision. For example, in a Commonwealth Electric Company case,[49] the Massachusetts Department of Public Utilities denied recovery of costs of a plant because it judged that the plant should have been abandoned sooner; it held that costs beyond the time that the plant should have been abandoned were imprudently incurred. In another similar case, the Texas Public Utility Commission disallowed $195 million

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[47]"New Jersey BPU Authorizes Rockland Electric Rate Increase," <u>NARUC Bulletin,</u> No. 32-1984, August 6, 1984, pp. 11-12.

[48]"New Jersey BPU Finds Hope Creek 2 Nuclear Plant Abandonment Prudently Made," <u>NARUC Bulletin,</u> No. 12-1982, March 22, 1982, pp. 13-14. Also see, in the Matter of Utility Construction Plans, Docket No. 8012-914 (NJBPU, April 1, 1982).

[49]In re Commonwealth Electric Co., 47 PUR4th 229 (1982).

of the $361 million invested in an abandoned plant on the basis that the utility was imprudent in not abandoning the plant sooner.[50]

In another case that relied on the concept of prudence, the New York Public Service Commission (NYSPC) denied full recovery to the Long Island Lighting Company and the New York State Electric and Gas Corporation of costs related to the planning and attempted licensing of the New Haven nuclear power facility. Instead, the NYPSC disallowed 30 percent of the costs incurred by the utilities on the grounds that the companies were imprudent in pressing for licensing of the plant in 1978, when a declining growth rate should have led them to conclude that the plant would not be needed.[51]

In a case decided in 1984, the Idaho Public Utilities Commission refused to allow the Idaho Power Company to charge ratepayers for $11.9 million of the $14.1 million that it had spent in the 1970s on the cancelled Pioneer coal-fired plant. In 1976, the Idaho Public Utilities Commission had turned down the siting application for the plant, but the company had previously entered into contracts requiring subsequent expenditures.[52] The Commission did not allow recovery of any expenditures incurred after January 13, 1975, the date of the first public hearing on the plant. From that time on, according to the Commission, the company was on notice that there was opposition to its siting application, and the only reasonable further expenditures were those associated with processing the application, not those associated with the construction of the plant.

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[50]In re Houston Lighting & Power Co., 50 PUR4th 157 (1982).

[51]Re Long Island Lighting Co. and New York State Electric and Gas Corp., Case 27811, Opinion No. 84-25 (NYPSC, 1984); and "Commission Limits Recovery for Suspended Nuclear Project," Public Utilities Fortnightly, December 6, 1984, pp. 64-65.

[52]See "Idaho PUC Limits Cost Recovery for Abandoned Generator," NARUC Bulletin, No. 32-1984, August 6, 1984, pp. 18-19.

Prudence issues have also arisen in federal cases associated with whether construction work in progress (CWIP) can be included in rates for a cancelled plant or for a plant on which construction has been suspended. This issue has arisen under the Federal Energy Regulatory Commission's current CWIP rule, which permits an electric utility to include 50 percent of its prudently incurred construction costs in rate base, subject to a limitation that the CWIP increase cannot exceed 6 percent of the utility's wholesale revenues. For example, an FERC administrative law judge held that it is "unreasonable" to include construction work in progress in rate base when construction on a plant (Seabrook-1) has been formally suspended and there is no assurance that the plant would ever be completed.[53]

In another FERC case, an administrative law judge held that the New England Power Company cannot charge its ratepayers for costs associated with the abandoned Pilgrim II nuclear power plant incurred before July 1980 because the New England Power Company had been imprudent in investing in the plant. According to the administrative law judge, the New England Power Company had been imprudent because it had accepted the terms of the Pilgrim-II Joint Ownership Agreement, which constrained the New England Power Company, a minority participant in the project, from exercising any control over the actions of the lead utility, the Boston Edison Company. The New England Power Company had also given up its right to sue the Boston Edison Company for losses caused by the mistakes, mismanagement, or misconduct of Boston Edison.[54]

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[53]New England Power Co., Docket No. ER83-674-005 (FERC ALJ, June 20, 1984). The joint owners of the Seabrook nuclear project have since voted to restart the construction of the Seabrook-1 unit, under a newly-formed division of the Public Service Company of New Hampshire called New Hampshire Yankee. The joint owners planned to have New Hampshire Yankee become a separate, independent company, presumably under the jurisdiction of the Federal Energy Regulatory Commission. See "New Hampshire: Seabrook Construction to Resume," Public Utilities Fortnightly, August 2, 1984, pp. 47-48.

[54]See Re New England Power Co., FERC Docket No. ER82-703-000, (FERC ALJ., May 4, 1984); also see "Cancelled Plant Costs Denied under Joint Participation Agreement," Public Utilities Fortnightly, June 21, 1984, pp. 66-67.

In other cases, where utilities have relied on the prudence test for inclusion of abandoned plant costs, courts or commissions have applied the "used and useful" test to prevent ratepayers from bearing any of the costs associated with such plant. A leading case in this regarding is the case of Consumer's Counsel v. Public Utilities Commission.[55] This case was discussed in detail in an earlier National Regulatory Research Institute report,[56] but the highlights of the case are mentioned here. In the case, the Ohio Supreme Court held that the Ohio Commission had exceeded its statutory authority when it approved amortization of an investment in four terminated nuclear plants on the basis of utility prudence. As stated in the Institute report:

> While the case was actually determined on the issue of whether the cancelled plant expenditures represent "the cost to the utility of rendering the public utility service for the test period" as required in Ohio's statutory language, the court set the test period considerations aside in its reasoning and disallowed the amortization on the grounds that the investment never provided anyservice whatsoever to the utility's customers. Thus, the disallowance of the utility investment as an expenditure that could be amortized was based on a theory somewhat akin to the "used and useful" doctrine, which concerns the inclusion of plant in rate base....And while the Ohio Supreme Court based its decision on an Ohio statute, other states have similar statues requiring plants to be "used and useful" in order to be included in the rate base.[57]

Several other states have used a similar rationale. For instance, the Montana Public Service Commission denied the Pacific Power and Light Company any relief associated with the company's investment in the Pebble Springs and the WPPSS-5 nuclear power projects. The company claimed recovery on the basis of prudence. The Commission, in denying recovery,

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[55]Consumers' Counsel v. Pub. Util. Comm., 67 Ohio St. 2d 153 (1981).

[56]Russel J. Profozich et al., Commission Preapproval of Utility Investments (Columbus: NRRI, 1981).

[57]Ibid., pp. 28-29.

determined that the appropriate test for recovery was not the prudent investment test, but was rather whether the projects were actually used and useful for the convenience of the public. In reaching its conclusion that no recovery would be allowed because the plant was not used and useful, the Commission reasoned that the utility shareholders risk not only the possibility that they may not earn a return on their investment, but they risk their initial investment itself if the project does not become used and useful. To hold otherwise would allow a utility's shareholder to have an investment that was risk-free or subject to only a limited risk.[58]

The Missouri Public Service Commission based its denial of recovery for the cost of the cancelled Callaway-2 nuclear unit on the language contained in the "Proposition One" initiative that was approved by voters in 1976 to ban construction work in progress. The operative language in Proposition One is that any "cost associated with owning...or financing any property before it becomes fully operational and used for service is unjust and unreasonable and is prohibited." The Missouri Public Service Commission interpreted this language as prohibiting any recovery of cancelled plant, whether prudently decided or not, if the plant is not used for service.[59]

One state, which has in the past applied the prudent investment test in an attempt to balance investor and ratepayer interests when a plant is cancelled or abandoned, has recently announced a change of policy. The Massachusetts Department of Public Utilities (DPU) has stated that the used-and-useful test will be used instead of the prudence test, at least for certain applications. If an electric plant on which construction is

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[58]See "Montana PSC Denied Pacific P&L Rate Relief for Two Abandoned Nuclear Projects," NARUC Bulletin, No. 19-1983, May 9, 1983, pp. 10-11; see also Pacific Power & Light, 53 PUR4th 24 (Mont. PSC, 1983).

[59]See In re Union Electric Company, Case No. ER83-163 (Mo. PSC, 1984); see also "PSC Denies U.E. Cancelled-Plant Recovery; Missouri 'Proposition One' Strikes Again," Electric Utility Week, October 31, 1984, pp. 1-2.

begun after July 31, 1984 is cancelled or abandoned, the utility will bear the entire risk of loss.[60]

Capacity Additions

For the most part, state commissions have been reluctant to use the prudence test to overrule capacity addition decisons. For example, the Michigan Public Service Commission held in a recent case that the decision by Detroit Edison to initiate the Greenwood-2 and -3 nuclear project was reasonable and prudent:

> The decision of applicant's [Detroit Edison's] board of directors to initiate the project was based on a load forecast issued in April, 1971. This forecast projected a summer peak demand of 11,650 megawatts in 1980. In mid-1971, applicant's installed generating capacity was 6,844 megawatts. The load forecast was based on an assumed continuation of historical load growth of 7.1 percent compounded annually.[61]

The initial projected growth rates were not realized. However, the Commission refused to substitute its judgment for that of the utility's planning department, which continued to find that the Greenwood project was needed until the units were abandoned in 1981. The Commission held that the utility's decision in 1978 to resume construction of the Greenwood project, after several years of suspension due to financing problems, was prudent given the facts as they existed at the time.[62]

Also, the Public Utilities Commission of Ohio, in determining whether the Dayton Power & Light Company had excess capacity, recently found that "[t]here had been no showing that applicant's [Dayton Power & Light's]

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[60]See In Re Western Massachusetts Electric Co. MassDPU Order 84-25 (Mass. DPU, 1984); See also "Mass. Bars Abandonment Cost Recovery for Plants Begun After July 31, 1984," Electric Utility Week, August 6, 1984, pp. 1-2.

[61]Re Detroit Edison Company, 52 PUR4th 318, 324 (Mich. PSC, 1983).

[62]Id., p. 325-328.

capacity planning has, in any way, been imprudent."[63] This indicates again that state commissions are reluctant to find that decisions based on a utility's demand forecast and capacity planning process are imprudent.

Many commissions hold that as long as "state-of-the-art" demand forecasting methods are used there should be no finding of imprudence. In short, the mere existence of excess capacity is not necessarily indicative of an imprudent demand forecasting or capacity planning process (the decision-making process), which is the subject of a prudence investigation. As the Iowa State Commerce Commission put it:

> extremely sophisticated forecasting methods are of recent origin and were not generally available for use during the time company's planning decisions were being made [for plants now being brought into service].[64]

But several state commissions also held that the question of prudence applies not only to the initial investment decision but also to decisions made (or not made) during construction about the continuing need for additional power. In this view, use of the prudence test requires an examination of management's ongoing decision-making process. As stated by the Iowa State Commerce Commission:

> The prudency of the management decision to invest in plant at the time the decision was made is a factor in the balancing process, but does not immunize company from penalties for excess capacity....The prudency test is a factor in balancing because public policy requires a reasonable amount of leeway in the management decision-making process; their decisions should be respected by us so long as the end result of those decisions is consistent with public policy. However, management of [a] company is under a continuing duty to reevaluate the prudency of its decisions and to readjust its actions accordingly, and thus, the prudency of the decision at the time the decision was made cannot end our inquiry.[65]

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[63]Re Dayton Power and Light Co., 45 PUR4th 549 (1982).

[64]Re Iowa Power & Light Co., 51 PUR4th 405, 411 (1983).

[65]Id., p. 412. Also see Re Iowa Public Service Co., 46 PUR4th 339, 368 (Iowa CC, 1982).

This responsibility to reevaluate initial decisions in light of changed circumstances is, of course, related to the responsibilities set out in the previous discussion of plant abandonments and cancellations. A failure to cancel a project that was prudently initiated, after it is no longer prudent to continue the project, can result in a finding of imprudence.[66]

Many commissions have dealt with excess capacity questions in cases where utilities have defended the resulting capacity on the basis that it resulted from prudent decision making.[67] However, at least two commissions have found a utility's capacity planning process to be imprudent. In one instance, the Florida Supreme Court upheld the Florida Public Service Commission's decision to exclude the Gulf Power Company's 50 percent interest in a coal-fired unit from rate base because of imprudent management decisions related to faulty load forecasting that failed to recognize that excess capacity would result from the capacity addition.[68]

In another case, the California Public Utilities Commission assessed a $14.4 million penalty against the Pacific Gas and Electric Company for its failure to pursue rigorously cogeneration as an energy source. The finding was based, in part, on a computer model for resource planning analysis introduced by an intervenor, the Environmental Defense Fund. The company's resource planning process was judged against the EDF resource planning analysis and was found to be inadequate in its treatment of cogeneration as

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[66]See Re Rochester Gas & Electric Corp., 41 PUR4th 438 (N.Y.P.S.C., 1981); Boston Edison Co., PUR4th 431 (Mass. DPU, 1982): Re Iowa Public Service Co., 46 PUR4th 339 (Iowa CC, 1982); and Re Wisconsin Electric Power Co., [Current State Decision] Util. L. Rep. Para. 23,557 (Wis. PSC, 1981).

[67]Alvin Kaufman, Kevin Kelly, and Ross Hemphill, Commission Treatment of Overcapacity in the Electric Power Industry (Columbus: The National Regulatory Research Institute, 1984).

[68]See Gulf Power Co. v. Florida Pub. Service Commission, 453 So.2d 799 (Fla., 1984); and "Court Upholds Rate Base Adjustment for Excess Capacity," Public Utilities Fortnightly, November 22, 1984, p. 69.

an energy source.[69] The case may serve as a warning that, as the state-of-the-art of demand forecasting tools and capacity planning models improves, utilities will be expected to keep pace with these developments in order to be adjudged prudent in their planning decisions.

Natural Gas Applications

Few state commission applications of the prudence test to the natural gas industry were found. However, states have a keen interest in the federal level findings of prudence (reported in chapter 2) regarding the gas purchase practices of interstate pipelines. In particular, many states question the prudence of various producer-pipeline contracts containing take-or-pay, third-party most-favored nation, and oil parity clauses, and lacking market-out clauses.

One example of a gas-related prudence inquiry is the actions of the Attorney General of Alaska before the Federal Energy Regulatory Commission and the Alaska Public Utilities Commission alleging that $1.6 billion of the $8 billion expenditures associated with the Trans Alaska Pipeline System were the result of managerial imprudence. The case involves an assessment of historical facts, which has utilized 600,000 records and has required a computerized document retrieval system. A computer model calculated the portion of costs attributable to the underutilization of construction equipment.[70]

Another example concerns a synthetic natural gas (SNG) plant being mothballed, that is, at least temporarily abandoned. It is the Marysville plant owned by the Consumers Power Company in Michigan. In the mid-1970s, the Marysville plant was an operating plant producing SNG from imported liquefied petroleum gas feedstocks. However, gas from other, less expensive

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69"California PUC to Compensate Environmental Defense Fund for Participation in PG&E Case," NARUC Bulletin, No. 38-1984, September 17, 1984, p. 10.

70Speck, "Proving Imprudent Management," pp. 6-7.

sources became available as natural gas supplies increased under the NGPA. As a result, Consumers Power Company announced that it intended to mothball the Marysville SNG plant for an indefinite period beginning in late 1979.

The Michigan Public Service Commission, in a subsequent case, excluded the Marysville SNG plant from rate base because the plant was incapable of responding to a short term gas supply disruption and was therefore not used and useful. However, the plant was being preserved in a mothballed state as insurance for ratepayers against future long term supply shortages. The Commission decided that this was a prudent utility decision and allowed the utility to recover the surveillance, upkeep, and mothballing costs of the plant. The Commission thus used a variety of regulatory tools--the used-and-useful test, the prudence test, and "a balancing of interests test"--to reach its decision.[71]

The concept of prudence was applied in an "informal" plant abandonment associated with a liquefied natural gas facility--the plant construction suspension of the Point Conception liquefied natural gas (LNG) terminal in California. This project was undertaken as a part of a plan by the Southern California Gas Company and the Pacific Gas and Electric Company to ship LNG from Indonesia and Southern Alaska to California. However, because of the increased availability of natural gas supplies (and the resulting decreased demand for more costly gas, such as LNG), the companies suspended construction of the plant. They then filed applications for a partial recovery of construction costs, including a return on allowance for funds used during construction, while also seeking authority to be allowed to resume construction at some later date when the demand for more costly gas might be greater.

The California Public Utilities Commission found that the management decisions to initiate the project and later to suspend construction were prudent when made and, therefore, gave the utilities two options. The

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[71]Re Consumers Power Company, 52 PUR4th 536 (Mich. PSC, 1983).

first option was that the companies might decide formally to abandon the plant, in which case the utilities would recover the direct project expenditures without AFUDC. The second option was that the companies might take up to 3 years to reevaluate the feasibility of the project, during which time the project site might be included in rate base as plant held for future use, with the direct costs of the plant to be partially recovered over a 4-year amortization period. The Commission made it clear that it would not allow recovery of AFUDC unless the plant comes into service and, hence, becomes used and useful.[72]

Summary and Discussion

The examples in this chapter illustrate that the use of the prudent investment test is indeed an emerging area of regulatory law. In conducting a prudence inquiry, a state commission may wish to assure that certain guidelines are followed. Initially, the burden of proof rests with the commission, staff, or other interested party to show that the utility's decision should not be presumed to be prudent. Once the presumption of prudence is rebutted, a commission is then prepared to examine the prudence of that decision. The decision should be judged on the basis of an objective test of reasonableness under the circumstances. Further, the commission's judgment must not rely on hindsight for determining whether the utility made a reasonable decision. Then, a factual inquiry into the circumstances in effect at the time of that decision is required. The final outcome of the decision ought not to matter. However, decisions made by the utility along the way, after the initial decision to make the investment, are properly part of a prudence inquiry. As a result, the commission needs to be specific about which decision (or decisions) is the subject of the investigation and about when the decision was made.

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[72]See Re Southern California Gas Co., Decision No. 84-09-089, Application Nos. 82-12-02 et seq. (Calif. PUC, Sept. 6, 1984), and "Temporary Rate Base Treatment Buys Time for Feasibility Review," Public Utilities Fortnightly, November 8, 1984, p. 66.

The use of the prudence concept is not a simple solution to a complex issue; instead, the determination of prudence may be quite complex. Commissions often rely on an extensive staff investigation to develop the evidence needed to judge prudence. It should be recognized that substantial resources might be necessary to conduct such an investigation. The use of consultants may be required, particularly if the investigation involves a nuclear power plant.

Several state commissions have conducted staff investigations to assess what portion, if any, of construction cost overruns for a plant about to come into service is the result of imprudence. These studies have been lengthy and expensive. They require an examinination in detail of the facts and circumstances known at the time a decision was taken. From these, the state commission obtains the information that allows a judgment about how much of the investment in plant ought to be allowed in rate base.

In varying degrees, commissions are relying on the test of reasonableness under the circumstances to adjudge prudence. Some use the test explicitly. Others may use this test together with some consideration of the final outcome of management decisions. Thus, it is difficult in practice to determine how closely commissions follow our "proscription against hindsight" guideline--especially in the construction cost overruns cases where the objective is not simply to judge prudence but also to determine the cost consequences, that is, the final outcome, of poor decisions.

In construction cost overruns inquiries, use of the prudent investment test may be said to work against utility interests in that the used-and-useful standard alone, depending on how it is interpreted, might lead to full cost recovery for an operating generating station. The opposite is usually the case where the prudence test is applied to abandoned plant. Here, utilities often introduce the prudent investment test in defense of their decisions.

The prudent investment test has recently been used most frequently by utilities to recover a portion of the costs of their cancelled or abandoned plants. In most cases where the prudent investment test has been utilized, the presumption of prudence has been applied to allow a utility to recover most of its investment. When recovery has been allowed, many state commissions have allowed the amortization of the costs over a period of years and have denied the utilities rate base treatment of the unamortized cost. This treatment of cancellation costs, in effect, divides the costs of an abandoned or cancelled plant between the ratepayers and utility investors. However, the prudence test does not always work in utility favor in these cases. Some commissions have denied recovery of the costs of an abandoned or cancelled plant based on a finding of imprudence. Frequently in such cases, commissions cite both prudence and used and useful as concepts that contribute to their findings.

The alternative to plant abandonment, of course, is to continue construction of the plant to completion. The prudent investment test has not been used very often for finding imprudence in electric utility decisions involving capacity additions. Presumably, utilities have decided to abandon plants in cases where they were clearly not required and have decided to continue construction in cases where plants are clearly needed or where the need is unclear. The latter situation may not lend itself to application of the prudence test. Further, if completed plants result in excess capacity, the used-and-useful test may more often form the basis of commission decisions than the prudence standard. However, prudence could be applied more in the future as state commissions expect that utilities will use state-of-the-art forecasting and capacity planning methods.

The prudent investment test, as applied by state commissions, has not been a test of whether the optimal or least-cost strategy was followed. Commissions do not necessarily require that the "best" investment decisions be made. They distinguish between the less-than-optimal investment decision that still may be prudent and the truly imprudent investment decision. The prudent investment test provides state commissions with the rationale and the regulatory tool for making this distinction.

CHAPTER 4

THE PRUDENCE TEST AS A REGULATORY TOOL IN A PERIOD OF HIGHER RISK

For energy utilities, particularly electric utilities, the environment for investment decision making has been riskier over the last 10 to 15 years than in the past. These risks relate primarily to uncertainty about costs, especially capital and fuel costs; uncertainty about demand growth rates; and uncertainty about the supply of generation capacity that needs to be built for the future. Because the environment is more risky, the chance for error in utility planning is greater. Stated another way, the opportunity for making an imprudent decision has been much greater recently than before.

The riskier environment is likely to continue as energy markets adjust to a new and larger role in the national and world economies. For electric utilities, this role reflects the current high cost of fuels and electric generation capacity and the intervention (or withdrawal) of the national government in energy markets, as well as the increasingly international character of energy markets and cartels.

As a result, an electric utility may choose to construct capacity that turns out to be too costly or that runs on fuel that is either too expensive, prohibited, or embargoed. Also, the capacity may be unneeded, either because demand is less than expected or because the utility is required to take power from a PURPA qualifying facility or, perhaps in the future, from a regional power pool with a lower energy cost. Gas utilities also face greater risks as wellhead deregulation proceeds and competition with other energy sources becomes commonplace.

Not only is the opportunity for error greater today, but--because of very high capacity costs--the consequences of error are greater also. Who suffers the consequences--utility customers or utility investors--becomes a more important issue as the stakes grow higher.

Regulatory commissions, therefore, recently looked for a sound criterion for resolving this issue and found it in the prudent investment test. Clearly, however, the degree of detail in applying the test reported in chapter 3 goes well beyond that envisioned in the original Brandeis test reported in chapter 2. The prudence test is an evolving area of regulatory law, and the change in risk environment is a main cause of this evolution.

In this chapter, we treat the main features of today's riskier environment for electric and gas utilities, demonstrate that the consequences of error have been greater recently than in the past, and discuss the emerging role of the prudent investment test as a regulatory tool in this more risky environment.

A Riskier Investment Environment

The various factors affecting the risks associated with electric utility generating capacity investment might best be taken up according to whether they result primarily in capital cost uncertainty, demand growth uncertainty, or supply uncertainty. Of course, these are all ultimately related in that anything raising capital costs tends to dampen electric demand and to stimulate the supply of cogeneration capacity.

For gas distribution utilities also, the risks have increased, especially since the enactment of partial wellhead price decontrol in 1978, the main effects of which may be felt following the two stages of decontrol in 1985 and 1987. Nevertheless, the examples in this chapter deal only with electric utilities.

Capital Cost Uncertainty

As electric utilities plan coal and nuclear generating capacity, there is uncertainty about the ultimate cost of the completed plant. The costs of completing the average U.S. nuclear or coal power plant have escalated tremendously over the last 10 years. As shown in table 4-1, the average costs of constructing a nuclear power plant increased in constant 1982

TABLE 4-1

AVERAGE U.S. NUCLEAR AND COAL POWER PLANT CONSTRUCTION COSTS IN CONSTANT 1982 $/kW, WITHOUT ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION

	Nuclear	Coal
Completed at the end of 1971	435	415
Completed at the end of 1978	1020	685
To be completed in 1982 or thereafter	2100	800-900

Source: Charles Komanoff, Komanoff Energy Associates, "Assessing the High Costs of New U.S. Nuclear Power Plants," a paper presented to the Seventh Annual National Conference of Regulatory Attorneys (Madison, Wisconsin, June 5, 1984), table 2.

dollars from $435 per kilowatt of capacity for nuclear plants completed at the end of 1971 to $2,100 per kilowatt of capacity for plants completed in 1982 or then under construction and to be completed thereafter. In other words, the construction costs of an average U.S. nuclear plant rose 482 percent over 10 years. The construction costs of completing a typical coal plant increased from $415 per kilowatt to $800-900 per kilowatt in constant 1982 dollars, an increase of approximately 100 percent. The entries in table 4-1 include construction costs only and do not include AFUDC. Because of the lengthening construction period for nuclear power plants and the recent high cost of capital for most projects, incorporating real AFUDC would further add to cost differences between old and new nuclear power plants, as well as to the differences between nuclear and coal power plants. According to one estimate, real AFUDC adds 30 to 40 percent to the cost of nuclear power plants and 15 percent to that of coal power plants to be completed in 1982 or thereafter.[1]

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[1]Charles Komanoff, "Assessing the High Costs of New U.S. Nuclear Power Plants," a paper presented to the Seventh Annual Conference of Regulatory Attorneys (Madison, Wisconsin, June 4, 1984). Komanoff also estimates that real AFUDC adds approximately 8 percent and 6 percent, respectively, to the costs of the typical 1971 nuclear and coal power plants, and 11 percent and 9 percent to those of the typical 1978 nuclear and coal power plants.

This recent uncertainty in ultimate cost of generating unit construction is due, in part, to environmental regulation of coal units and safety regulation of nuclear units. In some cases, it may also be due, in part, to inadequate management attention to cost control procedures.

Environmental Regulation of Coal Units

Environmental regulation of coal units has affected and continues to affect the degree of utility confidence in capital cost estimates for such units. While national air quality control legislation in the United States was first enacted with the Clear Air Act of 1963, the most important air pollution control legislation was the Air Quality Act of 1967 and the Clean Air Act Amendments of 1970. They authorized the U.S. Environmental Protection Agency (EPA) to promulgate regulations with these objectives: (1) to achieve a level of ambient air quality that would protect the public health; (2) to achieve a level of an ambient air quality that would protect the public welfare from any known or anticipated adverse effects; and (3) to prevent the significant deterioration of air quality in those areas where the air is already clean. State agencies could also determine and enforce their own ambient air quality standards as long as they are as strict or stricter than the U.S. EPA standards.

At first, the promulgated EPA air quality standards did not specify the emissions of particular power plants as long as adjacent air quality remained within specific limits. The utilities were thus allowed to dispatch units using an intermittent control system that monitored the ambient quality and curtailed the "dirtiest" coal and oil plants during the periods of highest pollution.

Under the 1970 act, the U.S. EPA established "New Source Performance Standards" (NSPS) as the pollution standards for new plants. The EPA set the NSPS in terms of absolute ceilings on the volume of pollutants per unit of output. For coal plants, these ceilings were set at certain acceptable levels of sulfur oxides, nitrogen oxides, and particulates per million BTU.

The absolute ceilings for pollutants were set to reflect the "best available control technology" for removing the pollutants. However, under this set of regulations, fuel switching from high sulfur coal or oil to low sulfur coal or oil was permitted.

In 1977, the Congress enacted further amendments to the Clean Air Act. The 1977 amendments require that pollutants in a fuel must be reduced by at least a specific percentage, which usually requires scrubbers to be used, regardless of the quality of the fuel burned. For new plants being built in areas that already have "clean air" (PSD areas), installation of the best available control technology is required.

Many electric utilities engaged in litigation to block implementation of the NSPS standards. When these attempts failed, they were forced to consider how to comply. For plants not subject to the 1977 amendments, the choice for meeting the new standards was principally between raising the stack heights and switching from high to low sulfur coal or oil. For plants subject to the 1977 amendments, utility managers were forced to redesign their plants so that stack scrubbers, baghouses, or other pollution control technologies could be fitted in. A few utilities found that they needed to retrofit plants under construction with scrubbers.

Managers of electric utilities constructing coal plants adapted to these changes in environmental regulations in the 1970s and early 1980s. Problems associated with burning low sulfur coal were learned about through actual experience. Solutions were eventually found, but at a cost. Switching to low sulfur coal in a plant designed for high sulfur coal can adversely affect power plant performance and may require substantial investments in the boiler and boiler auxiliaries. Burning low sulfur coal may also require additional coal preparation and handling and may require an electrostatic precipitator for particulate emissions control. The extra expense for low sulfur coal is estimated to exceed $100 billion (at 1982 prices) during the period from 1980 to 1999.[2]

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[2]Eugene M. Trisko and Robert E. Wayland, "Acid Rain Control and Public Utility Regulation," Public Utilities Fortnightly, August 30, 1984, pp. 15-22.

The costs of complying with the EPA's environmental regulations have been great. For the plants that were subject to the more lenient regulations in effect until the 1977 amendments to the Clean Air Act, the cost of complying were relatively modest. However, for the plants subject to regulations implementing the 1977 amendments to the Clean Air Act, the costs of complying with the environmental regulations have been and continue to be substantial. As shown in table 4-2, (according to Canaday) the real increase in plant costs due to changes in environmental regulations explains the bulk of construction cost overruns in the construction of a typical new coal plant.[3] Thus changes in environmental regulations have affected the ability of management to estimate correctly the construction cost of a coal plant.

TABLE 4-2

TYPICAL COAL PLANT
CONSTRUCTION COST OVERRUNS, BY CAUSE
(Expressed as a Proportion of the Original Estimate)

Original Estimate	1.00
Unanticipated Inflation	.14-.38
Total AFUDC Increase	.10
Real Increase in Plant Costs Due to Changes in Enviromental Regulations	.40-.65
Total	1.64-2.13

Source: Henry T. Canaday, Construction Cost Overruns in Electric Utilities: Some Trends and Implications (Columbus: The National Regulatory Research Institute, 1980), table 20, p. 32.

[3]Henry T. Canaday, Construction Cost Overruns in Electric Utilities: Some Trends and Implications (Columbus: The National Regulatory Research Institute, 1980), pp. 30-32.

Future regulations are likely to contribute to further uncertainty in new coal plant costs. The most recent controversy before the Congress concerns the reduction of acid deposition ("acid rain"). Some of the legislative proposals before the last session of Congress, in effect, called for retrofitting emission control devices onto existing, pre-1976 coal plants. While utility managers have learned through experience how a scrubber system can be carefully matched to boiler equipment and how to maintain scrubber systems for successful operation, only a few utilities have experience in retrofitting scrubbers. As noted above, switching from high to low sulfur coal often lowers plant performance. For some coal-fired boilers, including most wet-bottom and cyclone boilers, burning low sulfur coal is not technically feasible. Emerging emission control technologies will give utilities new options including wet limestone, advanced dry scrubbing systems, and coal washing. Future options might also include inter-utility emissions trading, early plant retirements, and a return to dispatching plants so as to minimize pollution emissions.

The capital and operating cost consequences of possible new legislation are uncertain. To date, the Congress has merely provided for further study of the acid rain issue. But, future legislation in this area is decidedly possible, and this creates uncertainties for utility decision makers regarding the minimum cost approach for future coal-fired generation. Utilities cannot be certain whether they should refurbish an existing coal plant to extend its useful life. They cannot forecast with assurance the cost of future coal-fired generation, which may depend on the cost of low sulfur coal. Furthermore, utilities cannot be certain of the capital cost of a future coal plant. As a result, optimal capacity expansion plans are uncertain.

Safety Regulation of Nuclear Units

Safety regulation of nuclear units has affected and continues to affect the degree of utility confidence in capital cost estimates for such units.

At least at first, the Atomic Energy Commission (AEC), the predecessor agency to the Nuclear Regulatory Commission (NRC), deferred to nuclear industry judgment both as to design and protection of the public health and safety. As the nuclear power industry grew, it became apparent that a greater degree of regulatory oversight would be necessary to assure the public safety. As a result the AEC, and then the NRC, expanded the scope of its regulation during the 1970s and 1980s. The importance of assuring the public health and safety was reaffirmed by the Congress in 1974 when the regulatory functions of the AEC were transferred to the Nuclear Regulatory Commission.

It is well known that the NRC licensing process for a utility constructing a nuclear power plant is complex. Opportunities exist at several stages in the process for objection, delay, and possibly redesign of the plant; these factors contribute to capital cost uncertainty.

The process was summarized well in a recent report by the Office of Technology Assessment,[4] which deals with the uncertainties associated with nuclear power and from which we abstracted the following brief review of the regulatory process. The process involves a lengthy initial planning stage before the utility files a construction permit application with the NRC. The construction permit application includes (1) a Preliminary Safety Analysis Report, (2) an Environmental Report, and (3) antitrust information. On receipt of the construction permit application, the NRC staff reviews it for completeness and requests any additional information that may be necessary. When the staff is satisfied that the application is complete, the application is docketed. Then, the NRC staff issues a notice that it will hold a hearing on safety and environmental issues associated with the proposed plant before the Atomic Safety and Licensing Board of the NRC.[5]

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[4]Office of Technology Assessment, Nuclear Power in an Age of Uncertainty, (Washington, D.C.: U.S. Congress, Office of Technology Assessment, OTA-E-216, February 1984), p. 144.

[5]The following description of the NRC licensing process concentrates on procedures for assuring safety rather than those dealing with environmental issues.

In the meantime, the NRC's Office of Nuclear Reactor Regulation reviews the construction permit application and compares it to the standards in the NRC's "Standard Review Plan." The NRC Office of Nuclear Regulation suggests design changes to the utility. If the suggested design changes are rejected by the utility, the Office of Nuclear Reactor Regulation issues a Safety Evaluation Report documenting the suggested design changes that are disputed by the utility. The NRC's Advisory Committee on Reactor Safeguards also reviews and comments on the application. The NRC staff is free to supplement its Safety Evaluation Report with issues raised by the Advisory Committee on Reactor Safety. The review process that results in the preparation of the staff's Safety Evaluation Report, during the 1970s, took 1 or 2 years.

After the staff's Safety Evaluation Report (along with an associated Environmental Evaluation Report) is completed, a hearing is held on safety and environmental issues before the Atomic Safety and Licensing Board.[6] The hearing is adjudicatory in nature and involves direct testimony and cross-examination. After the hearing is completed, the Atomic Safety and Licensing Board issues its initial decision on whether to grant the construction permit. Upon appeal by one of the parties in the proceeding or on its own motion (an investigation sua sponte), the initial decision can be reviewed by the Atomic Safety and Licensing Appeal Board. Further, an appeal is possible to the Nuclear Regulatory Commissioners. In fact, since the accident at Three Mile Island, the initial decision on a construction permit must be approved by the Nuclear Regulatory Commissioners before it becomes final.

Once the construction permit is issued, actual plant construction begins.[7] During plant construction, the NRC staff conducts tests and

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[6]The hearing can be split into two hearings, one on environmental issues and another on safety issues.

[7]Site preparation has usually already taken place before the construction permit is issued. It usually occurs after the limited work authorization is issued.

construction inspections. There may be additional backfitting orders by the NRC during plant construction or further modifications to the design requested by the utility.

Only when the construction of the plant is completed is the plant design considered final. Then the utility files an application for an operating license. As a part of the application, the utility must submit a Final Safety Analysis Report, which sets forth details on the plant's final design and information concerning testing, operations, and plans for coping with emergencies.

The process for granting an operating license is similar to that of granting a construction permit, except that a public hearing is not mandatory, but optional. Current NRC regulations allow the NRC staff to issue a low power operating license, but the Nuclear Regulatory Commission itself must approve a full power operating license.

According to the Office of Technology Assessment (OTA), if the current regulatory process were to run smoothly a nuclear power plant could begin commercial operation 8 years or less after the construction permit is applied for, or 10 years after initial planning begins.[8] Why then has nuclear construction lead time increased so dramatically during the 1970s and 1980s? The OTA has identifed three principal sources of delay: (1) the utilities slowed down the construction of nuclear plants because of slackening demand and because of the high cost of capital; (2) nuclear plant size was being scaled-up during the 1970s, and plants were beginning construction with incomplete design information; and (3) the increased complexity of plant design made it more difficult for the utilities to manage the construction process.[9] There is a recognition by most analysts that NRC backfitting requirements do lead to construction delays and increased costs in nuclear power plants.

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[8]Offices of Technology Assessment, op cit., at pp. 146 and 147.

[9]Ibid., at p. 157.

The NRC's backfitting requirements provide that the NRC may order "the addition, elimination, or modification of structures, systems or components of the [nuclear] facility [under construction] after the construction permit has been issued [if the backfit will] provide substantial additional protection which is required for the public health and safety or the common defense and security."[10] The NRC changes its regulatory and design requirements during plant construction and operation by issuing bulletins, circulars, regulatory guides, and "voluntary" codes and standards. These NRC requirements are prescriptive in nature.

Currently, nuclear power plant designs must conform to major portions of Title 10 of the Code of Federal Regulations, including appendices, and all of the bulletins, circulars, regulatory guides, and voluntary codes and standards that may be invoked by the NRC. According to Canaday, a major portion of construction cost overruns can be traced to the increasing stringency of nuclear safety regulation.[11]

For example, the design-related modifications mandated by the NRC ultimately comprised 61 percent of the ultimate cost of the Davis-Besse Unit, completed in November 1977, as shown in table 4-3. However, as pointed out by Canaday, some portion of the construction cost overruns in a typical nuclear power plant are due to changes in scope and changes in safety rules that might be unnecessary and the result of "design/construction/management inefficiency." This Canaday defines as the increases that occur because (1) the initial design was poorly suited to the safety rules, (2) the construction had to be interrupted or deferred to accomodate these changes, or (3) there was a general breakdown in cost control by management due to the difficult construction environment.[12]

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[10]50 C.F.R. Part 50.109(a).

[11]Henry T. Canaday, Construction Cost Overruns, pp. 21-27.

[12]Ibid., p. 26.

TABLE 4-3

CONSTRUCTION COST INCREASES FOR
DAVIS-BESSE NUCLEAR UNIT 1, BY CAUSE
(Expressed as a Proportion of the Original Estimate)

Original Estimate		1.00
Unit Size Increase from 800 MW to 906 MW		.13
Inflation in Labor and Materials		.63
Cooling Tower Addition		.08
Higher Than Anticipated Land Costs		.01
NRC Modifications and Their Chain Effects		
- Design Modifications	1.43	
- Loss of Productivity Due to Retrofitting the Design Changes	.53	
- Increase in AFUDC Due to Construction Delays and Cost Increments for the Design Changes	.81	
- Greater Cost for Training and Acceptance	.15	
	2.93*	2.93
Total Project Cost as Proportion of Original Estimate		4.78

* Entries may not add up to the total due to rounding.

Source: Authors' calculations, using data provided in Henry T. Canaday, Construction Cost Overruns in Electric Utilities: Some Trends and Implications, (Columbus: The National Regulatory Research Institute, 1980) table 12, p. 22. The ultimate source of the table is Christopher Bassett, "The High Cost of Nuclear Power Plants," Public Utilities Fortnightly, April 27, 1978.

Each new requirement adds to the complexity and hence to the uncertainty of nuclear power plant construction costs, and the number of NRC requirements is constantly increasing. According to Charnoff, in 1983 there were over 400 regulations and over 900 NUREGS (NRC policy reports) that a utility constructing a nuclear plant must comply with, compared with 250 regulations and 600 NUREGS in 1978, the year before the Three Mile Island accident.[13] Table 4-4 indicates how the number of nuclear power plant regulatory requirements in the form of rules, regulations, and policy

[13] Gerald Charnoff, "Why Management Did It All Right."

TABLE 4-4

THE APPROXIMATE NUMBER AND CUMULATIVE NUMBER OF FEDERAL NUCLEAR REGULATIONS, REGULATORY RULES, AND POLICY STATEMENTS PUBLISHED IN THE FEDERAL REGISTER CALENDAR INDEX FROM 1969 THROUGH OCTOBER 1983

Year	Approximate Number of Regulations	Cumulative Number of Regulations
1969	13	13
1970	42	55
1971	22	77
1972	28	105
1973	30	135
1974	25	160
1975	15	175
1976	20	195
1977	35	230
1978	30	260
1979	29	289
1980	40	329
1981	50	379
1982	49	428
1983	37	465

Source: Data derived from graphic presentations in Gerald Charnoff, "Why Management Did It All Right: Overregulation and Other Acts of God," a paper presented to the Seventh Annual National Conference of Regulatory Attorneys (Madison, June 4, 1984).

statements contained in the Federal Register has grown over the years. The increase in the number of regulatory requirements was particularly large following the 1976 Browns Ferry fire and the 1979 accident at Three Mile Island; plants being constructed following these events faced a significant number of back-fitting requirements. These, of course, are the plants that are being completed now.

The point of this section is to indicate that the uncertainties and risks that a utility faces in constructing a nuclear power plant in the 1970s and 1980s have increased substantially. While the opportunities for management error caused by back-fitting requirements have increased, it is not clear how much of the cost increases seen are due solely to regulatory requirements and how much, if any, are the result of managerial imprudence. The authors of a recent NRC staff study found:

> that the root cause for the major quality-related problems in design and construction was the failure or inability of some utility management to effectively implement a management system that ensured adequate control over all aspects of the project. These management shortcomings arose in part from inadequate nuclear design and construction experience on the part of one or more of the key participants in the nuclear construction project: the owner utility, architect-engineer, nuclear steam supply system manufacturer, construction manager, or the constructor, and the assumption by some participants of a project role which was not commensurate with their level of experience.[14]

The NRC staff also found that shortcomings in the nuclear construction quality assurance program were the result of shortcomings in the utility's project management. The NRC staff stated that at least one reason for these shortcomings is the "lack of prudence" on the part of managers, that is, their failure to see how the required quality assurance program would fulfill management's need for feedback on the quality of plant.[15]

But, not all recently constructed nuclear power plants have the type of project management shortcomings in scheduling, cost, and quality of construction just identified. The NRC staff noted that at least three recently completed projects were successful from a quality standpoint: Vogtle, St. Lucie-2, and Palo Verde. The NRC staff specifically cited St. Lucie-2 as an example of how "even in today's regulatory environment, capable, experienced management with very complete design and with adequate project planning can construct a quality nuclear plant, at a reasonably

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[14]W. Altman et al., Improving Quality and the Assurance of Quality in the Design and Construction of Nuclear Power Plants (Washington, D.C.: U.S. Nuclear Regulatory Commission, Office of Inspection and Enforcement, NUREG-1055 For Comment, May 1984), p. vii.

[15]Ibid., p. 3-23.

predictable cost, and in very little more actual construction time than is needed to construct a coal plant."[16]

It is not clear whether in the future, if any nuclear power units are built, the risks associated with cost uncertainty will be greater or less. The electric industry, the nuclear industry, and the NRC are considering measures to reduce these risks. Standardized plant designs, smaller units, and fundamentally safer designs are some of these measures. Further, in the NRC staff report, several proposals were made that might reduce the degree of cost uncertainty associated with future construction of a nuclear power plant. The proposals included (1) screening construction permit applicants for management competence and prior experience in nuclear construction, (2) conditioning construction permits on post-construction permit demonstrations by the applicant of its capability and effectiveness in managing a nuclear construction project, and (3) enhancing the NRC's resident inspector and team inspection program so as to address the issue of management capability and effectiveness on a routine basis, not just when the need for remedial action becomes apparent.[17]

Demand Growth Uncertainty

The historical peak demand growth of utilities through the 1960s was a relatively steady 7 percent per year, with demand growing at a rate of 7.7 percent between 1968 and 1972. The electric utility industry, on the whole, planned to continue adding capacity accordingly. However, energy market forces of the late 1960s and early 1970s, especially the 1973 oil embargo, caused the market price of oil and competing fuels to rise dramatically, which, in turn, drove up the price of electricity and suppressed consumer demand. As a result, peak demand grew at the rate of 1.5 percent in 1974 and 2.3 percent in 1975. This enormous reduction in peak demand growth caused the industry to begin to reexamine its peak demand growth forecasts.

[16] Ibid., p. 3-22.

[17] Ibid., pp. iii, viii, ix.

As early as 1975, electric utility forecasters began to revise and reevaluate their demand forecasts to reflect the slowdown in industrial activity and the strong demand elasticities that were being realized. The forecasters lowered their 10-year peak demand growth rate projection from 7.6 percent in 1974 to 6.9 percent in 1975. Thereafter, the forecasters continued to adjust their projections downward to reflect the lower demand growth actually being realized. By 1978, peak demand for a 10-year period was projected to grow at 5.2 percent. Five years later, in 1982, the forecasters dropped their 10-year peak demand growth rate projection to 3.0 percent.

The projected growth rate has nevertheless exceeded the actual growth rate for most years since 1973.

Today, many of the electric generating units that were begun in the early 1970s are being completed. However, much of the demand projected in the 1970s did not materialize in the 1980s. Utilities are thus faced with the risks associated with either (1) bringing the plant into service and seeking a rate increase to cover its costs (causing rate shock and driving rates higher, which causes customers to conserve and to further reduce their demand), or (2) cancelling plants that are nearly completed.

The risks associated with demand growth uncertainty are likely to continue into the foreseeable future. Uncertainty exists concerning electricity demand even over the next 10 years. The U.S. Department of Energy released a major electricity policy report in June 1983, in which electricity demand was projected to increase between 2 to 4 percent annually through the year 2000, with a 3 percent load growth given as a reasonable median estimate.[18] This report resulted from an interagency project, chartered by the Cabinet Council on Environment and Natural Resources, with

[18]"Critics of DOE Power Policy Report Hit Agency on Load Growth, Finances," Electric Utility Week, September 26, 1984, pp. 5-6; and "DOE Issues Electricity Policy Project Report," EPRI Journal, September 1983, pp. 31-33.

an interagency working group chaired by the Department of Energy. Yet, the 1984 10-year demand forecast by the North American Electric Reliability Council (NERC) is for substantially lower growth. It predicts an average annual summer and winter peak growth rate of 2.5 percent for the period 1984 through 1993.[19] Another U.S. Department of Energy forecast, not an independent forecast, but one based on the most recent NERC reports, is for a 2.27 percent summer and a 2.22 percent winter peak growth rate for the same period.[20] Independent forecasts can differ greatly from these. For example, two consultants, Siegel and Sillin, developed a 1982-1990 forecast about 3 years ago, which still receives considerable attention. It contends that electricity demand will grow at a relatively high annual rate of 4 to 5 percent.[21] Their growth forecast is based on sustained national economic growth and electricity's improved competitiveness, inferred from a recent fall in the real price of electricity. Thus, the electricity demand growth forecasts for the coming 10-year period vary substantially.

The uncertainty about future demand is due, in part, to uncertainty about the future prices for electricity and competing fuels and to uncertainty about how these prices affect electricity demand. Also, there is uncertainty about the various factors that contribute to demand in the industrial, residential, and commercial sectors.

Uncertainty exists, especially about how fast industrial demand will increase in the future.[22] Part of this uncertainty can be traced to

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[19]North American Electric Reliability Council, Electric Power Supply and Demand: 1984-1993 (Princeton: NERC, 1984).

[20]"DOE, NERC Prune their Load-Growth Estimates in New 10-Year Forecasts," Electric Utility Week, September 10, 1984, p. 7.

[21]John R. Siegel and John O. Sillin, "Rethinking Utility Strategy under Conditions of High Growth," Public Utilities Fortnightly, September 13, 1984, pp. 19-23; and "Utility Industry is Underbuilding Warn a Pair of Experts and DOE's Hodel," Electric Utility Week, March 26, 1984, pp. 5-6.

[22]Office of Technology Assessment, Nuclear Power, pp. 36-39.

recent economic performance of the industrial sector. One-half of all electricity used by industry is concentrated in the following specific industrial types, as identified by four-digit Standard Industrial Classification codes: primary aluminum, blast furnaces, industrial inorganic and organic chemicals not classified elsewhere, petroleum refining, paper mills, miscellaneous plastic products, industrial gas, plastics materials and resins, paperboard mills, motor vehicle parts, alkalis and chlorine, and hydraulic cement sectors. Several of these industries have recently undergone an economic slump. For example, industrial output of primary metals has recently decreased, and the production of several basic chemicals, which requires electricity, has grown only slightly or has decreased between 1974 to 1980. Industrial purchases of electricity made up 38 percent of the 2.1 billion kilowatt-hours sold in 1981, but industrial purchases fell as a result of the recession in 1982 to 35 percent of the total sold.

Furthermore, regardless of industry type, about half of all electricity used in industry serves a particular function: powering electric motors. Another 15 to 20 percent of all industrial use of electricity is for the electrolysis of aluminum and chlorine. Electricity use for these two functions is likely to decrease due to improvements in efficiency. A third function, electric process heating, now accounts for about 10 percent of industrial electricity. It has the potential for future growth, particularly as new electrotechnologies, such as plasma metals reduction, plasma chemicals production, and induction heating for casting and forging, become more widespread. However, demand growth in these areas assumes healthy domestic primary metals and chemical industries, and the health of these industries is in doubt. Additional uncertainty about industrial demand exists because of the potential for self-contained industrial cogeneration, that is, industrial cogeneration without sales to the outside electric grid.

Uncertainty about demand exists also for the residential and commercial sectors. For example, there is uncertainty about the future rate of household formation. While penetration of air conditioning and electric heating has been increasing in recent years, more efficient air conditioning and electric heating have become available. Regarding future commercial demand for electricity, there is no reliable, current source of data on the expansion of commerical building square footage. However, it is known that between 1974 to 1979, commercial building square footage increased at a rate slower than the GNP, while commercial electricity sales increased at a rate higher than the GNP.[23] Whether these trends will continue is subject to question. Also, while electricity usage per square foot in commerical buildings may increase due to increasing usage of office automation equipment, there is also a potential for increased efficiency that may offset the projected increase, by balancing and maintaining commercial electricity loads of lighting, cooling, heating, refrigeration, and machinery.[24]

Clearly, demand forecasting can no longer be done with the ease experienced in the past. The uncertainty in future demand is greater today than in the past, when a 7 percent demand growth rate was almost taken for granted. Electricity demand is no longer tied solely to GNP growth, appliance end use, or any single variable--if it ever was. Rather, long term electricity demand is determined by an interrelationship between GNP growth, available and future end-use technologies, alternative energy sources (including cogeneration), and the price of other fuels, as well as the consumers' elasticities of demand.

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[23]Energy Information Administration, Nonresidential Building Energy Consumption Survey: 1979 Consumption and Expenditures Part 1: Natural Gas and Electricity, March 1983, as cited in Nuclear Power in an Age of Uncertainty (Washington, D.C.: U.S. Congress, Office of Technology Assessment OTA-E-216, 1984), p. 40-41.

[24]Office of Technology Assessment, Energy Efficiency of Buildings in Cities, OTA-E-192, February 1983, as cited in Nuclear Power in an Age of Uncertainty (Washington, D.C., U.S. Congress, Office of Technology Assessment, OTA-E-216, 1984) p. 41.

Uncertainties in the Need for New Plant

Even if future demand were known with certainty, it may be uncertain how much and what type of generation capacity a utility should construct to meet that demand.

The number, type, and timing of new power plants needed to maintain a given reserve margin needs to be determined. The need for new plants is affected by plant retirements, oil and gas back-out, and the loss of availability of generating capacity due to increasing power plant age. According to the Office of Technology Assessment (OTA), by the year 2000, there will be 20 gigawatts of existing power plant of 50 or more years in age, 105 gigawatts of existing power plant of 40 years or more in age, and 230 gigawatts of existing power plant of 30 years or more in age. Further, there are currently 152 gigawatts of oil and gas steam-generating capacity that may be backed out because of the high cost of fuel. Furthermore, if older generating units are not retired, their availability tends to decrease, thus increasing the need for new capacity. The variety of decisions on how to deal with each of these factors can increase the range of projections on the amount, type, and timing of capacity needed in the future.

For example, the OTA estimated that, even for a given demand, the amount of new capacity (beyond NERC's planned resources for 1991) needed by 2000 could vary considerably. OTA's estimates of the need for new plant are shown in table 4-5. In the case of a 2.5 percent annual demand growth rate, the OTA finds that the amount of additional capacity that needs to come on line by the year 2000 varies by a factor of two, depending on assumptions about retirements and oil back-outs.

Uncertainty about the required generation supply is also affected by the presence of cogenerators and small power producers because of the recent emphasis on developing alternative sources of energy. The principal legislation affecting the development of these alternative energy sources, broadly defined, is the National Energy Act that contains five bills, each

TABLE 4-5

NEW GENERATION CAPACITY NEEDED IN THE CONTINENTAL UNITED STATES BY THE YEAR 2000 BEYOND THE GENERATING CAPACITY PLANNED FOR 1991*

Level of Replacing Existing Plants	Capacity Needed at 1.5%/Year Demand Growth in gigawatts	Capacity Needed at 2.5%/Year Demand Growth in gigawatts	Capacity Needed at 3.5%/Year Demand Growth in gigawatts
Low: Replace all plants over 50 years old (50 GW)	9	144	303
Moderate: Replace all plants over 40 years old and back out 23 GW of oil and gas capacity (125 GW)	84	219	379
High: Replace all plants over 40 years old and back out 95 GW of oil and gas capacity (200 GW)	159	294	454

* The planned generating capacity for 1991, as reported by NERC, is 740 GW. The starting point for the demand calculation is the 1982 summer peak demand of 428 GW. The North American Electric Reliability Council defines "planned resources" as generating capacity installed, existing, under construction, or in various stages of planning; plus scheduled capacity purchases less capacity sales; less total generating capacity out of service in deactivated shutdown status.

Source: Office of Technology Assessment, Nuclear Power in an Age of Uncertainty (Washington, D.C.: U.S. Congress, Office of Technology Assessment, OTA-E-216, February 1984), p. 46.

of which contain policies that, when implemented, affect either the supply or demand of electricity. The bill of particular interest here because of its effect on electricity supply is the Public Utility Regulatory Policies Act of 1978 (PURPA). In Title II of PURPA, Congress requires electric utilities to buy power from qualifying cogeneration and small power production facilities.

To the extent that qualifying facilities offer power for sale, some new capacity constructed by utilities may be unnecessary. Because many industries find the sale of cogenerated power at the utility's full avoided cost to be attractive, they file with the Federal Energy Regulatory Commission (FERC) as qualifying facilities. As shown in table 4-6, as of January 1, 1983, there were 119 filings for qualifying facility status. The rated capacities of these new qualifying facilities add up to 3,548 megawatts. While there is no guarantee that every qualifying facility filing will result in a cogenerator or small power producer that actually sells its power to the utility, if every qualifying facility were to operate at its rated capacity, the power produced by cogenerators at the beginning of 1983 would be roughly equivalent to that of 3 or 4 large base load units. Many new cogenerators have filed since then. The FERC staff once estimated that by 1995 there would be 16,600 megawatts of cogenerated electricity, of which 5,900 megawatts would have been induced by PURPA.[25]

The actual amount of power that will be supplied by cogenerators in the future is uncertain. Because of this uncertainty, electric utility managers cannot build new plant without facing the likelihood that the plant will not be needed because a potential cogenerator actually begins to generate power. On the other hand, if the electric utility fails to build a plant (with a lengthy construction lead time) and counts on the potential cogenerators to generate power, the cogenerators may not have power to sell when it is needed. Instead, the potential cogenerator may determine that selling cogenerated electricity to the utility is not in the cogenerator's own best interest; an alternative investment might be more profitable for the cogenerator. The electric utility would then need to take an alternate course of action, perhaps raising the avoided cost rates offered to cogenerators. The utility might then find that the new rate being paid to the cogenerator is higher than the cost of building a plant itself would have been.

The utility decision to build or not build must be prudently made. The point here is that risks exist that did not exist before and that opportunities for imprudent decision making are greater than in the past.

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[25]45 Fed. Reg. 23,608 (1980).

TABLE 4-6

FILINGS FOR QUALIFYING FACILITY STATUS BY STATE AT THE FEDERAL ENERGY REGULATORY COMMISSION THROUGH JANUARY 1, 1983*

State	Number of Filings	Rated Capacity (in Kilowatts)
Alabama	1	37,400
Arizona	1	375
California	55	1,009,975
Connecticut	1	150
Florida	13	383,120
Georgia	2	76,600
Hawaii	1	19,400
Idaho	1	5,000
Kansas	1	33,730
Louisiana	1	100,000
Maine	1	46,700
Massachusetts	3	583,400
Michigan	1	22,400
Mississippi	4	7,177
Missouri	1	80,000
New Hampshire	1	1,800
New Jersey	2	35,300
New York	1	100
North Carolina	2	58,000
North Dakota	1	9,000
Ohio	1	16,500
Oregon	2	100,000
Pennsylvania	2	55,500
Tennessee	7	27,228
Texas	4	750,000
Virginia	6	55,507
Washington	2	29,000
Wyoming	1	5,000
TOTALS	119	3,548,362

* There was at least one filing by a facility in Nebraska for which no data are available.

Source: Wooster, "Cogeneration: Revival Through Legislation" 87 Dickinson Law Review 758 (1983).

Greater Consequences of Error

Not only are the opportunities for imprudent decision making greater than in the past, but the consequences of an imprudent decision are also greater--both in absolute and relative terms. To show that the consequences are significantly greater today for electric utilities, we compare the present and past effects of a finding that a decision to invest in a generating unit is imprudent.

In table 4-7, construction expenditures and construction work in progress are compared with the value of net electric utility plant. The table shows in column 1 the annual production (i.e., generation-related) construction expenditures of U.S. privately-owned electric utilities from 1944 to 1983. Column 2 shows the annual total construction expenditure for these years. Column 3 gives electric construction work in progress for privately-owned utilities; unfortunately these data are available only for the years 1967 to 1983.

In column 4 are the values of net electric utility plant for each of the last 40 years. These values are intended to provide a good estimate of the total value of private investment in providing electric service and hence to permit comparison of the relative size of the investment in construction over the last 4 decades.[26]

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[26]Net electric utility plant is used because it is the best data available for the entire time period that indicates the value of the investment in capital equipment for providing electric service. Net electric utility plant is electric plant less accumulated provision for depreciation and amortization. Because of the potentially distorting effect that including nuclear fuel would have in comparing earlier with later years, net nuclear fuel is not included in table 4-7. Some categories of utility investment not included in net electric utility plant are "other property and investment," total current and accrued assets, and total deferred debits. These categories of assets are not typically a part of electric utility plant in service. Total construction expenditures, excluding nuclear fuel, represent the amount spent on constructing generation, transmission, distribution, and other general plant each year. Construction expenditures include an allowance for funds used during construction (AFUDC) where appropriate.

TABLE 4-7

CONSTRUCTION EXPENDITURES AND CONSTRUCTION WORK IN PROGRESS OF U.S. PRIVATELY-OWNED ELECTRIC UTILITIES AS A PERCENTAGE OF NET ELECTRIC UTILITY PLANT, 1944-1983

Year	(1) Annual Production Construction Expenditures ($ x millions)	(2) Annual Total Construction Expenditures ($ x millions)	(3) Electric Construction Work In Progress ($ x millions)	(4) Net Electric Utility Plant ($ x millions)	(5) Annual Production Construction As A Percent Of Net Electric Utility Plant (%)	(6) Annual Total Construction As A Percent Of Net Electric Utility Plant (%)	(7) Construction Work In Progess As A Percent Of Net Electric Utility Plant (%)
1944	90	240	N.A.	9,620	1	2	N.A.
1945	110	350	N.A.	9,647	1	4	N.A.
1946	170	650	N.A.	9,660	2	7	N.A.
1947	425	1,235	N.A.	10,575	4	12	N.A.
1948	750	1,830	N.A.	12,079	6	15	N.A.
1949	1,000	2,190	N.A.	13,758	7	16	N.A.
1950	890	2,050	N.A.	15,104	6	14	N.A.
1951	920	2,134	N.A.	16,579	6	13	N.A.
1952	1,251	2,599	N.A.	18,442	7	14	N.A.
1953	1,391	2,876	N.A.	20,733	7	14	N.A.
1954	1,280	2,835	N.A.	22,815	6	12	N.A.
1955	1,064	2,719	N.A.	24,579	4	11	N.A.
1956	1,029	2,910	N.A.	26,524	4	11	N.A.
1957	1,647	3,679	N.A.	29,212	6	13	N.A.
1958	1,879	3,764	N.A.	31,893	6	12	N.A.
1959	1,519	3,383	N.A.	34,243	4	10	N.A.
1960	1,342	3,331	N.A.	37,036	4	9	N.A.
1961	1,183	3,000	N.A.	38,975	3	8	N.A.
1962	1,057	3,037	N.A.	40,584	3	7	N.A.
1963	1,083	3,240	N.A.	42,392	3	8	N.A.
1964	1,115	3,558	N.A.	44,184	3	8	N.A.
1965	1,228	4,055	N.A.	46,691	3	9	N.A.
1966	1,640	4,941	N.A.	49,843	3	10	N.A.
1967	2,479	6,204	4,418	54,239	5	11	8
1968	3,102	7,118	5,896	59,393	5	12	10
1969	3,897	8,357	7,732	65,613	6	13	12
1970	5,249	10,047	10,330	73,451	7	14	14
1971	6,537	11,857	13,531	82,829	8	14	16
1972	7,917	13,463	16,623	93,341	8	14	18
1973	8,855	15,059	20,246	105,794	8	14	19
1974	10,094	16,702	22,846	117,986	9	14	19
1975	10,094	15,650	26,319	128,551	8	12	20
1976	11,964	17,360	31,717	141,404	8	12	22
1977	14,416	20,281	36,484	156,124	9	13	23
1978	16,132	22,937	42,476	172,584	9	13	25
1979	18,281	25,481	53,991	192,240	10	13	28
1980	19,238	27,011	60,440	211,909	9	13	29
1981	20,912	29,124	69,439	231,940	9	13	30
1982	25,339	33,602	82,026	255,171	10	13	32
1983	24,935	33,816	98,356	273,073	9	12	36

Sources: Authors' calculations based on data from Statistics of Privately-Owned Electric Utilities in the United States: Summary Sections for 1952, 1958, 1959, 1967, 1977, and 1980 (Washington, D.C.: Federal Power Commission); Financial Statistics of Selected Electric Utilities, 1982 (Washington, D.C.: Department of Energy, Energy Information Administration, 1984); Historical Statistics of the Electric Utility Industry Through 1970 (New York City: Edison Electric Institute, 1974); Edison Electric Institute Statistical Year Book of the Electric Utility Industry, 1972, 1978, 1979, 1981, 1982, 1983 (Washington, D.C.: Edison Electric Institute); and Financial Review: An Annual Report on the Electric Utility Industry (Washington, D.C.: Edison Electric Institute, 1984). Because various sources of data are used in the table, there are minor discrepancies in the data, as follows. From 1944 through 1959, the data sources for net electric utility plant are the Statistics for Privately-Owned Electric Utilities in the United States, published by the Federal Power Commission. Beginning in 1960, the sources for net electric utility plant data are the Statistical Year Book(s) of the Electric Utility Industry published by the Edison Electric Institute. Thus, there may be a slight discontinuity in the data between 1959 and 1960. The net electric utility plant data for 1948 through 1959 are based on estimates by the Federal Power Commission. The net electric utility plant data for 1944 through 1947 are estimated by the authors based on the data in the Statistics of Privately-Owned Electric Utilities in the United States: Summary Section for 1952. The annual total construction expenditures and annual production construction expenditures exclude data for Alaska and Hawaii prior to 1961. Net electric utility plant excludes data for Alaska prior to 1958 and excludes data for Hawaii prior to 1959. The discrepancies in the data, however, do not affect the general trends shown in the table. N.A. indicates that data are not available.

Notice that total construction expenditures as a percentage of net electric utility plant (column 6) have not changed greatly in the post-World War II years. From 1947 to 1959 the electric utility industry made annual construction expenditures ranging from 10 to 13 percent of its net electric utility plant value. Only in the years 1960 through 1965 were annual construction expenditures less than 10 percent of the value of the net electric utility plant, perhaps because in these years many oil or gas burning peakers were installed to meet peak demand at low investment cost. Even then, the expenditure rates were between 7 and 9 percent. Since 1969, capital expenditures have stayed between 12 and 14 percent of net electric utility plant. Perhaps surprisingly, despite the claims that utility investments are at historical highs, at least this one measure of investment shows the relative stability of the electric utility industry's construction expenditure program during the post-World War II years.

Consider, however, the annual production construction expenditures as a percentage of net electric utility plant. It has risen in recent years. Annual production construction expenditures ranged from 1 percent to 7 percent of net electric utility plant during the years 1944 through 1970, with a (straight) average value of 4.5 percent. However, from 1971 through 1983 annual production construction expenditures ranged from 8 to 10 percent of net electric utility plant, averaging 8.8 percent--about double the prior average. Production construction expenditures crossed over in 1971, from making up half or less of the annual total construction expenditures to making up more than half--up to three-fourths of these investment expenditures. Hence, while total construction has remained relatively stable in percentage terms, the generation portion of construction investment has increased significantly. It is this portion that is most at risk in recent prudence inquiries.

These data relate to investment expenditures in a single year. If these industry percentages are carried over to an "average" utility, then before 1971 a typical electric utility invested each year in generation construction an amount equal to about 4.5 percent of its net plant. Under the simplifying assumption that it built one unit at a time, the investment in a unit with a 4-year construction period was 18 percent (4.5% x 4 years) of net plant.

Since 1971, not only has the cost of annual generation construction increased in absolute terms, and not only has the annual cost increased as a percentage of net plant (up to 8.8 percent), but construction times have increased also. For example, average construction durations for nuclear units increased from slightly less than 4 years for units completed in 1971 to about 8 years in 1978, roughly the midpoint of the 1971-1983 period.[27] Construction times for nonnuclear units and for periods well before 1970 were less than 4 years. Construction periods for large coal-fired units have been increasing, and nuclear construction now takes well over 10 years.

During the 1971-1983 period, if the average utility invested 8.8 percent of net plant in a generating unit each year for 8 years (ignoring year-to-year variations in net plant), the investment in the unit amounts to 70 percent of the company's net plant. Clearly, the stakes are higher today than in the past.

In reality, a utility's construction program is usually smoother than this, providing for some plant addition to rate base every few years and reducing the exposure of construction investment. The value of construction work in progress (CWIP) is a better indicator of the risks that the electric utility industry faces in constructing new plant. It measures the cumulative investment not yet in rate base up to any given year. However, data on CWIP are not available for years before 1967. As can be seen in column 3 of table 4-7, the investment tied up in electric construction work in progress increased from $4.4 billion in 1967 to $98.3 billion in 1983.

The reasons for this increase in cumulative total construction expenditures include higher materials and labor costs, the lengthening of construction periods, and the high rate of inflation in the late 1970s and very early 1980s with the consequent high real cost of capital during these

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[27]Canaday, Construction Cost Overruns, p. 24.

years. As a result, not only are direct costs high, but the cost of capital is high, leading to a growing proportion of AFUDC in construction expenditures. The high AFUDC is compounded because of the increasingly long construction periods required to build a large, complex power plant. The data in column 3 show that the consequences of an imprudent decision have increased in absolute terms.

The consequences of an imprudent decision have also increased in relative terms. Column 7 of table 4-7 shows that CWIP as a percentage of net electric utility plant has increased continuously from 1967 through 1983, from 8 percent to 36 percent. This means that in 1983, the electric utility industry had 36 percent of the value of its net electric plant in service tied up in construction work in progress.

Assume that our average electric utility company has a capital structure of 40 percent equity and 60 percent debt. In such a situation, the average company would have "bet" nearly its entire stockholder equity value on the construction work in progress. Should the plant or plants under construction be kept entirely out of rate base due to imprudence, the consequences for the company would obviously be much more severe today than in the past.

A Regulatory Tool for Allocating Risk

As a result of these greater risks and greater consequences of risk, many current electric utility investment decisions expose stockholders or ratepayers to the possibility of severe financial losses. State utility commissions feel torn between two obligations. On the one hand, they want to keep utilities financially sound so they can continue to provide reliable service to customers. On the other hand, they are obliged to set rates at a level that is reasonably related to the costs required to provide service.

The first obligation implies that, since certain reasonable risk-taking is a part of any business, ratepayers should, as part of the cost of service, bear the costs associated with reasonable risks that do not "pan out." The second obligation implies that ratepayers ought not to bear unreasonable investment risks or levels of risk, which are normally borne by stockholders and for which they are compensated in the form of dividends when the risks pay off.

When the amount of risk was low, that is, when the utilities rarely "lost their bets," or when the impact on rates of a poor investment decision was small, commissions either did not need to choose between these obligations or could often choose in favor of financial soundness without significantly affecting the level of rates. Recently, however, commissions have increasingly been forced to choose between these two obligations in situations where large investment values are at stake and where a decision, one way or the other, will have a large impact on either investors or customers.

In response to these forces, commissions have searched for a principle for guiding decision making, a principle with some historical precedent in utility ratemaking and a principle that does not necessarily require an "all or nothing" decision in favor of one side, but can allow some appropriate sharing of the risk between investors and ratepayers. The concept of prudence is emerging as that principle.

Two types of risk can be identified: systematic and unsystematic risk. Systematic risk is the risk that affects all companies, such as risks arising from the general economy and the movement of financial markets as a whole. Unsystematic risk is the risk related to the circumstances of a particular company. In other words, unsystematic risk is the portion of total investment risk unique to the particular company.[28]

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[28]See generally Alvin Kaufman et al., Unplanned Electric Shutdowns: Allocating the Burden (Columbus: The National Regulatory Research Institute, 1980) and specifically Christopher C. Pflaum and J. Kenton Zumwalt, "Investment Risk Evaluation: The Special Case of the Regulated Firm," The Proceedings of the Fourth NARUC Biennial Regulatory Information Conference (Columbus: The National Regulatory Research Institute, 1984).

Without necessarily using these terms, many commissions choose to have ratepayers bear systematic risk and utility investors bear unsystematic risk. Indeed, commissions are prone to have ratepayers share the risks that only systematically affect the entire electric industry or gas industry--or sometimes the risks that systematically face just companies in a particular geographic region. The prudent investment test is, in such cases, a tool for identifying the unsystematic risk associated with a utility's investment in a new plant. The prudent investment test has usually operated so as to allow prudently incurred capital expenditures into the rate base. In the case of an abandoned electric plant, for example, the prudent investment test, as recently applied by most state commissions, provides for the eventual recovery of prudently incurred expenditures through amortization in order to protect utility investors from exposure to the systematic risk of generally declining electricity demands. If the commission believes that management shares some specific responsibility, the test provides the possibility of risk sharing: the unamortized balance typically is not allowed into rate base in most states.

In the case of excessive construction costs also, the concept of prudence permits a division of risk and responsibility between investors and customers. Overruns are due, in part, to systematic factors such as increased interest rates. But some other factors that have led to construction cost overruns are not attributable solely to a systematically riskier environment, but rather, in part, to managerial failure. With the greater stakes involved in the construction of larger nuclear and coal power plants, utility managers in some cases could have better controlled the costs, the scheduling, and the quality of construction. When utility managers fail to control these, the prudent investment test allows the regulator to eliminate from rates the investment costs that were due to managerial imprudence.

Yet the prudent investment test need not be applied so strictly that utilities become liable for every delay and error that occurs, whether or not the utility management is at fault. If a utility plant has a construction cost overrun, for example, because of an unforseeable change in regulatory policy such as a Nuclear Regulatory Commission regulation requiring backfitting, commissions usually allow a utility to recover the full costs of its investment in the plant. This seems justified because in a more competitive environment each competitor building a similar plant would have been required to backfit its plant to meet the new regulatory requirement also. All similarly situated competitors would raise their prices to cover the costs of the backfit. If such competitors, given the facts and circumstances known or foreseeable at the time, would have chosen to build such a plant and incur such a cost, then most regulators believe that it is appropriate to allow a utility to recover its investment in the plant--even if the investment decision turns out to be wrong.

In other words, most regulators do not choose to hold utility managers responsible for systematic or industry-wide risks that affect the electric utility industry as a whole. Instead, state commissions often use the prudent investment test to hold a utility harmless, except for the consequences of decisions that are unreasonable based on the known or the foreseeable.

Used in this manner, the prudent investment standard is a more flexible standard than the used-and-useful standard, which is often interpreted as an "all or nothing" standard for rate base treatment of investments.

The prudent investment test is currently being applied more often than in the past because of an increasingly risky environment. Because this riskier environment is likely to continue and perhaps become more risky in the future, it is also likely that the prudent investment test will be applied frequently, perhaps more frequently, in the future. Hence, the prudence test will grow more important as a regulatory tool, and it is important to examine some of the consequences of strict commission use of this tool.

ASH-6

CHAPTER 5

SOME LONG TERM CONSEQUENCES OF APPLYING THE PRUDENCE TEST STRICTLY

As we have seen, the prudence test can act in favor of utilities, providing compensation for prudently incurred investment expenses that end up being unneeded. It can also act against utility interests where large expenditures are based on an imprudent decision. In the second case, strict application of the prudent investment test by state commissions may have any of several unintended consequences. A discussion of some possible consequences of applying it routinely and universally, excluding large utility expenditures from rate base, is the subject of this chapter.

Many utility representatives say that under strict application of the prudence test utilities will stop investing in new plant, resulting in no growth in electric capacity. In order to avoid this, some assert that commissions must guarantee cost recovery to utilities planning new capacity. Many consumer representatives admit that strict application of the prudence test could result in utility bankruptcy, but argue that bankruptcy can lower rates appropriately without affecting the quality of service. Others claim that bankruptcy would result in loss of service to customers or in poor service at high rates--accompanied by loss of state commission authority to deal with the situation.

There is a perhaps more likely consequence of future strict application of the prudence test, which lies between the two extremes of no growth and bankruptcy. It is that the relationships between utilities and other parties involved in capacity development may change. The investment community may come to view the utility business as a permanently high risk business, resulting in an increase in the cost of capital for this capital-intensive sector. The relationship between managers and utility stockholders may change as investors hold managers legally responsible for decisions found to be imprudent by state commissions. Managers, architect-engineers, and construction contractors may develop more formal, "arm's length" relationships. Or utilities and state commissions may become closer, less "at arms lengths," as they become partners in assessing the need for power and determining the best way to meet that need.

In the sections that follow we explore further the arguments about some of these possible consequences, considering utility investment policy, utility bankruptcy, and utility relationships. (Discussion of the relationship between utilities and commissions is deferred to chapter 6.)

Utility Investment Policy

Here we consider the probable consequences of various regulatory environments on a utility's investment behavior, especially in the presence of business risk such as uncertain future demand. These environments relate to the degree of regulatory strictness in applying the prudent investment test. We examine the impacts by means of an electric utility example.

Consolidated Power Example

Consider the problem of forecasting electricity demand, an especially knotty problem for energy utilities since the Arab oil embargo of 1973. Suppose that the year is 1986 and that an electric utility called Consolidated Power needs 10 years to build a new plant. Given an expected marginal cost of power, the utility would do a demand forecast for 10 years into the future, to the year 1996. Ideally, this demand forecast for each year would contain two numbers: the expected demand at an assumed marginal cost, and the standard deviation of the expected demand. We will study the impact of risk in the next few subsections by generalizing from a specific example.

Assume our hypothetical utility, Consolidated Power, does such a demand forecast for the year 1996, 10 years into the future. In the example we assume that the state commission and the utility have agreed that load growth will be handled by constructing relatively small 400-MW units. The most beneficial way to build several small generating units is to wait several years after starting one unit before starting another. In order to keep the example simple, we assume that an unexpected rise in forecasted long term demand requires that several units be constructed as quickly as possible in order to alleviate an expected power shortage and that they all come on line in the same year, 1996. Also for simplicity, we assume that the cost of capital is 10 percent and that Consolidated intends to construct generating units that each cost $62.735 million per year for 10 years. With accrued interest (actually allowance for funds used during construction) at 10 percent, each unit will add $1 billion to the rate base in 1996, when the units are operational. Further, we assume that these units are expected to last 30 years and then will be costlessly scrapped;[1] hence each unit costs the users $.1061 billion per year for 30 years. Assume also that when the demand forecast is adjusted for the number of units needed at a standard load factor, expected demand is 4.0 units, the standard deviation is 1.0 unit, and the distribution is normal. Assume that if demand is between 3.50 and 4.49, then four new units will be built; between 4.50 and 5.49, five units; and so on.

The probability of demand for each number of units between zero and eight is given in table 5-1. The use of probability reflects our uncertainty in 1986 about the need for power in 1996. The table shows, for example, that the probability that four new units will be needed in 1996 is about 38 percent. The probability that four or fewer units will be required is about 69 percent. Conversely, the probability that more than four units will be required is about 31 percent (100-69). The probability distribution in this example has a standard deviation that is 25 percent of the mean estimated new capacity. This standard deviation-to-mean ratio seems plausible for an industry with generating units that take 10 to 12 years to construct, because utilities must forecast demand growth about

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[1]Of course, if the plants are nuclear, there is a substantial cost to decommissioning them. See Robert E. Burns et al., Funding Nuclear Power Plant Decommissioning (Columbus: The National Regulatory Research Institute, 1982).

TABLE 5-1

CONSOLIDATED'S NEED FOR NEW UNITS

Number of New Units Required	Probability	Cumulative Probability
0	.0002	.0002
1	.0060	.0062
2	.0606	.0668
3	.2417	.3085
4	.3830	.6915
5	.2417	.9332
6	.0606	.9938
7	.0060	.9998
8	.0002	1.0000

Source: Authors' calculations

12 years into the future. This ratio may even be low in light of the demand forecasting errors that were made during the 1970s.

After the utility determines that new capacity must be added, it collects estimates of construction costs and times for various technologies, and decides on the least-cost expansion plan with acceptable reserve capacity and reliability each year. Typically, a utility might require a reserve margin 20 percent above peak load to achieve a reliability of one generation-related power outage in 10 years. Depending on the state, the utility might then take this demand forecast and the least cost expansion plan to its state commission or other state agency and request that the state agency agree, in a power siting or certificate of need proceeding, that this least cost expansion plan would be a prudent investment.[2]

[2]Some thirty-two state commissions report making a needs determination for plant investment as part of a certification of convenience and necessity, a power plant siting hearing, or some other process. In addition, most commissions must grant approval for issuance of new securities to finance construction. The degree to which these proceedings constitute a formal commission agreement with the reasonableness or prudence of the construction decision varies considerably from state to state. See R. J. Profozich et al., Commission Preapproval.

In all the following analysis, we assume that the commission and the utility agreed at the time that construction began that the proposed construction was a prudent way to meet projected demand. We call projects that a commission or other state agency agreed were prudent before construction began "prudent ex-ante," or prudent before the fact. The analysis concentrates on the consequences of judging whether an investment is prudent after the project is completed (or even under construction). In other words, we analyze the consequences of a commission denying the addition of plant to the rate base because the decision to complete the project is no longer prudent, even though the decision to initiate construction was prudent. The commission would then be judging whether a project is "prudent ex-post," or prudent after the fact.

Three Regulatory Environments

We will examine the utility's investment strategy under three regulatory environments, or rules, for applying the prudence test to candidate investments for rate base treatment.

All-Investments Rule

Consider a regulatory environment where all investments that are prudent ex-ante are added to the rate base. Suppose all investments that are prudent ex-ante have a zero net present value (NPV) to the utility's investors. That is, regulation acts to prevent investors from earning any profits above those available from other similar investments and also prevents any losses that would detract from that "normal" level of profit. Then Consolidated will invest in whatever least-cost expansion plan the commission judges to be prudent ex-ante. From table 5-1, the socially optimal investment is $4 billion (four units at $1 billion each) if the social cost of underinvestment equals the social cost of overinvestment. If the commission agrees that beginning construction of four units at a projected cost of $4 billion is prudent ex-ante, then Consolidated will begin construction of the four units, a project with an expected zero NPV.

If demand turns out to be less than forecasted, this regulatory environment causes a utility to make the socially optimal decision about abandoning plants, which is to ignore sunk costs. Suppose that Consolidated has already spent $600 million on a nuclear power plant and needs to spend $400 million more to complete it. The socially optimal decision is to complete the plant only if the present value of marginal income (revenues less variable costs) from completing the plant exceeds $400 million. Consolidated uses this decision process because it will recover the $600 million in sunk costs that it prudently invested in the plant regardless of whether it finishes the plant.

If demand turns out to exceed four units and $4 billion, Consolidated would begin constructing additional plants.

The commission does not have to trust Consolidated to abandon partially completed, unneeded plants. It can require periodic reviews of the demand forecast and the least-cost expansion plan. If demand turns out to be less than previously forecast, the commission can decide that abandoning a plant is prudent and continuing construction is not. If it decides that the sunk costs of a partially completed plant can be added to the rate base, but the additional costs needed to finish the plant cannot be added to the rate base, the utility would choose the zero net present value project (to abandon the plant) rather than the negative net present value project (to continue construction).

The major drawback of this regulatory environment is that there are no profit incentives to encourage efficiency or good management. This lack of incentive provides a strong motivation for the prudent investment test.

Operational-Investments-Only Rule

Consider next a regulatory environment where neither abandoned plants nor plants under construction can be added to the rate base, but completed operations plants can always be added. This change in the regulatory environment alters the investment incentives for Consolidated when changes in economic conditions cause demand to be less than previously forecast. No matter what demand turns out to be, Consolidated will always complete a plant once construction has begun because Consolidated has no other way to recover money spent on an partially constructed plant. This regulatory environment provides short run incentives to overinvest in the sense that plants are completed even when it is socially optimal to abandon them.

Operational-and-Needed-Investments-Only Rule

Most commissions recognize the perverse incentives to complete unneeded plants if only operational plants can be added to the rate base. Statutes or court decisions in several states require that only needed and operational plants may be added to the rate base. In other words, the state or the commission reserves the right to judge that an investment that was prudent ex-ante is not prudent ex-post if a change in economic conditions reduces demand.

In the following analysis we assume that commissions distinguish between short term fluctuations in demand due to weather and business cycles and long term changes in demand due to changes in technology, demographics, and relative energy prices. In this analysis, commissions refuse to add a plant to the rate base only if the plant is unneeded due to a change in long term demand. In the short run, this regulatory environment causes plants that are unneeded ex-post to be abandoned, as intended. The following analysis examines the long run effects of this regulatory environment.

If a commission wishes not to add investments to the rate base that are not needed ex-post, it may favor a utility construction plan consisting of several small units rather than one large unit. Suppose that a utility could satisfy forecast demand with four small units or one large unit.

Suppose actual demand turns out to be only 75 percent of the forecast demand. The commission can rule that one of the four units is unneeded and cannot be added to the rate base, but might find it awkward to rule that only 75 percent of a large unit is needed and that only 75 percent of the cost of construction can be added to the rate base, because the unit cannot be operated, of course, until 100 percent of the construction is complete.

In the case we consider here, the commission will approve only prudently incurred costs for the prudent ex-post capacity expansion. However, Consolidated uses net present value analysis to determine the financial consequences of investing. Table 5-2 shows the expected NPV of building from zero to four new units given this regulatory environment and Consolidated's demand forecast of table 5-1. In table 5-2, the first column shows several possible levels of need for new units, from zero to four or

TABLE 5-2

EXPECTED NET PRESENT VALUE TO THE COMPANY OF BUILDING N NEW UNITS (IN BILLIONS OF DOLLARS)

Number of New Units Required	Probability	Gains or Losses from Building N Units				
		4 Units	3 Units	2 Units	1 Unit	0 Units
0	.0002	-$4	-$3	-$2	-$1	0
1	.0060	-$3	-$2	-$1	0	0
2	.0606	-$2	-$1	0	0	0
3	.2417	-$1	0	0	0	0
4-8	.6915	0	0	0	0	0
Expected NPV		-$.3817	-$.0732	-$.0064	-$.0002	0
Probability of Shortage		.3085	.6915	.9332	.9938	.9998

Source: Authors' calculations

more, and the second column shows the probability of each level of need. As mentioned with table 5-1, the probability that demand turns out to be for three units, for example, is 24.17 percent. The remaining columns show the gain or loss to Consolidated for building zero to four units at each level of actual demand. For instance, the fourth column shows that if Consolidated builds three units and demand turns out to be for two units, then Consolidated loses $1 billion because two units are granted rate base treatment and one, costing $1 billion, is not.

The next to last row of table 5-2 shows the expected net present value of each of the five investment plans and is computed by summing for each column the products of each gain or loss and the probability that the gain or loss occurs. For instance, suppose Consolidated builds two units. Then there is a .0002 probability that demand will turn out to be for no units, in which case Consolidated will lose $2 billion, and there is a .0060 probability that demand will turn out be for one unit, in which case Consolidated will lose $1 billion. Consolidated neither gains nor loses if demand turns out to be for two or more units. The expected NPV of building two units is

$$(-\$2,000,000,000 \times .0002) - (\$1,000,000,000 \times .0060) = -\$6,400,000,000$$

which is shown in the table as -$.0064 billion.

The final row in table 5-2 is the probability that building N units will result in a power shortage. Here, a power shortage refers to a situation in which the utility's reserve margin falls below the target value. For instance, if three units are built and the utility follows these investment rules, there is a 69.15 percent probability that there will be a capacity shortage (demand exceeds three new units with a probability of 69.15 percent).

Consolidated expects to lose \$382 million if it builds the socially optimal four units, but the expected loss declines as the number of units it builds declines. Logically, Consolidated would choose to construct no new units because this is the only investment strategy with a nonnegative NPV. Under this strategy the probability of a power shortage is 99.98 percent.

The calculations for this example were based on the assumptions that all units are started at the same time and construction for all units is completed. The utility could reduce its expected losses by cancelling units before completion and could reduce expected losses further by staggering the construction of its plants. Perhaps these two tactics could reduce Consolidated's expected loss from building four units by 50 percent, to \$191 million. Consolidated would still choose to build no units. Staggered construction and abandoning plants during construction reduces Consolidated's expected losses from any given investment, but these tactics do not change Consolidated's decision to make no investment.

We can easily generalize this example. Under this regulatory environment, every positive investment has no chance to earn a profit and has some probability of showing a loss. With no possible upside gains and possible downside losses, all investments have a negative expected NPV and no utility will voluntarily make any long run investments. Utilities would be willing to make short run investments to alleviate power shortages once they occur, if the commission agrees that some investment is needed. However, short term investments generally produce power at higher marginal cost than long term investments.

Overinvestment penalties increase risk to stockholders and, therefore, raise the cost of capital. Suppose that the increased risk raises the cost of capital from 10 percent to 11 percent. Then a generating unit with construction costs of \$62.735 million per year for 10 years adds \$1.0489 billion to the rate base. The effect is to multiply each gain or loss and expected NPV in table 5-2 by 1.0489. If each unit is expected to last exactly 30 years and then be costlessly scrapped, each unit costs users \$.1206 billion per year for 30 years, an increase of 13.73 percent over the \$.1061 billion per year each unit cost at a 10 percent cost of capital. (Of course, this increase in the cost of capital would be unimportant in a regulatory environment where no new investments are being made.)

Preventing Underinvestment

This analysis indicates that one consequence of strict application of the prudent investment test in an effort to protect ratepayers so that they have sufficient power at the lowest possible cost may be, under the operational-and-needed-investments-only rule, insufficient power at high cost. Commissions could try to correct this tendency to underinvest under this investment rule either by assessing penalties for underinvestment or by providing a gain, or real profit incentive, for utilities that invest the socially optimal amount.

Underinvestment Penalties

If actual demand turns out to be for five units and Consolidated only builds four units, regulators could impose a penalty. One penalty is to reexamine the utility's franchise to serve its current service area or to take certain other legal or regulatory actions. However, in keeping with the spirit of the financial analysis of this section, an appropriate response to underinvestment may be to impose a financial penalty--and for purposes of continuing the example we set aside here all questions regarding a commission's authority to impose such a penalty. In theory, if it is appropriately designed, the penalty for underinvestment would counterbalance exactly the incentive to underinvest. Carried to its logical conclusion, such a regulatory strategy would keep out of rate base an amount equal to the amount of underinvestment (\$5 billion - \$4 billion) and add to the rate base only Consolidated's actual investment less the underinvestment penalty (\$4 billion - \$1 billion = \$3 billion).

Such a rule would mean that, if a utility with a $20 billion rate base refuses to invest an additional $4 billion to meet expected demand (because of overinvestment penalties), the commission might threaten to reduce the existing rate base to $16 billion. From this, the utility's interest coverage ratio would suffer, probably to the point where the utility would face bankruptcy.

Underinvestment penalties can also take the form of disallowed expenses, inadequate inflation adjustments, or reductions in the rate of return. We do not consider here the various other types of financial penalties except to note that, according to the Averch/Johnson rule, a reduction in the rate of return below the true cost of capital gives the utility a disincentive to produce power with an optimal capital cost/variable cost mix.[3] If an underinvestment penalty lowers the rate of return below the cost of capital, the utility would have a further incentive to underinvest.

Assume that the commission can require Consolidated to make some investment through threats of underinvestment penalties and assume that expected demand is still for 4.0 units (ignoring any effect of the penalty on marginal cost and hence demand). The expected NPV of building four units would be negative but, because of the penalty, other investments would have even lower NPVs. Therefore, Consolidated might be forced to build four units, the socially optimal investment. Imposition of both underinvestment and overinvestment penalties on the basis of prudence can then force a utility to make the socially optimal investment, but such a policy probably amounts to expropriation of the utility by the state because current shareholders lose money every time demand turns out to be different from the forecast value. A utility in this environment could not raise capital by selling stock except at prohibitively high dividend yields

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[3]See Harvey Averch and Leland L. Johnson, "Behavior of the Firm under Regulatory Restraint," American Economic Review 52 (December 1962a): 1052-1069; and F. M. Scherer, Industrial Market Structure and Economic Performance, 1st ed. (Chicago: Rand-McNally, 1970).

because new stockholders require immediate dividends to compensate them both for expected losses when demand turns out to be different from the forecast value and for increased risk.[4] This increased dividend yield has the effect of raising electricity costs and prices. High prices, in turn, dampen demand and reduce the optimal amount of investment.

This regulatory policy produces small amounts of power at very high prices. There are two categories of alternatives to this policy. One is to eliminate penalties and hence risk. The other is to provide an opportunity for increased profits to compensate for risk.

Profit Incentives

Suppose that a commission imposes overinvestment and underinvestment penalties, but also gives the utility some form of profit incentive. Ideally from the financial point of view, it would consist of both a lump sum increase in the rate base as compensation for expected losses and an increase in the rate of return as compensation for increased risk. In practice, without a change in statutes, such an increase in rate base could probably not be implemented directly; instead, commissions would want to grant an appropriate increase in rate of return that would yield the same resulting profit. However, the commission must grant the compensation for expected losses as a lump sum change in rate base and not as an increase in

[4]Specific expected losses can be distinguished from increased risk. For example, assume that there is a 20 percent chance that firm C will be bankrupt 1 year from today, unable to pay either interest or principal on any bonds that it issues. If a risk neutral investor requires an expected 10 percent return, he would require a promised interest rate of 37.5 percent on 1-year discount bonds issued by firm C, with the extra 27.5 percent of promised interest being compensation for expected losses. (While a riskless bond has a zero standard deviation of returns, a 1-year discount bond issued by firm C has a 58 percent standard deviation of returns.) The typical investor is risk averse, not risk neutral, so he demands a higher than 10 percent expected return on a risky bond than on a riskless bond. Assume that he demands a 16 percent expected return on firm C bonds, in which case promised interest must be 45 percent. This 6 percent increase in expected return and the 7.5 percent increase in promised interest represent compensation for increased risk.

the rate of return. This is because an increase in the rate of return over the true cost of capital would again give the utility an incentive to produce power with a suboptimal capital cost/variable cost tradeoff. This incentive to overinvest, like the disincentive to invest discussed earlier, is also a result of the Averch/Johnson effect.[5] For purposes of simplicity in the example, however, we assume the "ideal" approach is possible.

Suppose that increased risk associated with penalties increases the cost of capital from 10 percent to 12 percent. A generating unit that costs \$62.735 million per year for 10 years then adds \$1.1009 billion to the rate base. If expected demand is still for four units, the NPV of building four units under the operational-and-needed-investments-only rule is -\$.8404 billion. Then the lump sum compensation for expected losses must be +\$.8404 billion also in order to make building four units a zero NPV project. If Consolidated builds four units and actual demand turns out to be for four units at a cost of \$4.4037 billion, the commission would have to add \$5.2441 billion to the rate base (\$4.4037 billion + \$.8404 billion). However, if demand turns out to be for three units or five units, the commission then adds \$4.143 billion to the rate base (1.1009 x 3 + .8404), and so on. That is, the company includes in rates the construction costs of the units less penalties plus the compensation for expected losses.

If units last 30 years and are then costlessly scrapped, a \$5.2441 billion increase in the rate base costs ratepayers \$.6510 billion per year for 30 years. This is a 53 percent increase in amortized capital costs over the \$.4243 billion in amortized capital costs with no penalties and a 10 percent cost of capital. These calculations were made assuming no change in demand, even though demand will necessarily decline in response to a 53.43 percent increase in amortized capital costs.

The commission can reduce the \$.8404 billion rate base adjustment for expected losses by x percent if it reduces the penalties for overinvestment

[5]See Averch and Johnson, "Behavior of the Firm"; and Scherer, Industrial Market Structure, pp. 529-537.

and underinvestment by x percent. The commission must make equal adjustments in the two penalties, however, because asymmetric penalties produce incentives to either overinvest or underinvest. For instance, a 100 percent penalty for overinvestment and a 0 percent penalty for underinvestment has already been shown to cause underinvestment (i.e., it causes no investment).

In the early 1980s, the Defense Department began using profit incentives for defense contractors, and Scherer advocates a similar use of profit incentives to encourage efficiency by public utilities.[6] It is an arguable point whether profit incentives for public utilities would increase efficiency enough to offset the increase in marginal cost that would occur because of the increased cost of capital.

Avoiding Poor Investment Incentives

There is a finite probability of management error in all corporations, including utilities. If commissions penalize these errors, for instance, by allowing only a part of the construction costs of a new unit to be added to the rate base, all investments have negative expected NPVs and no investments will be made. As we have seen, if the commission adds underinvestment penalties, unintended side effects can occur; for example, the cost of capital increases and the cost of electricity rises. There are at least three possible solutions to the problem of unintended side effects of penalties for mismanagement: contractor liability, insurance, and profit incentives.

For a sufficiently high increase in his bid, a contractor may be willing to accept liability for certain errors, such as some kinds of cost overruns. Here, we distinguish between two kinds of costs associated with cost overruns: controllable costs and uncontrollable costs. "Management mistakes" might be considered a controllable cost because a sufficiently competent and experienced management team could minimize these costs.

[6] See "Procurement Success Story." Wall Street Journal 6 February 1984, p. 20; and Scherer, Industrial Market Structure, p. 537.

Retroactive safety regulations and delays caused by environmental litigation are examples of uncontrollable costs, costs that managers cannot control. The contractor probably would refuse to accept liability for uncontrollable costs such as retroactive safety regulations and delays due to environmental litigation. These extra costs are not due to management error. The effects of not allowing these costs to be added to the rate base are seen as perverse once it is realized that all investments would have negative expected NPVs. (Further discussion of the consequences of strict application of the prudence test on the utility-contractor relationship is presented toward the end of this chapter.)

For a price, insurance companies might accept some of the risk. Insurance companies accept liability for mistakes, even crimes, committed by bank employees, private detectives, tree surgeons, and workers in a host of other occupations. It might be possible for a board of directors to purchase a "mismanagement" insurance policy for a corporation. The relevant question then, of course, is whether ratepayers or stockholders should pay the insurance premium.[7]

A commission could compensate a utility for mismanagement risk by adding to the rate base a premium in addition to the cost of the actual investment, before any penalties. In the absence of competitive bidding, however, the commission would have extreme difficulty in determining a fair compensation for mismanagement risk.

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[7]Since the premiums would vary depending on the quality of the managers and the types of projects under construction, it might be more efficient to raise each manager's salary and require him or her to provide his/her own mismanagement insurance (the utility would be the beneficiary). This policy would be similar to situations where job applicants must be bonded (provide their own insurance) in order to be hired. However, it would result in extremely high salaries! If ratepayers must always somehow bear the risk of large investments being unneeded, either by bearing the cost of the investment or the cost of the insurance (or even the cost of high managerial salaries designed to cover mismanagment premiums), then poor investment incentives may be avoided. In such case, perhaps ratepayers should become equity owners. See Warren J. Samuels, "A Consumer View on Financing Nuclear Plant Abandonments," Public Utilities Fortnightly, January 10, 1985, p. 24, for an argument in favor of this view.

Summary of Investment Consequences

In order to build a power plant with a 10 or 12 year lead time, a utility must forecast demand 12 years into the future. If economic conditions change during the intervening 12 years, demand will probably turn out to be higher or lower than forecasted. Commissions may deny rate base treatment to utilities on the basis of prudence when demand turns out to be lower than forecasted by asserting that the plant, even though it was prudent ex-ante, is not prudent ex-post. Three different applications of an ex-post prudent investment rule to demand forecasting errors have been shown to have perverse unintended effects on the investment policies of regulated utilities. At least one regulatory environment, in theory, produces socially optimal investment, but a real world application might show that this environment also creates unintended consequences.

Our economic analyses of penalties did not distinguish the causes of risk; the results were identical for demand risk, management mistakes, and uncontrollable costs. Penalties reduce investment to zero; underinvestment penalties raise capital costs; combining penalties with compensation for penalty risk may increase efficiency, but not necessarily enough to compensate for increased capital costs. If all economists were asked to vote about whether it is "fair" to charge utility customers for unneeded power plants, management mistakes, and uncontrollable costs, the most votes would probably be cast for the proposition that charging for uncontrollable costs is fair, and the fewest votes would be cast for the proposition that charging for management mistakes is fair. Fairness, however, is not a factor that can be measured in an economic analysis.

Our three analyses indicate that strict application of a prudent investment rule to a utility for some type of undesirable behavior or outcome ought also to include a penalty for underinvestment and compensation to the stockholders both for expected losses and for increased risk. Even if these precautions are taken, any given application of a prudent investment rule may still raise rates if the gain in efficiency does not fully compensate for increased capital costs due to increased risk.

The financial decision rule (NPV) used in this analysis was applied assuming that all types of generating units should be discounted at the same discount rate because the extra risk of the larger project is "diversifiable" and, therefore, not important to investors. However, the rule assumes no bankruptcy costs. As we know from the events of 1984, when a large nuclear unit has construction cost overruns, utilities may be threatened with bankruptcy. Therefore, projects with unproven technologies, uncertain costs, or requirements for great management skill that could threaten a utility with bankruptcy should be discounted at a higher project cost of capital than projects with proven technology.

Utility Bankruptcy

Utility bankruptcy is a possible consequence of applying the prudent investment test strictly so as either to disallow from rate base all or a part of a utility's investment in a completed electric utility plant or to disallow cost recovery for an abandoned plant in which a large investment has been made. Indeed major brokerage firms, such as Standard & Poor's, have openly discussed the possibility of utility bankruptcy. In a recent Standard & Poor's/Applied Economic Research Company Industry Survey (Utilities - Electric), the following appraisal was given about whether bankruptcy is possible in the electric utility industry:

> At least for the half of the industry currently involved in nuclear construction, the answer to this question is really who is going to bear the cost of the industry's nuclear nightmares: ratepayers or stockholders. How regulators will decide this issue realistically will be a matter of balancing ratepayer hostility against their judgement of utility management. Because the consequences of the regulator's decisions are more profound than any in current regulator's experience--the outcome could be anything from utility bankruptcies to electric rate increases markedly higher than even those during the energy crisis years--it is impossible

to foretell how the nuclear dilemma will be resolved. [Emphasis added.][8]

About half a dozen of the largest electric utilities are today on the brink of insolvency. One energy analyst at Goldman-Sachs has observed, "This is the closest utilities have come to bankruptcy in any time in our [recent] history...."[9] Yet, some critics dismiss the talk of bankruptcy as being a scare tactic, or as "a bluff or a negotiating ploy...[used] to force states to raise rates."[10] Nevertheless, the threat of utility bankruptcy has been taken seriously enough for the president of the National Association of Regulatory Utility Commissioners to request a meeting with the Secretary of Energy and the Vice President of the United States to discuss the role state regulators would play in the event of a utility bankruptcy.[11] Some consumer advocates have recommended bankruptcy as a solution to current problems, arguing that the advantages outweigh the disadvantages.

The following discussion is meant to summarize what is known and not known about the consequences of utility bankruptcy and the role of state regulators in that event.

The Consequences of Utility Bankruptcy for Investors and Customers

One recent study completed by the Congressional Research Service addresses the potential effects on rates of an electric utility bankruptcy.

8Standard & Poor's Applied Economic Research Company Industry Survey (Utilities--Electric), March 1, 1984, as cited in Public Utilities Fortnightly, March 29, 1984, p. 40.

9"Generators of Bankruptcy: Some Utilities Are Approaching the Brink," Time, July 23, 1984, p. 81.

10Ibid., quoting Michael Totten, Director of the Critical Mass Energy Project.

11"NARUC Chief Seeks Meeting with White House to Discuss Bankruptcy Threat," Electric Utility Week, May 28, 1984, p. 2.

In that study, entitled Utility Bankruptcy: Thinking the Unthinkable, Kaufman and Dulchinos suggest that the possible consequences of utility bankruptcy might be analyzed by considering a hypothetical case study.[12] They assume a hypothetical utility that (1) has the capital structure shown in table 5-3, (2) has $2.5 billion invested in the construction of a new plant, of which it is sole owner, (3) has funded the construction by short term construction loans, and (4) is allowed to accumulate AFUDC of $0.5 billion, but is not allowed construction work in progress (CWIP) in the rate base. They then assume that the construction of the new plant is halted and the plant is abandoned, with a salvage value of $500 million.

Kaufman and Dulchinos limit their analysis to a consideration of the increased costs resulting from changes in the cost of capital brought about by bankruptcy. They do not consider tax effects or the relative merits of allowing CWIP in the rate base over the use of AFUDC.

TABLE 5-3

INITIAL CAPITAL STRUCTURE OF A HYPOTHETICAL UTILITY

Component of Capital Structure	Book Value ($ in millions)	Percentage of Total Capital Structure	Component Cost of Capital	Weighted Cost of Capital
Debt	$1,300	43%	10%	4.3%
Preferred Stock	300	10	8	0.8
Equity	1,400	47	14	6.6
Total	$3,000	100		11.7
CWIP	$2,500			
Revenues Required to Achieve Authorized Return	$ 351			

Source: Alvin Kaufman and Donald Dulchinos, Utility Bankruptcy: Thinking the Unthinkable, Report No. 84-95 S (Washington, D.C.: Congressional Research Service, Library of Congress, 1984), p. 16.

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[12] Alvin Kaufman and Donald Dulchinos, Utility Bankruptcy: Thinking the Unthinkable, Report No. 84-95 S (Washington, D.C.: Congressional Research Service, Library of Congress, 1984), pp. 15-21.

First, Kaufman and Dulchinos assume that state regulators allow the utility to recover the direct construction costs of $2 billion over a period of time, but not the accumulated AFUDC. They then assume that the hypothetical utility converts its short term construction debt to long term notes and bonds covering the cost recovery period, at the current rate of 14 percent, resulting in the capital structure shown in table 5-4. Customers then pay an additional $279 million in rates to cover the cost of this debt. According to Kaufman and Dulchinos, this first case would imply an average annual increase of $235 for residential customers of the hypothetical utility.

TABLE 5-4

NO BANKRUPTCY CASE: CAPITAL STRUCTURE OF THE HYPOTHETICAL UTILITY

Component of Capital Structure	Book Value ($ in millions)	Percentage of Total Capital Structure	Component Cost of Capital	Weighted Cost of Capital
Old Debt	$1,300	26%	10%	2.6%
New Debt	2,000	40	14	5.6
Preferred Stock	300	6	8	0.5
Equity	1,400	28	14	3.9
Total	$5,000	100		12.6
Revenue Required to Achieve Authorized Return	$ 630			

Source: Alvin Kaufman and Donald Dulchinos, Utility Bankruptcy: Thinking the Unthinkable, Report No. 84-95 S (Washington, D.C.: Congressional Research Service, Library of Congress, 1984), p. 16.

Then, Kaufman and Dulchinos assume that (1) the state commission refuses to allow recovery of the costs of the abandoned plant in rates, (2) the utility becomes insolvent, defaulting on its debt payments, and (3) the utility goes into a Chapter 11 reorganization (a form of bankruptcy), either voluntarily or involuntarily. In such a case, the existing debt becomes due and payable, and interest rates of certain incentive agreements rise to current levels, assumed to be 14 percent as shown in table 5-5.

TABLE 5-5

BANKRUPTCY CASE: CAPITAL STRUCTURE OF THE HYPOTHETICAL UTILITY

Component of Capital Structure	Book Value ($ in millions)	Percentage of Total Capital Structure	Component Cost of Capital	Weighted Cost of Capital
Old Debt	$1,300	26%	14%	3.6%
New Debt	2,000	40	18	7.2
Preferred Stock	300	6	8	0.5
Equity	1,400	28	17	4.8
Total	$5,000	100		16.1
Revenue Required to Achieve Authorized Return	$ 805			

Source: Alvin Kaufman and Donald Dulchinos, Utility Bankruptcy: Thinking the Unthinkable, Report No. 84-95 S (Washington, D.C.: Congressional Research Service, Library of Congress, 1984), p. 16.

New debt is acquired to replace the short term debt, but has a substantial risk premium, costing 18 percent. The required return on equity is assumed to increase from 14 percent to 17 percent. Because of the increased cost of capital, the annual revenue requirement increases by $454 million over the base case. According to Kaufman and Dulchinos, an average annual rate increase of $382 is then required for residential customers of the hypothetical utility. However, if shareholders earn no return on equity, the residential customer of the hypothetical utility would see virtually no increase in rates.

Kaufman and Dulchinos recognize that the results of their hypothetical example are sensitive to changes in the assumed interest rate and the debt load, and that the hypothetical example is simplistic in that most state commissions amortize the construction cost of abandoned plant over a period of years. Also, there are tax effects that have not been incorporated, and a portion of debt is likely to be written off or restructured in bankruptcy. Yet, the point made is that bankruptcy may result in an increase in the cost of capital that could well require a larger increase in utility rates than that required without bankruptcy.

The Consequences of Bankruptcy for State Regulators

This subsection addresses the role of state regulators in a debt reorganization proceeding under Chapter 11 of the bankruptcy law. In law, two types of corporate bankruptcy are possible: debt reorganization and liquidation. It should be emphasized that the only possibility considered here for an insolvent utility to continue operating is a debt reorganization under Chapter 11 of the bankruptcy laws. A Chapter 7 liquidation would consist of a sale of assets that would probably result in a discontinuance of service by that utility. Hence, debt reorganization is considered the more likely alternative in bankruptcy. However, it might be possible for a neighboring (or another) utility to provide service to customers if it were to purchase the liquidated assets and immediately obtain a certificate of convenience from the state commission having jurisdiction over the sales.[13]

The role that state regulators would play in the event of a utility bankruptcy is uncertain because no utility has filed for debt reorganization under Chapter 11 of the bankruptcy law in several decades. Moreover, the recently enacted Bankruptcy Reform Act of 1978 contains major changes in both substantive and procedural bankruptcy law, which have been applied only recently to transportation utility bankruptcy proceedings.

Kaufman and Dulchinos observe that there were two major transportation utility cases in which the new bankruptcy law was applied. Both involve the airline industry. After the airline industry was deregulated in 1978, new entrants came into the industry and competed for customers against more established carriers by reducing fares on the more heavily travelled routes. Many of the airlines borrowed heavily to finance rapid expansion. During the same period, operating costs and interest rates increased, while the number of people flying declined during the 1980-82 recession. The

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[13]See Alvin Kaufman et al., Unplanned Electric Shutdowns: Allocating the Burden (Columbus: The National Regulatory Research Institute, 1980), pp. 63-68.

resulting negative cash flows caused Braniff and Continental airlines to file for debt reorganization under Chapter 11 of the bankruptcy laws in Spring 1983 and Autumn 1984, respectively.[14]

The effects of the Chapter 11 debt reorganization were different for the two airlines. While Braniff Airlines was closed for nearly 2 years after filing its Chapter 11 petition, Continental Airlines was back in operation within a few days. Both airlines eliminated some routes when they resumed service, and other airlines offered expanded service on many of those routes. Customers holding tickets at the time that Braniff filed for bankruptcy were provided service by other airlines, which were later reimbursed under existing default agreements among the airlines.

In both cases service to customers was maintained, even though some customers suffered a temporary inconvenience.[15] It is worth noting that Chapter 11 debt reorganizations of these airlines were processed under Subchapters 1 through 3 of Chapter 11 of the current bankruptcy law, which makes no mention of protecting "the public interest."

Subchapter 4 of the bankruptcy act, which deals solely with railroad reorganization and does mention the public interest, was not used for the airlines.[16] One can make a compelling argument that, in the case of an electric utility, there is a public interest in the continuation of service, just as there is a public interest in continuing rail service.[17]

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[14]Kaufman and Dulchinos, Utility Bankruptcy, pp. 8-13.

[15]Ibid.

[16]See Bankruptcy Reform Act of 1978, section 103, 11 USC § 103 (as amended 1978). Also see Sen. Rep. No. 95-989, 9th Cong., 2nd Sess. 133 (1978), which states that railroad reorganizations are a special case because of the public need for continuous service.

[17]For a fuller elaboration of this argument, see the Honorable Rosemary S. Pooler, "Legal Issues Confronting Regulation in the Event of Bankruptcies," a paper presented to the NARUC Technical Education Conference for Commissioners (San Diego, July 23, 1984).

This argument is even more persuasive when one considers that it is likely that the special provisions to protect the public interest in the case of a railroad reorganization probably found their origin in the United States Supreme Court case of Palmer v. Massachusetts, which held that the trustees for a bankrupt railroad could not abandon certain local passenger services over the objections of the state commission.[18] Considering that maintenance of adequate service is mandated under a utility's obligation to serve, by both state and federal regulatory commissions, the trustee in bankruptcy in a gas or electric utility reorganization is likely to continue to operate the utility.[19] In other words, it is unlikely that customer service would be discontinued in the event of a Chapter 11 debt reorganization.

The potential role of a state regulator in a utility debt reorganization under Chapter 11 is provided for in section 1129(a)(6) of the Bankruptcy Reform Act of 1978. Section 1129 generally concerns the confirmation of the debt reorganization plan, which actually occurs late in the debt reorganization process. Before this occurs, the court appoints creditors' and equity security holders' committees;[20] the court (on the request of a party in interest) appoints a trustee or examiner;[21] the debt reorganization plan is developed, either by the debtor or by a party in interest;[22] and each class of claims or of interests (as set forth in the reorganization plan) must accept the plan.[23] At that point, assuming

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[18]Palmer v. Massachusetts, 308 U.S. 79 (1939).

[19]See Atlantic Refining Co. v. Public Service Commission of New York, 360 U.S. 378, 388 (1959) for an example of the line of United States Supreme Court cases holding that a utility has an obligation to maintain adequate service in the public interest.

[20]Bankruptcy Reform Act of 1978, Section 1102, 11 U.S.C. §1102.

[21]Bankruptcy Reform Act of 1978, Section 1104, 11 U.S.C. §1104.

[22]Bankruptcy Reform Act of 1978, Section 1121, 11 U.S.C. §1121.

[23]Bankruptcy Reform Act of 1978, Section 1126, 11 U.S.C. §1126.

that the plan has not been modified by its proponent,[24] the court holds a confirmation hearing.[25] At no point prior to the confirmation hearing is there any explicit provision in the new bankruptcy act for a state commission to have a role. Moreover, it is somewhat doubtful whether a state commission would have any standing to be heard in the bankruptcy case because it is not clearly a party in interest in the bankruptcy.[26]

Section 1129(a)(6) provides that the bankruptcy court may confirm a reorganization plan only if

> [a]ny regulatory commission with jurisdiction, after confirmation of the plan, over the rates of the debtor has approved any rate change provided for in the plan, or such rate change is expressly conditioned on such approval.[27]

Thus, no reorganization plan proposed by any party in interest (including the debtor, the trustee, a creditors' or equity security holders' committee, a creditor, an equity security holder, or any indenture trustee) will be confirmed unless the regulatory commission that will have jurisdiction over the debtor after the confirmation of the plan has approved the rate change provided for in the plan. As an alternative, the rate change may be

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[24]Bankruptcy Reform Act of 1978, Section 1127, 11 U.S.C. §1127.

[25]Bankruptcy Reform Act of 1978, Section 1128, 11 U.S.C. §1128.

[26]The Bankruptcy Reform Acts provides that "[a] party in interest, including the debtor, the trustee, a creditor's committee, an equity holders' committee, a creditor, an equity security holder, or any indenture trustee, may raise and may appear and be heard on any issue in a case under this chapter." Bankruptcy Reform Act of 1978 §1109(b), 11 U.S.C. §1109. Because the list of parties in interest only includes the debtor, the creditors, the equity and bond holders of their representatives, an argument might be made that a state commission is not a party in interest. Also see, in re Devonian Mineral Spring Co., 272, F. 527, 532 (D.C. Ohio,), which uses a "pecuniary interest" test to define party in interest.

[27]Bankruptcy Reform Act of 1978, Section 1129 (a)(6), 11 U.S.C. §1129.

conditioned on such approval.[28] No provision, however, is made to allow a state commission to object to the reorganization plan.[29]

The precise wording of section 1129(a)(6) has several implications. First, it might be possible for a reorganization plan to be confirmed if the rate change is expressly conditioned on the approval of the regulatory commission with jurisdiction after confirmation of the plan. A state commission might then be faced with a tough decision about whether to approve a rate increase provided for in a utility debt reorganization plan. The commission might find it difficult to deny the rate increase because the increase would probably be necessary "to effectuate substantial consummation of [the] confirmed plan."[30] If the commission denies the rate increase and if the increase is necessary to effectuate the confirmed plan, the court would have the option of converting the debt reorganization under Chapter 11 into a utility liquidation under Chapter 7.[31] In effect, the commission could be faced with either granting the rate increase or seeing the assets of the utility liquidated.

Indeed, one prominent financial attorney, Jacob Worenklein, recently noted that a bankruptcy court can pressure state commissions to raise rates

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[28]S. Rep. No. 95-989, 9th Cong., 2nd Sess. 126 (1978).

[29]See Bankruptcy Reform Act of 1978, §1128 (b), 11 U.S.C. §1128, which states that "[a] party in interest may object to confirmation of a plan." The term "parties in interest" includes not only general creditors, but prior and several creditors as well, and also the bankrupt and every other party, whose pecuniary interest is affected by the proceedings. In re Devonian Mineral Springs, Co., 252 F. 527-532 (D.C. Ohio,). Cf., the Bankruptcy Reform Act of 1978, section 1164, 11 U.S.C. §1164, which expressly provides that "any State or local commission having regulatory jurisdiction over the debtor [railroad] may raise, may appear and be heard on any issue in a case.., but may not appeal from any judgment, order, or decree entered in the case." But as noted earlier, §103 (g) of the Bankruptcy Reform Act of 1978, makes it clear that subchapter IV of Chapter 11 applies only to railroad reorganizations.

[30]Bankruptcy Reform Act of 1978, section 1112 (b)(7) 11 U.S.C. §1112.

[31]Bankruptcy Reform Act of 1978, section 1112 (b), 11 U.S.C. §1112.

before it confirms the utility's reorganization plan. It is unlikely the bankruptcy court would confirm a reorganization plan without adequate rate relief, according to Worenklein. If a refusal of rate relief kept the court from confirming the reorganization plan, keeping the utility in Chapter 11, this could cause legal and financial complications that would threaten reliable service.[32]

It is worth noting that the provisions of section 1129(a)(6) specify that the reorganization plan will be confirmed provided the regulatory commission with jurisdiction over the rates of the utility after confirmation of the plan approves the rate changes (presumably rate increases) provided for in the plan. Thus, the provisions of section 1129(a)(b) do not necessarily require the approval of the rates by a state regulatory commission if the utility debt reorganization plan provides for a transfer from state to federal jurisdiction. Such a transfer of jurisdiction might occur if the reorganization plan provides for a spinning off of the utility's distribution facilities and creation of a generation and transmission entity. Furthermore, it is likely that the bankruptcy court could--if it chose to--execute a confirmed reorganization plan without state commission approval, transferring regulatory authority over a newly created generation and transmission facility to federal jurisdiction.[33] All the sales made by the new generation and transmission entity would then be on the wholesale level and regulated by the Federal Energy Regulatory Commission (FERC). If the FERC were willing to approve the rate increase provided for in the confirmation plan or the FERC had more favorable regulatory policies (such as providing for CWIP in rate base) than the state commission, then the utility might seek a shifting of jurisdictions in its reorganization plan. While the distribution entity would still be regulated by the state commission, there has been some suggestion that the state commission would

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[32]See "Utility in Chapter 11 Still Must Answer to States on Rates, Lawyer Says," Electric Utility Week, June 11, 1984, p. 11.

[33]See generally Bankruptcy Reform Act of 1978 section 1142, 11 U.S.C. §1142.

be required to pass through automatically the wholesale power rates approved by the FERC.[34] State regulators would then be left with direct regulatory authority over the local distribution company stripped of its generation and transmission facilities. If so, a utility reorganization plan could be written so as to limit the role of state regulators in determining the rates faced by ultimate customers.[35].

The studies of potential effects of bankruptcy reported above have, for the most part, emphasized the undesirability of utility bankruptcy from the state commission point of view. As demonstrated by Kaufman and Dulchinos, utility bankruptcy could lead to an increase in the cost of capital, which would in turn lead to increased rates.[36] Chapter 11 debt reorganization might result in a state commission being faced with the undesirable choice of either granting a rate increase or forcing a utility into liquidation, with the attendant uncertainties regarding continuation of service. A Chapter 11 debt reorganization might conceivably lead to a loss of commission jurisdiction over a generation and transmission entity that might be created by the debt reorganization plan.

Still, most state regulatory commissions possess broad powers to regulate financial and other corporate matters. For example, approval by the state commission is usually required prior to the purchase or sale of facilities, the issuance of securities, purchase of securities of other utilities, issuance of restricted stock options, and entrance into lease

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[34]See generally, Thomas Pietrantonio, "The Preemptory Effect of an FERC Rate Approval," Public Utilities Fortnightly, August 16, 1984, pp. 54-48, for a discussion of the conflict between the "Narragansett Doctrine" and the Pike County Light & Power cases.

[35]For a discussion of the issues that would arise should a public utility holding company or its subsidiary file a petition for a Chapter 11 reorganization, see Pooler, pp. 7-10.

[36]Kaufman and Dulchinos, Utility Bankruptcy.

transactions. Prior approval by the state commission is also usually required for a merger or consolidation.[37] Several commissions even participate as a party in corporate reorganization proceedings.[38] While their powers do not permit state commissions to release utilities from debts, the broad regulatory powers that they possess over the finances and corporate structure of regulated public utilities tend to approximate many of the powers available to a bankruptcy court. In other words, with the exception of release from a utility's debt, there is little available under the Chapter 11 bankruptcy proceedings that cannot be achieved under the state commission.[39]

Why then would a state commission, either by action or inaction, allow a utility to become insolvent? What can be gained from bankrupcty?

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[37]Geneva Beirerlein, ed., 1982 Annual Report on Utility and Carrier Regulation of the National Association of Regulatory Utility Commissioners (Washington, D.C.: NARUC, 1983), pp. 525-528.

[38]Ibid., p. 526-528. Specifically, the following state commissions participate as a party in a corporate reorganization proceeding: the Arkansas Public Service Commission, the California Public Utilities Commission, the Delaware Public Service Commission, the Indiana Public Service Commission, Louisiana Public Service Commission, Michigan Public Service Commission, the North Dakota Public Service Commission, the Oregon Public Utility Commissioner, the Pennsylvania Public Utility Commission, the Rhode Island Public Utilities Commission, and the Vermont Public Service Board. In addition, the New Hampshire Public Utilities Commission participates as a party in corporate reorganization proceedings to the extent that approval is required; the New Jersey Board of Public Utilities participates as a party at staff discretion; the Washington Utilities and Transportation Commission participates as a party if securities are to be issued; and the Public Utilities Commission of Ohio sometimes participates as a party, depending on the transaction. The New York Public Service Commission requires its approval of corporate reorganizations.

[39]Conversations with Aaron Levy of the Securities and Exchange Commission at the NARUC Staff Subcommittee on Law meeting, Madison, Wisconsin, June 6, 1984. See also Alvin Kaufman et al., Unplanned Electric Shutdowns, p. 67. Further, Kaufman and Dulchinos suggested that because most regulatory bodies already have many of the powers of a bankruptcy court, a utility bankruptcy can be considered a regulatory failure. See Kaufman and Dulchinos, Utility Bankruptcy, p. viii.

Regulators might allow a regulated utility to become insolvent, making it a candidate for bankruptcy, if it made a large investment that is not used and useful and will not become used and useful in the near future. Only then could a refusal of the rate increases necessary to allow the utility to continue to operate be considered to be in the best interest of the ratepayers (as well as be nonconfiscatory.)

Even then the state regulatory agency might need to take a more active role in a Chapter 11 debt reorganization than that expressly provided for in the Bankruptcy Reform Act of 1978. State regulators would need to seek standing as a party in interest in the debt reorganization.[40] Then, state regulators would be in a position to advocate that either (1) portions of the utility's debt be written off rather than converted to new debt at current interest rates, (2) the debt be restructured so as to tie the repayment to future earnings, or (3) the generating plant of the utility that is identified as not being used or useful be sold to utilities in the region with capacity shortages either now or projected in the near future.[41] The primary objective of state regulators, as opposed to that of the court and most other parties, would be to see that the utility's ratepayers receive electricity at the lowest reasonable cost, consistent with reliable, adequate service. Even with this objective in mind, state regulators might wish to reconsider carefully their actions or inactions before taking any steps that might force a utility into bankruptcy because of the indirect effects that a utility bankruptcy might have in the financial markets. Other utilities (particularly those utilities in financial difficulties and those in the same jurisdiction as the candidate bankrupt utility) might see their costs of capital rise to offset the higher risks perceived by investors. This too would eventually lead to higher rates.[42]

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[40]This suggestion might require statutory changes in the Bankruptcy Reform Act of 1978.

[41]Kaufman and Dulchinos, Utility Bankruptcy, p. 21.

[42]Ibid., p. 20.

Utility Relationships

Between the extreme consequences of a utility risking bankruptcy by undertaking construction and a utility refusing to undertake construction for fear of bankruptcy are many other, less severe, possible consequences of frequent, strict prudence applications. These represent shifting relationships among the parties with an interest in utility construction as they adjust to a possibly new regulatory environment.

The consequence of these shifting relationships is usually to increase costs in ways that ultimately are borne by utility customers. While these cost increases are important, they are all difficult to quantify. Hence, it is not possible to forecast the net effect on rates of protecting customers from imprudently incurred costs, forcing managers and other parties to be more efficient, and increasing costs because of shifting relationships.

Capital Costs

Frequent and severe application of the prudent investment test would affect utility relationships with the financial community and--even without a bankruptcy--would result in higher costs of capital. Bond rating agencies and the stock market take account of a utility's ability to have all of its capital expenditures recognized by its regulatory authorities and included in the rate base. If exclusion becomes common, a certain consequence is to increase the cost of raising capital, both debt and equity, in the financial markets. As the cost of money increases, so does the cost of financing construction and the cost to the ratepayer of providing a return on investments that enter rate base.

This consequence is, perhaps, to be expected in a period of higher utility risk, as discussed in the previous chapter. Investors, as risk-takers, may assume more risk but require a high return.

Utility-Contractor Relations

To date, most relationships between utility officials and equipment vendors, architect-engineers, and construction firms have been one of partnership in construction. A possible consequence of regular prudence investigations may be to move utilities into a more "arm's length" relationship with contractors, possibly one characterized by mutual mistrust and suspicion. If heavy pressure on utilities to question every activity of a contractor becomes the norm, the mutual trust and confidence between the parties and their treatment of each other as partners in a construction endeavor may be impaired, if not lost.

The utility should and must insist that it gets all it contracts for and pays for. But, a team atmosphere and a cooperative spirit are essential in undertaking a major project, and these can be weakened by the tension and apprehension of an "arm's length" relationship.

Such a posture is not all bad, of course. There are numerous occasions where a utility may ask the contractor to perform tasks that the contractor regards as unnecessary, wrong, or even foolish. Under the relationship to date, the contractor may agree to perform the tasks to preserve good relations. Under the likelihood of a prudence investigation, the contractor will be compelled to disagree and to do so in writing for his own protection.

However, if this mode of behavior is taken to extremes, it may become very difficult for the utility to function effectively with its contractors.

Bidding Policies

Until now, most major contractors have bid on utility projects on the basis of cost plus a reasonable fee. It was generally argued that this resulted in the utility obtaining the lowest cost. The alternative of a "fixed-price," lump sum bid requires the contractor to include a large provision for contingencies.

Under the cost-plus contract, however, contractors are unable to make provisions for the possibly large costs of their involvement in a prudence investigation, or resulting litigation, following construction. To protect themselves, contractors on relatively small utility undertakings will build into their bid proposals adequate protection against the potential liabilities they could incur if utilities seek compensation from their contractors on costs that have been disallowed on the basis of a prudence inquiry.

Lump sum bidding may then have to become the norm, possibly resulting in higher costs for the same services and equipment. For large contracts involving millions or even billions of dollars, the only contractors who might risk lump sum bids are those with only limited assets to protect. Their solution to a major repayment obligation could be to declare bankruptcy. The large established architect-engineering firms could well withdraw from bidding--to no one's long term advantage.

Moreover, insurance rates are reported to have risen very sharply for such firms, and other firms are reportedly experiencing difficulty in obtaining insurance because of concern over prudence questions. Rising insurance rates can add to the cost the ratepayer must bear.

Increased Litigation

If state commissions disallow certain expenses on grounds that utility management or its contractors did not act prudently, increased litigation is a probable consequence. Indeed, a commission might require a utility to recover all possible costs by litigation before deciding how the residual costs are to be treated. Where utility management has been found by the state commission to have been imprudent, stockholder derivative suits will almost certainly result.

Of course, commissions should not hesitate to act properly just because litigation, including stockholder suits against management, might result. What is worth considering, however, is the possible long term cost consequences of such a situation. An analogous situation may be the estimated $15 billion added yearly to medical costs in the U.S. by malpractice cases. These have increased from five per one hundred doctors in 1975 to sixteen per one hundred doctors in 1983.

Utility boards of directors should be held responsible for the actions of the managers they have selected. In some cases they have changed management because of overruns and inefficiencies leading to delays and much higher costs. The prudent investment test may play an important role in assuring that such utility directors responsibly discharge their duties. Increased litigation to bring this about may increase costs in the short to medium term. The long term effect on costs could be higher because of litigation or lower because of greater managerial efficiency.

Record Keeping

Another possible consequence is an increase in the expenses associated with the records that the various parties must keep. All business activities ought to be reasonably well documented, especially those dealing with major and complex contracts. If, however, the prudence test is applied with increasing strictness by state commissions, the consequence may be far greater and more detailed record keeping by both utilities and contractors. Much of this will be unnecessary for engineering purposes and will add to the cost of any facility being constructed. Insofar as nuclear facilities are concerned, the NRC already requires extensive and expensive record keeping.

This may increase to a level where, as in the field of medicine, contractors, like doctors practice "defensive medicine." This means that they routinely order all sorts of tests, many of which may be irrelevant and expensive, just to have a battery of results available for the malpractice suit. The doctors, of course, do not pay for them--the patients or their insurance companies do, increasing the cost of medical care.

The point here is not that careful records should not be kept. Certainly, the questions a regulatory body or its staff wishes to explore should not be dismissed with the simple observation that there are no records. Rather, it is that a prudence investigation well after the fact may force utilities and contractors to shift into a more burdensome type of record keeping, much of which is very likely to be self-serving to protect against a possible lawsuit.

Technical Innovation

Strict application of the prudent investment test could ensure that utilities seek out the best means of meeting the needs of the customers. Some economists believe that reducing risk for utilities has a perverse side effect, namely, it produces a reluctance to adopt new technology. This, in turn, may be costly to society because the rate of progress slows.

However, even if this were true, no commission can solve this problem by itself, because of the "free-rider" problem: requiring a utility to take on the risks of a new technology forces its consumers to bear the financial risk of the new technology. Once the new technology proves successful, other commissions can authorize use of the now proven technology and obtain its benefits for their consumers without exposing them to any of the risk.

On the other hand, commissions may unintentionally lead utilities to use new technology. Suppose that a utility considers building three 400-megawatt nuclear plants with proven technology and or one 1,200-megawatt plant with unproven technology and expected 12 percent economies of scale. Capacity planning models usually apply the same discount factor to both proposals and show the 1,200-megawatt plant to be 12 percent cheaper than the three 400-megawatt plants. A regulator might then require the utility to choose the 1,200-megawatt plant with unproven technology.

Further, architect-engineers and equipment manufacturers* have played major roles in putting and keeping the United States in the forefront of technological development in the field of electrical design and construction. A possibly stifling effect on new designs could result if they had to defend all efforts at improving equipment, systems, and construction technology to regulatory agencies, and perhaps the courts.

CHAPTER 6

FUTURE DIRECTIONS FOR THE PRUDENCE TEST

In this final chapter, we consider issues relating to the concept of prudence in public utility regulation that need to be resolved. Most of these issues will be resolved only in future applications of the concept by state and federal commissions and perhaps by judicial review of commission decisions. To conclude the chapter, we present our commentary of how some of these issues are likely to be decided. To begin, we summarize what we have said in the first five chapters about the current legal status of the prudent investment test.

Current Legal Status

The concept of prudence as it applies to public utilities has been judicially developed. It is not a hard and fast rule of law, but a concept that is in some respects vague and still evolving. The term "prudence" describes a tool available to regulators. Although it is not well articulated, it is used, and its application is referred to as the prudent investment test.

The use of prudence in utility law has direct antecedents in other areas of law where the concept continues to be used as a method of providing managerial oversight. Two principal areas--trust law and oil and gas law--provide important analogous case law that is instructive in the use of prudence in public utility law.

The United States Supreme Court has not given an explicit majority approval to the use of the prudent investment test, even as a method of valuation to determine the value of plant to go into rate base. Rather, the Court has adopted an end-result test, expressed in Hope Natural Gas, as its constitutional standard.[1] This end-result test looks not to the

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[1]Federal Power Commission v. Hope Natural Gas Co, 320 U.S. 591 (1944).

method or theory used in rate base valuation, but rather looks to the total effect of the end result of a rate order. If the end result is not unjust and unreasonable and does not result in confiscation, then the valuation method or theory will be upheld.

It appears that there are only a few instances where the prudence concept has been imposed as a statutory standard in public utility law. The Federal Power Act does not use the term. The Natural Gas Act and the Natural Gas Policy Act of 1978 do not use the term, although legislation is currently pending to amend the latter by including prudence as a standard governing natural gas acquisition. Most state utility statutes do not appear to use the term; although where it has been used in statutes, its meaning and usage have usually incorporated much of the judicially developed definition.

One decision apparently interpreting a state statutory provision is Northwestern Bell Telephone Co. v. State,[2] which held that the words "prudent acquisition," for the purpose of a statute allowing such an acquisition to be included in a telephone company's rate base, are not words of art referring only to a decision by one utility to acquire property belonging to another successor utility, but are also words applying to decisions regarding expenditures of every kind made by the utility.

Until recently, the prudent investment concept was treated for the most part in an almost perfunctory manner, as state regulators relied on the presumption of prudence in considering utility decisions. The frequent application of the prudent investment concept as a test to judge utility decisions involving construction cost overruns and plant additions and cancellations is relatively recent. Thus, while it is generally thought that the prudent investment test is a well-established standard in public utility regulation, it is not. Rather it is of more recent development as now applied. However, one can argue that the current stricter use of

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[2]Northwestern Bell Telephone Co. v. State, 216 N.W.2d 841,852, 299 Minn. 1 (1947).

prudence is the way that the law always would have been interpreted if today's riskier circumstances had arisen before.

The procedures for using the test are, in some ways, still not well defined. We know only that certain guidelines have been held as necessary for commissions to follow in order to have a prudent investment test application sustained by the courts. These four guidelines, which are explained in chapter 3, require (1) a rebuttal of the presumption of prudence, (2) a rule of reasonableness under the circumstances, (3) a proscription against hindsight, and (4) a retrospective, factual inquiry. But following these four guidelines does not necessarily place an application of the prudent investment test on solid ground with respect to judicial review because the legal weight of the test measured against other legal requirements is uncertain. Further, successful application of the concept in a specific case is uncertain because there is no specific, universally accepted checklist of what constitutes a prudent investment decision.

In practice, state commissions tend to move quickly to determining the facts of the particular case, without extensive articulation of the nature of the concept of prudence or of its procedural application. The prudent investment test as currently used in public utility regulation is an important but imprecise standard against which regulators judge the investment decisions of utility managers. Nevertheless, the concept of prudence is legally available--certainly for reviewing current and future utility decisions, and perhaps in a more limited way for reviewing the decisions of the past.

While useful parallels can be drawn between the concept of prudence in public utility law and the prudence concept in analogous areas of law, many issues concerning prudence and its application are as yet unresolved in the public utility law: What is it? Toward what is it evolving? How useful is it? How can it be better articulated? To some extent, those who refer to the prudence test in its current role as a long-standing regulatory principle are characterizing the concept as something that it is not. As a result, there is a danger of misapplication of the concept in the hearing room where the legal concept often merges with its policy application.

In the two sections that follow, we first consider issues to be resolved in future applications of the prudent investment test. Then, we present our concluding analysis regarding future directions for the prudent investment test and our views on some of these issues.

Issues To Be Resolved

One set of issues relates to articulating more fully both the nature of a prudent investment decision in the utility business and the regulatory procedures for judging the prudence of a utility decison. Debates over prudence have prompted some spokesmen, both for regulators and for utilities, to call for greater commission involvement in regulated company investment planning. A second set of issues concerns the appropriateness of such involvement. Also, as discussed in the previous chapter, concerns over the consequences of strict application of the concept of prudence to large capital investment decisions raise a set of issues relating to appropriate limitations in applying the prudent investment test. These three sets of issues are taken up next.

Nature and Use of the Prudence Test

While several state commissions have recently used the prudent investment test extensively, the substantive and procedural elements of the standard are not yet well articulated. State commissions in applying the test have concentrated more on setting out the facts of specific cases than on the elements of a prudent decision or on the procedural elements of a prudence inquiry. What still needs to be developed is a well-established process for determining what constitutes a prudent decision for utility managers.

While many agree that the substantive elements of prudence need to be further articulated, there is no ready agreement about what this means. To some, it means establishing for each type of case (cost overruns, abandonment, and so on) what is a prudent or imprudent decision under various circumstances. The problem is that this may amount to issuing a "guidebook" to utilities for each type of decision they must make. Such a utility "guidebook" will not necessarily result in the avoidance of imprudent decisions--only good decision making will. To others, articulating the elements of prudence means simply introducing into the regulatory inquiry some clear standard of prudence that is generally applicable.

Further, it is necessary to develop and articulate the regulatory procedures for looking at prudence. This could be accomplished by means of state regulators announcing the general procedural elements of the prudence test in any case where it is used. Alternatively, it might best be accomplished by a gradual case-by-case development of procedure. Of course, the procedural elements of the prudent investment test could be articulated by state legislation. However, this would tend to remove from the procedures the flexibility and discretion that regulators might find desirable as the test evolves in regulatory law.

Articulation of the prudent investment test process may be necessary in order to assure deference by state and federal courts to state commissions in cases involving application of the prudent investment test. Courts normally give judicial deference to the quasi-judicial processes of administrative agencies such as the state commissions. However, in order to assure judicial deference in state applications of the prudent investment test, the procedure for the test should be spelled out; otherwise, a court might find the commissions' decisions to be arbitrary and capricious, and hence unlawful, either under the applicable state administrative procedures act or as a matter of due process.

Perhaps the most significant issue to be resolved about the nature of the prudent investment test is how it relates to the used-and-useful test.

In one view, the prudent investment test and the used-and-useful test are two distinct tests. Viewed another way, the prudent investment test and the used-and-useful test are actually two statements of the same valuation standard.

If the tests are distinct, an important issue is whether rate base treatment requires an investment to be both prudently decided and used and useful, or just either one of these. Some analysts have suggested that only one of the two tests need be applied in a rate base determination. This, of course, raises the question of which test should be chosen, since the outcome will depend heavily on the test. Some utility representatives have asserted that it is unfortunate that all state utility statutes have a used-and-useful test because it confuses the real issue of whether utility management has acted prudently. In certain recent excess capacity cases, electric utilities have admitted that some generating capacity is (at least temporarily) not useful, but they have argued for rate base treatment of that capacity on the basis of the prudence of the decisions that led to excess capacity. Commissions in some cases have agreed with this argument.

In some other cases, the language in commission opinions supports the view that investments must be both used and useful and must be prudently incurred for the value of the resulting plant in service to be added to rate base.

If the tests are distinct and both are to be applied and met, does the order of application matter? Some would argue that the prudent investment standard should be applied first, and applied solely to the initial investment decision. Then the used-and-useful standard would be applied second, as a higher standard, once the investment is ready for rate base treatment. Here, the used-and-useful test substitutes for what competitive companies would call a market test of demand for their product. (Managers of competitive companies frequently make major investment decisions that are reasonable at the time, but turn out nevertheless to be wrong in the sense that there is little or no market for their product. It is interesting to note that competitive companies are not unregulated, only less regulated. They are subject to environmental, occupational safety, tax, and many other regulations that are subject to changes which can affect the eventually profitability of an earlier investment decision.) Thus, in the case of a monopoly utility, if the initial decision to build a plant was prudent, but the plant is not used and useful when completed, then the plant could be excluded from rate base if the two distinct tests are applied in this order.

On the other hand, some would argue that the used-and-useful test should be applied first, and the prudent investment test applied second as a more exacting standard. The used-and-useful test would be applied to see if a plant is actually used in service and useful in providing service. If this initial test is met, then one could apply the prudent investment test to any doubtful investment decisions, from the initial decision to build the plant through the significant decisions involved in the construction of the plant and the final decision to complete the plant. The purpose would be to decide exactly how much of the expenditures on the plant were prudently decided. With the view that the prudent investment test and the used-and-useful test are two distinct tests, one can see that the order of application may affect the resulting rate base treatment of the investment.

The alternate view is that the prudent investment test and the used-and-useful test are very much akin, perhaps actually different aspects of the same rate base standard. Historically, it is clear that both the used-and-useful test and the prudent investment test are used in the determination and valuation of rate base. The used-and-useful test is an inventory-of-rate-base test that normally results in a simple "yes or no" determination of whether a facility is used and useful and should be included in rate base.[3] The prudence test, on the other hand, has been used as a

[3]However, a commission may find that some components of total plant facilities are not used and useful and exclude these from rate base.

valuation test that determines how much of the investment is used and how many of the investment dollars were spent usefully as opposed to wastefully. It makes this determination by looking at the investment decisions at the time that they were made. Rather than being an inventory-of-rate-base test, the prudence test is a value-oriented test for determining the value of a facility that belongs in the rate base inventory. Viewed in this way, the prudence test is merely an extension of the used-and-useful standard, a particular way of expressing the capability of this standard to do more than a simple yes/no analysis. In this view, the prudence test is not a new test, but a newly emerging facet of the used-and-useful standard that is solidly entrenched in every state's public utility laws.

The relationship of prudence to a possible third investment standard needs to be resolved. This is the so-called least-cost investment standard. It requires that utilities actively investigate several ways of providing service so as to determine which is of least cost. For example, according to current thinking, electric utilities under this standard would have to consider a variety of ways of matching supply and demand, including extended service lives for older units, new alternate fuel technologies, cogeneration, long term power purchases, interruptible service, and utility-sponsored conservation programs. The issue here is whether the prudent utility decision maker must consider all such factors in the planning process and select the least cost strategy.

Recall that prudence is not a test of optimality in decision making; prudence does not require that the best investment decision be made, only that a reasonable one be made. On the other hand, it is typically said that regulated monopolies are expected to provide adequate service at "the lowest reasonable cost." The least-cost standard has firm legal standing when a utility faces clearly defined choices with predictable outcomes.[4] As alternative strategies for meeting electricity demand are increasingly studied and as analytical tools for comparing the long run values of these

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[4]See Atlantic Refining Co. v. Public Service Commission of New York, 360 U.S. 378, 388 (1959).

strategies continue to be developed, the standard of reasonableness may evolve. As it does, the distance between the prudence test and the least-cost investment test may shrink.

Hence, what needs to be resolved is how the used and useful standard, the prudence standard, and the least-cost investment standard relate to one another. Are they three aspects of a single standard for valuation of rate base, perhaps with any of the three aspects coming to the fore depending on the circumstances of the case? Or are these three distinct regulatory hurdles that a utility must leap over, one after the other, to receive rate base treatment of an investment?

Besides the issues about the nature of the prudence test, there are several issues to be resolved that relate to the use of the test. One issue is the regularity with which the prudence test should be used. Should it be a routine consideration in rate base valuation, or should it be reserved for occasions when there is overwhelming evidence for casting aside the presumption of prudence? As commissions evolve practices for using the prudence test, care should be taken, on the one hand, to avoid making the test routine, and, on the other hand, to avoid confining the applications so narrowly as to limit appropriate future use of the test. An important consideration here is the ease with which intervenors are permitted to challenge a utility investment on the basis of the prudence of utility decisions. Because of the costs involved, in time and manpower, to support a prudence inquiry, properly defining the level of proof required to overcome the presumption of prudence is vital.

A second issue about using the prudent investment test is the degree to which it should be used as a tool to help formulate commission policy. The prudent investment test lends itself to being developed and articulated in a manner that reflects commission policy and practice. It is important to recall that state commissions are quasi-judicial bodies, not judicial bodies, so that lack of a firmer legal basis for prudence is not as vital as it would be in a court. Thus, it is to be expected that a commission would care less about the articulation of a concept than about gathering and weighing evidence in order to determine the facts of a case and the appropriate policy for the circumstances. In their role as policy makers, state commissioners can determine how the prudent investment test will apply to various types of utility investment decisions in various contexts and thus make clear to the managers of its regulated utilities what course of action is expected of them in new circumstances.

The prudent investment test is not, however, a tool for dealing with complex policy problems in a simple way. It is not a panacea; the application of the prudent investment test to complex issues is itself complex.

When the prudence test is used to determine the number of dollars of imprudently incurred expenditures, regulators may wonder about just how precisely this figure can be defined. In complex prudence investigations, such as those involving nuclear power construction, this will be a difficult task that requires judgment as well as data. It is not, however, an impossible task; juries in negligence cases, for example, routinely make similar judgments.

Another important issue that may emerge in actual uses of the prudent investment test is the question of to whom utility managers are answerable for their prudent decision making. State commissions need to understand to whom the standard of reasonable care is owed. Utility managers may make decisions that are in the best interests of the stockholders, the current ratepayers, future ratepayers, or society as a whole. If the prudent investment test is applied from other than the stockholder's point of view, application of the test causes a potential conflict between management's goals and society's goals. One duty of management to its stockholders is to maximize profits given the existing and anticipated regulatory constraints. Of course, utility managers look at the regulatory "rules-of-the-road" as they chart a course that they hope will maximize profits. As regulatory rules and applications change, managerial decision making changes. Applying the prudent investment test from the stockholder's point of view avoids the divided managerial loyalty that results when the goals of the stockholders are not the same as those of society. Of course, applying the prudent investment test from the stockholders' point of view would make the test little more than a surrogate for other legal rights that protect stockholders, such as stockholder derivative suits, and would also do little to protect the utility customers.

Alternatively, the prudent investment test could be applied to see if decisions were prudently made on behalf of current ratepayers. That is, were utility decisions directed toward providing adequate service at just and reasonable rates today? Managers are expected to make decisions directed toward this goal because the utility accepts this goal when it accepts the franchise to provide service. However, applying the prudent investment test on behalf of current ratepayers is not without difficulties. Consider the case where a utility has a generating unit that is three-fourths completed when it finds that the plant is no longer required. To make the example simple, suppose it is in a situation where, if the costs of abandoned plant could not be recovered in rates, the abandonment would mean, if not bankruptcy, very high capital costs in the future. This will impose a cost on future ratepayers. This cost can be avoided if the unit is completed, but this action imposes a cost on current ratepayers. Setting aside management obligations to investors, what is the prudent decision for management? Should it decide solely on the basis of current ratepayer interests, or does it have an obligation to keep the company financially sound so that adequate power is available at reasonable rates in the future?

If some weight is to be given to the interests of future ratepayers, perhaps all parties' interests should be taken into account in the prudent decision: current ratepayers, future ratepayers (with appropriate discount factors), investors, utility employees, state treasurers, and so on. If the decision is based on all parties' interests, properly weighted, then the decision may be prudently made from the viewpoint of society as a whole. This is a proper viewpoint for commissioners to take as agents of state government, but the hardest to deal with in the hearing room.

The prudent investment test, if applied to protect society as a whole, would give due recognition to the quid pro quo nature of the arrangement between the regulated utilities and the commission qua state. The utility is to receive reasonable compensation for providing adequate service in exchange for being granted a territorial monopoly. The utility knows it will not be allowed to earn extraordinary profits, but expects it will be protected from certain losses, at least the loss of business to competitors. Because a utility is a regulated company acting in the public interest, it must provide service at the lowest reasonable cost consistent with adequate and reliable service, as indicated in the Atlantic Refining Company case cited above. If this duty is owed not only to current ratepayers but to future ratepayers, the utility should continue to take into account the needs of future ratepayers in its utility investment decisions. Then a state commission, in applying the prudent investment test, would want to judge whether utility management sought to protect the interests of future as well as current ratepayers when making investment decisions.

As state commissions develop the prudent investment standard, it is important that the regulatory "rules of the game" be as explicit as possible. Otherwise, utility managers may justifiably complain that, in aiming at achieving a reasonable utility investment decision-making process, they are trying to hit a shifting target. Managers need to know what the standards are by which they will be judged in order to decide with confidence. The use of the prudence test should not be so uncertain that managers are afraid to make decisions. After all, a decision not to decide or a failure to manage can also be imprudent. The proper role of management is to manage, not to allow events to run their course.

Clarifying the role of prudence is not only in the managers' interest; it helps to further the objective of having a prudence test. This objective is to make utility managers more cognizant of the import of major investment decisions. The test, properly used, can have a "cleansing effect" on the managerial decision-making process, leading to better utility investment decision making. Use of the test need not mean managerial paralysis if the ground rules are understood by all parties.

Commission Involvement in the Decision-Making Process

As shown in chapter 4, the risks that utilities face today in making investment decisions are significantly greater than in earlier years, and the consequences are greater also. Because of these factors, the prudent investment test has emerged as a tool frequently used by state commissions to allocate risk between customers and investors. Now many state regulators, legislators, and governors are seeking to have state commissions become more involved in the utility decision-making process. This involvement is aimed at ensuring better decisions and lowering the level of risk. Sometimes a supplementary goal is to recognize that, when regulators must allocate a large share of the risk to ratepayers, regulators should participate in the decision-making process. Utility representatives seem divided on the question of greater commission involvement, some objecting to infringement of management prerogatives and others welcoming a process that they see as shifting more of the risk onto utility customers. The prudent investment test may act so as to define the boundary between commission regulation and managerial prerogative.

Several issues are involved in use of the prudent investment test where commissions participate to some degree in either making or approving investment decisions. The fundamental issue is whether state commissions ought to become very involved in the utility investment decision-making process on an ongoing basis. Such involvement could take the form of periodic prudence reviews or of an immediate review of each major utility investment decision as it takes place.

Several factors favor greater commission participation in approving investment decisions by utilities. The most important factors relate to the opposing threats of future excess capacity and future capacity shortages for electric utilities. Excess capacity resulted from overly optimistic utility views on the growth potential of the industry, and many regulators believe that greater commission involvement in deciding future capacity needs will assure a more realistic judgement about demand growth. This, in turn, would protect commissions in the future from facing major bankruptcy-versus-rate-shock decisions related to overcapacity. If commissioners believe that rate base exclusion of major investments is realistically impractical, they have a special incentive to review the investment decision before the funds are committed.

On the other hand, without an assurance of favorable regulatory treatment, utilities are likely to underinvest in new capacity, for the reasons set out in chapter 5. Regulators would give such an assurance only if they were very involved in the utility decision-making process on an ongoing basis. Absent early commission approval of a major construction project, the utility would be reluctant to undertake construction if the possible rewards were small or nil and the possible penalties large. However, a utility would be encouraged to make investments in needed plant if the commission determined, once and for all, the prudence of the investment decision at the earliest planning stages, or if the commission participated in periodic prudence reviews during construction.

Another factor favoring greater commission involvement in major utility decisions is risk reduction and hence capital cost reduction for utilities. In a regulatory environment where the commission withholds judgment on the acceptability of investments for 10 years or more, investors require a risk premium in the form of higher return on debt and equity if they fear that the commission may reject some or all of the investment expenditures as imprudently incurred. If early commission involvement assuages this fear, the utility's cost of capital is lower and the ratepayer's cost of service is lower.

However, if the objective that state regulators seek to achieve is better utility investment decision making so that society as a whole benefits, then involvement by a state commission or other state agency in the decision-making process might be ineffective or counterproductive.

Commission participation in, or even periodic review of, the decision-making process would require significant staff resources and levels of expertise. Otherwise such participation could be ineffective. It is easier for utilities to know their own business and to carry it on than it is for commissions and their staffs to try to duplicate the decision-making machinery of a utility. Without adequate staff resources, there would always be a question about whether the staff carries out a truly independent review of the decision. The difficulty is that the commission, in supporting its own staff's analysis, may in effect feel bound to support a utility decision that may not be adequately reviewed.

With state commission involvement, there might be less incentive for the utility managers to use the best available decision-making procedures. Instead, decision making may be only as good as "the state" requires. Further, regulators may favor a new technology (such as photovoltaics, wind generation, or geothermal generation) or a mode of balancing supply and demand (such as conservation, reliance on cogeneration, or interregional purchased power), which may not ultimately prove to be the most reliable and economical power supply strategy. Yet, utilities might adopt a less-than-optimal power supply plan if this assured regulatory preapproval of construction plans.

Regulatory preapproval suggests two closely related issues that arise with greater commission involvement: the possibility of co-optation and the possibility of a regulatory estoppel. If a commission (or other state agency) takes part in the utility investment decision-making process--by being directly involved in demand forecasting and capacity expansion planning and by reviewing all subsequent major utility investment decisions--the commission might be unwilling to find a decision to be imprudent. By taking part in the decision-making process, the commission may step away from its role of judge and take up the role of defender of the decision.

In this way, participation in the decision-making process may lead to co-optation. If the commission or other state agency actually takes part in the decision-making process and is therefore reluctant to find that an investment decision was imprudent when made, the result will be that the utility customer must bear the risk of poor decisions. If commission participation leads to better decisions, perhaps the ratepayer will be satisfied. If it does not, the ratepayer may view commission participation as a mistake, especially if it seems that the reason for commission inaction is that the commission feels bound by its prior review.

Even if the commission does not feel bound by its taking part in utility decision making, the commission might nonetheless actually be bound by the operation of a regulatory estoppel, a legal principle that could prevent the commission from penalizing a utility for an imprudent decision in which the commission took part. The legal doctrine of estoppel operates to prevent miscarriages of justice when one party has justifiably relied on another and the first party has suffered a detrimental change in position.[5] This doctrine might prevent a state commission from disallowing investment expenses incurred by the utility if the investment decision was given prior approval by the commission. A regulatory estoppel might also prevent the commission from penalizing a utility for an imprudent decision in which another state agency took part. The operation of a regulatory estoppel would lessen the risks that a utility faces in making an investment decision. But it would have the same pitfalls as co-optation and do as little to assure that good decisions are made.

Whether a regulatory estoppel would actually operate is as yet unclear. However, there are some indications that the courts would weigh

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[5]The doctrine of estoppel was described in detail in the preapproval study referred to earlier. See Russell J. Profozich et al., Commission Preapproval.

commission involvement in decision making heavily to the point where any subsequent denial of cost recovery might represent confiscation. The issue of a regulatory estoppel has already arisen in the context of whether a state commission can refuse to permit a utility to recover the costs of a cancelled plant, based on the used-and-useful test: a Wyoming Supreme Court decision affirmed the Wyoming Public Service Commission's denial of cost recovery, but stated in dicta that its decision would have been different if the commission had granted prior approval to the utility before entering into the project.[6] In effect, the court ruled that prior approval of major utility expenditures could create an equitable estoppel that would prevent a commission from disallowing utility expenditures on an investment in plant that was later cancelled, abandoned, or otherwise not brought into service.

An estoppel can operate only if a utility justifiably relies on the state commission's prior approval of an investment. A utility's reliance would not be justifable if the utility makes imprudent expenditure decisions not directly approved by the commission. For example, a commission's prior approval of a utility's investment in a nuclear unit need not prevent the commission from later disallowing associated investment expenditures that are incurred in excess of what is reasonably required. Nevertheless, a state commission would be well advised to specify in an order granting prior approval to a major utility investment that only reasonable expenditures will be recoverable.[7]

Regulatory estoppel presumably would not operate if, after commission approval of a major construction project, conditions change sufficiently to occasion a re-examination of the project. However, an equitable estoppel might operate to keep a state commission from finding that investment expenditure decisions in an ongoing utility project were imprudent if the commission were to review the progress of the project periodically or were

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[6] See Pacific Power & Light Co. v. Public Service Commission, 677 P.2d 799 (1984).

[7] Russell J. Profozich et al., <u>Commission Preapproval</u>, at pp. 35-38.

otherwise involved in oversight of project construction. Granted, if a commission were to become highly involved in reviewing a construction project, it might better judge the prudence or imprudence of management decisions while the facts are still fresh, without the danger of engaging in hindsight years later.[8] But, a commission and its staff may work best in retrospect, rather than "on the job."

The heart of the issue is whether regulators ought to create procedures for prospectively assuring prudence that are so detailed that the concept of prudence becomes unnecessary as a tool for retrospective review, or whether they ought to abstain from participating in utility decisions in order to reserve the right to review and criticize these decisions.

Limitations on Applying the Prudence Test

A third set of issues relates to how far state commissions can or should go in applying the prudent investment test where a very large utility investment is involved. Clearly, the results of applying the test in a particular circumstance depend greatly on the judgment of the decision makers. If that judgment is to make utility investors bear the full burden of an imprudent decision, how burdensome can the treatment be before the courts will overturn the commission decision?

As discussed in chapter 2, the end-result test of Hope sets the outer boundary of a prudent investment test application. This is that the prudent investment test (or any other valuation method for that matter) cannot be so applied as to reach a confiscatory result. Confiscation takes place whenever there is a taking of property without just compensation. For a regulated industry, this occurs if it is not allowed an adequate return on its investment.

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[8]Ibid., p. 40.

The courts have repeatedly ruled that keeping property out of rate base because it is not used and useful does not result in confiscation. It is not yet clear whether rate base exclusion based on a finding of imprudence would be viewed as confiscatory. Recalling our earlier discussion, if the prudent investment test is found to be merely an aspect of the broader used and useful standard, then its use presumably would not be confiscatory.

However, if the prudent investment test is viewed as a distinct test from the used and useful test, then the resolution of this issue is less certain. It might be that an application of the prudent investment test would not lead to a confiscatory result because confiscation does not take place if management is found to be inefficient. This is because a return would be considered adequate if, under _efficient_ management, it would maintain and support the utility's credit and allow the utility to raise the money necessary for the proper discharge of its public duties.[9] In other words, if management is found to be inefficient, then it cannot be said that the return is inadequate solely because of an application of the prudent investment test. No confiscation would have taken place due to the application of the test.

On the other hand, if the prudent investment test and used and useful test are viewed as distinct, the prudent investment test may be judged as conflicting with the used and useful test, which has the firmer statutory basis. Then a finding might be possible that an application of the prudent investment test resulted in confiscation. In any event, future challenges, if any, to the prudent investment test on the grounds that the application of the test leads to a confiscatory result must be on a case-by-case basis, and according to _Hope_ only the particular end result could be held to be confiscatory. Hence, the prudent investment test itself would likely survive the challenge.

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[9] See Bluefield Waterworks & Improvement Co. v. Public Service Commission, 262 U.S. 679, 692-693 (1923).

how "useful" utility property is--both in an absolute sense and in a relative sense. Many circumstances may be considered by regulators in the name of prudence--cheaper capital alternatives that were available at the time planning decisions were made, the effectivenes of cost controls for capital projects, the validity of demand forecasts, and project necessity, to mention only a few. Clearly, not every capital investment alternative is equally "useful." Prudence provides a qualitative means of assessing the degree to which investments are "useful," by potentially allowing less than full costs incurred to be utilized in rate calculations on the basis of the worthiness of the costs. Prudence is not confined, however, to the capital cost component of ratemaking, for it may be used to assess the quality of operating expenses as well as to examine the worthiness of their incurrence. In these ways, prudence can be, and is being, used in the traditional ratemaking determination, a process that is no longer an esoteric accounting exercise confined to the bowels of utility commission hearing rooms.

Because of increased public awareness of the financial condition of utilities, particularly electric utilities, more public attention is drawn to rate proceedings. The recent cover story in Business Week magazine, entitled "Are Public Utilities Obsolete? A Troubled System Faces Radical Change,"[11] is but one example of the increasing public attention that is being focused on the many issues facing electric utilities today. Certainly, Congressional consideration of many of the issues facing public utilities has had the effect of focusing increased public attention on the matter.[12] And significant and fundamental changes in the existing

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[11]"Are Utilities Obsolete? A Troubled System Faces Radical Change," Business Week May 21, 1984, p. 116.

[12]See, for example, "U.S. Electric Power System Reliability," Hearings before the Subcommittee on Energy Development and Applications of the House Committee on Science and Technology, 97th Cong., 2d Sess. (1982); "Centralized vs. Decentralized Energy Systems: Diverging or Parallel Roads?" (Committee Print), Subcommittee on Energy and Power of the House Committee on Interstate and Foreign Commerce, 96th Cong., 1st Sess. (1979); "U.S. Energy Outlook: A Demand Perspective for the Eighties," (Committee Print), House Committee on Energy and Commerce, 97th Cong., 1st Sess. (1981); "Are the Electric Utilities Gold Plated? A Perspective on Electric Reliability," (Committee Print), Subcommittee on Energy and Power of the House Committee on Interstate and Foreign Commerce, 96th Cong., 1st Sess. (1979).

regulatory framework are being advocated.[13]

Yet, despite this public attention a utility's rate proceeding continues to be the significant pressure point in the existing regulatory framework that provides accountability to the consuming public and the investing public. Traditional rate methodology may not be providing a wholly satisfactory mechanism for the solution of the many issues facing utilities, although rate methodology continues to be discussed extensively.[14] One recent article described the continuing utility rate controversy this way:

> Valuation of public utility property for rate-making purposes has been controversial since the beginning of public regulation. Despite much academic research and practical experience, there is no consensus of academician or practitioners concerning the appropriate value of physical property used for providing service to customers.[15]

But the study underscored the inadequacy of the traditional rate methodology debate because it showed "...no systematic relationships between methods of rate base determination and profits or prices charged by electric utility firms [because] [r]egulatory commissions were usually

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[13]See, for example, Pierce, "Reconsidering the Roles of Regulation and Competition in the Natural Gas Industry," 97 Harvard Law Review 345 (1983); and Collins, "Electric Utility Rate Regulation: Curing Economic Shortcomings Through Competition," 19 Tulsa Law Journal 141 (1983).

[14]See generally, Mullin, "Rate of Return Determination in Nebraska," 7 Creighton Law Review 206 (1974); Comment, "Determination of Allowable Rate of Return by the Texas Public Utilities Commission," 57 Texas Law Review 289 (1979); Comment, "Due Process: Applicability to Utility Rates," 42 Missouri Law Review 152 (1977); Levin, "Illinois Public Utility Law and the Consumer; A Proposal to Redress the Imbalance," 26 DePaul Law Review 259 (1977); Demet and Demet, "Legal Aspects of Rate Base and Rate of Return in Public Utility Regulation," 42 Marquette Law Review, 331 (1959); and Comment, "Reassessing 'Confiscation' Under Section 305 of Maine's Public Utility Law," 29 Maine Law Review 194 (1977).

[15]Primeaux, Bubnys, and Rasche, "Fair Value Versus Original Cost Rate Base Valuation During Inflation," 5 Energy Journal 93, 93 (1984).

either overcompensating or undercompensating for inflation occurring in the economy."[16]

Because of the increased scale of operations and economic decision making being undertaken by utility management, encouraging efficiency and prudence by management for the ultimate benefit of the public and ratepayers has become a dominant theme in utility oversight. According to one analyst of modern finance theory,

> [t]here exists, however, a set of problems that will continue to be with us whichever approach is used [for ratemaking]. Among these are...[h]ow to compensate efficiency and penalize inefficiency. A well-managed, efficient company should be entitled to share to some extent the benefits resulting from an efficiently run operation. Similarly, an inefficient company should be forced to bear the costs of inefficiency. The mechanics of developing a system that would resolve this point in an equitable manner faces regulators today and will continue to face them under the proposed approach.[17]

The stark reality of financial problems confronting the electric utility industry raises some very profound problems beyond simply establishing a means through the rate system to reward soundly managed and efficiently operated utilities. Clearly, many utilities presently face difficult financial problems that are the product of investment decisions made long ago. The solution to those financial problems may not be quite as simple as the adoption of abbreviated regulatory methodology:

> The fiscal problems of the utility industry will not be solved by financial innovations or gimmickery. Any new development in utility financing must come gradually. Its soundness and validity must be carefully scrutinized and tested, and it must be consistent with outstanding obligations and <u>investment standards</u>. That great change has already taken place reflects not only the extreme financial pressures on the industry, but the willingness of issuers and investors to

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[16]*Id.*, p. 94.

[17]Alexander A. Robichek, "Regulation and Modern Finance Theory" 33 *Journal of Finance* 705 (1978).

> accept something new which responds to changing conditions without varying extensively from past practice. Yet all financing, whether conventional or innovative (a much misused and misunderstood word in this connection), must rest ultimately on the fundamental economic soundness of the industry and the particular company within that industry. It is the credit of the company which supports all financing, whether it be joint ownership, project financing, leasing, some variant of debt or equity or conventional issue. Only if the utility has adequate earnings, made acceptable to the public and regulatory authorities through good service and capable management, can the financial future of the electric utility industry in this country be assured. [Emphasis added.][18]

The prudent investment concept, as a supplement to traditional rate methodology, may provide the means for a new regulatory "hard look" at utility management decision making. A recent summary of what might be described as the modern usage of the prudent investment concept is applicable generally to other aspects of utility regulation:

> Public utilities have an obligation to operate their business in a reasonable, prudent and efficient manner for the benefit of their customers. This well established principle may have practical application to access questions in those cases where electric utilities or gas pipelines have significant unused capacity. The question in such cases is whether the utility's or pipeline's failure to seek the business of willing, would-be customers constitutes imprudence or inefficiency.
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> The cases suggest that management imprudence or inefficiency is a broad concept. Thus, clearly excessive payments for various inputs can be disallowed. The cases likewise suggest that while management decisions, prudent when made, will not be judged by hindsight, the failure to make cost efficient decisions may be reflected in reduced rate allowances. In that sense, lost savings opportunities as well as unnecessary expenditures can be attributed to the utility.
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> It is through the concept of foregone savings that prudent management principles may affect the availability of pipeline and transmission facilities. In Public Service Co. of Indiana, [10 F.E.R.C. para. 61,236] the [Federal Energy Regulatory] Commission stated that prudent management obligations might require public utilities to seek cost-saving power pooling opportunities, and hinted

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[18] Katzin, "Electric Utility Financing Today," 55 Oregon Law Review 479, 491 (1976).

that the failure to seek reasonably available savings might be examined in future rate cases. The reasonable implication to be drawn from the Commission's statements is that under-utilization of pipeline and transmission capacity may also be open to examination. Full utilization of facilities, to the extent that revenues from new customers can cover variable costs and defray fixed ones, may be deemed the prudent course, with foregone revenues attributed to the pipeline or utility involved.

This is not to suggest that claims of imprudence will always be successful. There may be legitimate reasons for maintaining unused capacity, for example. Or, the utility or pipeline may simply accept the rate penalty rather than provide access to a competitor. Moreover, whether or not a bottleneck exists should have some bearing on the obligation to provide access. Thus, absent monopoly power, the refusal to deal may simply be a reasonable election by the pipeline or utility involved. On the other hand, where the essential nature of the facility is demonstrated, the refusal to serve for anticompetitive reasons, and the loss of revenues suffered as a result, might indeed support a rate reduction based on a finding of imprudence....

Rapidly escalating prices for natural gas and electric energy charged by major gas pipelines and electric utilities have forced consumers, particularly gas and electric distribution systems, to increasingly seek a means to contain their costs. Competitive solutions, i.e., reliance on market forces, depend upon the availability of supply options. Access to the wholesale supplier's gas pipeline system or electric transmission network is often essential to any customer plan for the development or acquisition of alternative gas or energy sources. [Footnotes deleted.][19]

Certainly, one of the most important issues raised with regard to utility performance is the relationship between the quality of service offered by the utility and the level of rates allowed. One summary of the relationship expresses it this way:

The three ways to protect the public interest by "quality of service" are (A) making the rate base dependent upon the "adequacy of service" provided, (B) insuring that management decisions by the public utilities are in the public's best interest, and (C) allowing the

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[19]Reiter, "Competition and Access to the Bottleneck: The Scope of Contract Carrier Regulation under the Federal Power and Natural Gas Acts," 18 Land and Water Law Review 1, 79 (1983).

about the usefulness of property already in existence and an after-the-fact judgment about whether existing property is in actuality being used to discharge service to the public. The used-and-useful requirement, based both on Bluefield and contemporary statutory prohibitions, often prevents the incorporation of property into the rate base while construction is in progress and therefore necessarily mandates an evaluation of the property for rate purposes after it has come into existence. In short, the constitutional and statutory criteria for ratemaking are retrospective.

The current rate process does not normally provide for a mechanism to evaluate proposed investment decisions or operating expense decisions of public utilities in advance of the actual outlay of funds or the making of long term financial commitments. But, there is nothing inherent in the concept of prudent investment that limits it to a retrospective evaluation.

Under a changed regulatory framework, the concept of prudence could easily be used in a prospective sense to assure the recovery of investment costs by blessing certain investment decisions as they are being made, or before they are made. But such a scheme would require a more nearly perfect predictive ability to fix costs in advance, to project the usefulness of utility property, to project utility demand for services, to forecast the national economy, and to speculate about many other future occurrences. Even if such a system could be adopted as a regulatory incentive toward sound planning by locking in a guaranteed return in advance of actual investments, leaving the financial effects of good planning and bad planning to the exigencies of the future would provide little assurance to the public of efficient future utility operation. Bad guesses approved in advance and locked in place by regulatory approval would only lead to a decline in the ability of a public utility to discharge its public service obligations.

The concept of prudent investment should be seen, under the existing regulatory framework, as a way to place the appropriate amount of risk of utility mismanagement on utility equity owners. The fact that the risk may not be exclusively economic because of the use of a regulatory requirement of prudence is not particularly significant, for the marketplace provides little ability to enforce sound investment or expenditure requirements on monopoly utilities apart from the regulatory process anyway. The prudent investment concept as applied in public utility regulation involves many of the very same judgments that are made legally about management investment decisions in analogous fields. The major areas of trust supervision and oil and gas leasing, as well as corporate obligations to shareholders, all involve particular legal obligations to make sound (read "prudent") investment decisions. All contain a significant measure of retrospective evaluation, and all are imposed for essentially the same reasons: protecting proprietary interests of investors or owners, where they have assigned legal managerial control to others. In this regard, public utilities are no different. Utilities are assured, through regulation, a fair return for business activities conducted on behalf of their investors and of their customers. The question that remains, however, is the extent to which the public should be at risk for decisions over which it presently exercises little or no advance control except through regulation.

The problem of adjudging the conduct of financial affairs by public utilities argues strongly for improved regulatory controls, like the use of the prudence test, to assess utility financial decision making.

What is needed, however, is a more specific elaboration of the case-by-case application of the prudent investment standard in order that its later application can be anticipated at the time investment decisions are being made by utility managers. As a device for the solution of the current dilemmas of utility managers and utility regulators that have been created by overconstruction and excessive demand projections, the prudent investment test is limited. The concept of prudent investment provides at best an imperfect solution to the problems raised by unwise decisions of the past.

Prudence nevertheless offers a regulatory opportunity within the existing framework to deal with many existing and future utility issues. The breadth of discretion and flexibility that prudence offers can be assumed to be constitutional under the result-oriented doctrine of Hope, so long as the use of the concept does not have a confiscatory result. While the regulatory flexibility of prudence provides an advantage, the attendant potential for misuse must be avoided through its sound application.

It can be fairly asserted in today's regulatory scene, where rights are balanced with duties, that the substantial benefits derived from the exclusive right granted to utilities to do business in a particular territory require more rigorous regulatory attention to the manner in which that business is conducted. The scale of investments and the degree of risk to investors and the public ratepayers can be substantial. The proper use of the prudent investment obligation can put the economic risk where it belongs--with the utility owners and their management agents.

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