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GOVERNMENT OF THE DISTRICT OF COLUMBIA
OFFICE OF THE ATTORNEY GENERAL

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ATTORNEY GENERAL

Public Advocacy Division
Housing and Environmental Justice Section

E-Docketed

January 24, 2025

Ms. Brinda Westbrook, Secretary
Public Service Commission
of the District of Columbia
1325 G Street, N.W., Suite # 800
Washington, DC 20005

Re: Formal Case No. 1180 – In the Matter of the Application of Washington Gas Light Company for Authority to Increase Existing Rates and Charges for Gas Service.

Dear Ms. Westbrook:

On behalf of the District of Columbia Government (DCG), I enclose for filing the Direct Testimony of DCG Witness Dr. Asa S. Hopkins. This document is preliminarily identified as Exhibit DCG (A), with attached exhibits preliminarily identified as DCG (A)-1 through DCG (A)-7, inclusive. If you have any questions regarding this filing, please contact the undersigned.

Sincerely,

BRIAN L. SCWALB
Attorney General

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BEFORE THE PUBLIC SERVICE COMMISSION
OF THE DISTRICT OF COLUMBIA

Formal Case No. 1180

IN THE MATTER OF THE APPLICATION OF WASHINGTON GAS LIGHT COMPANY FOR AUTHORITY TO INCREASE EXISTING RATES AND CHARGES FOR GAS SERVICE

Direct Testimony of Dr. Asa S. Hopkins

On Behalf of the District of Columbia Government

Exhibit DCG (A)

January 24, 2025

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I. INTRODUCTION AND QUALIFICATIONS

Q1 Please state your name, business address, and position.

A1 My name is Asa S. Hopkins. My business address is 485 Massachusetts Ave., Suite 3, Cambridge, Massachusetts 02139. I am the Senior Vice President for Consulting, at Synapse Energy Economics, Inc (Synapse). 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.

Q2 Please describe Synapse.

A2 Synapse 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.

Q3 Please describe your professional experience before beginning your current position at Synapse.

A3 Before joining Synapse 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 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 DCG (A)-1.

Q4 Have you previously testified before the District of Columbia Public Service Commission (PSC or Commission)?

A4 Yes. I testified on behalf of the District of Columbia Government (DCG or the District) in Formal Case No. 1142 (FC 1142), *In the Matter of the Merger of AltaGas, Ltd. and Washington Gas Holdings, Inc.,* in Formal Case No. 1169, *In the Matter of the Application of Washington Gas Light Company for Authority to Increase Existing Rates and Charges for Gas Service* – Washington Gas Light Company's (WGL) last general rate case decided in 2023, and in Formal Case No. 1179, *In the Matter of the Investigation into Washington Gas Light Company's Strategically Targeted Pipe Replacement Program.*

Q5 Have you previously submitted comments to the Commission on other matters?

A5 Yes. I have also assisted DGC with comments over the last few years in a number of other PSC proceedings, including a January 22, 2024, analysis evaluating the performance of WGL's current Accelerated Pipe Replacement Program known as "PROJECTpipes 2"[1] and May 2, 2023, comments on WGL's "PROJECTpipes 3" filing.[2]

Q6 Have you previously provided testimony in other jurisdictions on topics similar to those you are testifying on in this case?

A6 Yes. I have testified on gas utility issues, as relates to capital decision-making, rates, and business risk in Quebec, Ontario, Maryland, Connecticut, Wisconsin, and New York. When I testified before the Régie de l'Energie in Quebec I was recognized as an expert in "energy transition in the gas industry, and business risk." The Ontario Energy Board qualified me as an expert on "the future of

[1] Formal Case No. 1154, In the Matter of Washington Gas Light Company's Application for Approval of a *PROJECTpipes 2 Plan*, District of Columbia Government's Comments in Response to Public Notices Issued on December 22, 2023, and January 8, 2024 (attached Memorandum) (Jan. 1, 2024).

[2] Formal Case No. 1175, In the Matter of Washington Gas Light Company's Application for Approval of *PROJECTpipes 3 Plan*, Initial Comments of the Department of Energy and Environment on WGL's Pipes 3 Application (May 2, 2023).

electric and gas utility regulatory and business models and associated business risk in the context of deep building decarbonization objectives."

Q7 On whose behalf are you providing evidence in this case?

A7 I am testifying on behalf of DCG.

Q8 What is the purpose of your testimony?

A8 The purpose of my testimony is to review WGL's request for a rate increase, with particular focus on the prudence of WGL's capital planning process and resulting investments added to rate base, and to recommend improvements the PSC could order in this case.

Q9 How is your testimony organized?

A9 After this introduction, my testimony continues in Section 2 with a summary of my conclusions and recommendations. Section 3 provides an overview of prudence review and my approach in this case. Section 4 lays out the competitive and policy context for WGL's decisions reflected in its request in this docket. Section 5 evaluates the prudence of WGL's actions and resulting proposals. In Section 6, I propose remedies for WGL's imprudent planning. Section 7 concludes.

Q10 Are there any exhibits attached to your testimony?

A10 Yes. In addition to my resume, I have attached certain data responses from WGL that I relied upon while preparing my testimony. I have also attached a Synapse white paper entitled *Long Term Planning to Support the Transition of New York's Gas Utility Industry* and a paper by Burns *et al*. from the National Regulatory Research Institute (NRRI) entitled *The Prudent Investment Test in the 1980s*.

II. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q11 What conclusions do you draw in this case?

A11 I find that:

- WGL faces competition from electricity to provide similar services to customers, and its market share is falling. WGL's requested rate increases in this proceeding will further harm WGL's competitive position.
- Public policy in the District of Columbia will likely lead to sales and customer reductions for WGL.
- If WGL fails to account for its competitive and policy context, it could cause significant adverse impacts, both for the utility itself and its customers.
- WGL has imprudently failed to account for its competitive and policy context when making capital decisions.
- In its testimony, WGL describes how it prioritizes and selects pipeline replacement projects. However, WGL has failed to provide evidence that it executes this process.
- WGL has not evaluated its current and future competitive position, despite the evident state of competition between WGL's services and electrification and WGL's inexorable rising rate trajectory.
- WGL has not accounted for the District's climate and energy policies when planning the capital investments proposed for inclusion in rate base in this case, despite the fact that those policies will have a material impact on demand for WGL's services and thus the prices it may sustainably charge its customers.
- WGL does not conduct capital planning that looks out more than a few years, despite investing in assets with multi-decade useful lives while

customers make choices about retaining or reducing WGL's service on a much shorter timeframe (e.g., every 10 to 20 years).

- WGL has not evaluated or used non-pipeline alternatives (NPAs) to replacing assets, despite the opportunity to use alternatives to lower costs, increase safety, reduce pollution, and align with competitive and policy drivers.
- WGL does not track all the information required to conduct good planning.
- WGL does not acknowledge or analyze the financial risks of stranded assets on its system, despite orders from the Commission directing WGL to plan system investments in a manner that minimizes the risk of stranded assets.

Q12 What are your recommendations to the PSC based on these conclusions?

A12 I recommend that the PSC:

- Find that WGL has lost the presumption of prudence regarding its capital decision-making, due to its failure to prudently plan within its competitive and policy context and due to its failure to provide substantive information supporting its claimed project selection and prioritization process.
- Order WGL to keep records of which of its assets are used to deliver service to customers each year.
- Order WGL to develop and use comprehensive gas system planning practices and processes that reflect its competitive and policy context, reflect best practices for gas system planning, and mitigate stranded asset and safety risks.
- Establish that it will not entertain a future rate case from WGL until such time as WGL demonstrates that it has developed and used an approved

comprehensive gas system planning approach to support its capital and operating costs.

III. PRUDENCE REVIEW OF UTILITY DECISION-MAKING

Q13 Could you please describe the role of prudence review in utility ratemaking?

A13 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 take steps to ensure that utilities prudently make plans and support their decisions, including potentially disallowing imprudent investments, to impose the same kind of discipline.

Q14 Are there established principles about how to conduct prudence reviews?

A14 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 DCG (A)-2 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:[3]

- "[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

[3] ASH-6 at page *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.

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."
- "[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."[4]

Q15 When a regulator or legislature provides some kind of pre-approval for spending, does that change the need for retrospective prudence review?

A15 No. Preapproval to spend funds does not insulate a utility from a finding of imprudence.[5] Utility management has an ongoing obligation each day to decide

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

[5] See, for example, PSC Formal Case 1154, Order 20671 (Dec. 11, 2020), Paragraph 38: "…the approval of a program does not reflect a decision on the prudence of the investment. Similar to the PIPES 1 Plan, the Commission anticipates reviewing the prudence of investments in a future base rate case where WGL seeks recovery of costs through the Company's base rates."

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.

Q16 Please describe your approach to prudence review in this proceeding.

A16 I reviewed the testimony that WGL's witnesses have filed, identified gaps in those filings, and assisted the DCG in scoping its request for supplemental testimony, which focused on providing necessary information to conduct a prudence review. I then reviewed the supplemental testimony, assisted the DCG in crafting discovery questions regarding that testimony, and reviewed WGL's responses to those discovery questions. I have also drawn upon the information filed in the closely related Formal Case No. 1179, as well as discovery responses provided in that case. My review focused on three aspects of prudence: (1) whether WGL's planning processes are prudent; (2) whether WGL's execution of those plans through capital decision-making is prudent; and (3) whether project execution is prudent. Due to time and budget limitations, I have been unable to dig into the third aspect (project execution) to the extent it may warrant. However, my primary concern is that WGL is identifying and executing an imprudent set of projects due to the failures of WGL's planning and decision-making processes.

IV. THE COMPETITIVE AND POLICY CONTEXT FOR WGL'S ACTIONS

Q17 Why is it prudent for a utility to account for the competitive and policy context in which it operates?

A17 Utilities operate in a business that is profoundly shaped by public policy. As franchised monopolies subject to economic regulation, they provide essential services to customers in a manner that is grounded in public policy for safe and reliable service at just and reasonable rates. Utilities are "affected with a public interest": it is in the public interest to regulate monopoly service providers to prevent the infliction of wrongs upon the public.[6] Where public policy shapes the operating context of a regulated utility, the utility must take that policy into account as part of its regulatory responsibilities.

There is less economic literature on the question of how a regulated utility should respond to competitive forces. This is because part of the justification for economic regulation is the lack of competition. In 1848, John Stuart Mill argued that when a service can only be provided by an operator at "so large a scale as to render the liberty of competition almost illusory, it is an unthrifty dispensation of the public resources that several costly sets of arrangements should be kept up for the purpose of rendering to the community this one service. It is much better to treat it at once as a public function; and if it be not such as the government itself could beneficially undertake, it should be made over entire to the company or association which will perform it on the best terms for the public."[7] That is, it makes sense to sanction and regulate monopolies when it does not make sense to build and maintain large competing infrastructures.

As I discussed earlier in my testimony, prudence review is a key part of how regulation acts as a proxy for market forces. When competitive pressures do develop, challenging the natural monopoly paradigm, regulated utilities need to react in some manner that reflects how they would react if unregulated. At the very least, they need to be aware of and plan to respond to competitive challenges that impact their business and take the resulting appropriate actions.

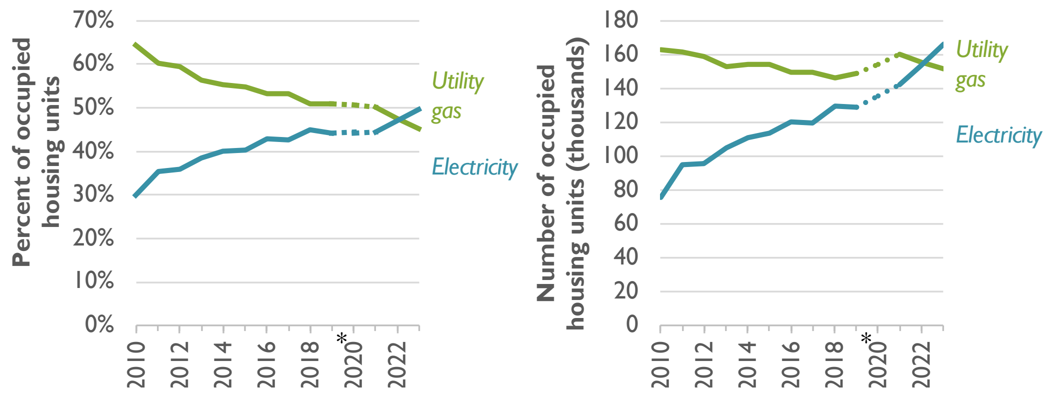
Q18 What are the primary aspects of WGL's context for which prudent utility management should account?

A18 WGL is losing market share for residential building heating in the District of Columbia. While WGL has not yet experienced a sustained decline in the number of heating customers, it has failed to capture virtually any net growth from the

[6] Paul M. Hogan. *Utilities, the State, and the Public Interest.* 10 Hastings Law Journal 176 (1958). Available at: https://repository.uchastings.edu/hastings_law_journal/vol10/iss2/4.
[7] John Stuart Mill. 1848. *Principles of Political Economy*.

District of Columbia's substantial increase in households since 2010. Figure 1 shows the number of households heating with natural gas and electricity, and WGL's steadily declining market share over the past fifteen years. This market dynamic indicates that WGL is losing a competition for heating service.

Figure 1. Heating fuel for occupied housing units in the District of Columbia, by share and number



Source: U.S. Census, American Community Survey.

Over the time period shown in Figure 1, residential gas prices in the District of Columbia have, on average, risen slightly relative to electric prices.[8] WGL should be evaluating and measuring the competitiveness of its offerings relative to electricity in order to make prudent plans regarding investments, operations and maintenance costs, and the stability of its business model. If WGL continues to

[8] According to U.S. Energy Information Administration data, residential natural gas got 5.6 percent more expensive relative to electricity between 2010 and 2023. This analysis averages customer charges into overall bills and average prices. Customers who electrify can eliminate paying the gas customer charge, whereas customers who choose gas cannot eliminate the electric customer charge. Average residential electricity prices were 14.01 cents/kWh in 2010 and 16.45 cents/kWh in 2023 (an increase of 17.4 percent). (Electricity Data Browser: https://www.eia.gov/electricity/data/browser/#/topic/7?agg=0,1&geo=0000002&endsec=vg&linechart=ELEC.PRICE.DC-ALL.A~ELEC.PRICE.DC-RES.A~ELEC.PRICE.DC-COM.A~ELEC.PRICE.DC-IND.A~ELEC.PRICE.DC-TRA.A~ELEC.PRICE.DC-OTH.A&columnchart=ELEC.PRICE.DC-ALL.A&map=ELEC.PRICE.DC-ALL.A&freq=A&start=2001&end=2023&ctype=linechart&ltype=pin&rtype=s&pin=&rse=0&maptype=0). Average residential natural gas prices were $1.353/therm in 2010 and $1.679/therm in 2023 (an increase of 24 percent). (Average Price of Natural Gas Delivered to Residential and Commercial Consumers by Local Distribution and Marketers in Selected States: http://www.eia.gov/dnav/ng/ng_pri_rescom_dcu_sdc_a.htm)

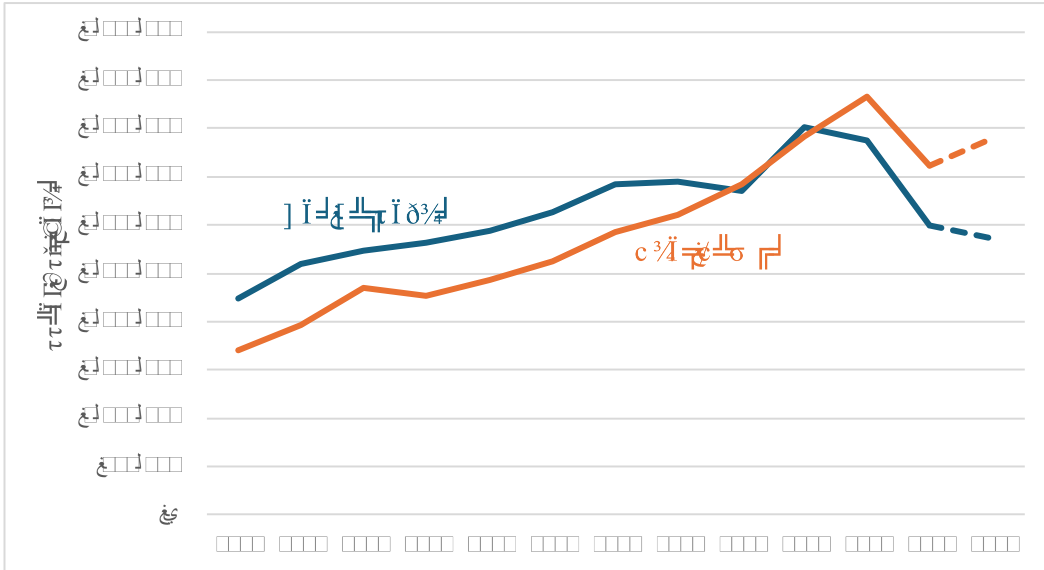
invest heavily in its system, while sales stay flat or fall, gas rates will rise substantially (such as the 25 percent increase for customer charges and 38 percent increase for variable charges for residential heating customers requested in this case). The electric system is also seeing substantial investment, which will drive electric revenue requirements up as well; whether volumetric electric rates will rise depends on rate design choices and the increasing volume of sales over which the revenue requirement is collected. WGL should be evaluating these investments and their impact on electric rates, while accounting for increased electric sales from transportation and building electrification that would tend to mitigate electric rate pressure. WGL should also be examining other considerations that may be driving the trend towards increasing electrification, including technological advancements in heat pumps and concerns for indoor air quality, and plan accordingly.

While market forces are challenging WGL's growth prospects and future competitiveness, the District's public policy and programs are also pushing in the direction of reduced gas sales. WGL should also be accounting for the impact of these policies in order to prudently map a path forward. This includes monitoring existing assets to ensure that every asset for which cost recovery is requested remains used and useful in light of competitive pressures.

Q19 Is competition between gas and electricity confined to the District of Columbia?

A19 No. There is a steady nationwide shift in heating technology toward electric systems, such as heat pumps, and away from gas systems. As shown in Figure 2, based on data from the Air-Conditioning, Heating, and Refrigeration Institute (AHRI), gas furnaces outsold heat pumps by 32 percent in 2012, while through November 2024 heat pumps outsold gas furnaces by 37 percent.

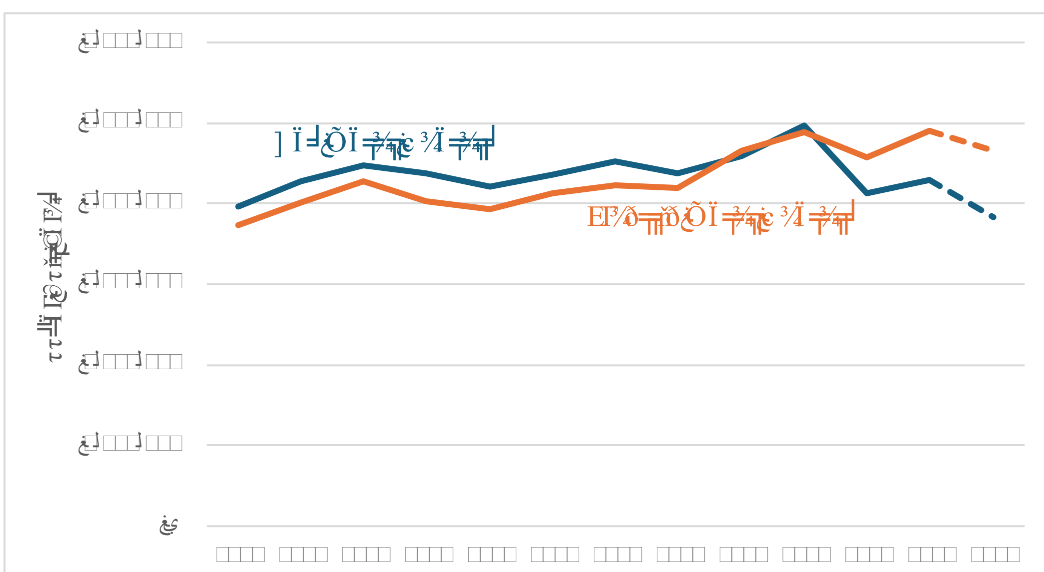
Figure 2. Annual sales of gas furnaces and heat pumps; 2024 data are through November



Source: AHRI, https://www.ahrinet.org/analytics/statistics/monthly-shipments.

A similar shift has also happened in the market for storage water heaters. Figure 3 shows how relatively steady market leadership for gas water heaters has collapsed in the last few years. Where gas water heaters outsold electric by 6 percent in 2012, electric water heaters outsold gas by 22 percent through November 2024.

Figure 3. Annual sales of gas and electric storage water heaters; 2024 data are through November



Source: AHRI, https://www.ahrinet.org/analytics/statistics/monthly-shipments.

Q20 What governmental policies and programs provide context for WGL's decision-making over the time since its last rate case?

A20 In addition to the technology and market trends explained above, the District has multiple policies that will accelerate the trends towards electrification. These include policies aimed at promoting the creation of net-zero energy buildings, which are highly efficient buildings that generate or procure enough renewable energy to meet or exceed their annual energy consumption.[9] While it is possible for a net zero building to use gas, in practice the market share data above shows that new residential construction is overwhelmingly choosing not to use gas for space heating. The current energy conservation code includes a voluntary net-zero energy code.[10] The *Greener Government Buildings Amendment Act of 2022* requires new District-owned buildings and substantial improvement projects that receive 15 percent or more of their funding from the District to comply with this net-zero energy code.[11] By 2026, all new and substantial improvements to commercial buildings and residential buildings taller than three stories must meet net-zero energy standards, including a prohibition on on-site fossil fuel combustion for thermal energy except as specified by a code official.[12]

Another policy helping the District make progress towards its 2045 goal is the Building Energy Performance Standards (BEPS) policy, which set energy performance targets for specific existing building types. Reducing the amount of energy that buildings use directly reduces emissions associated with this energy usage. The standard currently applies to privately owned buildings 50,000 square feet or larger and District-owned buildings 10,000 square feet or larger. In 2027,

[9] Department of Energy & Environment. "Green Building in the District." Accessed 9/24/2024 Available at: https://doee.dc.gov/service/greenbuilding.

[10] 2017 District of Columbia Energy Conservation Code Appendix Z. 2020. Available at: https://doee.dc.gov/sites/default/files/dc/sites/ddoe/service_content/attachments/2017%20DC%20Energy%20Conservation%20Code_Appendix%20Z.pdf.

[11] *Greener Government Buildings Amendment Act of 2022.* D.C. Law 24-306. Effective March 10, 2023. Available at: https://code.dccouncil.gov/us/dc/council/laws/24-306.

[12] *Clean Energy DC Building Code Amendment Act of 2022.* D.C. Law 24-177 Effective September 21, 2022. Available at: https://code.dccouncil.gov/us/dc/council/laws/24-177. Appendix Z of the District of Columbia Energy Conservation Code – Commercial Provisions. Available at https://doee.dc.gov/sites/default/files/dc/sites/ddoe/service_content/attachments/2017%20DC%20Energy%20Conservation%20Code_Appendix%20Z.pdf.

privately owned buildings 25,000 square feet or larger must also comply with the BEPS, and starting in 2033, all buildings over 10,000 square feet must comply.[13,14]

In addition to increasing building energy efficiency, electrification of existing buildings will be important to achieving the District's requirement to be carbon neutral by 2045, established by the *Climate Commitment Amendment Act of 2022*. Electrification is expected to be a primary compliance pathway for energy and emissions reduction under BEPS. The DC Council has accelerated the trend towards electrification by passing laws such as the *Healthy Homes and Residential Electrification Act of 2024*, which created the Breathe Easy Program to provide 30,000 low-income and moderate-income households with electrification retrofits.[15]

Federal government buildings in the District of Columbia are also electrifying. Electrification of the Ronald Reagan Building, one of the largest buildings in DC, provides a case in point.[16]

Q21 What are your conclusions regarding the competitive and policy context in which WGL has operated since its last rate case?

A21 Throughout this period, market share and policy continue to indicate that WGL's product will not see substantial growth, either in number of customers or volumetric sales. Technology, policy, and market trends are likely to drive toward

[13] Building Innovation Hub. "BEPS Standards and Compliance Rules Finalized." Accessed 9/24/2024. Available at: https://buildinginnovationhub.org/special-update-beps-rules-released/.

[14] The District of Columbia City Council has passed legislation changing the BEPS deadlines. If enacted the deadlines may be extended to 2028 for privately-owned buildings with 25,000 square feet of gross floor area and to 2034 for buildings of 10,000 square feet or more. See https://lims.dccouncil.gov/Legislation/B25-0801.

[15] *Healthy Homes and Residential Electrification Amendment Act of 2024.* D.C. Act 25-488. May 31, 2024. Available at: https://lims.dccouncil.gov/downloads/LIMS/52291/Signed_Act/B25-0119-Signed_Act.pdf?Id=191649.

[16] GSA awards $22.7 million contract for electrification of the Ronald Reagan Building and International Trade Center as part of Investing in America Agenda. November 30, 2023. General Services Administration. Accessed 1/22/25: https://www.gsa.gov/about-us/newsroom/news-releases/gsa-awards-227-million-contract-for-electrification-of-the-ronald-reagan-building-and-international-trade-center-as-part-of-investing-in-america-agenda-11302023.

reduction in both sales and customers. WGL's gas delivery services are and have been in competition with electrification.

Q22 What could be some of the impacts on WGL and its customers if it fails to account for its competitive and policy context?

A22 If WGL fails to account for its competitive and policy context, it could cause significant adverse impacts, both for the utility itself and its customers. One of the most concerning potential outcomes is the onset of a "death spiral" for gas utilities. This term refers to a vicious cycle where rising costs and declining sales reinforce each other, leading to escalating rates and further customer departures.

Firstly, as WGL continues to invest heavily in gas infrastructure without considering the shift towards electrification and stringent climate policies, it risks creating stranded assets. These are investments that become obsolete or underutilized due to changes in market conditions or regulatory requirements. Stranded assets represent a financial burden, as the utility may not be able to recover the costs of these investments, leading to significant financial losses for investors. This risk is particularly acute where the utility cannot show that the decision to make the investments was prudent given what it should have known at the time it made the investment.

For customers, WGL's failure to adapt to the competitive and policy context would mean that they would face higher gas rates. Regulators or policymakers could determine that customers must pay for stranded assets, even if those assets could have been avoided by better utility planning. As more customers switch to electric heating and other alternatives to avoid high gas costs, the remaining customer base will shrink. This reduction in the number of customers means that the fixed costs of maintaining the gas infrastructure will be spread over a smaller customer base, leading to even higher rates for those who remain. This cycle of rising rates and declining customer numbers can quickly become unsustainable. This financial instability can impact the utility's ability to maintain and operate a safe and reliable gas system. In extreme cases, WGL might not have sufficient funds to address critical infrastructure needs, leading to safety and reliability concerns.

In summary, if WGL does not plan and adapt well to its competitive and policy context, it risks entering a death spiral that could lead to higher rates, stranded assets, financial instability, and compromised safety and reliability. Both customers and investors would bear the brunt of these negative outcomes, highlighting the urgent need for WGL to align its planning and operations with the evolving energy landscape.

Q23 Doesn't WGL have to invest heavily in its system to maintain safety and reliability, regardless of the competitive and policy context?

A23 WGL has a responsibility to maintain safe and reliable service. This includes planning to mitigate safety risks from aging assets. WGL's approach to this requirement has been to invest heavily in traditional infrastructure solutions, which risks setting the company and its customers up for an unsustainable and unsafe future. WGL admits that its investment in replacing aged assets is not actually resulting in an overall reduction in risk, because the risk from remaining assets is increasing faster than they can be replaced.[17] WGL has stuck with this path, despite evidence that it is unsustainable and unsafe, instead of developing alternatives that allow for faster retirement of risky assets, use of repair to reduce risk for assets with limited lifetimes, and utilizing electrification rather than fighting it.

[17] Formal Case No. 1179. WGL Response to DCG DR 1-11. "While replacement activities will incrementally reduce risk for the facilities replaced, the system continues to age and the overall risk will continue to increase at a rate that outpaces the impact of the proposed planned replacement activities."

V. EVALUATION OF THE PRUDENCE OF WGL'S ACTIONS IN CONTEXT

Q24 Has WGL been accounting for its competitive and policy context in a prudent manner?

A24 No, it has not.

Q25 Is failure to account for context the only way in which WGL might be acting imprudently?

A25 No. WGL has an obligation to act prudently in all aspects of its operations and decision-making. It happens that capital investment decision-making is an aspect of WGL's actions that is most impacted by the company's failure to account for context, while also being a primary driver of the increase in revenue requirement. All aspects of WGL's capital planning and decision-making are therefore worthy of detailed scrutiny.

Q26 Could you provide examples of WGL's decision-making, reflected in the request for new rates in this proceeding, that you believe are imprudently failing to reflect good utility planning and decision-making practice?

A26 Of course. Here is a short summary of some prominent examples:

1. In its testimony, WGL describes how it prioritizes and selects pipeline replacement projects. However, WGL has failed to provide evidence that it executes this process.
2. WGL has not evaluated its current and future competitive position, despite the evident state of competition between WGL's services and electrification and WGL's inexorable rising rate trajectory.
3. WGL has not accounted for the District's climate and energy policies when planning the capital investments proposed for inclusion in rate base in this case, despite the fact that those policies will have a material impact on demand for WGL's services and thus the prices it may sustainably charge its customers.

4. WGL does not conduct capital planning that looks out more than a few years, despite investing in assets with multi-decade useful lives while customers make choices about retaining or reducing WGL's service on a much shorter timeframe (e.g., every 10 to 20 years).
5. WGL has not evaluated or used non-pipeline alternatives (NPAs) to replacing assets, despite the opportunity to use alternatives to lower costs, increase safety, reduce pollution, and align with competitive and policy drivers.
6. WGL does not track all the information required to conduct good planning.
7. WGL does not acknowledge or analyze the financial risks of stranded assets on its system, despite orders from the Commission directing WGL to plan system investments in a manner that minimizes the risk of stranded assets.

A. Project selection and prioritization

Q27 Where in its testimony does WGL characterize its distribution system capital project prioritization and selection process?

A27 WGL Witness Murphy describes WGL's process for project selection and prioritization in his Supplemental Direct Testimony (Exhibit WG(P)). On pages 7 to 11 of that testimony, Witness Murphy describes how WGL identifies the need for different kinds of distribution capital projects, such as pipeline replacement projects (referred to as APRP projects), safety and maintenance projects, and new business projects. On pages 11 to 14, Witness Murphy summarizes the process that WGL uses to prioritize capital projects in each category. On page 14, Witness Murphy states that there are generally no alternatives to the projects selected and prioritized using the previously described methodology.

Q28 How does Witness Murphy structure his testimony on the methodology for project selection and prioritization?

A28 Witness Murphy states that WGL uses different processes for each type of distribution project: APRP projects, safety and maintenance projects, and new business projects.

Q29 Could you summarize the methodology for project selection and prioritization that Witness Murphy describes for APRP?

A29 For APRP, Witness Murphy testifies that WGL creates projects by creating localized groupings of similar assets based on criteria such as age, material, pressure, and risk profile. Witness Murphy states that WGL uses risk analysis for each asset, which is rolled up into the project. Witness Murphy states projects are limited in size in order to limit duration and allow for appropriate resolution of control. Witness Murphy states that projects can also be identified by field operations based on direct observation of deteriorated mains and service. Witness Murphy testifies that the APRP prioritizes projects using the total risk and cost. He states that WGL develops a "parametric estimate of the cost for each project" and then "ranks projects to achieve the greatest reduction of overall risk per dollar invested," with adjustments for observed asset conditions, schedules for work compelled by others, and ongoing projects.[18]

Q30 Could you summarize the methodology for project selection and prioritization that Witness Murphy describes for safety and maintenance projects?

A30 Witness Murphy states that safety and maintenance projects include (1) projects whose need is identified by third parties, such as projects to relocate assets in the right of way or relocate assets such as service lines at customer request, (2) projects that are identified through the APRP risk analysis process but are not within the scope of the APRP program, and (3) projects that emerge from operational necessity such as third-party line strikes. Witness Murphy states that prioritization for these projects is driven by coordination with third parties regarding their timelines (for projects driven by third parties' needs) or using the same process as for APRP projects (for projects identified through risk analysis). Witness Murphy further states that other factors influence priority for emergent and customer-requested projects.

[18] Exhibit WG (P), page 13.

Q31 Could you summarize the methodology for project selection and prioritization that Witness Murphy describes for new business projects?

A31 Witness Murphy testifies that project selection for new business projects is driven by the need for timely responses to customer requests, and they are prioritized based on the customer-requested schedule and available crew resources.

Q32 If WGL follows the process for project selection described in Witness Murphy's testimony, would the resulting investments be prudent and therefore suitable for inclusion in rate base?

A32 Not necessarily. Prudently incurred expenses must be the product of a prudent planning process, prudent project selection consistent with the plan, and prudent project execution. Witness Murphy's testimony relates to the question of project selection within WGL's implicit capital plan. Later in my testimony I will address the prudence of WGL's capital planning process. I do not have access to sufficient information to opine on the prudence of project execution from a construction project management perspective.

Q33 What do you see as the most important qualitative differences between (1) APRP and safety projects and (2) other distribution capital projects?

A33 The most important difference is the extent to which WGL can plan for the projects. WGL may not be able to plan the details of projects driven by third parties, such as government entities, other utilities, or customers, until they are requested or identified by those other entities. Similarly, projects that result from responding to emergent situations cannot be pre-planned. However, projects identified through risk analysis, whether formally part of the APRP or not, are the result of a broader gas system planning framework.

Q34 Could you elaborate on what you mean when you say that there is no evidence that WGL executed the capital project prioritization and selection process it describes for pipeline replacement and other risk-driven projects?

A34 Based on the process described by Witness Murphy, WGL should have identified more projects for potential investment than it actually executed, and its prioritization process (based on risk reduction per dollar of project cost) should have been used to select which projects should proceed. In discovery, DCG asked WGL to provide a list of all APRP projects (and safety-related projects that used the same analysis process as APRP projects) identified for potential investment such that they would have resulted in projects being in service in the test year for this proceeding.[19] DCG further requested WGL to provide the asset-level risk and total project-level risk, as well as the cost estimate, for each project considered, and the ranked list that WGL used to select projects. Each of these are products that should exist if WGL follows the process described by Witness Murphy, and this should include information about projects not selected for investment.

WGL provided two responses to DCG's request. In its first response, WGL states that "The Company has not risk ranked" the accelerated pipeline replacement projects in the list of projects provided in Witness Morrow's testimony. If this is true, then it contradicts Witness Murphy's testimony regarding risk ranking. In its second response, following the PSC's order regarding DCG's Motion to Compel, WGL provided (1) PROJECTpipes project lists (identifying selected projects) and (2) a list of filings that include information about executed pipe replacement projects. WGL also provided further generalities regarding evaluating all assets on its system each year and restated its claimed prioritization process. WGL has not, however, provided the requested documentary evidence that it undertakes the prioritization process described in Witness Murphy's testimony for either APRP projects or similar safety projects. The evidence on the record in this proceeding includes no information about projects considered for investment but rejected or deferred. If WGL has such evidence, it was obligated to provide it in response to the DCG's data request. Therefore, I am left to conclude that there is no evidence that WGL in fact follows the process described in Witness Murphy's testimony.

[19] WGL Initial and Supplemental Responses to DCG Data Request 2-17, combined responses included as Exhibit DCG (A)-3

Q35 What are the implications of this lack of evidence for consideration of the prudence of WGL's investments proposed for inclusion in rate base in this proceeding?

A35 The principles of prudence I detailed earlier in my testimony state that the "there 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." Through its failure to provide substantive information supporting its claimed project selection and prioritization process, WGL has lost the presumption of prudence.

B. Customer alternatives

Q36 Could you elaborate on what you mean when you state that WGL has not evaluated its current and future competitive position?

A36 At the request of the Apartment and Office Building Association, the PSC ordered WGL to provide supplemental testimony regarding WGL's evaluation of customers' costs for alternatives to continued use of natural gas for specific end uses.[20] In Exhibit WG (2A), Witness Steffes states that WGL "is not aware that the Commission has approved or directed the Company to evaluate customers' costs for alternatives for continued use of natural gas for specific end uses. Consequently, the Company does not undertake detailed appliance and specific end-use alternatives evaluations."[21] If WGL does not understand the customer economics associated with its services, it does not understand its competitive position.

Q37 What concerns do you have with WGL's response to the PSC's order, given the evident state of competition between WGL's services and electrification and WGL's inexorable rising rate trajectory?

A37 I have two concerns. First, Witness Steffes's response indicates that WGL takes a limited view of its responsibilities, such that it does not undertake evaluations

[20] DC PSC Order 22311, para. 7.
[21] Exhibit WG (2A), page 6, lines 3-7.

unless specifically directed by the PSC to do so. WGL is an independent business entity responsible for its own decisions and actions; it is not a creature of the PSC which must undertake only actions approved or directed by the PSC. I am concerned that Witness Steffes's response indicates that WGL believes it lacks the ability or authority to act independently. The PSC does not, and should not, have sufficient information to direct WGL's actions in all aspects of its business; a prudent utility would recognize its independent authority and responsibility and not be held back by the PSC's lack of direction if an evaluation would be prudent to undertake.[22]

Second, Witness Steffes's response indicates that WGL has not taken the prudent step of understanding the customer economics of alternatives to gas service. In Formal Case No. 1179, WGL Witness Rogers devotes a section of her testimony to the claim that other parties "ignore customer choice."[23] Witness Rogers proceeds to address the perception that electrification of customer buildings will require the District of Columbia government to force existing customers to convert to electric service.[24] As I discussed earlier in this testimony, I am concerned that WGL faces a competitive threat from electrification because the customer economics and performance of electrification options appear to be favoring the choice of electric alternatives, such that WGL is losing market share. Witness Steffes's admission that WGL does not even evaluate where it stands from a competitive standpoint on customer alternatives means that Witness Rogers has no analysis on which to base her assessment that government action would be required for customers to adopt electrification. The Senior Vice President for Washington Gas Light Company and WGL's Vice President, Regulatory and Climate Strategy are both blind to the comparative customer economics of WGL's service and its competitors. Prudent management of any company, whether regulated or operating in a competitive market context, would

[22] Furthermore, even though WGL does not require the PSC's pre-approval to evaluate and plan for its competitive position, if for some reason WGL believed it needed the PSC's approval to undertake such a critical analysis, then it should proactively seek approval from the PSC.
[23] FC No. 1179, Exhibit WG(2A), page 22, line 16.
[24] FC No. 1179, Exhibit WG(2A), page 25, lines 9-18.

be aware of and require analysis of the customer cost and value of competing services. and market share trends regarding customer adoption of alternatives. It would account for that competitive context when making decisions that impact the price of its services. Additionally, not having a clear picture of its competitive position puts into question WGL's ability to forecast its sales and number of customers. Capital investment decisions grounded in inaccurate forecasts are more likely to be imprudently made.

C. Accounting for District climate and energy policies

Q38 What did the PSC order WGL to do regarding District policies, and how did WGL respond?

A38 At DCG's request, the PSC ordered WGL to file supplemental testimony regarding how WGL incorporates District climate, equity, and other policies into its capital planning and selection processes.[25] WGL Witness Steffes responded to this order by stating that WGL's actions to replace leak-prone infrastructure reduce GHG emissions over time, WGL's new JANA Lighthouse risk model is unbiased so risk forecasts are equity neutral, and WGL's community benefits agreement with LiUNA requires WGL to pay the prevailing wage. Witness Steffes further opines that this is a backward-looking rate case concerned with historical actions and not the venue to address the District's climate goals, even though many District laws and policies regarding climate and equity were in effect during the historic test year period.[26]

Q39 Could you elaborate on what you mean when you say that WGL has not accounted for the District's climate and energy policies when planning the capital investments proposed for inclusion in rate base in this case?

A39 WGL's sole climate-related response to the PSC's order is a recitation that reducing expected methane emissions by replacing leak-prone infrastructure lowers GHG emissions. As I detailed earlier in this testimony, the District of

[25] DC PSC Order 22311, para. 6.
[26] Exhibit WG(2A), pages 4-5.

Columbia has promulgated numerous policies that impact the demand for gas delivered over WGL's infrastructure. WGL apparently did not account for the impact of these policies in its capital investment decision-making processes leading to assets proposed for inclusion in rate base in this case. If it did account for them, Witness Steffes was obliged to describe how in his response to the PSC's order, which the witness did not do.

Q40 What concerns do you have with WGL's response to the PSC's order, given the material impact the District of Columbia's policies will have on demand for WGL's services and thus the prices it may sustainably charge its customers?

A40 WGL's customers, and the District of Columbia as a whole, are depending on WGL to maintain sufficient financial health so that it can maintain a safe and reliable system. Because of the nature of WGL's cost-of-service ratemaking structure, reductions in volumetric sales (billing determinants) associated with District policies will cause rate increases. Meanwhile, WGL's rates are also increasing due to the pace of its capital investments, which have not been offset by reductions in operations and maintenance costs. When combined with WGL's choice to be ignorant regarding customer economics, I am concerned that imprudent management is leading WGL to invest in capital without a full understanding of the impact of that investment on WGL's competitive position, its future sales, and the long-term sustainability of its business model.

D. Planning timeframe

Q41 Could you elaborate on what you mean when you say that WGL does not conduct capital planning that looks out more than a few years?

A41 For project types where WGL's capital planning can impact investments, WGL appears to plan only a small number of years in advance. For example, in its proposed Customer Choice Pilot in Formal Case No. 1179, WGL identifies the services to be replaced only between one and two years in advance.[27] When

[27] See Formal Case No. 1179, Exhibit WG (A) at pg. 9.

pressed to extend the foresight in the program WGL's Witness Rogers argues that WGL would need a funding plan beyond three years in order to extend its planning horizon beyond three years.[28] WGL does not prepare customer count or sales forecasts that extend more than five years.[29]

Q42 Is it reasonable for WGL to limit capital planning to a short time horizon because accelerated cost recovery is only assured for that timeframe?

A42 No. WGL has an obligation to plan for the future of its system, regardless of availability of accelerated cost recovery for some of the required capital. By conducting long-term planning, WGL could understand the implications of its capital investments and the impact of different approaches to investment and cost recovery.

Q43 Why does a short capital planning horizon give you concern?

A43 I am concerned that WGL is making decisions based only on a very near-term forecast, while the implications of those decisions will carry forward for decades due to WGL's multi-decade expected useful life for those assets. WGL should be conducting capital planning at least over a sufficient timeframe to examine the impact of customer choice when replacing assets. Given that water heaters have a typical lifetime of about 10 years (and represent more than a quarter of WGL's residential sales[30]), and space heating systems have a typical lifetime as long as 20 years (and represent more than 60 percent of residential consumption[31]), each of WGL's customers are making decisions at least every 10 to 20 years regarding whether to retain gas service. By looking forward at its capital plan and resulting

[28] FC1179, Exhibit WG(2A), page 47, lines 19-22. ("To the extent Witness Hopkins is recommending the Company can or should be directed to reach beyond a three-year planning period, the entire District SAFE Plan and the funding for it should match any expanded planning term, as these are all inextricably intertwined.")

[29] WGL Response to DCG DR 2-1, attached hereto as Exhibit DCG (A)-4 (confidential attachments omitted).

[30] See U.S. Dept. of Energy, Energy Information Administration Report: "Annual household site natural gas end-use consumption in the United States by state—totals and percentages, 2020", released June 2023, available at: https://www.eia.gov/consumption/residential/data/2020/state/pdf/ce4.1.ng.st.pdf

[31] Id.

rate implications for at least 10 to 20 years, a prudent utility would be able to account for the impact of customer choices and competition. A similar minimum planning horizon also accords with the District's climate and energy policies, which detail policy requirements over the next 20 years.

E. Non-pipeline alternatives

Q44 What is an NPA?

A44 An NPA refers to an activity or investment that delays, reduces, or avoids the need to build or upgrade traditional natural gas infrastructure such as pipelines, storage, and peaking resources.

Q45 What are examples of NPAs in the context of a local distribution company like WGL?

A45 New York State Electric and Gas (NYSEG) is developing a process for implementing a portfolio of NPAs. In 2022, NYSEG introduced a Request for Proposals for NPAs in the Canadaigua area to avoid a main reinforcement where the distribution system was near reaching maximum capacity.[32] NYSEG issued a similar request for proposals in 2019 in the Lansing area to avoid the need for a pipeline reinforcement project, where delivery pressures have been at unacceptable levels during peak conditions. In 2022, NYSEG entered into contracts with six developers to create a portfolio of NPAs in the Lansing area including installing efficient heat pumps, converting existing heat pumps to electric, replacing inefficient technology, adding other energy efficiency solutions in specific public buildings, and a waste heat recovery program for a large industrial customer.[33]

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[32] NYSEG. Accessed December 28, 2023. "Non-Pipe Alternatives." Available at: https://www.nyseg.com/ourcompany/reliableservice/reliability-projects/non-pipe-alternatives.
[33] NYSEG. 2022. "Lansing Non-Pipes Alternatives (NPA) Portfolio." Available at: https://www.nyseg.com/documents/40132/5899449/22-5069+NYSEG+Lansing+Non-Pipes+Alternatives_12.30.22.pdf/.

Another New York utility, Con Edison, has also developed a "Whole Building Electrification Service" NPA program. The utility has identified for consideration of NPAs more than 40 segments of leak-prone pipe that would otherwise be replaced over the next decade, after finding NPAs to be cost-effective when evaluated against traditional pipe-based solutions.[34] 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 instead retire it. Con Edison developed screening and suitability criteria for costs and lead times of worthwhile NPA projects; at least 24 months of lead time is required.[35]

Q46 Could you elaborate on what you mean when you say that WGL has not evaluated or used NPAs to replace assets?

A46 WGL has presented no evidence or testimony in this docket that it has considered or implemented NPAs.

Q47 Could you provide a simple example of an NPA that WGL could have implemented?

A47 WGL states that the average cost to replace a leak-prone service line is $35,300.[36] (The average cost during the time period covered by this case may have been somewhat lower.) If WGL identified a service line that would be replaced in the next few years (providing time for the owner to plan and respond before the replacement was scheduled) and offer the building owner an incentive of $15,000 to fully electrify, that could result in a cost-effective NPA. If the owner accepted the incentive, WGL and its ratepayers would avoid the $35,300 cost of replacing the service line (and all associated financing and tax cost associated with that asset) at the cost of a $15,000 incentive payment (which could be passed through

[34] Consolidated Edison Company of New York, Non-Pipeline Alternatives Implementation Plan, NY PSC Case No. 19-G-0066 (Nov. 17, 2022), page 20; NY PSC Case No. 19-G-006, Consolidated Edison Company of New York, Benefit Cost Analysis: MRP Non-Pipeline Alternative Projects (Nov. 17, 2022), page 4.
[35] Consolidated Edison Company of New York, Non-Pipeline Alternatives Implementation Plan, NY PSC Case No. 19-G-0066 (Nov. 17, 2022), page 4.
[36] See Formal Case No. 1179, WGL Response to DCG DR 3-11, attached as Exhibit DCG (A)-5.

or capitalized). The net outcome would be a safer gas system, lower rates, building systems consistent with District policy, and lower stranded asset risk. WGL could have requested regulatory approval for such activities, as utilities in other states have done, or even begun implementation and come before the PSC in this case and argued for the prudence of its actions.

Q48 Why is the failure to consider NPAs an indication of imprudent management and decision-making?

A48 NPAs provide an opportunity to lower rates while reducing risk. If gas distribution were an unregulated competitive business, utilities that did a better job of identifying and implementing NPAs would be more competitive, reduce costs for consumers, and have the opportunity to create greater returns for their investors. By failing to consider NPAs, WGL has imprudently ignored opportunities to reduce rates and risk.

F. Information tracking

Q49 Does WGL track its assets in a manner sufficient to identify stranded assets when they occur?

A49 Not that I can tell. When asked to account for meters and service lines that were not used during the test year, WGL provided dispiriting responses. On meters, WGL does not track usage in a way that identifies whether the assets have been used during the year.[37] This means that some meters may already not be used and useful, and thus potentially stranded, but WGL lacks the information and analysis required to identify the extent to this problem. On services, WGL says that identifying the services that were not used would require special study, and the PSC therefore excused WGL from answering the DCG's question. It is concerning that WGL does not have sufficient information about its system that it can identify which services are used and useful without a special study. If WGL faced increasing customer departures in the future, neither WGL nor the PSC

[37] See Exhibit DCG (A)-3.

would have the information at hand to understand the extent of the stranded asset risk facing the company and ratepayers.

Q50 Can a utility conduct prudent planning without understanding which of its assets are used?

A50 No. If WGL does not understand which of its assets are used, it does not have a sufficiently clear picture of its business to be conducting comprehensive and prudent planning.

G. Stranded asset risks

Q51 Could you elaborate on what you mean when you say that WGL does not acknowledge or analyze the financial risks of stranded assets on its system?

A51 In Paragraph 48 of Order 22003, the PSC ordered WGL to develop an approach to replacing the highest-risk assets while minimizing stranded assets as the District continues to undergo the energy transition. WGL's response to this charge was to develop a limited pilot program as part of its District SAFE proposal. WGL did not respond by demonstrating that its full suite of current pipe installation and replacement activities were designed with full knowledge and understanding of stranded asset risks. In Formal Case No. 1179, Witness Rogers states that "the Company is not currently aware of any data on its system that indicates there is a threat posed by stranded assets."[38] (Witness Rogers clarified in response to a data request from the DCG that she was referring to a financial threat.[39]) However, by presenting a pilot program to avoid replacing service lines as its mechanism to reduce stranded asset risk, WGL implicitly acknowledges that all assets it does install are at risk of stranding, including those installed during or preceding the test year in this case. WGL's conflicting statements on stranded asset risk indicate that it did not conduct a comprehensive analysis of the financial risks of stranded assets for the assets included in the rate base in the test year.

[38] Formal Case No. 1179, Exhibit WG (2A), page 11, lines 14-16.
[39] Formal Case No. 1179, WGL Response to DCG DR 3-10, attached hereto as Exhibit DCG (A)-6.

Q52 Would a prudently-run utility analyze its stranded asset risk?

A52 Yes. Stranded costs are a potential major risk to the company's investors and customers. If management has not analyzed that risk, understanding the assets implicated, as well as the likelihood, consequence, timing, and potential mitigation, then both its investors and its customers (through the PSC) should require WGL to conduct such an analysis.

H. Gas planning proceeding

Q53 Has the PSC recognized a need for improved gas planning?

A53 Yes, it has. The PSC has requested participants in Formal Case No. 1167 to submit comments regarding the feasibility of a gas planning proceeding, including how it may relate to electric system integrated distribution system planning.[40]

Q54 Does the potential for a PSC proceeding on gas planning mean that WGL's practices leading to its proposed test year revenue requirement are adequate?

A54 No. WGL has an obligation to undertake prudent actions, including good planning, regardless of whether the PSC has ordered it to take those actions or established specific expectations or requirements regarding the content or structure of that planning. The PSC's desire to improve gas planning going forward does not insulate WGL from review of its actions before and during the test year in this case. At all points before and during the test year, WGL had an obligation to undertake adequate planning to support its investment decisions. If WGL were undertaking gas planning that did not have the numerous deficiencies that I listed earlier in this section of my testimony, it is possible that the PSC and other District stakeholders would not see the need for such a proceeding. The potential need to hold such a proceeding is indicative of WGL's failures and its imprudent decision to refuse to engage in proper planning.

[40] DC PSC Order 22339, para. 26.

VI. REMEDY FOR WGL'S IMPRUDENT PLANNING

Q55 What should the PSC do in this case to remedy WGL's failure to undertake prudent planning that accounts for its competitive and policy context?

A55 I propose three linked remedies relate to gas system planning:

1. The PSC should order WGL to maintain records sufficient to identify which assets are used to provide service to customers each year.
2. The PSC should require WGL to conduct comprehensive long-term gas system planning, and review, amend, and approve WGL's planning practices.
3. The PSC should set an explicit standard that going forward, it will not approve inclusion into rate base of any capital investments, or inclusion in the cost of service of any operations and maintenance expenses, that have not been evaluated and shown to be consistent with an approved long-term planning methodology.

A. Maintain records

Q56 What should the PSC order WGL to do regarding record-keeping?

A56 The PSC should order WGL to maintain records regarding which assets, including service lines and meters, are used each year to provide service in the District of Columbia. This information is foundational to understanding what WGL's plant in service actually contains, and to conducting comprehensive gas planning.

B. Require comprehensive long-term gas planning

Q57 What role does gas system planning play in making prudent investments?

A57 Planning is essential to prudent management of and investments in the gas pipeline infrastructure. 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 or decline 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- or retirement-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 a replacement-focused approach, but the former also may be more targeted and nimbler with the ability to adjust to changing system utilization. Retirement completely eliminates safety risk and emissions, while also avoiding stranded asset risk and reducing competitive pressure. Replacement offers a longer lifetime, with associated reduction in flexibility and increase in the need to manage stranded asset 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.

Q58 Can you suggest some principles for long-term gas system planning, in the context of the energy transition?

A58 Yes. My colleagues and I published a white paper in the context of New York's gas planning proceeding,[41] which identified the following 14 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 greenhouse gas constraints.
- Apply a high threshold for approving new gas infrastructure investments.
- Assess multiple gas utility business models.
- Develop comprehensive non-pipeline alternative screening frameworks.
- Adopt practices for strategic asset retirement.
- Update gas load forecasting practices.
- Account for customer actions.

[41] Woolf et al. 2021. *Long-Term Planning to Support the Transition of New York's Gas Utility Industry*. Synapse Energy Economics on behalf of Natural Resources Defense Council. Attached as Exhibit DCG (A)-7.

- Account for risk.
- Articulate an action plan.
- Update plans periodically.

In a recent literature review, Pacific Northwest National Laboratory researchers highlighted key points from their review, including:[42]

> Gas planning capabilities and requirements need to become more detailed and transparent. Specific ideas included in these reports and proceedings include:
> - Gas system mapping conducted by Local Distribution Companies…
> - New solution acquisition processes…
> - Disclosure of locational system needs…
> - Comprehensive capital investment forecasts…
> - 3-step non-pipeline alternative processes…
> - Evaluating non-pipeline alternatives for safety-related projects…
> - Modeling a 'no-infrastructure option' within planning scenarios [internal citations removed]

Q59 Does WGL's planning practice meet these standards today?

A59 As far as I can tell, it does not.

- WGL has not undertaken long-term capital planning consistent with the principles I laid out above.
- WGL's business approach is not designed to succeed within its competitive context and alongside the District's carbon neutrality and electrification policies.
- WGL's approach does not minimize risk compared with alternatives that are lower cost and policy-consistent.
- WGL's approach does not account for the long-term safety implications of a potentially precarious financial position.

[42] Shipley, J., J. Barlow, and G. Relf. October 2024. *Review of Literature and Utility Commission Proceedings Relevant to Integrated System Planning: Annotated Bibliography Prepared to Support the Washington Utilities and Transportation Commission*. U.S. Department of Energy. Available as FC1167-2024-M-288 at https://edocket.dcpsc.org/apis/api/filing/download?attachId=215017&guidFileName=0de24867-cfcd-421d-a008-82c6272bdf8a.pdf.

- WGL does not propose to recover the costs for its programmatic investments using depreciation rates grounded in a comprehensive view of their long-term utilization and useful lives.

Q60 How does your testimony with planning principles relate to the DCG's forthcoming comments in Formal Case No. 1167?

A60 My testimony may inform, but does not replace or duplicate, the DCG's comments in Formal Case No. 1167 regarding the feasibility of a new gas or thermal planning proceeding.

Q61 How do customers directly benefit from better gas system planning?

A61 Customers benefit from better gas system planning in several ways. First, prudent gas system planning is necessary to minimize financial risks and improper rate increases. Second, prudent gas planning can assist customers in making important capital decisions in their premises (such as the choice of heating system equipment when their existing system is approaching end of life); they benefit from understanding the full range of options they face and the cost implications of those choices. If a customer understands that the cost or nature of their gas service is likely to change during the lifetime of their new equipment, they should be able to account for that. This type of foresight is only possible if the gas utility is planning far enough ahead to be able to provide relevant information and has reliable means to share up-to-date information with customers and other stakeholders. For example, if a customer understands that a prudent gas system transition will result in the retirement of the main that serves their home within the lifetime of the equipment, they may make a different choice. Alternatively, if they understand that they will have service but that gas delivery rates will be substantially higher, that may also inform their choice. In addition, better and more transparent planning would allow District electrification programs to target assistance to households where that choice makes the most sense from a gas system perspective.

Q62 How would better planning benefit WGL?

A62 Better planning benefits WGL in several significant ways. 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. This approach helps WGL mitigate the risk of stranded assets and align with the District of Columbia's climate laws, resulting in significant benefits in system safety and financial stability. These actions would place the utility on a more stable financial footing, enabling it to make necessary expenditures to maintain a safe and reliable system while managing the energy transition.

Q63 How would better gas planning benefit the PSC?

A63 Better planning by WGL would benefit the PSC by providing the necessary information to make informed decisions that set the utility on a prudent and safe course through the energy transition. It would ensure that the PSC can trust WGL's planning and project selection process, which is crucial for approving proposals such as accelerated cost recovery for safety investments or evolutions in WGL's business model (such as NPAs and or new services). Moreover, better planning looking out past 10 years would allow the PSC to ensure that replaced pipes are not expected to be decommissioned within 10 years of installation. Long-term planning would help the PSC to be certain that assets replaced are not going to be stranded (whether because they will have long useful lives or because the depreciation rates are set appropriately), aligning with the multi-decade engineering lives of gas system assets with the ongoing energy transition, and manifesting the PSC's responsibility to advance District climate and energy policy.

Q64 How do evolving market trends and District and federal policy interact with prudent gas system planning?

A64 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 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. The utility's planning processes need to account for customers who are responding to policy signals, and simultaneously the utility's planning needs to be transparent to inform customers as they make those choices. The utility also needs to keep careful track of how its assets are used, and account for those which are no longer used and useful.

Q65 What are the implications of these principles for review of the prudence of a gas utility's planning processes and pipe replacement program, in the context of the energy transition?

A65 The gas system operates within the context of the well-established energy transition, and planning must account for that context in order to be prudent. When reviewing gas system investments for prudence, therefore, it is essential for regulators to consider whether the investment planning and selection process has accounted for the energy transition. For example, has the process included the items that I listed above from Synapse's New York whitepaper and the national laboratory literature review? Depending on information availability, it may be possible to evaluate specific investments and whether the process of selecting and executing those investments took the energy transition into account. Looking forward towards future rate years and rate cases, it may also be necessary to set planning requirements for utility investment to limit stranded-cost risk, rather than select specific investments to disallow. Taking this approach would set a clear structure and expectation around making investment choices and evaluating alternatives in order to find the best investments. This approach would also make clear that a simple *status quo* approach is not prudent. In the context of WGL's proposal in this docket, prudent investments should account for market trends and customer electrification, forecasted sales and rates, other NPAs, and District emission reduction policies and objectives.

Q66 Would better gas planning enable more accurate depreciation rates?

A66 Yes. In this docket, WGL Witness White has taken a "business as usual" approach to depreciation rates and recommends an overall increase in depreciation costs of about $6.5 million per year.[43] WGL has not updated its depreciation rates in any way to reflect the changes coming for its assets and infrastructure. A comprehensive plan would allow WGL to explore using other approaches to depreciation, such as utilization-based depreciation.[44] Utilization-based depreciation would be more intergenerationally fair because it would allocate costs to the customers who use the assets in proportion to how much they use them. Comprehensive gas planning would also result in changes in salvage rates, because the impact of inflation on asset salvage costs would be mitigated to the extent that assets retire earlier. Salvage costs should also be updated to reflect whether assets will be removed or retired in place, consistent with the results of comprehensive planning. Once the company has developed and conducted planning of the sort described here, it needs to update depreciation rates and approach to reflect the expected utilization and lifetime of its assets.

Q67 How would better long-term planning relate to rate design?

A67 Better planning would allow WGL to account for the state of competition between electric and gas when making rate design choices. For example, increasing the volumetric rate more than the fixed charge, as WGL proposes in this proceeding for residential heating customers, creates a worse competitive position for gas on a marginal basis, while reducing the savings available to customers for fully disconnecting. If fixed charges increase more, and variable charges less, then electrification could be less advantageous on the margin, but there is greater incentive for customers to fully disconnect (and thus result in potentially stranded service lines).

[43] Exhibit WG(G), page 2.

[44] As Exhibit WG(G)-2 notes on pages 14-15, "If it is reasonable to predict that the net revenue pattern of an asset will either decrease of increase over time, then an accelerated or decelerated time-based method should be used to approximate the rate at which service potential is actually consumed."

C. Require planning using approved methods before entertaining any future rate case

Q68 How can the PSC enforce a requirement to conduct comprehensive planning of the sort you've just described, or which may be developed in a new proceeding stemming from Formal Case No. 1167?

A68 I recommend that the PSC require that WGL affirmatively demonstrate that all of its capital investments in any future rate case are consistent with the comprehensive planning principles and practices the PSC may adopt (whether in response to my testimony in this case and/or a new process stemming from Formal Case No. 1167). WGL has lost the presumption of prudence, so it must affirmatively demonstrate that its actions are prudent in order to have the resulting investments recovered in rate base, or operations and maintenance costs included in the cost of service. The only way the PSC can be sure that WGL has remedied its imprudent planning practices is by requiring WGL to make such a demonstration. The PSC should require WGL to demonstrate it is using approved planning principles and practices before it can file its next rate case.

Q69 Have other jurisdictions established planning requirements as a prerequisite for inclusion of assets in rate base?

A69 Yes. In the 2023 rate case for People's Gas and North Shore Gas Company, the Illinois Commerce Commission ordered the companies to develop a long-term gas infrastructure plan and use it to show that proposed investments are societally least-cost and consistent with public policy:[45]

> To remedy the difficulty of obtaining information in this case and to aid in the Commission's informed review of the Companies' future rate increase requests, the Commission adopts certain reporting recommendations made by both the PIO and AG as identified below. PGL and NS shall file a long-term infrastructure plan ("Long-Term Gas Infrastructure Plan") with the Commission every two years beginning July 1, 2025, including at a minimum:

[45] Illinois Commerce Commission. November 16, 2023. Order in Cases 23-0068 and 23-0069. Pages 119-120

- List of proposed system expenditures and investments, including analysis of infrastructure needs and detailed information on all planned projects within the action plan;
- Demonstration that each project or program plan complies with all applicable Commission rules and jurisdiction requirements, such as safety and reliability, among others;
- 5-year action plan of investments with a longer-term planning horizon analysis where applicable;
- Estimated total cost and annual incremental revenue requirement of the proposed action plan;
- Explanation for the pace of each project or program, including reasoning as to why the project or program cannot be deferred to future years;
- Comparative evaluations of resource procurements and major capital investments;
- Distribution mapping that identifies areas of constraint and risk, location of planned projects, pressure districts served by each project, and locations of environmental justice communities;
- Description of lowest societal cost gas distribution system investments necessary to meet customer demand and comply with public policy objectives;
- Demonstration that the program or project will minimize rate impacts on customers, particularly low-income and equity investment eligible communities;
- Scenario and sensitivity analysis to test robustness of utility's portfolio and investments under various parameters;
- Publicly filed workpaper documenting all inputs and assumptions with limited use of confidentiality; and
- Summary of stakeholder participation and input and an explanation of how the Company incorporated stakeholder engagement."

No later than 12 months prior to the due date of the Long-Term Gas Infrastructure Plan, PGL and NS shall file a work plan that outlines at a minimum: (1) the content of the Long-Term Gas Infrastructure Plan; (2) the method for assessing potential resources; and (3) the timing and extent of public participation.

Q70 Could this requirement have the effect of delaying WGL's next rate case?

A70 The sooner WGL can remedy its planning practices and show the PSC that it has remedied its failures, the sooner it would be able to file another rate case. This requirement will also ensure that WGL prepares an effective long-term gas infrastructure plan in a timely manner, rather than relying upon Commission acquiescence for continued rate approvals in the absence of proper planning. This requirement thus complements any companion efforts the PSC may take in this docket, Formal Case 1167, or other dockets to improve gas system planning. Finally, this requirement will incentivize WGL to control costs in the interim period between rate cases, benefitting consumers through lower costs, and help improve WGL's overall financial health and the safety of the gas system over the long term.

VII. CONCLUSIONS AND RECOMMENDATIONS

Q71 What conclusions do you draw in this case?

A71 I find that:

- WGL faces competition from electricity to provide similar services to customers, and its market share is falling. WGL's requested rate increases in this proceeding will further harm WGL's competitive position.
- Public policy in the District of Columbia will likely lead to sales and customer reductions for WGL.
- If WGL fails to account for its competitive and policy context, it could cause significant adverse impacts, both for the utility itself and its customers.
- WGL has imprudently failed to account for its competitive and policy context when making capital decisions.
- In its testimony, WGL describes how it prioritizes and selects pipeline replacement projects. However, WGL has failed to provide evidence that it executes this process.
- WGL has not evaluated its current and future competitive position, despite the evident state of competition between WGL's services and electrification and WGL's inexorable rising rate trajectory.
- WGL has not accounted for the District's climate and energy policies when planning the capital investments proposed for inclusion in rate base

in this case, despite the fact that those policies will have a material impact on demand for WGL's services and thus the prices it may sustainably charge its customers.

- WGL does not conduct capital planning that looks out more than a few years, despite investing in assets with multi-decade useful lives while customers make choices about retaining or reducing WGL's service on a much shorter timeframe (e.g., every 10 to 20 years).
- WGL has not evaluated or used non-pipeline alternatives (NPAs) to replacing assets, despite the opportunity to use alternatives to lower costs, increase safety, reduce pollution, and align with competitive and policy drivers.
- WGL does not track all the information required to conduct good planning.
- WGL does not acknowledge or analyze the financial risks of stranded assets on its system, despite orders from the Commission directing WGL to plan system investments in a manner that minimizes the risk of stranded assets.

Q72 What are your recommendations to the PSC based on these conclusions?

A72 I recommend that the PSC:

- Find that WGL has lost the presumption of prudence regarding its capital decision-making, due to its failure to prudently plan within its competitive and policy context and due to its failure to provide substantive information supporting its claimed project selection and prioritization process.
- Order WGL to keep records of which of its assets are used to deliver service to customers each year.
- Order WGL to develop and use comprehensive gas system planning practices and processes that reflect its competitive and policy context,

reflect best practices for gas system planning, and mitigate stranded asset and safety risks.

- Establish that it will not entertain a future rate case from WGL until such time as WGL demonstrates that it has developed and used an approved comprehensive gas system planning approach to support its capital and operating costs.

Q73 Does this conclude your testimony at this time?

A73 Yes, it does.

BEFORE THE
PUBLIC SERVICE COMMISSION
OF THE DISTRICT OF COLUMBIA

IN THE MATTER OF:

The Application of Washington Gas	)	
Light Company for Authority to Increase	)	**Formal Case No. 1180**
Existing Rates and Charges for	)	
Gas Service	)	

AFFIDAVIT

I declare under penalty of perjury that the foregoing testimony was prepared by me or under my direction and is true and correct to the best of my knowledge, information, and belief.

Asa S. Hopkins

box SIGN 4KK9K634-1VQVY29J

Asa S. Hopkins

Executed this 24th day of January, 2025.

DCG (A)-1

Asa S. Hopkins, **Ph.D.,** Senior Vice President, Consulting

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PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA. *Senior Vice President*, April 2024 – Present; *Vice President*, April 2019 – April 2024; *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 much of 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.

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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.

Hopkins, A. S., B. Lev, H. Mabuchi. 2004. “Proposed Magnetoelectrostatic Ring Trap for Neutral Atoms,” *Physical Review A* 70, 053616.

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

TESTIMONY

Washington DC Public Service Commission (FC 1179): Provided direct testimony regarding Washington Gas’s application for accelerated cost recovery of pipeline replacement costs. On behalf of the District of Columbia Government, December 2024.

Connecticut Public Utilities Regulatory Authority (Docket No. 23-11-02): Direct and surrebuttal testimony regarding the application of Connecticut Natural Gas Corporation and the Southern Connecticut Gas Company to amend their rate schedules, with focus on gas capital planning in the context of decarbonization. On behalf of the Connecticut Office of Consumer Counsel, February and March 2024.

Public Utilities Commission of the State of Colorado (Proceeding No. 23A-0392EG): Answer and cross-answer regarding the application of Public Service Company of Colorado for approval of its 2024-2028 Clean Heat Plan, with focus on rate and bill impacts. On behalf of Sierra Club and Natural Resources Defense Council, January and February 2024.

Maryland Public Service Commission (Case No. 9692): Direct and Surrebuttal Testimony of Asa Hopkins regarding the application of Baltimore Gas and Electric Company for an Electric and Gas Multi-Year Plan. On behalf of the Maryland Office of People’s Counsel, August 2023.

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. “Coming Challenges to the Gas Distribution Utility Status Quo” presented at the Future of Heat Initiative, November 2024.

Hopkins, A. S. “Rising Gas Rates: The Need for Consumer-Focused Leadership in Light of a Looming Death Spiral” presented at the National Association of State Utility Consumer Advocates, November 2024.

Hopkins, A. S. “Analysis and Activism: The Gas Distribution Utility Status Quo is Unsustainable” presented at the Caltech Y Social Activism Speaker Series, November 2024.

Hopkins, A. S., S. Kwok, A. Napoleon, K. Schultz, K. Takahashi. “Massachusetts Clean Heat Standard: Policy and Regulatory Analysis” presented with Conservation Law Foundation, February 2023.

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 2017-2024, Co-Chair 2023-2024

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

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THE PRUDENT INVESTMENT TEST
IN THE 1980s

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April 1985

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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, first, 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 second 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 third 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 fourth 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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ACKNOWLEDGEMENTS

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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 <u>decision</u>--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

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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 fore-casts
		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.

EXHIBIT DCG (A)-2

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.

[30]Hanes 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 *prudently* 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 *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.* 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 *Southwestern Bell*, 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 *Yale Law Journal* 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 Natural Gas Pipeline 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

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[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....
>
> ...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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[53]Richard W. Hemingway, The Law of Oil and Gas (St. Paul: West Publishing Co., 1983), Sec. 8.3., p. 414.

[54]Trust 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]

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[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 own property but how a prudent trustee would act in administering the property of others or how he would act in conserving property.
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> In re Mild's Estate, 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:

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"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.
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> 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.
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> 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 overbearing 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

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[78]Senate Report 98-205, 98th Congress, 1st Session (1983), at p. 32.

[79]_Id._, at p. 154.

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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 <u>Permian Area Rate Base</u> 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]Id., 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), aff'd 260 N.Y.S.2d 340 (1965), modified on other grounds 217 N.E.2d 140 (1960) (per curiam), 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," NARUC Bulletin, No. 32-1984, August 6, 1984, pp. 11-12.

[48]"New Jersey BPU Finds Hope Creek 2 Nuclear Plant Abandonment Prudently Made," NARUC Bulletin, 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]

[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]

[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."

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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.

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[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

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[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

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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).

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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.

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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

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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., <u>Funding Nuclear Power Plant Decommissioning</u> (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

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[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

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[5]See Averch and Johnson, "Behavior of the Firm"; and Scherer, <u>Industrial Market Structure</u>, 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.

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[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.

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[8]Standard & 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.

[10]Ibid., 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.

[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.

EXHIBIT DCG (A)-2

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

[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

[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., Commission Preapproval, 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] <u>Id</u>., p. 94.

[17] Alexander A. Robichek, "Regulation and Modern Finance Theory" 33 <u>Journal of Finance</u> 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.
>
> 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

[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.

EXHIBIT DCG (A)-2

DCG (A)-3

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE GOVERNMENT OF THE DISTRICT OF COLUMBIA

DCG DATA REQUEST NO. 2

QUESTION NO. 2-17

Q. Regarding Witness Murphy's testimony at pages 8-9 and 12-13 (APRP and safety project identification and prioritization):

A. Provide a list (with sufficient identifying information to understand the project) of all APRP projects and safety-related projects that used the same analysis as APRP projects, identified for potential inclusion in the capital additions reflected in this rate case. That is, list the APRP and Safety projects considered for action that would have resulted in those projects being in service during the test year. This should include projects that are included in this rate case as well as those that were not selected or were not completed by March 31, 2024. On this list, please identify which projects were completed and use a common identifier with the projects listed in Exhibit WG(2I)-1.

B. Were all known risk-prone assets on WGL's system included in at least one of the APRP projects listed in part (a) of this question? If not, why not?

C. Provide the asset-level risk and estimated total risk (as described on page 12, lines 21-24) for the assets included in each project listed in part (a) of this question.

D. What software products, models, or tools, did WGL use to estimate the risk for each of the added assets proposed for inclusion in plant in service in this case?

E. Provide the "parametric estimate of the cost for each project" developed for each project listed in part (a) of this question.

F. Provide all ranked lists of APRP projects (by overall risk reduction per dollar invested, produced per lines 2-4 on page 13) that WGL used to evaluate projects that are additions to plant in service being considered in this rate case.

G. Describe in detail how WGL identifies the need for and prioritizes investments in project types other than distribution assets. These include (but may not be limited to) transmission projects of various types, communications equipment projects, intangible computer software, and general structures and improvements.

WASHINGTON GAS'S OBJECTION 11/18/2024

Washington Gas objects to this request on grounds that it is vague, unclear, voluminous, and calls for a special study. The Company further objects on grounds that APRP projects are already publicly identified. Furthermore, this request is unlikely to lead to relevant or admissible evidence.

WASHINGTON GAS RESPONSE 11/27/2024

By agreement of counsel, Washington Gas is providing the following response:

Company Witness Morrow provided detail in his Direct Testimony regarding capital projects costing $100,000 or more. Accelerated pipeline replacement projects are included and identified in that list. The Company has not risk ranked these capital projects.

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE GOVERNMENT OF THE DISTRICT OF COLUMBIA

DCG DATA REQUEST NO. 2

QUESTION NO. 2-17

Q. Regarding Witness Murphy's testimony at pages 8-9 and 12-13 (APRP and safety project identification and prioritization):

A. Provide a list (with sufficient identifying information to understand the project) of all APRP projects and safety-related projects that used the same analysis as APRP projects, identified for potential inclusion in the capital additions reflected in this rate case. That is, list the APRP and Safety projects considered for action that would have resulted in those projects being in service during the test year. This should include projects that are included in this rate case as well as those that were not selected or were not completed by March 31, 2024. On this list, please identify which projects were completed and use a common identifier with the projects listed in Exhibit WG(2I)-1.

B. Were all known risk-prone assets on WGL's system included in at least one of the APRP projects listed in part (a) of this question? If not, why not?

C. Provide the asset-level risk and estimated total risk (as described on page 12, lines 21-24) for the assets included in each project listed in part (a) of this question.

D. What software products, models, or tools, did WGL use to estimate the risk for each of the added assets proposed for inclusion in plant in service in this case?

E. Provide the "parametric estimate of the cost for each project" developed for each project listed in part (a) of this question.

F. Provide all ranked lists of APRP projects (by overall risk reduction per dollar invested, produced per lines 2-4 on page 13) that WGL used to evaluate projects that are additions to plant in service being considered in this rate case.

G. Describe in detail how WGL identifies the need for and prioritizes investments in project types other than distribution assets. These include (but may not be limited to) transmission projects of various types, communications equipment projects, intangible computer software, and general structures and improvements.

WASHINGTON GAS'S OBJECTION 11/18/2024

Washington Gas objects to this request on grounds that it is vague, unclear, voluminous, and calls for a special study. The Company further objects on grounds that APRP projects are already publicly identified. Furthermore, this request is unlikely to lead to relevant or admissible evidence.

WASHINGTON GAS'S RESPONSE 11/25/2024

By agreement of counsel, Washington Gas is providing the following response:

Company Witness Morrow provided detail in his Direct Testimony regarding capital projects costing $100,000 or more. Accelerated pipeline replacement projects are included and identified in that list. The Company has not risk ranked these capital projects.

WASHINGTON GAS'S RESPONSE 12/23/2024

A.

(A) – (C). The Company has filed project lists with regards to PROJECTpipes.

These lists are available on the Commission web site and are listed below:

Case Number	Date Filed	Description
FC1154	6/5/2019	WGL's Initial year 6 annual Project List covering October 1, 2019 - December 31, 2020.
FC1154	12/30/2020	WGL's PROJECTpipes Year 7 (CY 2021) Partial Annual Project List.
FC1154	2/26/2021	WGL's PROJECTpipes 2 ("PIPES 2") CY 2021 Final Annual Project List. ("Year 7 Annual Project List").
FC1154	9/1/2021	WGL's Initial Year 8 Annual Project List.
FC1154	9/13/2021	WGL's Modification to Year 7 Project List.

FC1154	11/1/2021	WGL's PROJECT*pipes* 2 ("PIPES 2") CY 2022 Final Project List ("Year 8 Annual Project List").
FC1154	11/5/2021	WGL's for Approval of Revision to Year 7Annual Project List.
FC1154	6/10/2022	WGL's Application for Modification of Project List.
FC1154	7/14/2022	WGL's Informational Update to Year 8 PROJECTpipes Project List.
FC1154	9/1/2022	WGL's Initial Annual Project List – Year 9.
FC1154	10/31/2022	WGL's PIPES 2 Year 9 (CY 2023) Final Annual Project List.
FC1154	2/1/2023	WGL's Application for Approval of Revision to Year 9 Annual Project List.
FC1154	4/3/2023	WGL's Informational Update for its Year 9 PROJECTpipes ("PIPES") Project List.
FC1154	6/2/2023	WGL's Annual Informational Update for its Pipes 2 Year 9 PROJECTpipes ("PIPES") Project List.
FC1154	6/8/2023	WGL's Notice of Modification to Year 9 Project List.

Washington Gas annually evaluates all distribution assets in the system, including all leak prone assets. However all leak-prone assets have not been included on at least one of the project lists. Project lists represent one year's worth of replacement activity, whereas addressing all leak-prone assets represents many years of work. For each annual project list, projects are selected to eliminate the most risk for the available funds in the coming year, while remaining projects are deferred to be included on a future list, subject to the annual re-evaluation.

The Company has filed reports with regards to non-PROJECTpipes pipeline replacement. Also, these filings include the annual risk ranking output from the risk ranking tool. These reports are available on the Commission web site and are listed below:

Case Number	Date Filed	Description
WGPRPR2024-01-G	10/1/2024	WGL's Quarterly Report on Pipe Replacement Projects for the period June 2024 – August 2024
WGPRPR2024-01-G	7/1/2024	WGL's Quarterly Report on Pipe Replacement Projects for the period March 2024 – May 2024
WGPRPR2024-01-G	4/1/2024	WGL's Quarterly Report on Pipe Replacement Projects for the period December 2023 – February 2024

WGPRPR2024-01-G	1/2/2024	WGL's Quarterly Report on Pipe Replacement Projects for the period September 2023 – November 2023
WGPRPR2023-01-G	10/2/2023	WGL's Quarterly Report on Pipe Replacement Projects for the period June 2023 – August 2023
WGPRPR2023-01-G	7/2/2023	WGL's Quarterly Report on Pipe Replacement Projects for the period March 2023 – May 2023
WGPRPR2023-01-G	4/3/2023	WGL's Quarterly Report on Pipe Replacement Projects for the period December 2022 – February 2023
WGPRPR2022-01-G	1/4/2023	WGL's Quarterly Report on Pipe Replacement Projects for the period September 2023 – November 2023
WGPRPR2022-01-G	10/3/2022	WGL's Quarterly Report on Pipe Replacement Projects for the period June 2022 – August 2022
WGPRPR2022-01-G	7/1/2022	WGL's Quarterly Report on Pipe Replacement Projects for the period March 2022 - May 2022
WGPRPR2022-01-G	4/1/2022	WGL's Quarterly Report on Pipe Replacement Projects for the period December 2021 – February 2022
WGPRPR2022-01-G	1/3/2022	WGL's Quarterly Report on Pipe Replacement Projects for the period September 2021 – November 2021
WGPRPR2022-01-G	10/1/2021	WGL's Quarterly Report on Pipe Replacement Projects for the period June 2021 – August 2021
WGPRPR2021-01-G	7/1/2021	WGL's Quarterly Report on Pipe Replacement Projects for the period of March 2021 – May 2021
WGPRPR2020-01-G - 7	4/1/2021	WGL's Quarterly Report on Pipe Replacement Projects for the period December 2020 – February 2021.
WGPRPR2020-01-G - 5	1/4/2021	WGL's Quarterly Report on Pipe Replacement Projects for the period September 2020 – November 2020.
WGPRPR2020-01-G - 3	10/1/2020	WGL's Quarterly Report on Pipe Replacement Projects for the period June 2020 – August 2020.
WGPRPR2020-01-G - 1	7/1/2020	WGL's Quarterly Report on Pipe Replacement Projects for the period March – May 2020.
WGPRPR2019-01-G - 11	4/1/2020	WGL's Quarterly Report on Pipe Replacement Projects for December 2019 - February 2020.

D) This is publicly available in Formal Case Nos. 1175 and 1179 in the direct testimony of Company Witness Stuber.

E) The Company is required to provide AACE Class III estimates for all projects. These estimates are provided on the publicly available project lists noted in sub part (A).

F) See response to subpart (A) above.

G) The process for identifying the need and prioritization for investments in project types other than distribution assets, including the consideration of alternatives, is the same as described on Page 6, Lines 1 through Page 8, Lines 12 in the Supplemental Direct Testimony of Company Witness Murphy. Please also see the Company’s response to DCG DR 2-18(C).

SPONSOR: Kevin Murphy
Vice President, Asset Management, Engineering and GSO

DCG (A)-4

CONFIDENTIAL

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE GOVERNMENT OF THE DISTRICT OF COLUMBIA

DCG DATA REQUEST NO. 2

QUESTION NO. 2-1

Q. Refer to Exhibit WG(B)-8, page 12 of 22.

A. Does WGL provide a forecast of growth in the number of customers to AltaGas?

B. Does WGL provide a forecast of growth in the number of customers to rating agencies such as Fitch Ratings?

C. Please provide the annual customer growth forecasts that WGL has provided to AltaGas and to any ratings agencies over the last five (5) years.

D. What is WGL's customer growth forecast for each of Virginia, Maryland, and the District of Columbia, for the next ten (10) years?

E. Does WGL provide a forecast of growth in volumetric sales to AltaGas?

F. Does WGL provide a forecast of growth in volumetric sales to rating agencies such as Fitch Ratings?

G. Provide the annual volumetric sales forecasts that WGL has provided to AltaGas and to any ratings agencies over the last five (5) years.

H. What is WGL's volumetric sales forecast for each of Virginia, Maryland, and the District of Columbia, for the next ten (10) years?

WASHINGTON GAS'S OBJECTION 11/18/2024

Washington Gas objects to this request on grounds that it is irrelevant and outside the scope of the proceeding.

WASHINGTON GAS'S RESPONSE 12/23/2024

A. A Yes, Washington Gas provided forecasts of growth in the number of customers to AltaGas.

B. The Company does not provide a forecast of growth in the number of customers to rating agencies.

C. Washington Gas does not prepare forecasts of customer growth for 10 years. See CONFIDENTIAL Attachment 1 for a summary of the 5-year forecasts provided to ALA in the last 5 years. CONFIDENTIAL Attachments 2 to 5 provide the annual amounts.

D. Washington Gas does not provide jurisdictionally specific customer counts amounts.

E. Yes, Washington Gas provides forecasts of growth in volumetric sales to AltaGas.

F. The Company does not provide a forecast of growth in volumetric sales to rating agencies.

G. Washington Gas does not prepare annual volumetric sales forecasts of customer growth for 10 years. See CONFIDENTIAL Attachment 1 for the annual volumetric sales forecasts that WGL has provided to AltaGas for 2020 to 2024.

H. Washington Gas does not provide jurisdictional growth in volumetric sales.

SPONSOR: Janet Burrows
VP and Treasurer, AltaGas Ltd.
(parts B and F)

SPONSOR: Robert E. Tuoriniemi
Chief Regulatory Accountant
(parts A, C, D, E, G, and H)

DCG (A)-5

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FC 1179

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE GOVERNMENT OF THE DISTRICT OF COLUMBIA

DC GOVERNMENT DATA REQUEST NO. 3

QUESTION NO. 3-11

Q. What is WGL's estimated average cost per mile to replace leak-prone mains in the proposed program? Provide WGL's estimated average cost per mile (1) with, and (2) without the cost of replacing services connected to the leak-prone main.

WASHINGTON GAS'S RESPONSE 11/26/2024

A. The Company's District SAFE program includes main and service projects that are estimated at a fully loaded cost per mile, as the associated service work is necessary to maintain the flow of gas to its customers; therefore, the Company cannot provide item (2) as requested. Additionally, due to the extension of PROJECT*pipes* and the uncertainty surrounding the program parameters for District SAFE, the Company will have to adjust the estimated units and dollars for CY 2025; therefore, the units and costs for CY 2025 were not included in the average costs. The estimated average cost per mile of main with affected services is $10.7 M and average cost per service only replacement is $35.3k.

SPONSOR: Wayne A. Jacas, PMP
Director, Construction Program Strategy and Management

DCG (A)-6

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FC 1179

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE GOVERNMENT OF THE DISTRICT OF COLUMBIA

DC GOVERNMENT DATA REQUEST NO. 3

QUESTION NO. 3-10

Q. Witness Rogers states that "I would note that the Company is not currently aware of any data on its system that indicates there is a threat posed by stranded assets." Identify the stranded asset threat to which this statement is referring (i.e. physical safety threat? Financial threat? Environmental threat? Some other type of threat?)

WASHINGTON GAS'S OBJECTION 11/12/2024

Washington Gas objects to this request on grounds that the testimony (and the definition of a stranded asset in the context of a public utility) speaks for itself.

WASHINGTON GAS'S RESPONSE 12/16/2024

A. The definition of stranded asset is "assets that have suffered from unanticipated or premature write-downs, devaluation or conversion to liabilities."[1] From this definition, the stranded asset threat is financial.

SPONSOR: Jessica R. Rogers
Vice President, Regulatory and Climate Strate

[1] "Stranded Assets Programme". Smith School of Enterprise and the Environment. 25 March 2014. Archived from the original on 27 March 2014. https://web.archive.org/web/20140327230917/http://www.smithschool.ox.ac.uk/research/stranded-assets/

DCG (A)-7

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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EXHIBIT DCG (A)-7

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.

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[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

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[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.

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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.

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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.

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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.

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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.

CERTIFICATE OF SERVICE

I hereby certify that on this 24th day of January 2025, I caused true and correct copies of the foregoing Direct Testimony and Exhibits of District of Columbia Government Witness Dr. Asa S. Hopkins to be electronically delivered to the following:

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