Completing the Energy Innovation Cycle: The View from the Public Utility Commission

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Achieving widespread adoption of innovative electricity generation technologies involves a complex system of research, development, demonstration, and deployment, with each phase then informing future developments. Despite a number of non-regulatory programs at the federal level to support this process, the innovation premium—the increased cost and technology risk often associated with innovative generation technologies—creates hurdles in the state public utility commission ("PUC") process. These state level regulatory hurdles have the potential to frustrate federal energy goals and prevent the learning process that is a critical component to technology innovation. This Article explores how and why innovative energy technologies face challenges in the PUC process, focusing on case studies where PUCs have approved or denied utility proposals to deploy high cost, first-generation energy technologies. This Article concludes with an outline of possible strategies to address PUC concerns by allocating the innovation premium beyond a single utility's ratepayers.

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Introduction

The federal government has long supported development and deployment of innovative, cost-effective energy technologies.[1] After World War II, for example, the application of atomic energy research and development to support peacetime economic growth aided the commercialization of nuclear power.[2] Following the energy crisis of the 1970s, the federal government expanded its focus beyond fossil fuels and atomic energy to include renewable and energy efficiency technologies.[3] Interest in technology innovation has increased in recent years, as lawmakers and stakeholders focus on the challenge of mitigating climate change and other environmental impacts of the electric power sector. Innovative energy technologies also offer the promise of additional benefits, including employment for technology developers and installers, reduced costs for consumers, improved electricity reliability, and energy security.

While scholars and policymakers have paid considerable attention to the role of the federal government in fostering innovation in electricity generation technologies,[4] there has been far less focus on the important

1. *See generally* Fred Sissine, Cong. Research Serv., RS22858, Renewable Energy R&D Funding History: A Comparison with Funding For Nuclear Energy, Fossil Energy, and Energy Efficiency R&D (2011).

2. *Id.*

3. *Id.*

4. *See, e.g.*, A.D. Sagar & J.P. Holdren, *Assessing the Global Energy Innovation System: Some Key Issues*, 30 Energy Pol'y 465, 465–66 (2002); Varun Rai et al., *Carbon Capture and Storage at Scale: Lessons from the Growth of Analogous Energy Technologies*, 38 Energy Pol'y 4089 (2010). *See generally* Peter Folger, Cong. Research Serv., R42496, Carbon Capture and Sequestration: Research, Development, and Demonstration at the U.S. Department of Energy (2013); Interagency Task Force on Carbon Capture & Storage, U.S. Dep't of Energy & Envtl. Prot.

role of state utility regulators in ensuring that the technologies reach the marketplace.[5] Nascent electricity generation technologies are often more expensive than conventional options and may also present significant technology risks. These higher costs and increased risks can create hurdles in the state public utility commission ("PUC") process, as commissioners compare proposals for installing new technologies against the costs and risks associated with conventional options. These hurdles can exist even when the federal government provides a sizable level of funding to support a project, highlighting the need to better understand the intersection of federal technology development goals and the state regulatory process.[6]

This Article first explores how and why innovative energy technologies face hurdles in the PUC process. It then outlines strategies for achieving technology deployment that avoid placing the cost and risk of that deployment on a single utility's ratepayers. Parts I through IV characterize the challenge that innovative electricity generation technologies present to state utility regulators. Part I provides an overview of innovation in the electric power sector. Part II discusses federalism in the energy innovation context, where the federal government pursues technology development through a number of non-regulatory strategies such as funding and incentives, while state PUCs play a direct regulatory role by approving or denying utilities' decisions to adopt the technologies. Part III describes the state utility regulation process and explains the challenges facing innovative technology deployment. Part IV explores case studies where PUCs have considered utility proposals to construct facilities with expensive, first generation technologies. Finally, Part V introduces possible strategies to accelerate innovation within the electricity sector and more equitably allocate the "innovation premium"—the added cost and risk that implementation of novel technology inherently presents.

I. Innovation in the Electric Power Sector

Energy technology innovation is a broad concept, covering changes that (1) reduce the monetary cost of a given energy service, (2) increase the quality of the energy service for a given cost, or (3) reduce the environmental or political impacts of a given energy service at a cost that

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Agency, Executive Summary: Report of the Interagency Task Force on Carbon Capture and Storage (2010) [hereinafter Carbon Capture and Storage]; Richard G. Newell, *Literature Review of Recent Trends and Future Prospects for Innovation in Climate Change Mitigation* (OECD Environment Working Paper, No. 9, 2009), *available at* http://dx.doi.org/10.1787/218688342302.

5. A few authors have discussed the important role of state utility regulators. *See generally* Ken Costello, Nat'l Reg. Research Inst., New Technologies: Challenges for State Utility Regulators and What They Should Ask (2012); Scott Hempling, *Joint Demonstration Projects: Options for Regulatory Treatment*, 21 Electricity J. 30, 30 (2008).

6. *See infra* Part IV.A.2–3.

is considered worthwhile.[7] There are numerous examples of innovation throughout the electricity generation system, from fuel extraction to electricity generation, transmission, and end use. For example, the combination of horizontal drilling and hydraulic fracturing to access shale gas resources has resulted in a dramatic increase in the domestic supply of natural gas, causing prices to drop and many electric utilities to undergo a rapid transformation to increase natural gas-fired generation in their portfolios.[8] Innovations in electricity generation include advances in solar energy technologies, offshore wind, coal-fired electricity generation facilities with carbon capture and storage ("CCS"), and improved efficiencies with new natural gas turbines.[9] Advances in smart grid technologies are resulting in innovations in the delivery of electricity that allow grid operators to manage grid stability and better incorporate renewable energy and energy efficiency.[10] Smart grid technology advancement is also facilitating demand side management to help reduce consumer demand and shift load from peak to off-peak times.[11] Improvements in appliance efficiency are also reducing electricity demand, regardless of whether these appliances are part of an integrated smart grid system.[12] Each of these advances can contribute to a reliable electricity system that minimizes environmental impacts in a cost-effective manner.

Innovations in business practices are also affecting demand for new technologies for the electricity sector. In states with restructured electricity markets, for example, two major grid operators—the New England Independent System Operator ("ISO-NE") and the PJM Interconnection Regional Transmission Organization—conduct auction-based forward capacity markets, allowing "a wide range of demand-side resources to compete with supply-side resources in meeting the resource adequacy requirements of the region."[13] Resources eligible to bid in the

7. Kelly Sims Gallagher et al., *Energy-Technology Innovation*, 31 ANN. REV. ENVTL. RESOURCES 193, 195 (2006).

8. Lincoln Pratson et al., *Fuel Prices, Emission Standards and Generation Costs for Coal Versus Natural Gas Power Plants*, 47 ENVTL. SCI. & TECH. 4926, 4926 (2013).

9. *See* Carin Hall, *GE's Innovative Natural Gas Turbines See Global Popularity*, ENERGY DIGITAL (Mar. 6, 2013), http://www.energydigital.com/oil_gas/ges-innovative-natural-gas-turbines-see-global-popularity; *DOE-Sponsored Research Improves Gas Turbine Performance, Dep't of Energy*, OFFICE OF FOSSIL ENERGY (June 17, 2013, 10:33 AM), http://energy.gov/fe/articles/doe-sponsored-research-improves-gas-turbine-performance; Press Release, The Shaw Group, Inc., Shaw and Exelon Join NET Power to Develop Next-Generation Power Technology (June 6, 2012), *available at* http://www.reuters.com/article/2012/06/06/idUS99091+06-Jun-2012+BW20120606.

10. INT'L ENERGY AGENCY, TECHNOLOGY ROADMAP: SMART GRIDS 1, 6 (2011).

11. *Id.* at 5, 24.

12. *See* Steve Pacala & Robert Socolow, *Stabilization Wedges: Solving the Climate Problem for the Next 50 Years with Current Technologies*, 13 SCIENCE 968, 970 (2004).

13. MEG GOTTSTEIN & LISA SCHWARTZ, THE ROLE OF FORWARD CAPACITY MARKETS IN INCREASING DEMAND-SIDE AND OTHER LOW-CARBON RESOURCES: EXPERIENCE AND PROSPECTS, REG. ASSISTANCE PROJECT 3 (2010).

ISO-NE market include: "traditional power generation; intermittent generation resources such as wind, solar, and hydro; imports of capacity from outside New England; and demand resources, including real-time demand response, load management, distributed generation, and energy efficiency."[14]

State policies such as renewable energy mandates, energy efficiency mandates, and cap-and-trade systems—all relatively recent policy developments—can create demand for new energy technologies. Each of these examples can provide market incentives for companies to develop and deploy new energy technologies that achieve the government mandates in a cost-effective manner and meet the demand for reliable electricity.[15] For example, the North Carolina renewable energy portfolio standard requires 0.2% of generation from swine waste by 2020.[16] This mandate has created an opportunity to test and improve biogas-to-energy technology and achieve economies of scale such as by centralizing energy production from neighboring farms.[17] As of early 2014, twenty-nine states have implemented renewable portfolio standards and twenty have implemented energy efficiency portfolio standards—legislative mandates requiring that the electricity mix include a specified percentage of renewable energy, or that utilities invest a certain amount in energy efficiency measures to reduce overall demand.[18] Other states have identified renewable energy and energy efficiency goals and objectives.[19] Ten states have implemented cap-and-trade systems that require electricity generation facilities to purchase a state-issued allowance for each ton of carbon dioxide ("CO_2") emitted into the atmosphere and surrender those allowances to specified government regulators at the end of a compliance period. Nine of those states—located in the Northeast and Midwest—are participating in a regional market known as the

14. Cheryl Jenkins et al., *Energy Efficiency as a Resource in the ISO New England Forward Capacity Market*, 4 ENERGY EFFICIENCY 31, 34 (2011).

15. The effectiveness of the incentive depends on numerous factors, including, inter alia, levels of stringency, electricity demand, and technology costs. *See generally* Caroline Fischer & Louis Preonas, *Combining Policies for Renewable Energy: Is the Whole Less than the Sum of its Parts?*, 4 INT'L REV. ENVTL. & RESOURCE ECON., 2010, *available at* http://www.rff.org/Documents/Fischer_Preonas_IRERE_2010.pdf.

16. N.C. GEN. STAT. § 62-133.8(e) (2009).

17. DARMAWON PRASOJDO ET AL., NICHOLAS INST. FOR ENVTL. POL'Y SOLUTIONS, A SPATIAL-ECONOMIC OPTIMIZATION STUDY OF SWINE WASTE-DERIVED BIOGAS INFRASTRUCTURE DESIGN IN NORTH CAROLINA 4 (2013).

18. *See Renewable Portfolio Standard Policies*, DSIRE: DATABASE OF STATE INCENTIVES FOR RENEWABLES & EFFICIENCY [DSIRE] (Mar. 2013), http://www.dsireusa.org/documents/summarymaps/RPS_map.pdf; *Energy Efficiency Resource Standards*, DSIRE (Feb. 2013), http://www.dsireusa.org/documents/summarymaps/EERS_map.pdf.

19. *See Renewable Portfolio Standard Policies*, DSIRE (Mar. 2013), http://www.dsireusa.org/documents/summarymaps/RPS_map.pdf.

Regional Greenhouse Gas Initiative.[20] California has implemented its own cap-and-trade system, and has formally signed an agreement to link its system with Quebec.[21] California officials have also indicated a willingness to explore additional linkages.[22] The impacts of these programs vary depending on the stringency of the mandate, the time horizon of the policy, and political dynamics that may affect policy certainty.

This Article explores the critical, and often overlooked, role of state public utility commissions in determining whether innovative electricity generation technologies reach the marketplace. State PUCs regulate monopoly providers of electricity, a service "affected with a public interest" to protect the common good[23] by ensuring new infrastructure investments satisfy public convenience and necessity,[24] and by establishing just and reasonable rates.[25] Thus, the viability of a utility-scale demonstration project often depends on commission approval. As the case studies presented in Part IV of this Article demonstrate, utility commissions may facilitate or frustrate utility plans to implement innovative technologies, including pre-commercial demonstration projects and utility-scale projects relying on early generation technologies—both critical aspects of the technology innovation cycle.[26] "Innovation . . . is not complete unless it includes the further steps through which the new technologies or improvements attain widespread application."[27]

20. These states include Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont. *See RGGI, Inc.*, REG'L GREENHOUSE GAS INITIATIVE, http://www.rggi.org/rggi (last visited June 1, 2014).

21. *See Linkage*, CAL. ENVTL. PROTS. AGENCY AIR RESOURCES BD., http://www.arb.ca.gov/cc/capandtrade/linkage/linkage.htm (last visited June 1, 2014).

22. *See* Mary Nichols, *California's Cap-and-Trade Program Has Learned From Europe*, ENERGY BIZ (July 16, 2013), http://www.energybiz.com/article/13/07/californias-cap-and-trade-program-has-learned-europe ("Because of the way our linkage process works, any future partners will have that same ability to build a program that keeps central focus on those reductions and their needs but built around a shared platform that tracks allowances and offsets.").

23. *See* Munn v. Illinois, 94 U.S. 113, 126 (1876) ("Property does become clothed with a public interest when used in a manner to make it of public consequence, and affect the community at large. *When, therefore, one devotes his property to a use in which the public has an interest, he, in effect, grants to the public an interest in that use, and must submit to be controlled by the public for the common good*, to the extent of the interest he has thus created." (emphasis added)).

24. *See* William K. Jones, *Origins of the Certificate of Public Convenience and Necessity: Developments in the States 1870–1920*, 79 COLUM. L. REV. 426, 427 (1979).

25. *See* Bluefield Waterworks & Improvement Co. v. Pub. Serv. Comm'n of W. Va., 262 U.S. 679, 690 (1923) ("Rates which are not sufficient to yield a reasonable return on the value of the property used at the time it is being used to render the service are unjust, unreasonable, and confiscatory, and their enforcement deprives the public utility company of its property in violation of the Fourteenth Amendment.").

26. Energy technology innovation includes when technologies "are conceived; studied; built, demonstrated, and refined in environments from the laboratory to the commercial marketplace; and propagated into widespread use." Gallagher et al., *supra* note 7, at 195.

27. *Id.*

II. Federalism and the Innovation Process: The Intersection of Regulatory and Non-Regulatory Strategies

Technology innovation is a multistage process, often summarized into four general phases: research, development, demonstration, and deployment.[28] Rather than a linear process, progressing chronologically from one phase to the next, recent innovation policy scholarship points out that moving energy technologies through the innovation system depends on an iterative cycle of learning and feedback, with knowledge gained during each phase informing subsequent research, development, demonstration, and deployment efforts.[29]

Experience in the electricity sector and across other areas of the economy suggests the cost of relatively new technologies will decrease as industry accumulates experience with design, construction, and operation.[30] A combination of learning-by-researching, learning-by-doing (for producers), and learning-by-using (for customers) contributes to reduced costs and enhanced performance over time.[31] For example, the investment costs for flue gas desulfurization technologies, which employ similar principles of operation to CCS, "declined by 13% for each doubling of capacity worldwide."[32] Empirical studies have similarly identified a ten-to-thirty percent decline in cost with each doubling of production across a wide range of technologies.[33] Learning and economies of scale allow technologies that successfully diffuse in markets to reach acceptable levels of cost and risk.

Successfully stewarding an energy-technology concept through these phases and achieving wide-scale deployment involves numerous public

28. President's Comm. of Advisors on Sci. & Tech., Exec. Office of the President, Powerful Partnerships: The Federal Role in International Cooperation on Energy Innovation 1–2 (1999) (defining the energy innovation process as "energy research, development, demonstration, and deployment"). It is possible to identify additional phases necessary for innovation. For example, the U.S. Environmental Protection Agency ("EPA") characterizes this process as a "research and development continuum" and identifies six stages: (1) research or proof of concept, (2) development, (3) demonstration, (4) verification, (5) commercialization, and (6) diffusion and utilization. Envtl. Prot. Agency, *Environmental Technology Opportunities Portal: Research and Development Continuum* (July 12, 2012), http://epa.gov/environmentaltechnology/continuum.html.

29. Kelly Sims Gallagher et al., *The Energy Technology Innovation System*, 37 Ann. Rev. Envtl. Resources 137, 140 (2012). In addition, Gallagher and her colleagues replace the deployment phase with "market formation and diffusion." *Id.*

30. Tooraj Jamasb, *Technical Change Theory and Learning Curves: Patterns of Progress in Electricity Generation Technologies*, 28 Energy J. 51, 64–66 (2007).

31. *See, e.g.*, Sonia Yeh & Edward S. Rubin, *A Centurial History of Technological Change and Learning Curves for Pulverized Coal-Fired Utility Boilers*, 32 Energy 1996, 1996–97 (2007) (describing the role of learning-by-doing, research and development, and other factors on cost trends); *see also* Paul L. Joskow & George A. Rozanski, *The Effects of Learning by Doing on Nuclear Plant Operating Reliability*, 61 Rev. Econ. & Stat. 161, 161 (1979) (arguing that increases over time in capacity factors of nuclear power plants in the United States and around the world are attributable to learning-by-doing).

32. Keywan Riahi et al., *Technological Learning for Carbon Capture and Sequestration Technologies*, 26 Energy Econ. 539, 561 (2004).

33. David Popp, *Innovation and Climate Policy*, 2 Ann. Rev. Resource Econ. 275, 283 (2010).

and private actors, including a range of regulatory entities at various levels of government (federal, regional, state, and local) and among entities located on the same governmental plane—such as state environmental regulators, state energy offices, and public utility commissions at the state level; and the Federal Energy Regulatory Commission, the Department of Energy, and the Environmental Protection Agency at the federal level.[34] Much recent scholarship examines various approaches to federalism in the energy sector.[35] The range of energy federalism inquiries typically center on questions of jurisdiction,[36] exploring the regulatory roles for different levels of government,[37] whether lawmakers and judges have drawn or interpreted those lines correctly,[38] and suggesting alternative approaches to better achieve a desired policy outcome.[39] For example, smart grid technologies and expansion of the electricity grid may raise questions about the interaction between the Federal Energy Regulatory Commission ("FERC") and state utility commissions.[40] Similarly, transportation and storage of CO_2 emissions captured from power plants may require interactions between the FERC, the U.S. Department of Transportation, the U.S. Environmental Protection Agency ("EPA"), state environmental regulators, state pipeline regulators, and local and state regulators overseeing protection of mineral rights.[41]

Energy technology innovation requires viewing federalism through a different lens, one that recognizes the intersection of regulatory and non-regulatory policy approaches implemented at different levels of government.[42] While Congress and the federal agencies may foster

34. *See generally* Hari M. Osofsky & Hannah J. Wiseman, *Dynamic Energy Federalism*, 72 MD. L. REV. 773 (2013).

35. *See, e.g.*, Jim Rossi & Thomas Hutton, *Federal Preemption and Clean Energy Floors*, 91 N.C. L. REV. 1283 (2013); Robin Kundis Craig, *Hydraulic Fracturing (Fracking), Federalism, and the Water-Energy Nexus*, 49 IDAHO L. REV. 241 (2013); David B. Spence, *Federalism, Regulatory Lags, and the Political Economy of Energy Production*, 161 U. PA. L. REV. 431, 460 (2013); Daniel K. Lee & Timothy P. Duane, *Putting the Dormant Commerce Clause Back to Sleep: Adapting the Doctrine to Support State Renewable Portfolio Standards*, 43 ENVTL. L. 295 (2013); Alexandra B. Klass & Elizabeth J. Wilson, *Interstate Transmission Challenges for Renewable Energy: A Federalism Mismatch*, 65 VAND. L. REV. 1801 (2012).

36. *See, e.g.*, Symposium, *Transcript of the Federalist Society's 2012 National Lawyers Convention: Environmental Law Federalism, and the Energy Revolution: Can State and Federal Regulators Adapt to Innovations?*, 14 VT. J. ENVTL. L. 575 (2013).

37. *See, e.g.*, Klass & Wilson, *supra* note 35.

38. *See, e.g.*, Lee & Duane, *supra* note 35.

39. *See, e.g.*, Spence, *supra* note 35.

40. *See generally* Joel B. Eisen, *Smart Regulation and Federalism for the Smart Grid*, 37 HARV. ENVTL. L. REV. 1 (2013); Klass & Wilson, *supra* note 35.

41. *See generally* Jonas J. Monast et al., *A Cooperative Federalism Framework for CCS Regulation*, 7 ENVTL. & ENERGY L. & POL'Y J. 1 (2012).

42. The concept of "dynamic" federalism provides a useful framework for evaluating "vertical" interactions across multiple levels of government, as well as "horizontal" interactions among regulatory bodies within the same level of government. *See* Osofsky & Wiseman, *supra* note 34. Jody

development and deployment of new technologies through pollution reduction mandates,[43] the primary mechanisms for achieving deployment of innovative energy technologies under current federal law involve a range of private sector incentives, government research programs, and research grants to universities.[44] These federal incentives and research funding opportunities are aspirational, as they aim to reduce the costs of energy technologies but rely on the private sector to adopt them rather than create specific compliance obligations to ensure technology adoption. They do not, therefore, raise the types of jurisdictional issues that are the focus of typical energy federalism inquiries.

From a constitutional perspective, there is little doubt that the federal government could justify a more direct regulatory role in deploying electricity generation technologies under the Commerce Clause. The electricity grid is regional in nature and electricity produced in one state is regularly consumed in another state.[45] In fact, the federal government already has a direct regulatory role in many aspects of the electricity sector. For example, the Public Utility Regulatory Policies Act of 1978 required electric utilities to purchase electricity from qualifying non-utility generators—including renewable and cogeneration facilities of eighty megawatts ("MW") or less—at their avoided cost of generation.[46] Later, the Energy Policy Act of 2005 called for an electric reliability organization to develop and enforce reliability standards for the U.S. electricity grid—a role served by the self-regulatory organization North American Electric Reliability Corporation.[47] The EPA—which regulates numerous aspects of power plant operations that affect air quality, water quality, and hazardous waste—has promulgated a number

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Freeman proposes another framework—"network federalism"—that similarly offers a constructive approach to exploring energy innovation federalism. *See* Jody Freeman, Network Federalism (Nov. 18, 2013) (unpublished manuscript), *available at* http://papers.ssrn.com/sol3/papers.cfm?abstract_id=2356380 ("The network analogy best captures three features of how certain contemporary governance systems actually work: authority is divided among different levels of government, dispersed across institutions at the same level of government, and shared among both public and private actors.").

43. These mandates may come in the form of specific technology mandates—e.g., requiring installation of Best Available Control Technology—or through market mechanisms requiring regional reductions in pollution but allowing flexibility regarding the location of the pollution reductions—e.g., Acid Rain Trading Program and scrubbers.

44. *See, e.g.*, *Science and Innovation*, U.S. Dep't Energy, http://energy.gov/science-innovation (last visited June 1, 2014).

45. The continental United States electricity grid consists of three large regions: the Eastern Interconnection, the Western Interconnection, and the Electric Reliability Council of Texas. *See NERC Interconnections*, Nat'l Elec. Reliability Council, http://www.nerc.com/AboutNERC/keyplayers/Documents/NERC_Interconnections_Color_072512.jpg (last visited June 1, 2014). Within the Eastern and Western Interconnections, there are also a number of regional electric power markets. *See Electric Power Markets: National Overview*, Fed. Energy Reg. Comm'n (Feb. 4, 2014), http://www.ferc.gov/market-oversight/mkt-electric/overview.asp.

46. 16 U.S.C. § 824a-3 (2012).

47. *Id.* § 824a-2.

of rules affecting the power sector, and is considering additional regulations governing coal ash[48] and CO_2.[49] In April 2013, the EPA announced a New Source Performance Standard that, if enacted as proposed, will require any new coal-fired power plant to install carbon capture technologies.[50] Congress has also considered legislative proposals to create a nationwide cap-and-trade system for CO_2 emissions[51] and a federal renewable portfolio standard,[52] with the goal of stimulating development and adoption of new energy technologies.[53]

Nonetheless, Congress and federal agencies have consistently upheld the traditional role of the states in governing intrastate electricity generation and transmission[54] and rates charged to consumers.[55] As long as policymakers maintain the current framework, it is important to recognize the relationship between non-regulatory programs to develop energy technologies and the direct role of PUCs in influencing whether electric utilities deploy the technologies. This Article contributes to the understanding of energy innovation federalism by exploring the role of PUCs in the innovation process and offers a framework for addressing barriers that may frustrate commercialization of promising energy technologies.

A. Federal Efforts to Foster Energy Innovation

Federal investment in innovative electricity generation technology dates to the late 1940s, when President Eisenhower embarked on a landmark effort to commercialize nuclear energy.[56] In response to the energy crises of the 1970s, efforts to accelerate energy technology innovation expanded to include renewable and advanced fossil fuel technologies.[57] Current U.S. Department of Energy ("DOE") programs

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48. Hazardous and Solid Waste Management System; Identification and Listing of Special Wastes; Disposal of Coal Combustion Residuals from Electric Utilities, 75 Fed. Reg. 35,128 (June 21, 2010) (to be codified at 40 C.F.R. pts. 257, 261, 264, 265, 268, 271, 302).

49. Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units, 77 Fed. Reg. 22,392 (Apr. 13, 2012) (to be codified at 40 C.F.R. pt. 60).

50. *Id*.

51. *See, e.g.*, America Clean Energy and Security Act of 2009, H.R. 2454, 111th Cong. (2009); America's Climate Security Act of 2007, S. 2191, 110th Cong. (2007).

52. *See, e.g.*, American Renewable Energy and Efficiency Act, H.R. 5967, 112th Cong. § 2(a) (2012).

53. *See, e.g.*, S. 1567, 110th Cong. § 1(a) (2007) (establishing preference in allocating funds under the program to "state programs to stimulate or enhance innovative renewable energy technologies").

54. *See* Jones, *supra* note 24.

55. Gary D. Allison, *Judging the Prudence of Constructing Nuclear Power Plants: A Report to the Oklahoma Corporation Commission*, 15 Tulsa L.J. 262, 264 (1979) (observing that PUCs can influence nuclear power plant development through their authority to protect consumers from bearing the cost of imprudent investments).

56. Energy Info. Admin., U.S. Dep't of Energy, Direct Federal Financial Interventions and Subsidies in Energy in Fiscal Year 2010, at 33 (2011).

57. *See* Sissine, *supra* note 1, at 2.

seek to reduce the cost of carbon capture,[58] enable the grid to handle more intermittent renewable electricity,[59] and develop and deploy offshore wind technology in the United States.[60] Each of these programs aims to reduce cost to improve competitiveness and increase adoption.[61] The DOE implements research, development, and deployment ("RD&D") programs through a host of research grants and private sector incentives including grants and loan guarantees. The DOE's Advanced Research Projects Agency-Energy ("ARPA-E") provides funding and technical assistance to companies seeking to commercialize "transformational" energy technologies.[62] The Loan Programs Office offers loan guarantees to reduce investment risk for companies developing or installing certain categories of new technologies.[63] These non-regulatory efforts may run headlong into the PUC process especially, although not exclusively, in states that maintain the traditional "cost of service" regulatory model that seeks to protect consumers from the monopoly power of vertically-integrated electric utilities.[64]

B. The PUC Role in Energy Innovation

A public utility is a private business that provides a public service, such as the production and distribution of electricity, and is subject to public restraints on its commercial activities, such as the production and distribution of electric power.[65] The "regulatory compact" established between the public utility and the state grants the utility an exclusive service territory, and in exchange, obligates the company to provide adequate service at reasonable rates to all consumers within its territory.[66]

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58. *See Carbon Capture R&D*, U.S. Dep't of Energy, http://energy.gov/fe/science-innovation/carbon-capture-and-storage-research/carbon-capture-rd (last visited June 1, 2014).

59. *See SunShot Initiative High Penetration Solar Portal: Power Electronics*, U.S. Dep't Energy, https://solarhighpen.energy.gov/topics/system_technologies/power_electronics (last visited June 1, 2014).

60. *See Offshore Wind Research and Development*, U.S. Dep't of Energy, http://energy.gov/eere/wind/offshore-wind-research-and-development (last visited June 1, 2014) [hereinafter U.S. DOE, *Offshore Wind*].

61. *See Carbon Capture R&D*, *supra* note 58 (stating the program goal of achieving costs below $40 per ton for second generation technology and below $10 per ton for transformational technology); *SunShot Initiative*, *supra* note 59 (describing the goal to make solar cost-competitive by the end of the decade); *Offshore Wind*, *supra* note 60 (describing the program's goal to "overcome key barriers to wind development, including the relatively high cost of energy").

62. *Advanced Research Projects Agency-Energy: About*, U.S. Dep't of Energy, http://arpa-e.energy.gov/?q=arpa-e-site-page/about (last visited June 1, 2014).

63. *Loan Programs Office: Our Mission*, U.S. Dep't of Energy, http://lpo.energy.gov/about/our-mission (last visited June 1, 2014).

64. *See infra* Part III.B.

65. *See* Jones, *supra* note 24, at 426.

66. *See, e.g.*, Raymond Jackson, *Regulation and Electric Utility Rate Levels*, 45 Land Econ. 372, 373 (1969).

Under this system, also known as cost of service regulation,[67] utilities may recover all "prudent" costs and a reasonable rate of return on invested capital from ratepayers within a utility's service area subject to commission approval.[68] Rates must be "just and reasonable," and not confiscatory, which requires PUCs to balance consumer protection goals and the utility's right to the opportunity to earn a fair return on its investment.[69]

In states that retain a traditional model of electricity regulation, state PUCs oversee the activities of vertically integrated utilities regarding electricity generation, transmission, and distribution.[70] New generation facilities typically require a Certificate of Public Convenience and Necessity ("CPCN"), wherein the PUC must determine that there is a need for the additional capacity and construction of the proposed facility satisfies the public interest.[71] Additionally, PUCs set utility rates to allow a reasonable return on prudently invested capital, which discourages utilities from incurring expenses that are likely to be found imprudent and unrecoverable.[72]

In restructured states, lawmakers have replaced traditional regulation of vertically integrated electric utilities with wholesale markets for electricity generation in which electricity generators sell power competitively.[73] In these states, regulators oversee electric distribution companies, including investments in new distribution technology, such as smart grid.[74] The challenge of implementing innovative generation technologies in restructured states is primarily driven by market forces. Merchant developers may be unable to recoup the high costs of innovative technologies by selling into wholesale markets where they face competition from generators using conventional technologies. In practice, early applications of generation technologies in restructured

67. *See, e.g.*, KARL MCDERMOTT, EDISON ELEC. INST., COST OF SERVICE REGULATION IN THE INVESTOR-OWNED ELECTRIC UTILITY INDUSTRY: A HISTORY OF ADAPTATION (June 2012).

68. *See, e.g.*, Jackson, *supra* note 66; *see also* Denver Union Stock Yard Co. v. United States, 304 U.S. 470, 475 (1938) (defining the fair value of utility assets for ratemaking purposes as based on whether the assets are used and useful); Missouri *ex rel.* Sw. Bell Tel. Co. v. Pub. Serv. Comm'n of Mo., 262 U.S. 276, 289 n.1 (1923) (Brandeis, J., dissenting) (explaining the prudence standard excludes from rate base dishonest or obviously wasteful or imprudent expenditures).

69. *See* Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n of W. Va., 262 U.S. 679, 690 (1923).

70. Paul L. Joskow, *Restructuring, Competition and Regulatory Reform in the U.S. Electricity Sector*, 11 J. ECON. PERSP. 119, 121 (1997).

71. *See generally* Jones, *supra* note 24, at 427.

72. Richard D. Gary & Edgar M. Roach, Jr., *The Proper Regulatory Treatment of Investment in Cancelled Utility Plants*, 13 HOFSTRA L. REV. 469, 470–71 (1985) (citing W. Ohio Gas Co. v. Pub. Util. Comm'n, 294 U.S. 63, 72 (1935)).

73. Peter Fox-Penner & Heidi Bishop, *Mission, Structure, and Governance in Future Electric Markets: Some Observations*, 89 OR. L. REV. 1107, 1108 (2011).

74. *See id.* at 1110; *see also* PUB. SERV. COMM'N OF MD., ORDER NO. 83410, CASE NO. 9208, BALT. GAS & ELEC. CO. (June 21, 2010) (order).

states often require long-term power purchase agreements for above-market energy prices between project developers and distribution utilities—subject to PUC approval—in order to obtain financing.[75] A number of restructured states have enacted legislation that directs distribution utilities to solicit proposals for renewable energy projects and enter into power purchase agreements subject to PUC approval,[76] and utilities have brought proposals for innovative projects before state regulators under these directives.[77]

Demonstration and early deployment are both particularly important elements of the innovation cycle described above, and progress at these phases often requires approval by state PUCs. Demonstration projects contribute to learning and technology development in a number of ways[78] and also assist in scaling up technology in cases where laboratory tests are much smaller than potential real-world applications, such as for power plants.[79] For example, demonstration projects "generate information about the design of components at commercial scale, process reliability and risk of production failure."[80] Technical and economic performance data can then inform additional research and development to refine technology.[81] Demonstration projects also produce information on profitability of the technology and can reduce marketing hurdles by demonstrating the feasibility of technology to potential buyers, which enhances confidence and contributes to future market development.[82]

Even after technology has been adequately demonstrated at scale, barriers may continue to frustrate early deployment. For example, cost, information, market organization, infrastructure, regulations, or slow

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75. *See, e.g.*, Mass. Dep't Pub. Util., D.P.U. 10-54, 48–51, Mass. Elec. Co. & Nantucket Elec. Co. (Nov. 22, 2010) (petition) ("The evidence demonstrates that a project like Cape Wind would face difficulty attracting financing without a predictable source of revenues with a creditworthy entity . . . . [T]he [power purchase agreement] will help overcome obstacles to Cape Wind obtaining financing.").

76. *See, e.g.*, Long Term Contracting Standard for Renewable Energy, R.I. Gen. Laws § 39-26.1 (2006); An Act To Implement the Recommendations of the Governor's Ocean Energy Task Force, Me. Pub. L. ch. 615 (2010); Green Communities Act, 2008 Mass. Legis. Serv. ch. 169, § 83 (West); 220 Mass. Code Regs. §§ 17.03(1)–(2) (2008).

77. *See, e.g.*, R.I. Pub. Util. Comm'n, Docket No. 4111, Review of Proposed Town of New Shoreham Project (Apr. 2, 2010) (report and order); Mass. Dep't Pub. Util., D.P.U. 10-54, 48–51, Mass. Elec. Co. & Nantucket Elec. Co. (Nov. 22, 2010).

78. *See generally* Ambuj Sagar & Kelly Sims Gallagher, *Energy Technology Demonstration & Deployment* (Belfer Ctr. for Sci. & Int'l Affairs, 2004), *available at* http://belfercenter.hks.harvard.edu/publication/2596/energy_technology_demonstration_and_deployment.html.

79. *See id.*; *see also* Paul Harborne & Chris Hendry, *Pathways to Commercial Wind Power in the US, Europe and Japan: The Role of Demonstration Projects and Field Trials in the Innovation Process*, 37 Energy Pol'y 3580, 3580 (2009) (describing how demonstration and field trials provided feedback to basic research and development that helped Danish firms capture the market for wind turbines which had been dominated by U.S. firms in the early 1980s).

80. Stephen R. Lefevre, *Using Demonstration Projects to Advance Innovation in Energy*, 44 Pub. Admin. Rev. 483, 487 (1984).

81. *See* Sagar & Ghallager, *supra* note 78, at 3.

82. *See* Lefevre, *supra* note 80, at 487.

capital stock turnover can hinder market diffusion.[83] These factors are persistent barriers to the commercialization of new electricity generation technology because the electricity sector is characterized by slow capital stock turnover and utility regulators seek the least-cost resources to meet electricity demand.

In the energy sector, companies infrequently pursue demonstration projects independently because long time horizons for investment returns and high capital requirements make it difficult to monetize benefits on an acceptable timeline for investors. Government-funded demonstration programs, therefore, are designed to facilitate the demonstration and early deployment of innovative energy technologies.[84] Because these demonstration programs frequently require participating companies to take on a portion of the cost and risk, electricity generators often must seek approval from a PUC. Commissioners must then assess the additional costs and technology risks associated with the project to ensure that cost recovery is consistent with state-level consumer protection goals.[85] If the costs and risks are deemed too high, the PUC may prohibit a utility from passing project costs to ratepayers, thereby denying an opportunity for the companies involved, or perhaps the electricity sector as a whole, to learn from the project and improve upon the technologies.

III. State Regulatory Hurdles to Implementation of Innovative Generation Technologies

PUCs can provide the certainty necessary to demonstrate and deploy new technologies through approval of utility-owned projects, long-term power purchase agreements, and inclusion of above-market costs in electricity rates. PUC approval and cost recovery through rates can remove investment risk for shareholders, effectively shifting the risk to ratepayers. However, PUCs have historically emphasized cost minimization, posing a challenge for large-scale demonstration projects, which are characterized by high short-term costs and diffuse long-term benefits. Furthermore, innovative generation technologies introduce unique financial and technological risks that complicate the public interest inquiry.

In accordance with the just and reasonable standard of ratemaking[86] and the broad public interest duties of PUCs,[87] commissions have sought the lowest possible cost of service for consumers within a set of

83. *See* Sagar & Ghallager, *supra* note 78, at 4–8.
84. *See* Harborne & Hendry, *supra* note 79, at 3585.
85. *See infra* Part III.
86. *See* Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n, 262 U.S. 679, 683 (1923).
87. *See* Ford P. Hall, *Certificates of Convenience and Necessity*, 28 Mich. L. Rev. 107, 108 (1929) ("Statutes of this kind have several purposes, but that most emphasized by courts and commissions is the purpose of protecting the consuming public.").

constraints—such as reliability, financial health of the utility, and renewable energy mandates.[88] It is challenging for early applications of innovative technologies to strictly meet the least cost standard, especially in the current era of large capital investment needs, declining sales growth, and the resulting upward pressure on electricity rates.[89]

Early applications of new technology are generally expensive relative to mature technologies that have benefited from learning and economies of scale.[90] For example, the U.S. Energy Information Administration projects that the levelized cost of energy for advanced coal with CCS is $70 per megawatt-hour ("MWh") higher than for natural gas combined cycle, as shown in Table 1, *infra*. Thus, it is difficult for state utility regulators to approve implementation of new technologies unless they believe the relative costs of various technology options is likely to shift during the operational life of the new facility, for example due to fuel price volatility or future environmental regulations.[91]

88. *See generally* Shimon Awerbuch, *Portfolio-Based Electricity Generation Planning: Policy Implication for Renewables and Energy Security*, 11 MITIGATION & ADAPTATION STRATEGIES FOR GLOBAL CHANGE 693 (2006) ("[L]east-cost planning has provided the basis for electricity generation capacity expansion."); *see also* KY. PUB. SERV. COMM'N, CASE NO. 2009-00545, KY. POWER CO., at 5 (June 28, 2010) ("The Commission has long recognized that 'least cost' is one of the fundamental principles used when setting rates that are fair, just, and reasonable."); MINN. PUB. UTIL. COMM'N, DOCKET NO. E-6472/M-05-1993, EXCELSIOR ENERGY, INC., at 7 (Aug. 30, 2007) (order resolving procedural issues) (noting the administrative law judge finding that the proposed integrated gasification combined cycle ("IGCC") project is not a least cost resource and the Commission's opinion that the cost is unreasonable).

89. *See* MCDERMOTT, *supra* note 67, at 41.

90. *See, e.g.*, Daniel Cusick, *Southern Co. Vows to Continue Miss. 'Clean Coal' Plant Despite Mounting Losses*, E&E PUBL'G, LLC (Aug. 1, 2013), http://www.eenews.net/climatewire/stories/1059985429.

91. *See generally* MINN. PUB. UTIL. COMM'N, DOCKET NO. E-6472/M-05-1993, EXCELSIOR ENERGY, INC. (Aug. 30, 2007).

Table 1: Estimated Levelized Cost of New Generation Resources, 2018. (2011 $/MWh)[92]

Plant type	Capacity factor (percent)	Levelized capital cost	Fixed O&M	Variable O&M (including fuel)	Transmission investment	Total system levelized cost
Dispatchable Technologies						
Convent-ional Coal	85	65.7	4.1	29.2	1.2	100.1
Advanced Coal	85	84.4	6.8	30.7	1.2	123.0
Advanced Coal with CCS	85	88.4	8.8	37.2	1.2	135.5
Natural Gas-fired						
Convent-ional Combined Cycle	87	15.8	1.7	48.4	1.2	67.1
Advanced Combined Cycle	87	17.4	2.0	45.0	1.2	65.6
Advanced CC with CCS	87	34.0	4.1	54.1	1.2	93.4
Convent-ional Combustion Turbine	30	44.2	2.7	80.0	3.4	130.3
Advanced Combustion Turbine	30	30.4	2.6	68.2	3.4	104.6
Advanced Nuclear	90	83.4	11.6	12.3	1.1	108.4
Geothermal	92	76.2	12.0	0.0	1.4	89.6
Biomass	83	53.2	14.3	42.3	1.2	111.0
Non-Dispatchable Technologies						
Wind	34	70.3	13.1	0.0	3.2	86.6
Wind-Offshore	37	193.4	22.4	0.0	5.7	221.5
Solar PV	25	130.4	9.9	0.0	4.0	144.3
Solar Thermal	20	214.2	41.4	0.0	5.9	261.5
Hydro	52	78.1	4.1	6.1	2.0	90.3

92. *Levelized Cost of New Generation Resources in the Annual Energy Outlook 2013*, U.S. ENERGY INFO. ADMIN. (Jan. 2013), http://www.eia.gov/forecasts/aeo/electricity_generation.pdf.

Unique risks associated with early applications of innovative technologies further complicate the least cost inquiry. These include financial risks, such as risk that a vendor will be unable to complete the project, risk of cost overruns and unforeseen spikes in capital costs, and technological risk.[93] Due to the cost of large-scale electricity generation facilities, a technology failure can undermine the financial viability of an entire utility. For early technology applications, utilities may be unable to obtain firm pricing from vendors without paying a premium on an already expensive project, whereas it is difficult for a PUC to evaluate and approve a project without assurance that the utility's cost estimate is credible.[94] Duke Energy's integrated gasification combined cycle ("IGCC") coal plant in Edwardsport, Indiana, provides a recent example of the risk associated with new technologies. The plant went offline just six days after Duke declared the plant operational as a result of damage to fans required to operate the plant's gasifiers.[95] A Duke spokesperson told the press, "that's not unusual with any new plant, but it is more common with advanced technology on this scale. We expect to deal with technical issues early in operations."[96]

Beyond the level of financial and technological risk, the allocation of risk between utility shareholders and ratepayers is an important question for state regulators' public interest inquiry.[97] Risk may also be allocated between two or more utility operating companies owned by the same holding company, between two or more utilities that will co-own a demonstration project, or between a utility and its vendors.[98] If consumers shoulder significant financial and technological risk, construction cost overruns or underperformance have the potential to render a seemingly cost-effective project very expensive for ratepayers.

The mechanism for cost recovery is an important factor in risk allocation. Traditionally, utilities have recovered invested capital plus a

93. *See generally* MINN. PUB. UTIL. COMM'N.

94. *See, e.g.*, VA. STATE CORP. COMM'N, CASE NO. PUC-2007-00068, APPALACHIAN POWER CO., at 5–6 (Apr. 14, 2008) (final order) (likening project approval to allowing ratepayers to write a blank check); *see also* MINN. PUB. UTIL. COMM'N, DOCKET NO. E-6472/M-05-1993, EXCELSIOR ENERGY, INC., at 15 (Aug. 30, 2007).

95. *Update: Duke's Edwardsport IGCC Plant Operating Intermittently*, POWER ENGINEERING (Aug. 2, 2013), http://www.power-eng.com/articles/2013/08/dukes-edwardsport-igcc-plant-operating-intermittently.html.

96. *Id*.

97. *See, e.g.*, MISS. PUB. SERV. COMM'N, DOCKET NO. 2009-UA-014, MISS. POWER CO., at 4 (Apr. 24, 2012) (final order on remand); *see also* COLO. PUB. UTIL. COMM'N, DECISION NO. C09-0472, DOCKET NO. 09A-15E, PUB. SERV. CO. OF COLO., at 6 (Apr. 27, 2009) (final order) (noting that commission staff opposed the project, reasoning that it constituted research and development that is properly funded by shareholders, and ratepayers should not be responsible for the project's financial and operational risk).

98. *See, e.g.*, VA. STATE CORP. COMM'N, CASE NO. PUE-2009-00030, APPALACHIAN POWER CO., at 20–21 (July 15, 2009) (final order); MINN. PUB. UTIL. COMM'N, DOCKET NO. E-6472/M-05-1993, EXCELSIOR ENERGY, INC., at 17 (Aug. 30, 2007).

reasonable rate of return through periodic general rate cases.[99] Under this arrangement, utility rates are calculated based on used and useful invested capital, meaning that construction costs are not recoverable until the first rate case after a new unit is placed into service.[100] Costs allowable in rates are subject to retrospective prudence reviews, thereby protecting ratepayers from imprudent management decisions and allocating a portion of the risk of cost overruns to the utility.[101]

In recent years, it has been increasingly difficult for utilities to access capital for large generation projects with long construction timelines.[102] States and regulators have responded by allowing recovery of costs incurred during construction in certain cases, sometimes as an incentive to promote development of specific technologies.[103] However, relative to cost recovery through general rate cases, early recovery of construction costs reduces the utility's risk and increases risk for ratepayers.[104] For example, the Maryland Public Service Commission ("PSC") found that early recovery of advanced metering infrastructure costs through surcharges unacceptably allocates financial risk to ratepayers.[105]

Similarly, agreements between utilities and contractors are important risk allocators. Contractors may assume risk through firm pricing agreements or pass on costs exclusively to the utility and its ratepayers. For example, in the case of a proposed IGCC facility in Minnesota, the Public Utility Commission found that:

> Normally, independent power producers . . . offer power purchase contracts under which they assume the risks of plant design and construction. Here, the terms and conditions of the proposed contract shift nearly all those risks to Xcel and its ratepayers, by requiring payment of the full costs associated with engineering, procurement, and plant construction. . . .
>
> . . . [Though the newness of the technology complicates] setting a firm power price . . . the proposed contract does not even provide second-

99. ICF INT'L, INVESTMENT DECISIONS FOR BASELOAD POWER PLANTS I-12 (Jan. 29, 2010), http://www.netl.doe.gov/energy-analyses/pubs/investmtdecsnsbsldpp4.pdf.

100. *Id*.

101. Missouri *ex rel.* Sw. Bell Tel. Co. v. Pub. Serv. Comm'n of Mo., 262 U.S. 276, 276 n.1 (1923) (explaining that the prudence standard excludes from rate base dishonest or obviously wasteful or imprudent expenditures).

102. *See* ICF INT'L, *supra* note 99.

103. *See, e.g.*, MISS. CODE ANN. § 77-3-101 (2013); *see also* FLA. STAT. § 366.93 (2013).

104. IND. UTIL. REG. COMM'N, CAUSE NO. 43114, DUKE ENERGY IND., INC., at 51 (Nov. 20, 2007) (final order).

105. *See* PUB. SERV. COMM'N OF MD., ORDER NO. 83410, CASE NO. 9208, BALT. GAS & ELEC. CO., at 7–8 (June 21, 2010) ("[W]e conclude that BGE ratepayers should not exclusively shoulder the burden in the event that costs associated with the Proposal are greater than expected, or that anticipated benefits do not materialize."); MINN. PUB. UTIL. COMM'N, DOCKET NO. E-6472/M-05-1993, EXCELSIOR ENERGY, INC., at 19 (Aug. 30, 2007).

> best protections, such as price ceilings, competitive bidding, or regularly scheduled prudence-review conferences.[106]

PUCs can and do accept increased cost and risk in order to accomplish other state policy goals, such as development of in-state energy resources and generation diversity.[107] However, specific energy policy goals articulated by state legislatures have played a critical role in facilitating PUC approval of a handful of innovative energy generation projects in recent years.[108] Although PUCs have frequently considered economic development, environmental, and other broad benefits of innovative generation technologies, these factors alone have so far proven insufficient to outweigh the inherent cost and risk associated with demonstration projects.[109]

The number of utility proposals to demonstrate or deploy innovative technologies in recent years is small compared to the momentous need for innovation in the electricity sector to meet climate mitigation and national security goals. One likely reason that relatively few projects have advanced to the stage of PUC approval (or disapproval) is reluctance on the part of regulated utilities to invest time and resources into projects that PUCs are unlikely to approve.[110] Utility proposals to invest in mature renewable energy resources have faced similar state regulatory hurdles, further illustrating the challenge of implementing nascent technology.[111]

To explore the intersection of energy innovation goals and state PUCs in detail, this Article draws on eleven recent PUC cases with well-

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106. MINN. PUB. UTIL. COMM'N at 19.

107. *See infra* Part III.A.4. (describing the importance of Mississippi's Baseload Act, and West Virginia and Indiana's preference for clean coal technology in their state PUCs' respective decisions to approve IGCC plants).

108. *See infra* Part III.A.4.

109. *See infra* Part III.A.4.

110. One analysis of the effect of regulation on utility innovation behavior posits that utilities today are more risk averse and less likely to innovate because during the 1970s many utilities abandoned construction of nuclear power plants and public utility commissions frequently denied cost recovery of imprudent expenses. *See* NAT'L REGULATORY RESEARCH INST., REGULATORY PRACTICES AND INNOVATIVE GENERATION TECHNOLOGIES: PROBLEMS AND NEW RATE-MAKING APPROACHES 64 (1994). Utilities and merchant developers have also noted the difficulty of moving forward with innovative generation projects as regulated entities. *See, e.g.*, *AEP Places Carbon Capture Commercialization On Hold, Citing Uncertain Status Of Climate Policy, Weak Economy*, AM. ELEC. POWER (July 14, 2011), http://www.aep.com/newsroom/newsreleases/Default.aspx?id=1704 (quoting Chairman and CEO Michael G. Morris's statement that, "as a regulated utility it is impossible to gain regulatory approval to recover our share of the costs . . . without federal requirements . . . already in place"); Glenn Adams, *Maine Offshore Wind Project Gets Key Approval*, ASSOCIATED PRESS (Jan. 24, 2013), http://bigstory.ap.org/article/maine-offshore-wind-project-gets-key-approval ("The PUC vote was the biggest hurdle the Hywind Maine project faced.").

111. *See, e.g.*, KY. PUB. SERV. COMM'N, CASE NO. 2009-00545, KY. POWER CO., at 8 (June 28, 2010) (denying Kentucky Power Company's proposal to enter into a long-term power purchase agreement for wind energy); OHIO PUB. UTIL. COMM'N, CASE NOS. 10-501-EL-FOR, 10-502-EL-FOR, OHIO POWER CO., at 25–28 (Jan. 9, 2013) (opinion & order) (denying AEP-Ohio's proposal to build an approximately fifty megawatt ("MW") solar energy farm).

developed records in which utilities sought approval of large-scale demonstration projects. These cases include five applications to construct or purchase power from proposed IGCC coal facilities with and without CCS,[112] two applications to recover the cost of demonstrating CCS technology on an existing coal-fired power plant,[113] and four applications to enter into long-term contracts to purchase power from proposed offshore wind farms.[114] The Authors have identified additional examples of recent utility proposals to implement innovative generation technologies (biomass gasification,[115] grid-scale electricity storage,[116] solar-coal hybrid generation,[117] solar-to-battery,[118] space-based photovoltaic,[119] ocean energy[120]), but those cases have involved smaller scale demonstrations or limited documentation of the PUC decision process.

A. Other Factors PUCs Consider When Evaluating Demonstration Projects

A review of recent well-documented PUC decisions regarding utility proposals to demonstrate or deploy innovative technologies reveals three factors that regulators have deemed important, in addition to the central goal of minimizing cost, including hedging value, fuel diversity, and local economic competitiveness. This Subpart describes each factor and discusses the critical role of state legislation in establishing explicit energy policy goals guiding state regulatory approval of innovative generation technologies.

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112. *See generally* Ind. Util. Reg. Comm'n, Cause No. 43114, Duke Energy Ind., Inc. (Nov. 20, 2007); Minn. Pub. Util. Comm'n, Docket No. E-6472/M-05-1993, Excelsior Energy, Inc. (Aug. 30, 2007); Miss. Pub. Serv. Comm'n, Docket No. 2009-UA-014, Miss. Power Co. (Apr. 24, 2012); W. Va. Pub. Serv. Comm'n, Case No. 06-0033-E-CN, Appalachian Power Co. (Mar. 6, 2008) (order); Va. State Corp. Comm'n, Case No. PUC-2007-00068, Appalachian Power Co. (Apr. 14, 2008).

113. *See generally* Va. State Corp. Comm'n, Case No. PUE-2009-00030, Appalachian Power Co. (July 15, 2009); W. Va. Pub. Serv. Comm'n, Case No. 10-0699-E-42T, Appalachian Power Co. (Mar. 30, 2011) (order on the application for a rate increase).

114. Me. Pub. Util. Comm'n, Docket No. 2010-00235, Order Approving Term Sheet (Feb. 26, 2013); Mass. Dep't Pub. Util., D.P.U. 10-54, 48–51, Mass. Elec. Co. & Nantucket Elec. Co. (Nov. 22, 2010); R.I. Pub. Util. Comm'n, Docket No. 4111, Review of Proposed Town of New Shoreham Project (Apr. 2, 2010).

115. Wis. Pub. Serv. Comm'n, Case No. 4220-CE-169, Northern State Power Co.—Wis. (Dec. 22, 2009) (final decision).

116. Utah Pub. Serv. Comm'n, Docket No. 11-035-140, Rocky Mountain Power (Nov. 22, 2011) (report & order).

117. Colo. Pub. Util. Comm'n, Decision No. C09-0472, Docket No. 09A-15E, Pub. Serv. Co. of Colo. (Apr. 27, 2009).

118. Colo. Pub. Serv. Comm'n, Decision No. C12-0026, Docket No. 11A-713E, Pub. Serv. Co. of Colo. (Jan. 11, 2012) (decision granting application for rehearing, reargument, and reconsideration).

119. Cal. Pub. Util. Comm'n, Docket No. AL-3690-E/NB2, Resolution E-4380, Pac. Gas & Elec. Co. (Dec. 16, 2010).

120. Cal. Pub. Util. Comm'n, Docket No. AL-3181-E, Resolution E-4196, Pac. Gas & Elec. Co. (Oct. 16, 2008).

1. Hedging Value

PUCs have recognized the potential for new technologies to hedge against risk.[121] For example, regulations governing emissions of hazardous air pollutants and interstate transport of air emissions have increased the cost of generating electricity from coal in recent years.[122] Future climate policy could dramatically alter the economics of conventional fossil-fuel technologies and newer low-carbon options, such as renewables and advanced fossil generation with CCS.[123] Other forthcoming environmental rules, such as coal ash[124] for coal-fired power plants have the potential to influence relative costs. Inclusion of alternative technologies in a utility's generation portfolio reduces utility and ratepayer exposure to these environmental regulatory risks.[125] Experience with construction and operation of certain technologies, such as CCS, could also prove valuable under future climate policy.

2. Fuel Diversity

Similar to the hedging value described above, PUCs have recognized the inherent value of diversity in a utility's generation portfolio, thereby limiting exposure to a host of risks associated with specific generation technologies. For example, a portfolio comprised overwhelmingly of coal or natural gas generation is more vulnerable to changes in fuel prices than a portfolio that includes a mix of coal, natural gas, nuclear, and renewables.[126] This was an important factor in the Mississippi Public Service Commission's ("MPSC") decision to allow Mississippi Power Company to proceed with an IGCC coal-fired power plant that will capture and sixty-five percent of its CO_2 emissions.[127] At the time of the MPSC's decision, Mississippi Power already generated more than fifty percent of its electricity from natural gas.[128]

121. *See, e.g.*, W. Va. Pub. Serv. Comm'n, Case No. 06-0033-E-CN, Appalachian Power Co., at 70 (Mar. 6, 2008); Ind. Util. Reg. Comm'n, Cause No. 43114, Duke Energy Ind., Inc., at 42–43 (Nov. 20, 2007).

122. *See generally* Pratson et al., *supra* note 8.

123. *See* ICF Int'l, *supra* note 99, at I-3.

124. Hazardous and Solid Waste Management System Proposed Rule, 75 Fed. Reg. 35128 (June 21, 2010) (to be codified at scattered parts of 40 C.F.R.).

125. For example, the West Virginia Public Service Commission ("PSC") found that the cost of an IGCC plant is nine percent cheaper than a pulverized coal plant if considering the expected cost of future environmental regulations. W. Va. Pub. Serv. Comm'n, Case No. 06-0033-E-CN, Appalachian Power Co., at 72 (Mar. 6, 2008).

126. Patrick Bean & David Hoppock, *Least-Risk Planning for Electric Utilities* (Nicholas Inst. for Envtl. Pol'y Solutions, Working Paper No. 13-05.).

127. *See generally* Miss. Pub. Serv. Comm'n, Docket No. 2009-UA-014, Miss. Power Co. (Apr. 24, 2012).

128. *Id.* at 30, 32, 82.

3. Local Economic Competitiveness

PUCs commonly consider economic development concerns when weighing utility proposals. For example, the number of jobs created or destroyed when a new power plant is proposed or an old plant retires often factors into PUC decisions. Likewise, PUCs have considered direct and indirect local economic development opportunities when evaluating proposals to implement innovative technologies. For example, PUCs have recognized the potential for technology to attract new industries to the state,[129] develop under-utilized natural resources,[130] or provide a new market for existing industries as benefits.[131]

4. Explicit State Policy Goals

Although PUCs have commonly recognized the benefits of innovative energy generation projects described above, state legislation that explicitly identifies one or more factors as a public interest goal has factored heavily into PUC decisions to approve a limited number of innovative generation projects.[132] For example, PUCs have recognized as benefits the potential for technology to attract new industries to the state, develop under-utilized natural resources, or provide a new market for existing industries.[133] Virginia, which has no similar preference, rejected the same IGCC project that West Virginia approved on account of high cost and risk to ratepayers.[134] Similarly, the 2008 Mississippi Baseload Act declares construction of diverse, baseload power plants to be in the public interest and directs the PUC to consider advanced technologies such as for coal and nuclear.[135] The Baseload Act was a key factor in the MPSC decision to approve the IGCC coal plant referenced above.[136] Similar deference to explicit state policy goals has aided PUC

129. *See, e.g.*, ME. PUB. UTIL. COMM'N, DOCKET NO. 2010-00235, ORDER APPROVING TERM SHEET, at 14 (Feb. 26, 2013) ("[T]here is an unquantifiable, but nevertheless important, economic value associated with establishing Maine on the forefront of offshore wind development. This Project is the kind of investment contemplated by the Ocean Energy Act as the foundation for building a strong offshore wind industry in Maine.").

130. *See generally* MISS. PUB. SERV. COMM'N, DOCKET NO. 2009-UA-014, MISS. POWER CO. (Apr. 24, 2012).

131. *See generally* IND. UTIL. REG. COMM'N, CAUSE NO. 43114, DUKE ENERGY IND., INC. (Nov. 20, 2007); *see also* W. VA. PUB. SERV. COMM'N, CASE NO. 06-0033-E-CN, APPALACHIAN POWER CO., at 2, 70 (Mar. 6, 2008).

132. *See, e.g.*, R.I. PUB. UTIL. COMM'N, DOCKET NO. 4111, REVIEW OF PROPOSED TOWN OF NEW SHOREHAM PROJECT, at 78 (Apr. 2, 2010).

133. *See generally* IND. UTIL. REG. COMM'N, CAUSE NO. 43114; *see also* W. VA. PUB. SERV. COMM'N, CASE NO. 06-0033-E-CN, APPALACHIAN POWER CO., at 2, 70 (Mar. 6, 2008).

134. VA. STATE CORP. COMM'N, CASE NO. PUC-2007-00068, APPALACHIAN POWER CO., at 8 (Apr. 14, 2008).

135. MISS. CODE ANN. § 77-3-101 (2013).

136. *See generally* MISS. PUB. SERV. COMM'N, DOCKET NO. 2009-UA-014, MISS. POWER CO. (Apr. 24, 2012).

approval of a handful of offshore wind projects on the eastern seaboard.[137]

A state policy preference for implementation of new technology has not always been sufficient to move demonstration projects forward, however.[138] The following Part describes four PUC inquiries into whether proposed innovative generation projects satisfy the public interest, including the weight PUCs afforded to the benefits described above and the role of specific state policy goals in each PUC's decision process.

IV. Case Studies: PUC Decisions Regarding Innovative Electric Power Technologies

Recent PUC decisions from West Virginia, Virginia, Mississippi, and Rhode Island highlight the intersection between electric power technology innovation and the state PUC process. The case studies below describe federal programs that are dedicated to developing new electricity generation technologies, and PUC treatment of utility proposals to construct demonstration projects or enter into long-term power purchase agreements to purchase electricity produced by advanced technologies that are not currently deployed in the United States.

A. Carbon Capture and Sequestration

CCS is a three-step process that consists of: (1) capture and compression of CO_2 that is released as a byproduct of fossil fuel combustion or industrial processes; (2) transportation of the CO_2 to a long-term storage site, typically via pipeline; and (3) storage of the CO_2 in geologic formations to prevent its release into the atmosphere.[139] With CCS, the power sector could reduce CO_2 emissions dramatically while continuing to rely on fossil fuels for electricity generation.

The U.S. Energy Information Administration's *International Energy Outlook 2013* reference case projects that coal will comprise a major portion of national and global electricity generation through 2040.[140] Global demand for coal is projected to increase for the foreseeable future absent significant policy intervention,[141] and coal will continue to provide a major portion of U.S. electricity generation despite projections

137. *See generally* Mary Ann Christopher & Tom Mullooly, *Early Offshore Wind PPAs Have Influential Supporters*, N. Am. Wind Power, Oct. 2010; *see also* Me. Pub. Util. Comm'n, Docket No. 2010-00235, Order Approving Term Sheet, at 14 (Feb. 26, 2013).

138. *See, e.g.*, Minn. Pub. Util. Comm'n, Docket No. E-6472/M-05-1993, Excelsior Energy, Inc. (Aug. 30, 2007); R.I. Pub. Util. Comm'n, Docket No. 4111, Review of Proposed Town of New Shoreham Project (Apr. 2, 2010).

139. *See* Carbon Capture and Storage, *supra* note 4, at 2.

140. *International Energy Outlook 2013: Interactive Table Browser, World Installed Coal-fired Generating Capacity by Region and Country*, U.S. Energy Info. Admin., http://www.eia.gov/oiaf/aeo/tablebrowser/#release=IEO2013 (last visited June 1, 2014).

141. *Id.*

that the nation's electricity sector will build few additional coal-fired power plants.[142] Given these trends, the International Energy Agency describes CCS as critical to attainment of global climate mitigation goals.[143] Though the recent boom in natural gas production contributed to a decline in CO_2 emissions from the U.S. electricity sector,[144] energy modeling indicates that CCS will also be needed to control emissions from natural gas power plants in order to achieve significant global reductions in CO_2 emissions.[145]

1. *Federal Support for CCS*

The DOE has pursued CCS research and development since 1997,[146] but launched its efforts in earnest after the Energy Policy Act of 2005 provided a ten-year framework and authorization for CCS RD&D.[147] The Energy Independence and Security Act of 2007 further provided for seven large-scale CCS demonstration projects.[148] With the American Recovery and Reinvestment Act of 2009,[149] Congress appropriated an additional $3.4 billion for CCS RD&D.[150] In February 2010, President Obama established the Interagency Task Force on Carbon Capture and Storage and set a goal of bringing five to ten commercial demonstration projects online by 2016.[151] The Task Force has described the focus of CCS RD&D efforts as twofold: (1) to demonstrate the operation of current CCS technologies integrated at an appropriate scale; and (2) to improve CCS technologies and advanced generation technologies such as gasification that, together, will facilitate widespread cost-effective deployment.[152]

Although technology exists at all three steps of the CCS process, current methods are very expensive as applied to the power sector and must be integrated with power plant design at scale. For example, CO_2 capture from industrial gas streams dates to the 1930s, but existing capture technology is energy intensive and would reduce electricity

142. *Id.*

143. INT'L ENERGY AGENCY, TECHNOLOGY ROADMAP: CARBON CAPTURE AND STORAGE 1 (2013).

144. *Energy-Related CO_2 Emissions*, U.S. ENERGY INFO. ADMIN. (Dec. 16, 2013), http://www.eia.gov/forecasts/aeo/er/early_carbonemiss.cfm.

145. INT'L ENERGY AGENCY, *supra* note 143, at 15.

146. *See* FOLGER, *supra* note 4, at 1.

147. *Id.* at 4 (citing Energy Policy Act of 2005, Pub. L. No. 109-58, § 963, 2005 U.S.C.C.A.N. (119 Stat.) 594, 891–92).

148. *Id.* (citing Energy Independence and Security Act of 2007, Pub. L. No. 110-140, 2007 U.S.C.C.A.N. (121 Stat.) 1492, 1704–16).

149. American Recovery and Reinvestment Act of 2009, Pub. L. No. 111-5, 2009 U.S.C.C.A.N. (123 Stat.) 115, 139.

150. *FE Implementation of the Recovery Act*, OFFICE OF FOSSIL ENERGY, U.S. DEP'T OF ENERGY, http://energy.gov/fe/fe-implementation-recovery-act (last visited June 1, 2014).

151. Presidential Document, 75 Fed. Reg. 6087, 6087 (Feb. 5, 2010).

152. CARBON CAPTURE AND STORAGE, *supra* note 4, at 3.

output and increase electricity rates.[153] The DOE estimates that application of current technology to a supercritical coal-fired power plant would increase the cost of electricity by eighty percent.[154] Capture of CO_2 contributes approximately seventy to ninety percent of the cost, and as a result, the DOE has focused on RD&D to lower the cost of capture in addition to integration and demonstration of existing technologies at scale.[155] The DOE's portfolio also includes development of advanced generation technologies that simplify the process of separating CO_2, such as gasification.[156] Today, the DOE is pursuing rapid commercialization of cost-effective CCS technologies,[157] which will require state regulatory approval of an increasing number of demonstration projects.

2. *The Mountaineer IGCC Project—West Virginia and Virginia*

In 2007, Appalachian Power Company (APCo), a subsidiary of American Electric Power Company, applied to the West Virginia and Virginia PUCs for approval of a 629 MW "carbon capture ready" IGCC coal facility in Mason County, West Virginia.[158] At an estimated cost of $2.23 billion, the project would cost twenty to thirty percent more than a similar size pulverized coal facility.[159] APCo planned to pursue federal tax credits and additional state incentives to offset the cost[160] and argued that the value of IGCC technology is its potential to cost-effectively capture CO_2 emissions.[161] Though West Virginia regulators approved the project, the Virginia State Corporation Commission ("SCC") denied APCo's bid for approval, preventing the project from moving forward.[162]

This project—and a similar effort by APCo to recover costs of a CCS demonstration project on the existing Mountaineer coal-fired power plant described below—provides a particularly useful case study for two reasons. First, because APCo serves customers in both states, this example highlights the disparate reactions of two state PUCs that evaluated the same set of facts surrounding a single proposed demonstration project. Second, this example serves to illustrate the added complexity of

153. *Id.* at 2.

154. U.S. Dep't of Energy & Nat'l Energy Tech. Lab., DOE/NETL Carbon Dioxide Capture and Storage RD&D Roadmap 3 (2010).

155. Carbon Capture and Storage, *supra* note 4, at 3.

156. Capture and Storage RD&D Roadmap, *supra* note 154, at 12–13.

157. *Id.* at 3.

158. Va. State Corp. Comm'n, Case No. PUC-2007-00068, Appalachian Power Co., at 1 (Apr. 14, 2008).

159. *Id.*

160. W. Va. Pub. Serv. Comm'n, Case No. 06-0033-E-CN, Appalachian Power Co., at 65–66 (Mar. 6, 2008).

161. Va. State Corp. Comm'n, Case No. PUC-2007-00068, Appalachian Power Co., at 13 (Apr. 14, 2008).

162. *Id.* at 2.

demonstration projects that require approval from multiple state PUCs because many utilities operate across state lines.

a. West Virginia PSC Evaluation

The West Virginia PSC approved APCo's application on March 6, 2008, though not without concern.[163] The PSC began its evaluation of the project by stating four broad concerns regarding cost and risk: (1) even if the project were completed under budget, it would be the single most expensive project ever considered by the commission; (2) the direction of federal climate policy is uncertain, and a primary benefit of the project is its potential to cost effectively meet these unknown future standards; (3) the special ratemaking treatment requested by APCo—which would allow recovery of costs during construction—places an early and substantial burden on the consuming public; and (4) IGCC and CCS technologies are relatively new and therefore inherently risky. However, the PSC reasoned, a host of other factors tipped the scale in favor of approval, including the fact that "specific statutory provisions relating to the Commission, direct[] the Commission to '[e]ncourage the well-planned development of utility resources in a manner consistent with state needs and in ways consistent with the productive use of the State's energy resources, such as coal.'"[164]

While West Virginia's stated preference for utility resources that support an ongoing market for the state's natural resources—a local economic development concern—was a key factor in the PSC's decision, the commission also recognized the project's value as a hedge against future environmental regulations.[165]

b. Virginia SCC Evaluation

On April 14, 2008, the Virginia SCC evaluated the same set of facts and came to the contrary conclusion that "it is neither reasonable nor prudent for APCo to construct the proposed IGCC Plant."[166] As with the West Virginia PSC, the SCC began with an inquiry into the project's cost and risk. First, the SCC found that the company's cost estimate was not credible.[167] In particular, the SCC noted the absence of a fixed price contract and meaningful price or performance guarantees.[168] The SCC further expressed concern regarding the company's own doubts as to whether it could obtain firm pricing without paying an "exorbitant risk

163. W. VA. PUB. SERV. COMM'N at 2.
164. *Id.* at 2 (citing W. VA. CODE § 24-1-1 (2008)).
165. *Id.* at 70, 72.
166. VA. STATE CORP. COMM'N, CASE NO. PUC-2007-00068, APPALACHIAN POWER CO., at 2–3 (Apr. 14, 2008).
167. *Id.* at 5.
168. *Id.*

premium" given the complexity and duration of the project.[169] In addition, the SCC noted that uncertainty in the cost estimate is compounded by the question of whether IGCC is a mature technology.[170] While West Virginia regulators described IGCC as a mature but relatively new technology,[171] the SCC questioned the maturity of the technology at scale and the expected capacity factor of the plant.[172]

With regard to the value of hedging against future environmental compliance costs—which the West Virginia commission recognized as potentially significant—the Virginia SCC dismissed any potential benefits as uncertain. The SCC stressed that the addition of CCS would add hundreds of millions of dollars to the total cost and would be driven by climate policy "that is yet to come."[173] The SCC further reasoned that uncertainty surrounding the technology, cost, and future policy rendered it impossible to assess the potential CO_2 benefits of the proposed plant.[174]

3. *The Mountaineer CCS Demonstration Project—West Virginia and Virginia*

Undeterred by the 2008 failure to gain approval for the IGCC facility, APCo sought approval from West Virginia and Virginia regulators in 2009 to include in electricity rates the cost already incurred during phase I of a CCS demonstration project at the existing Mountaineer pulverized coal-fired power plant in Mason County, West Virginia. APCo's parent company, AEP, launched the demonstration project in partnership with Alstom, RWE, the National Energy Technology Laboratory, and the Battelle Memorial Institute.[175] The phase I pilot project operated between twelve and eighteen months, capturing CO_2 from a thirty MW side slip,[176] and was the first CCS demonstration project on an in-service coal plant.[177] Phase II would have entailed a commercial-scale demonstration of carbon capture, with the DOE providing a grant for fifty percent of the project costs ($334

169. *Id.* at 5–6.

170. *Id.* at 11.

171. W. VA. PUB. SERV. COMM'N, CASE NO. 06-0033-E-CN, APPALACHIAN POWER CO., at 70 (Mar. 6, 2008).

172. VA. STATE CORP. COMM'N, CASE NO. PUC-2007-00068, APPALACHIAN POWER CO., at 11–12 (Apr. 14, 2008).

173. *Id.* at 7 (emphasis omitted).

174. *Id.* at 7–9.

175. *AEP Mountaineer Fact Sheet: Carbon Dioxide Capture and Storage Project*, CARBON CAPTURE & SEQUESTRATION TECH. PROGRAM, MASS. INST. OF TECH. (Jan. 30, 2014), http://sequestration.mit.edu/tools/projects/aep_alstom_mountaineer.html.

176. *Id.*

177. W. VA. PUB. SERV. COMM'N, CASE NO. 06-0033-E-CN, APPALACHIAN POWER CO., at 19 (Mar. 6, 2008).

million), but AEP cancelled the project citing the difficulty of recovering project costs as a regulated utility, among other challenges.[178]

a. West Virginia Evaluation

Here, the West Virginia PSC acknowledged the broad societal benefits of testing CCS technology but was "troubled" by the cost recovery request for a number of reasons.[179] First, when the PSC approved the IGCC project described above, it specifically held that retrofitting with CCS would constitute a major modification and require a CPCN.[180] In the present case, APCo did not file for a CPCN for CCS demonstration project.[181] Though phase I consisted of a small-scale pilot project, the cost—$30.9 million—was nontrivial.[182]

Further, the West Virginia PSC articulated a broader responsibility for sharing the cost of demonstration projects with diffuse benefits, stating, "We believe that this operating cost also needs to be shared among all AEP operating facilities."[183] Accordingly, the PSC allowed a portion of the cost commensurate with APCo's share of AEP load.[184] The PSC acknowledged its lack of authority to allocate the remaining cost to other AEP jurisdictions, but stated that AEP companies and state regulatory commissions can and should cooperate.[185]

b. Virginia Evaluation

In response to APCo's request to recover a portion of the CCS demonstration project costs through its rates, the Virginia SCC again articulated the difficulty of asking ratepayers to shoulder the cost of demonstration projects with diffuse societal benefits. Here, the commission stated:

> It is reasonable for AEP to evaluate and explore options regarding potential federal legislation or regulation regarding GHG emissions. We do not find, however, that it was reasonable for APCo to incur the Mountaineer CCS project costs and then seek recovery from Virginia ratepayers. . . . *[A]lthough AEP asserts that this demonstration project will benefit customers of all of AEP's operating companies and of all*

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178. Am. Elec. Power, *supra* note 110 (quoting Chairman and CEO's statement that, "as a regulated utility, it is impossible to gain regulatory approval to recover our share of the costs . . . without federal requirements . . . already in place").

179. W. Va. Pub. Serv. Comm'n, at 47.

180. *Id.* at 79.

181. *Id.* at 45.

182. *Id.* at 45.

183. *Id.* at 47.

184. *Id.* at 47–48.

185. *Id.* at 48.

> *utilities in the United States, APCo's ratepayers (not shareholders) are being asked to pay for all of the costs incurred by this project.*[186]

In contrast to West Virginia's solution of allowing recovery for only a fair share of the demonstration project costs, the Virginia SCC denied the entire request.[187]

4. *The Kemper County IGCC Project—Mississippi*

At the time of writing, Mississippi Power Company, a subsidiary of Southern Company, is constructing a 582 MW IGCC power plant in Kemper County Mississippi, known as Plant Ratcliffe.[188] Plant Ratcliffe will burn locally mined lignite coal and capture sixty-five percent of its CO_2 emissions for enhanced oil recovery.[189] The plant has an expected operation date of 2015.[190] Plant Ratcliffe was one of two projects selected to receive a federal loan guarantee under round two of the DOE's Clean Coal Power Initiative but has since withdrawn its application, stating that the company can obtain lower cost financing elsewhere.[191]

Plant Ratcliffe is the only advanced coal plant with CCS that is under construction in the United States.[192] Though the Mississippi PSC approved the project in May 2010,[193] state regulatory approval has presented an ongoing challenge. The Mississippi commission denied the company's initial bid to construct Plant Ratcliffe on April 29, 2010.[194] At that time, the PSC held that, as proposed, the benefits would not outweigh the costs and risks borne by ratepayers.[195] It also found, however, the project could in concept benefit ratepayers.[196] The PSC invited Mississippi

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186. VA. STATE CORP. COMM'N, CASE NO. PUE-2009-00030, APPALACHIAN POWER CO., at 20 (July 15, 2010) (final order) (emphasis added).

187. VA. STATE CORP. COMM'N, CASE NO. PUC-2007-00068, APPALACHIAN POWER CO., at 2 (Apr. 14, 2008).

188. *Kemper County IGCC Fact Sheet: Carbon Dioxide Capture and Storage Project*, CARBON CAPTURE & SEQUESTRATION TECH. PROGRAM, MASS. INST. OF TECH. (Dec. 13, 2013), http://sequestration.mit.edu/tools/projects/kemper.html.

189. *See id.*; *see also* MISS. PUB. SERV. COMM'N, DOCKET NO. 2009-UA-014, MISS. POWER CO., at 6, 89, 91 (Apr. 24, 2012).

190. Eileen O'Grady, *Southern Co Delays Advanced Coal Plant to 2015 Amid Rising Costs*, REUTERS (Apr. 29, 2014), http://www.reuters.com/article/2014/04/29/utilities-southern-kemper-idUSL2N0NL2K220140429.

191. *Id.*

192. The Texas Clean Energy Project, Hydrogen Energy California, and FutureGen 2.0 are in the planning stages and considered active CCS demonstration projects. *See The United States CCS Financing Overview*, CARBON CAPTURE & SEQUESTRATION TECH. PROGRAM, MASS. INST. OF TECH. (Dec. 20, 2013), http://sequestration.mit.edu/tools/projects/us_ccs_background.html. In addition, Duke Energy is constructing a "CCS-ready" IGCC coal plant in Edwardsport, Indiana, but has no current plan to install CCS. *See Edwardsport Integrated Gasification Combined Cycle (IGCC) Station*, DUKE ENERGY, http://www.duke-energy.com/pdfs/igcc-fact-sheet.pdf (last visited June 1, 2014).

193. MISS. PUB. SERV. COMM'N, DOCKET NO. 2009-UA-14, MISS. POWER CO. (Apr. 29, 2010).

194. *Id.* at 49.

195. *Id.* at 2.

196. *Id.*

Power Company to submit an alternative proposal that equitably distributes the project's uncertainties and risks.[197] Approximately one month later, the PSC approved the company's amended proposal in a two-to-one vote.[198] In February 2011, the Mississippi Supreme Court reversed and remanded the Commission's order on appeal, holding that the PSC had not supported its decision to approve the facility with substantial evidence.[199] In another two-to-one vote, the PSC affirmed its decision to approve the plant on April 24, 2012, drawing on the existing record to substantiate its decision.[200]

In contrast to the West Virginia and Virginia commissions, the Mississippi PSC began its initial evaluation of the IGCC project proposal with a discussion of its benefits.[201] First, the PSC found that the project would meet an existing need for stable, baseload energy.[202] Here, the PSC relied upon the state's recently enacted Baseload Act,[203] which establishes a preference for diverse baseload generation, in its decision to impart particular importance on this feature.[204] Notably, the Baseload Act declares "that the State should take advantage of advances in nuclear, coal and other technologies, including technologies that reduce or minimize, or that facilitate the future reduction or minimization of, regulated air emissions."[205]

Next, the PSC assigned significant weight to the project's contribution to fuel diversity, noting that Mississippi Power's generation portfolio was already more than fifty percent natural gas and would reach seventy percent if the company relied on natural gas to meet its need rather than the proposed IGCC facility.[206] Plant Ratcliffe will burn lignite—a lower-ranked and lower-priced coal—that is mined locally with minimal transportation cost.[207]

In addition, the PSC noted that the proposed plant would ensure compliance with existing environmental laws and regulations and mitigate risk of future climate change legislation.[208] Beyond the ratepayer benefits of environmental compliance, the PSC found that the project would contribute to clean coal and enhanced oil recovery technology and thereby contribute to national energy security and efforts to mitigate

197. *Id.* at 2–3.
198. Miss. Pub. Serv. Comm'n, Docket No. 2009-UA-14, Miss. Power Co., at 25 (May 26, 2010).
199. Sierra Club v. Miss. Pub. Serv. Comm'n, 82 So. 3d 618, 618 (Miss. 2012).
200. Miss. Pub. Serv. Comm'n, Docket No. 2009-UA-014, Miss. Power Co., at 132 (Apr. 24, 2012).
201. Miss. Pub. Serv. Comm'n, Docket No. 2009-UA-14, Miss. Power Co., at 2 (Apr. 29, 2010).
202. *Id.* at 6.
203. Miss. Code Ann. § 77-3-101 (2008).
204. *Id.*
205. *Id.* § 77-3-101(c).
206. Miss. Pub. Serv. Comm'n, Docket No. 2009-UA-014, Miss. Power Co., at 30, 32, 82 (Apr. 24, 2012).
207. *Id.* at 89.
208. *Id.* at 91.

climate change.[209] While the broad national benefits of Plant Ratcliffe would accrue beyond Mississippi Power's ratepayers, the PSC acknowledged a number of government grants, tax incentives, and loan programs that would defray a portion of the costs.[210]

Finally, the PSC pointed to state and local economic development opportunities that would flow from Plant Ratcliffe. For example, the project would directly create temporary jobs to construct the IGCC plant and nearby lignite mine, create permanent jobs at the power and mine facilities, and increase mineral royalties and state and local tax revenues.[211] In addition, Plant Ratcliffe would provide a catalyst to expand lignite business opportunities, which represent a large and relatively untapped Mississippi natural resource, and foster enhanced oil recovery projects within the state.[212]

However, the PSC also identified and expressed concern regarding a number of risks associated with Plant Ratcliffe, including risks associated with construction of any baseload facility and implementation of a new technology.[213] For example, like all large electric utility capital investments, Plant Ratcliffe bears capital cost risk and project cancellation risk.[214] In addition, the project carries performance risk, first of a kind technology risk, potential loss of federal incentives, and risk that expected supplemental revenue streams—CO_2, ammonia, and sulfuric acid byproducts, which the company intends to sell to offset ratepayer costs—never materialize.[215]

Several measures to mitigate and allocate risk were critical to the PSC's approval, including: (1) allowance for recovery of only a fraction of construction costs rather than the full costs incurred during construction;[216] (2) a cost cap of twenty percent ($2.88 billion) above the company's approved estimate, shifting risk to the utility for any construction cost overruns beyond the cap;[217] (3) performance parameters to assure that ratepayers will not pay for an underperforming asset;[218] and (4) a requirement to periodically reevaluate the economics to mitigate risk that a subsequent technology becomes a better option.[219] Plant Ratcliffe has since faced considerable construction cost overruns that have

209. *Id.* at 92–93.
210. *Id.* at 91.
211. *Id.* at 92.
212. *Id.* at 92–93.
213. *Id.* at 82.
214. *Id.*
215. *Id.* at 82, 85–86.
216. *Id.* at 106.
217. *Id.* at 9, 21.
218. *Id.* at 9.
219. *Id.*

increased the facility's estimated cost to approximately $5.5 billion, nearly double the $2.88 billion cap.[220]

B. Offshore Wind

Offshore winds are stronger and blow more consistently than winds over land.[221] The DOE estimates the nation's offshore energy resource, including the Great Lakes, is approximately four times the combined generating capacity of all U.S. power plants.[222] Offshore wind technology has the potential to capture this abundant renewable energy resource, contribute to greenhouse gas reduction and renewable energy goals, and provide coastal populations with a local renewable energy option.[223] However, offshore wind faces a number of challenges to development and deployment in the United States, including high cost relative to alternative fossil fuel and renewable energy technologies,[224] technical challenges to installation and interconnection with the electricity grid, and permitting challenges in federal and state waters.[225] Europe has successfully developed shallow water offshore wind technology, with approximately 2000 MW installed capacity, but the European market is heavily subsidized.[226]A recent market analysis describes the U.S. offshore wind industry as in a slow transition from early development to commercial demonstration.[227] In addition, accessing the abundant wind resources located in deep waters off the coast of the United States will require innovative wind turbine designs.[228]

1. Federal Support for Offshore Wind

From 2006 to 2012, the DOE awarded more than $300 million to offshore wind RD&D.[229] The DOE is focused on reducing the cost of offshore wind energy to accelerate development and deployment of offshore wind in the United States through its Offshore Wind Innovation and Demonstration initiative ("OSWInD").[230] The DOE estimates that a fifty percent reduction in cost of energy projections is necessary to achieve a scenario of fifty-four gigawatts of offshore wind deployed by

220. O'Grady, *supra* note 190.

221. Wind & Water Power Tech. Office, U.S. Dep't of Energy, Offshore Wind Projects 2006–2012, at 2 (2012).

222. *Id.*

223. U.S. Dep't of Energy, A National Offshore Wind Strategy: Creating an Offshore Wind Industry in the United States 6–7 (2011).

224. *See supra* Part III.B. tbl. 1.

225. National Offshore Wind Strategy, *supra* note 223, at 2.

226. *Id.* at 5–6.

227. Navigant Consulting, Inc., Offshore Wind Market and Economic Analysis xv (2013).

228. Offshore Wind Projects 2006–2012, *supra* note 221, at 1.

229. *Id.* at 2.

230. National Offshore Wind Strategy, *supra* note 223, at 2.

2030.[231] In addition to reducing the costs of various components, start-up and permitting processes, and grid interconnection, achieving a lower cost of capital for offshore wind development requires demonstration and validation of offshore wind technologies.[232] In the short term, OSWInD is focused on the initial deployment of offshore wind technology in U.S. waters,[233] such as the projects described in this Article that have come before utility commissions in several eastern states. OSWInD's longer-term research and development efforts seek to develop new cost-competitive offshore wind technologies.[234] The federal government also remains focused on resolving federal and state permitting issues, related to leasing of federal waters for wind farms and related transmission infrastructure and environmental reviews.[235]

2. *The Block Island Offshore Wind Demonstration Project—Rhode Island*

In 2009, Rhode Island enacted a Long Term Contracting Standard for Renewable Energy, which directed the state's electric distribution companies to annually solicit proposals from renewable energy developers for long-term contacts subject to PUC approval.[236] The Act directed the Rhode Island PUC to approve such contracts if they are "commercially reasonable,"[237] defined as: "terms and pricing that are reasonably consistent with what an experienced power market analyst would expect to see in transactions involving newly developed renewable energy resources."[238] It also established that the public interest would be served by a small-scale offshore wind demonstration project off the coast of Block Island.[239] The legislation also identified a number of benefits the Block Island project would provide, including local economic development benefits of becoming a forerunner in the nascent offshore wind industry, and its contribution to energy independence and reduced reliance on fossil fuels.[240] Although Rhode Island is a restructured state, relying on a competitive market for electricity generation as opposed to vertically integrated utilities, the Rhode Island PUC has jurisdiction over long-term power purchase agreements between regulated distribution utilities

231. *Id.* at iii, 9.
232. *Id.* at 9–10.
233. *Id.* at 14.
234. *Id.*
235. *See id.* at 10–13.
236. R.I. GEN. LAWS §§ 39-26.1-3(a)–(b) (2010).
237. *Id.* § 39-26.1-3(b).
238. *Id.* § 39-26.1-2(1).
239. *Id.* § 39-26.1-7(a).
240. *Id.*

and merchant developers.[241] As noted earlier, merchant firms are free to pursue generation projects without PUC approval, but implementation of novel technologies typically requires developers to secure long-term contracts to convince investors that there is a market for above-market generation.[242]

National Grid—the electric distribution company serving all but a small corner of Rhode Island—solicited proposals and received a single application from Deepwater Wind to construct an offshore wind demonstration project off the coast of Block Island.[243] The project would consist of six wind turbines with a nameplate capacity of 21.6 MW.[244] The Rhode Island PUC rejected the proposed long-term contract, finding the project commercially unreasonable.[245] Two months after the PUC rejected the proposed power purchase agreement, the general assembly amended the definition of "commercially reasonable," only as it applied to the Block Island project, to "terms and pricing that are reasonably consistent with what an experience power market analyst would expect to see for a project *of similar size, technology, and location*."[246] The amendment also required the Rhode Island PUC to expedite review of an amended power purchase agreement and specified that the new contract must include a mechanism whereby ratepayers receive the full benefit of any savings relative to the estimated project costs.[247] National Grid then reapplied to the Rhode Island PUC with an amended proposal for a long-term power purchase agreement for the Block Island project, and the Rhode Island PUC approved the amended proposal two-to-one.[248]

a. *Rhode Island Initial Evaluation*

The Rhode Island PUC based its initial decision to reject the Block Island power purchase agreement solely on the above-market cost of energy. Relying on the original definition of commercially reasonable, the PUC concluded that the price (24.4 cents per kilowatt-hour ("kWh"), escalating annually at 3.5 percent) was higher than an experienced power market analyst would expect to see for transactions involving newly

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241. *See supra* Part III.A (explaining the role of PUCs in restructured states in overseeing innovative energy projects).

242. *See supra* Part III.A.

243. R.I. PUB. UTIL. COMM'N, DOCKET NO. 4111, REVIEW OF PROPOSED TOWN OF NEW SHOREHAM PROJECT, at 3 (Apr. 2, 2010).

244. *Id.* at 4.

245. *Id.* at 68.

246. *See* R.I. GEN. LAWS § 39-26.1-7(c)(iv) (2010) (emphasis added); *see also In re* Review of Proposed Town of New Shoreham Project, 25 A.3d 482, 496 (R.I. 2011).

247. R.I. GEN. LAWS §§ 39-26.1-7(a)–(b), (e).

248. *See generally* R.I. PUB. UTIL. COMM'N, DOCKET NO. 4185, PROPOSED TOWN OF NEW SHOREHAM PROJECT PURSUANT TO R.I. GEN. LAWS § 39-26.1-7 (Aug. 16, 2010).

developed renewable energy resources.[249] Notably, the Rhode Island PUC further concluded that "[t]he pricing of the PPA must stand or fall on its own," excluding consideration of benefits such as economic development.[250]

Despite the Rhode Island PUC's explicit exclusion of non-cost project values, the PUC also determined that the record could not support a finding that project benefits justify the $390 million in above-market costs, even if the commercially reasonable standard required consideration of project benefits.[251] Here, the Rhode Island PUC relied on Deepwater Wind's estimate of approximately $2.4 million in annual direct economic benefits.[252] The commission reasoned that any evidence of "first-mover" benefits that may accrue from "getting something in the water that permitting agencies and financial markets can understand and accept" are not based on Rhode Island-specific studies, and therefore cannot be quantified or seriously considered.[253]

b. Rhode Island Round Two Evaluation

In the Rhode Island PUC's subsequent decision to approve the amended power purchase agreement, the commission began with a recognition that it is "a creature of statute, and . . . possesses only those powers, duties, and responsibilities conferred upon it by the General Assembly."[254] The commission's evaluation then recognized that the General Assembly "substantially altered" the standard of review in this case so as to "dramatically reduce[] the plenary discretion afforded to the Commission" as it pertains to the commercial reasonableness of the project.[255] Applying the new definition of commercially reasonable—requiring "terms and pricing that are reasonably consistent with what an experienced power market analyst would expect to see for a project *of similar size, technology, and location*,"[256]—the Rhode Island PUC considered the testimony of four expert witnesses, excluded consideration of the cost of projects of different scale and projects that employ other renewable energy technologies, and concluded that the project met the new standard.[257] However, the Commission also observed that the

249. R.I. Pub. Util. Comm'n, Docket No. 4111, Review of Proposed Town of New Shoreham Project, at 68 (Apr. 2, 2010).

250. *Id.* at 69.

251. *Id.* at 78.

252. *Id.* at 78–79.

253. *Id.* at 79–80.

254. R.I. Pub. Util. Comm'n, Docket No. 4185, Proposed Town of New Shoreham Project Pursuant to R.I. Gen. Laws § 39-26.1-7, at 129 (Aug. 16, 2010).

255. *Id.* at 129–30.

256. *See* R.I. Gen. Laws § 39-26.1-7(c)(iv) (2010) (emphasis added); *see also In re*: Review of Proposed Town of New Shoreham Project, 25 A.3d 482, 496 (R.I. 2011).

257. R.I. Pub. Util. Comm'n, Docket No. 4185, at 130–36.

General Assembly mandated the standard of review "[f]or purposes of review of *this one single PPA*," meaning that future proposals would have to meet the original, more stringent, commercially reasonable standard.[258]

C. Challenges to Technology Innovation in the State Regulatory Process

The above case studies highlight several challenges to PUC approval of utility-scale energy demonstration projects: high, uncertain costs; uncertain economic benefits; interstate generation requiring approval from multiple state PUCs; and diffuse societal benefits.

1. High, Uncertain Costs

Demonstration projects tend to be expensive compared to mature generation projects, which have benefited from technological learning and economies of scale. In addition, it is inherently difficult to estimate construction and operating costs of projects that rely on new technologies. As a result, it is difficult for PUCs—charged with ensuring that electricity rates are just and reasonable—to allow ratepayers to accept the cost and risk of demonstration projects.

Allowing ratepayers to fund certain types of demonstration projects can be especially challenging because these projects are expensive relative to other demonstration projects in the electricity sector. For example, the nation's largest smart grid demonstration project will cost $178 million,[259] shared between the DOE (fifty percent) and other project participants, including eleven utilities, Bonneville Power Administration, and private investors.[260] One utility's share of the cost—such as the $2.1 million that Northwest Energy will invest—is a small fraction of the costs of advanced coal demonstration projects described above.[261] Even the total project cost of $178 million is substantially lower than APCo's $334 million share of the CCS demonstration project proposed at the Mountaineer coal-fired power plant. The Block Island offshore wind demonstration project off the coast of Rhode Island is estimated to cost ratepayers $370 million in above-market energy costs.[262] The project developer testified that a larger offshore wind farm could produce energy at a lower price, but would be inadvisable to pursue until permitting

258. *Id.* at 132.

259. Carl Imhoff, *Largest U.S. Smart Grid Demo is Set to Roll*, IEEE: SMART GRID (June 2012), http://smartgrid.ieee.org/june-2012/601-largest-u-s-smart-grid-demo-project-is-set-to-roll.

260. *About the Project*, PAC. NW. SMART GRID DEMONSTRATION PROJECT, http://www.pnwsmartgrid.org/about.asp (last visited June 1, 2014).

261. *Smart Grid*, NW. ENERGY, http://www.northwesternenergy.com/our-company/environmental-commitment/smart-grid (last visited June 1, 2014).

262. R.I. PUB. UTIL. COMM'N, DOCKET NO. 4185, at 103.

authorities and financial markets become familiar with the technology through smaller scale, but higher cost, demonstrations.[263]

2. *Uncertain Economic Benefits*

Innovative low-carbon generation technologies have the potential to provide direct benefits to ratepayers through reduced compliance costs if and when the utility faces a policy to reduce greenhouse gas emissions. Without a policy in place, however, the timing and magnitude of those benefits are unknown, making it difficult for state utility regulators to weigh the costs and benefits of proposed projects. For example, the Virginia PUC, in its denial of a certificate of need for the Appalachian Power Company's proposed IGCC project, discounted any potential climate policy compliance benefits due to policy uncertainty.[264]

3. *Challenges of Interstate Cooperation*

Utility service areas frequently cross state boundaries, complicating the task of securing regulatory approval for new investments. The differential treatment of advanced coal projects in West Virginia and Virginia illustrates the added risk for projects that require the approval of multiple state PUCs. Further complicating the challenge of interstate cooperation, certain economic benefits of demonstration projects—jobs, economic development, potentially creating demand for coal—accrue primarily to the state where the plant is located.

Although cooperation across multiple states is inherently more difficult than individual state action, a group of states working together would have significant advantages over individual state action. Sharing costs and risks across multiple utilities in multiple states reduces rate impacts and makes financing multiple, full-scale demonstration projects feasible from a consumer protection perspective.

4. *Diffuse Societal Benefits*

In addition to any direct benefits to ratepayers from reduced future compliance costs, demonstration projects provide learning benefits to the U.S. economy, the electricity sector, and all electricity consumers.[265] Additional benefits to implementing utilities and their ratepayers—such as the development of engineering protocols that improve reliability and

263. R.I. Pub. Util. Comm'n, Docket No. 4111, Review of Proposed Town of New Shoreham Project, at 83 (Apr. 2, 2010).

264. Va. State Corp. Comm'n, Case No. PUC-2007-00068, Appalachian Power Co., at 6–7 (Apr. 14, 2008).

265. *See* Sonia Yeh & Edward S. Rubin, *A Review of Uncertainties in Technology Experience Curves*, 34 Energy Econ. 762 (2012).

reduce the cost of future applications,[266] or the attraction of a budding industry to the state—are similarly long term and uncertain.[267] It is difficult, therefore, for a utility commission to ask one utility's ratepayers, or subset of ratepayers, to bear the cost and risk of a project with widespread benefits. The diffuse benefits from technology development may be larger than project benefits realized by ratepayers, especially for small-scale demonstration projects with minor emissions reductions, further discouraging commission approval of ratepayer support for these types of projects.

With the exception of policies promoting renewable energy and energy efficiency,[268] utility regulation in the United States is generally not designed to extend costs beyond a utility's service area. As a result, approving demonstration projects requires commissions to make the difficult decision that ratepayers within a particular service area should bear the cost and risk of a project with widespread benefits. Statutory directives for utility regulators to encourage the continued use of coal facilitated commission approval of advanced coal projects in Indiana and West Virginia.[269] Similarly, Mississippi commissioners approved an IGCC project to balance the utility's heavy reliance on natural gas, citing the legislature's directive to seek diverse, baseload energy resources.[270] However, construction cost overruns in Indiana and Mississippi, low natural gas prices, climate policy uncertainty, and fewer federal dollars suggest that these decisions will become even more difficult without innovative strategies that protect ratepayers and provide for an equitable distribution of costs and benefits.

V. Addressing State-Level Barriers to Electric Power Technology Innovation

A. The Innovation Premium

Constructing new electricity generation facilities is inherently costly. Even a natural gas-fired combined cycle power plant—currently boasting

266. *See, e.g.*, Colo. Pub. Util. Comm'n, Decision No. C09-0472, Docket No. 09A-15E, Pub. Serv. Co. of Colo., at 8 (Apr. 27, 2009).

267. *See* Me. Pub. Util. Comm'n, Docket No. 2010-00235, Order Approving Term Sheet, at 10–11 (Feb. 26, 2013).

268. A major difference between advanced coal and renewable energy/energy efficiency is the size of individual projects and their capital costs. Policies that spread the cost of energy efficiency/renewable energy projects across all ratepayers tend to have relatively small impacts on rates. However, the theory behind widely sharing the cost of renewable energy/energy efficiency projects, which create external benefits such as improved air quality and technological advancement, is similar to the rationale for sharing the costs of advanced coal projects. The goal of the policy tools proposed here is to similarly share costs so that advanced coal projects have relatively small rate impacts.

269. *See generally* Ind. Util. Reg. Comm'n, Cause No. 43114, Duke Energy Ind., Inc. (Nov. 20, 2007); W. Va. Pub. Serv. Comm'n, Case No. 06-0033-E-CN, Appalachian Power Co. (Mar. 6, 2008).

270. Miss. Pub. Serv. Comm'n, Docket No. 2009-UA-14, Miss. Power Co. (Apr. 29, 2010).

the lowest total levelized cost of electricity among conventional generation options—can cost well over $500 million to construct.[271] When a PUC considers a utility proposal to construct a new generation facility or enter into a power purchase agreement, the commission typically asks two questions: Does the utility need the additional generation or capacity to meet demand? If so, is the proposed facility the best (least-cost) alternative to meet that need?[272] This inquiry conceives consumer benefit as primarily the availability of electrons to reliably meet electricity demand at the lowest reasonable rate. Utilities and other participants in these proceedings may also introduce secondary considerations, such as local economic development benefits of specific projects—the number of jobs created, the estimated increase in state and local tax revenues.[273]

As Part III of this Article explains, early applications of new technology can carry significant additional costs and technology risks. Whereas mature technologies have benefited from the learning process and economies of scale, learning is a primary benefit of putting innovative technologies into practice. Implementation of novel technology is also inherently risky. The technology could fail, underperform, or cost substantially more than expected. Furthermore, the benefits of innovative generation projects include factors that are more difficult to quantify and accrue well beyond a utility's service area. For example, demonstration projects create learning benefits that feed back into the innovation cycle and contribute to improvements in cost and performance of later applications of similar technology.[274]

The difference between the cost and risks associated with a conventional electricity generation technology and an innovative demonstration project creates an *innovation premium.*[275] PUCs have recognized the broad social benefits of innovative generation projects but the diffuse learning benefits of technology innovation often do not outweigh the premium that ratepayers must pay to implement innovative generation technologies.[276] In this sense, the innovation premium is a

271. For example, Indianapolis Power and Light is constructing a 650 MW natural gas combined cylce plant for $631 million. *See* PennEnergy Editorial Staff, *IPL to Build a 650 Combined-Cycle Gas Turbine Power Station*, PENNENERGY (May 1, 2013), www.pennenergy.com/articles/pennenergy/2013/05/ipl-to-build-650-mw-combined-cycle-natural-gas -turbine-power-station.html.

272. *See generally* Jones, *supra* note 24 (explaining the mandate of the PUC to ensure reliable electricity at a reasonable cost).

273. *See, e.g.*, R.I. PUB. UTIL. COMM'N, DOCKET NO. 4185, PROPOSED TOWN OF NEW SHOREHAM PROJECT PURSUANT TO R.I. GEN. LAWS § 39-26.1-7, at 63, 93, 114 (Aug. 16, 2010).

274. Kelly Sims Gallagher et al., *The Energy Technology Innovation System*, 37 ANN. REV. ENV'T RESOURCES 137, 140 (2012). The authors also replace the deployment phase with "market formation and diffusion." *Id.* fig. 1.

275. For example, the West Virginia public utility commissions noted that an IGCC coal plant is estimated to cost twenty to thirty percent more than a pulverized coal plant. *See* W. VA. PUB. SERV. COMM'N, CASE NO. 06-0033-E-CN, APPALACHIAN POWER CO., at 72 (Mar. 6, 2008).

276. *See supra* Part IV.

barrier to widespread demonstration and deployment of a host of technologies needed to meet national energy goals. The remainder of this Part outlines two possible solutions: (1) ensuring that ratepayers capture more of the added benefits of innovation; and (2) allocating the innovation premium more widely to reflect the widespread benefits of innovation. The details and feasibility of these and other possible solutions should be explored in future research.

B. Allocating the Innovation Premium: Aligning Costs and Benefits of Innovative Electricity Generation Projects

Numerous options exist to address the premium associated with first generation energy technologies. A direct strategy for addressing the premium, for example, is to reduce the cost difference between conventional technologies and new technologies, either by reducing the cost of new technologies or increasing the cost of conventional technologies. As described above, the federal government currently has numerous programs aimed at reducing the cost of new energy technologies.[277] Federal programs, such as loan guarantees, can lower the cost of capital by reducing investment risk, and tax incentives that provide additional income for certain types of electricity generation can also reduce the cost of a new technology. Market-based strategies, such as the carbon markets in California and the Northeastern states[278] and the EPA's Acid Rain Program[279] create a price for emitting specific pollutants, thereby raising the cost of operating facilities with high emissions (e.g., coal) and making zero emitting technologies, such as nuclear energy or renewable energy, more competitive.[280] While these strategies may mitigate the cost premium, technology risks could remain a concern.

This Subpart provides an overview of three additional strategies for addressing the innovation premium. First, policymakers could ensure that ratepayers capture a larger portion of the broad benefits that accrue from demonstration and deployment of novel technologies. Second, policymakers could spread the innovation premium over a larger populace to reduce the per capita premium for ratepayers, commensurate with widespread societal benefits. Third, multi-utility or multi-state innovative

277. *See supra* Part I.

278. *See Cap-and-Trade Program*, Ca. Envtl. Protection Agency Air Resources Board (May 21, 2014), http://www.arb.ca.gov/cc/capandtrade/capandtrade.htm; Regional Greenhouse Gas Initiative, http://www.rggi.org (last visited June 1, 2014).

279. *See Acid Rain Program*, Envtl. Protection Agency: Clean Air Markets (July 25, 2012), http://www.epa.gov/airmarkets/progsregs/arp.

280. Lori A. Bird et al., *Implications of Carbon Cap-and-Trade for US Voluntary Renewable Energy Markets*, 36 Energy Pol'y 2063, 2064 (2008) (explaining that "[i]n general, renewable energy will benefit from carbon cap-and-trade programs because compliance with the cap will increase the costs of fossil fuel generation, which will improve the cost-effectiveness of renewables and may provide an incentive to capped entities to use renewable energy to meet future load growth").

technology portfolio standards can spread the costs of a new facility beyond a single utility's ratepayers, while also providing market demand for the technologies.

1. Capturing the Added Benefits of Innovation

While the traditional ratepayer benefit of utility investments consists of reliable service at reasonable rates,[281] utilities and PUCs can adopt measures that help ratepayers capture a portion of the added benefits of innovation, offsetting the innovation premium at least in part. For example, technology development and operational knowledge gains are key benefits of demonstration projects. Though it is impossible to capture all of the learning benefits of an individual project, intellectual property laws allow companies to capture a portion of these benefits through patents.[282] PUCs can require utilities to share monetized learning benefits with ratepayers to ensure that these added benefits of innovation are divided in accordance with the allocation of cost and risk. For example, as part of a recent settlement agreement between the Mississippi Public Service Commission and Mississippi Power Company, Mississippi Power customers will receive ten percent of any royalty revenues from the licensing of the Kemper plant gasification technology.[283] The Colorado PUC has established a similar requirement that utilities submit a plan to allocate the intellectual property benefits along with demonstration project proposals.[284]

Demonstration projects also create benefits by reducing regulatory risk for utilities and ratepayers. For example, advanced coal generation technologies capture or facilitate capturing CO_2 emissions and generally have conventional pollutant emissions that are significantly lower than traditional pulverized coal plants.[285] In the future, these lower emissions rates and potentially sequestered CO_2 could create benefits for project owners if federal emissions standards are tightened or if the cost of emissions increases under a cap-and-trade or taxing mechanism. If ratepayers are paying the innovation premium, ensuring that ratepayers directly benefit from potential upsides should encourage willingness to pay and project approval.

In traditionally regulated electricity markets, utilities typically pass the costs—operating and capital—of environmental compliance to

281. *See, e.g.*, Jackson, *supra* note 66 (describing the consumer benefits of the regulatory compact).

282. Tanya Woker, *Principles of Copyright in Intellectual Property Law: An Overview*, 20 CRITICAL ARTS: S. N. J. CULTURAL & MEDIA STUD., no. 1, 2006, at 36.

283. MISS. PUB. SERV. COMM'N, CIV. ACTION 2012-UR-01108, MISSISSIPPI POWER COMPANY v. MISSISSIPPI PUBLIC SERVICE COMMISSION (Jan. 24, 2013) (settlement agreement).

284. CO. PUB. UTIL. COMM'N, NO. 11A-713E 3, APPROVAL OF AN INNOVATIVE CLEAN TECH. PROJECT CONSISTING OF A SOLAR-TO-BATTERY DEMONSTRATION PROJECT AT THE SOLAR TECH. ACCELERATION CTR. & FOR AN ORDER AUTHORIZING DEFERRED ACCOUNTING OF ALL PROJECT COSTS (Oct. 12, 2011).

285. Michael T. Burr, *Battle Royal: Pulverized Coal vs. IGCC*, 143 PUB. UTIL. FORT., Dec. 2005, at 32–35.

ratepayers.[286] Lower emissions should result in lower compliance costs for ratepayers, but ratepayers may not capture all of these benefits depending on rate structures and the frequency of rate cases. For example, if ratepayers fund an advanced coal plant that sequesters CO_2 and the corresponding emissions reduction can later be sold, ratepayers who paid extra for the project might not see lower rates because traditional regulation may not include the sequestration profits in a future rate case. PUC rate-setting mechanisms should ensure that ratepayers benefit from potential sales of sequestered or reduced emissions in the future.

2. *Aligning the Innovation Premium with the Widespread Benefits of Innovation*

In addition to recognizing and capturing more of the broad consumer benefits of technology innovation, sharing the innovation premium more widely can alleviate the burden for individual ratepayers and is commensurate with the broad social benefits of technological innovation. There are multiple options for sharing costs and risks, including strategies that could be adopted by utilities, a single state, or groups of states. For example, states could help align the innovation premium with the broad social benefits of demonstration projects by establishing state funding through tax incentives,[287] system benefits charges, wire charges, or fees on each megawatt hour of coal or fossil generation.[288] These measures would spread the innovation premium beyond a particular utility's service area, reducing the premium borne by consumers within the implementing utility's service territory. Allocating a portion of the innovation premium to the state would mirror the distribution of certain economic development benefits—such as by attracting a nascent industry and increased tax revenues.

Notably, this is the rationale for federal incentive programs to demonstrate and deploy innovative technologies. However, the examples discussed in this Article demonstrate that federal incentives do not offset the entire innovation premium, leaving a substantial portion of the project's cost and risk to be borne by ratepayers. State PUCs have come down on both sides with regard to projects that have been—or have the possibility of being—awarded federal funds to promote innovation. While states could provide a source of funding that augments federal incentives and is commensurate with the state economic development benefits of innovative generation projects, state funds may be difficult to

286. *See, e.g.*, *Understanding Utility Rates*, IND. OFFICE OF THE CONSUMER COUNCIL, http://www.in.gov/oucc/2389.htm (last visited June 1, 2014).

287. *See generally* NAT'L ENHANCED OIL RECOVERY INITIATIVE, CARBON DIOXIDE ENHANCED OIL RECOVERY: A CRITICAL DOMESTIC ENERGY, ECONOMIC, AND ENVIRONMENTAL OPPORTUNITY (2012).

288. DALIA PATINO ECHEVERRI ET AL., RES. FOR THE FUTURE, FLEXIBLE MANDATES FOR INVESTMENT IN NEW TECHNOLOGY (2012).

establish or insufficient to fully mitigate the innovation premium for ratepayers. This Subpart describes two additional measures to further distribute the innovation premium: joint ownership of demonstration projects and multi-utility long-term contracting requirements.

3. Joint Ownership

It is not uncommon for utilities to share ownership of large generation facilities through bilateral or multilateral agreements. Recent examples include nuclear units under construction in South Carolina[289] and Georgia.[290] Mississippi Power recently announced a sale of fifteen percent of Plant Ratcliffe to South Mississippi Electric Power Association ("SMEPA"), which provides electricity to eleven cooperatives in the state.[291] These ownership arrangements help utilities attain economies of scale, spread risk, and reduce the impact on individual ratepayers.

Sharing ownership more widely and spreading costs across all or most of the ratepayers in an individual state or group of states would reduce the rate impacts of the innovation premium on a dollar-per-kilowatt-hour ("$/kWh") basis. For example, a $1 billion dollar demonstration project with $100 million in annual incremental operating costs paid for by a utility serving a population of 500,000[292] would increase electricity prices by almost 3 cents/kWh,[293] but sharing these costs across a state with a population of 4 million[294] would raise electricity prices approximately 0.35 cents/kWh. Sharing costs across the top five coal states would raise price less than 0.1 cents/kWh.

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289. South Carolina Electric & Gas Company ("SCE&G") is jointly developing two new nuclear reactors in Jenkinsville, South Carolina. SCE&G will own fifty-five percent of the two units, and Santee Cooper, an electric cooperative supply company, will own forty-five percent. In its order granting a Certificate of Public Convenience and Necessity ("CPCN") for the units, the South Carolina Public Service commission notes, "the construction of two units allows SCE&G to partner with Santee Cooper, spreading risk in the project, and providing a benefit to the state's electric cooperatives and customers." S.C. Pub. Serv. Comm'n, No. 2008-196-E, Order No. 2009-104(A), In re Combined Application of S.C. Elec. & Gas Co. for a Certificate of Envtl. Compatability and Pub. Convenience and Necessity and for a Base Load Review Order for the Construction and Operation of a Nuclear Facility in Jenkinsville, S.C. 27 (Mar. 2, 2009).

290. Georgia Power is constructing two new nuclear units at Plant Vogtle. The company will own 45.7% of the facility. Oglethorpe Power Corporation (an electric supply cooperative), MEAG Power (a consortium of public power systems), and Dalton Utilities (a municipal utility) will own 30%, 22.7%, and 1.6%, respectively. Ga. Pub. Serv. Comm'n, No. 27800-U, Georgia Power's Application for the Certification of Units 3 and 4 at Plant Vogtle and Updated Integrated Resource Plan 6 (Aug. 1, 2008).

291. *See SME to Buy Gas-Fired Batesville, Kemper IGCC Power Plant Assets*, PennEnergy (Aug. 24, 2012), http://www.pennenergy.com/index/power/display/9992743905/articles/pennenergy/power/gas/2012/august/sme-to_buy_gas-fired.html.

292. In this illustrative example, we assume the utility serves industrial, commercial, and residential customers. Based on per capita electricity sales to all customer classes in West Virginia in 2011, $1 billion capital costs are incremental capital costs relative to alternative generation options.

293. Assuming a pre-tax cost of capital of 12.7% and thirty-year amortization.

294. Same assumptions as above, but for a larger population.

Table 2: Rate Impacts of $1 Billion Advanced Coal Demonstration Project with $100 Million Incremental Operating Costs.[295]

Cost Sharing Entity	$/kWh	Increase in 2011 West Virginia Residential Rate
Individual utility serving 500,000 residents*	$0.027	29%
Individual state with 4 million residents†	$0.003	4%
Top 5 coal states by percent generation	$0.001	1%
Top 10 coal states by percent generation	$0.0004	0.4%

*Based on per capita electricity use in West Virginia in 2010.
†Assumes all generation consumed locally; no exports.
Data from EIA Electric Power Monthly 2/2012.

Utilities are free to form and propose joint demonstration projects without state legislative action. Utility commissions cannot require utilities to submit joint proposals for demonstration projects that share costs across a large customer base, but they can express support for these actions during regulatory proceedings or through public comments and approve projects that meet their criteria for prudency.[296] Utility commissioners can also use national (and regional) organizations, such as the National Association of Regulated Utility Commissioners, to express support for utility cooperation on demonstration projects.[297]

Sharing costs across an entire state or multiple states would more directly address the concern that benefits accrue more widely than costs, but it would likely mean that some of the ratepayers paying for the demonstration project would never "use" the generation because it is outside of the local market or balancing area. This would represent a meaningful change from traditional financing for nonrenewable generation. However, Delaware provides a recent example wherein the state determined that demonstration project costs should be distributed among a distribution utility's entire customer base—regardless of the generation supplier—so that all customers would benefit from the project.[298]

295. Sarah K. Adair et al., Nicholas Inst. for Envtl. Pol'y Solutions, The State Role in Technology Innovation 11 (2013), *available at* http://nicholasinstitute.duke.edu/sites/default/files/publications/ni_wp_13-01.pdf.

296. For example, the Mississippi PSC outlined specific conditions under which it would consider Mississippi Power Company's proposed IGCC project to be in the public interest in an order denying a CPCN under the company's proposed terms. *See* Miss. Pub. Serv. Comm'n, Docket No. 2009-UA-14, Miss. Power Co. (Apr. 29, 2010).

297. The National Association of Regulated Utility Commissioners regularly passes resolutions supporting various actions or explaining commissioner perspectives. *See generally Resolutions*, Nat'l Assoc. of Regulatory Util. Comm'rs, http://www.naruc.org/Policy/resolutions.cfm (last visited June 1, 2014).

298. Christopher & Mullooly, *supra* note 137.

4. *Portfolio Standards and Multi-Utility Long-Term Contracting Requirements*

A state or groups of states could establish a portfolio standard for innovative energy generation, similar to the advanced coal portfolio standard in Illinois.[299] This would create a guaranteed market for above-market generation, with all ratepayers helping to pay for a portion of the project cost. If the developer is a vertically integrated utility, its ratepayers would pay the majority of the cost unless the price of portfolio credits rose significantly because of supply shortfalls.

Alternatively, multi-utility long-term contracting requirements could distribute the innovation premium to more closely match the broad social benefits of demonstration projects. This would ensure a market for the project developer while spreading the innovation premium across all participating utilities (and ratepayers) in contrast to previous proposals—such as Appalachian Power Company's proposed IGCC and CCS demonstration projects—which would have allocated costs across state lines but to ratepayers of a single utility.[300] This policy would work similarly to Minnesota's law, which grants Innovative Energy Projects the right to a long-term power purchase agreement subject to PUC approval.[301] Instead of establishing the requirement that a single utility enter into a power purchase agreement, however, states could require multiple utilities to purchase a share of the generation. States and commissions could also adopt clear standards for allocating the risk premium between project developers and participating utilities.

Conclusion

To meet national and global climate mitigation goals, a host of innovative low-carbon electricity generation technologies must be developed and deployed at a rate that far exceeds the pace of innovation and adoption today. The federal government has long supported innovation in the energy sector to support economic growth, enhance security, and reduce pollution, and technological solutions are a key to President Obama's climate change strategy.[302] The President's 2015 budget includes $27.9 billion in discretionary funds for the DOE to "position the United States to compete as a world leader in clean energy and advanced manufacturing; enhance U.S. energy security; cut carbon pollution and respond to and prepare for the threat of climate change; and modernize

299. Int'l Energy Agency, A Policy Strategy for Carbon Capture and Storage 23 (2012).

300. *See supra* Part IV.A.2–3.

301. *See, e.g.*, Office of Mgmt. & Budget, Exec. Office of the President, Budget of the United States Government, Fiscal Year 2015 (2014); Office of Mgmt. & Budget, Exec. Office of the President, Budget of the United States Government, Fiscal Year 2014 (2013).

302. 2015 Fiscal Year Budget, *supra* note 301, at 73.

the nuclear weapons stockpile and infrastructure."[303] For these strategies to succeed, however, project developers must demonstrate to state PUCs that utility-scale demonstration projects satisfy their consumer protection goals. States, state utility regulators, utilities, and merchant project developers need strategies to allocate the costs, risks, and benefits of demonstration projects equitably, limiting the cost and risk borne by individual ratepayers to finance projects with widespread societal benefits.

303. *Id.* at 7.

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