THE COST OF COAL: CLIMATE CHANGE AND THE END OF COAL AS A SOURCE OF "CHEAP" ELECTRICITY

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I. INTRODUCTION

Coal is the dominant source of electric power in the United States, providing nearly 50 percent of all electricity in the country.[1] In comparison, the other major sources of electricity – natural gas and nuclear power – supply only about 20 percent each of the country's electricity, and renewable energy sources account for less than 10 percent.[2] Until recently, it appeared that coal would retain its superior position over these other electricity sources, despite decades of environmental regulation aimed at controlling the environmental harm caused by coal mining and combustion, because coal remained the cheapest source of electricity.[3] However, the specter of climate change legislation may threaten coal's supremacy. Coal-powered electricity is the largest contributor of greenhouse gas emissions

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1. ENERGY INFO. ADMIN., ANNUAL ENERGY REVIEW 2008 228 fig.8.2a (2009), *available at* http://www.eia.doe.gov/aer/pdf/aer.pdf.

2. *Id.*

3. *See id.* (showing coal use in electricity increasing consistently since 1949, while natural gas and nuclear energy have seen small spikes in production that have ultimately plateaued). *See also* John A. Sautter, Note, *The Clean Development Mechanism in China: Assessing the Tension Between Development and Curbing Anthropogenic Climate Change*, 27 VA. ENVTL. L.J. 91, 92 (2009) (explaining that coal is cheap because it is abundant). Many federal environmental laws regulate aspects of coal mining and combustion, including the Clean Air Act, 42 U.S.C. §§ 7401-7671 (2006), the Clean Water Act, 33 U.S.C. §§ 1251-1387 (2006), and the Surface Mining Control and Reclamation Act, 30 U.S.C. §§ 1201-1328 (2006). However, many commentators have argued that agencies do not adequately apply these laws to coal. *See, e.g.*, Reid Mullen, Note, *Statutory Complexity Disguises Agency Capture in* Citizens Coal Council v. EPA, 34 ECOLOGY L.Q. 927 (2007) (discussing inadequate regulation under the Clean Water Act); BRUCE A. ACKERMAN & WILLIAM T. HASSLER, CLEAN COAL/DIRTY AIR (1981).

in the United States,[4] and coal has therefore become a primary target of climate change legislation pending before Congress.[5] As regulators evaluate the potential costs of climate change regulation, they have begun to reject coal as a cheap electricity source.[6] If more regulators follow suit, the energy system in the United States could profoundly change.

Traditional utility regulation has favored coal to provide abundant, reliable, and above all, cheap electricity to utility consumers.[7] Under traditional utility regulation regimes, electric utilities receive permission to operate as natural monopolies and, in exchange, they agree to provide service to all customers within their service area and to earn revenues set by public utility commissions (PUCs) under cost-of-service ratemaking proceedings.[8] Traditional cost-of-service ratemaking aims to achieve two ostensibly competing goals.[9] Ratemaking must provide the utility an adequate rate of return that will enable it to retain its investors and attract new ones, and ratemaking attempts to protect consumers from exploitative rates.[10] For decades, PUCs have embraced coal as an ideal electricity source that enables PUCs to accomplish their paradoxical regulatory objectives, because coal is both profitable for the industry and cheap for consumers.[11]

Until very recently, it appeared that PUCs would continue to favor coal as the ideal source of abundant, reliable, and cheap power.[12] However, in a handful of decisions issued since 2007, PUCs have rejected or restricted utilities' proposals to construct new coal-fired power plants.[13] In some cases, the PUCs referenced potential climate change legislation or carbon costs as the justification for their decisions, noting that project costs

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4. ENVTL. PROT. AGENCY, INVENTORY OF U.S. GREENHOUSE GAS EMISSIONS AND SINKS: 1990-2007 Annex I at A-4 tbl.A-1 (2009), *available at* http://www.epa.gov/climatechange/emissions/downloads09/Annex1.pdf.

5. *See* American Energy and Security Act of 2009, H.R. 2454, 111th Cong. (2009) (amending current regulatory policies to establish a combined efficiency and renewable electricity standard that requires utilities to supply an increasing percentage of their demand from energy efficiency savings and renewable energy and setting forth performance standards for new coal-fired power plants).

6. *See infra* notes 135-196 and accompanying text.

7. *See* JOSEPH P. TOMAIN & RICHARD D. CUDAHY, ENERGY LAW IN A NUTSHELL 73 (3d ed. 2004) (noting producers reliant on fossil fuel are favored because they can realize economies of scale).

8. *Id.* at 122-24.

9. FRED BOSSELMAN ET AL., ENERGY, ECONOMICS AND THE ENVIRONMENT: CASES AND MATERIALS 93 (2d ed. 2006).

10. Jersey Cent. Power & Light Co. v. Fed. Energy Reg. Comm'n, 810 F.2d 1168, 1189 (D.C. Cir. 1987) (Starr, J., concurring).

11. *See* TOMAIN & CUDAHY, *supra* note 7 at 223 (noting coal's abundance).

12. *See id.* at 254 (predicting coal would maintain or increase its importance in the U.S. energy portfolio).

13. *See infra* notes 135-196 and accompanying text.

associated with climate change would make coal unduly expensive and risky.[14] Regulators have also resisted proposals for new "clean coal" plants because the technology remains unproven and costs of "clean coal" could be enormous.[15] In these decisions, PUCs have no longer embraced coal as an unambiguously reliable or cheap source of power.

The history of the nuclear power industry during the 1970s and 1980s sheds light on the regulators' cautious approach to new coal plant proposals. During the 1950s and 1960s, PUCs approved construction of dozens of nuclear power plants in the United States.[16] By the 1970s, however, the nuclear industry imploded when electricity-use projections proved wrong, plant construction costs skyrocketed, and the reactor at Three Mile Island had a near-meltdown.[17] As desire and demand for nuclear power dissipated, utilities stopped building nuclear plants and declined to bring completed plants into operation.[18] When the utilities sought to recover their costs from electricity ratepayers, PUCs faced hard decisions and unhappy stakeholders. PUCs could pass on the costs to ratepayers who never received any electricity; they could force the utilities' investors to bear the costs of plants even though the PUCs had authorized their construction; or PUCs could attempt to fairly allocate the costs between ratepayers and utilities.[19] No matter what choice they made, PUCs could not reach a politically satisfactory result. Regulators' reluctance to allow new coal plants likely reflects their desire to avoid repeating the mistakes made with nuclear plants.

The recent PUC decisions rejecting new coal plants reflect concerns that future climate change legislation may drive up the costs of coal to the point that it no longer represents a viable source of affordable energy. Cost estimates of the climate change bill recently passed by the House of Representatives[20] predict that coal will lose its dominance over time as climate change controls become more stringent.[21] Even if Congress does not enact climate change legislation in the near term, the uncertainty associated with prospective regulation will likely alter regulators' views of coal. Having been burned during the ascendancy of the nuclear industry, PUCs will proceed with particular caution before approving new facilities

14. *See infra* notes 135-169 and accompanying text.
15. *See infra* notes 170-196 and accompanying text.
16. ENERGY INFO. ADMIN., *supra* note 1, at 275 tbl.9.1.
17. *See infra* notes 87-92 and accompanying text.
18. *See infra* notes 91-92 and accompanying text.
19. *See infra* notes 94-108 and accompanying text.
20. American Energy and Security Act of 2009, H.R. 2454, 111th Cong. (2009).
21. *See* ENERGY INFO. ADMIN., ENERGY MARKETS AND ECONOMIC IMPACTS OF H.R. 2454, THE AMERICAN CLEAN ENERGY AND SECURITY ACT OF 2009 26 (2009) [hereinafter ENERGY MARKETS AND ECONOMIC IMPACTS OF H.R. 2454] (projecting coal production and consumption will decrease dramatically by 2030 under ACESA cap-and-trade program).

that could be subject to carbon regulation. The threat of any law is enough to keep PUCs cautious and to alter the dynamics in the electricity sector.

Regulators' skepticism regarding the future of coal could help transform the nation's energy system whether or not Congress passes an aggressive climate change bill. In the short term, utilities will likely turn to natural gas.[22] Over time, however, utilities will need to transition to other energy sources to avoid price volatility.[23] Although some scholars predict that "clean coal" and nuclear energy will replace existing coal plants if Congress passes climate change legislation,[24] the recent coal plant denials may signal a broader reluctance by PUCs to expose ratepayers to the financial risks "clean coal" and nuclear facilities present. Regulators' current doubts about coal may therefore prompt near-term investment in renewable energy technologies and a longer-term switch away from coal, natural gas, and even nuclear power. Under this alternative scenario, traditional utility regulation, which typically eschews innovation and uncertainty, may prove to be an important tool in making renewable energy sources economically viable.

Part II of this article provides an overview of traditional utility regulation and explains why traditional ratemaking has favored coal. Part III describes the failure of the nuclear industry during the 1970s and 1980s and explains how PUCs allocated the costs between ratepayers and utilities for electricity they never received. Part IV explains why coal plants face particular risks in a carbon-constrained world, introduces different coal combustion technologies, and explains how these technologies present both opportunities and limitations for the coal industry. Part V then describes how PUCs have restricted or rejected utilities' proposals to construct new coal-fired power plants in an effort to protect ratepayers from avoidable cost risks. Part VI concludes that the specter of climate change regulation will irrevocably change PUCs' attitudes toward coal. This, in turn, has the potential to create more opportunities for renewable energy technologies and to fundamentally alter the electricity system of the United States.

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22. JOHN D. PODESTA & TIMOTHY E. WIRTH, CTR. FOR AM. PROGRESS, NATURAL GAS: A BRIDGE FUEL FOR THE 21ST CENTURY (2009), *available at* http://www.americanprogress.org/issues/2009/08/pdf/naturalgasmemo.pdf (describing the benefits of and opportunities for natural gas use).

23. Natural gas prices, like oil prices, also may be subject to unpredictable price swings. *See* David B. Spence, *Can Law Manage Competitive Markets?*, 93 CORNELL L. REV. 765, 799 (2008) ("Natural gas prices are notoriously volatile, complicating the projection of revenues for sellers on energy markets.").

24. *See, e.g.*, Victor B. Flatt, *Paving the Legal Path for Carbon Sequestration from Coal*, 19 DUKE ENVTL. L. & POL'Y F. 211 (2009) (proposing legal strategies to promote "clean coal"); Fred Bosselman, *The Ecological Advantages of Nuclear Power*, 15 N.Y.U. ENVTL. L. J. 1, 13-14 (2007) (outlining the greater profitability of nuclear power plants in comparison to natural-gas-fired plants).

II. AN OVERVIEW OF TRADITIONAL UTILITY REGULATION

Shortly after Thomas Edison established the first central power station in Manhattan in 1882, the electricity system in the United States became dominated by vertically integrated investor-owned utilities (IOUs).[25] Vertically integrated utilities own and operate all three components of the electricity system: generation of the electricity at power plants, transmission of the electricity over high-voltage power lines, and distribution of the electricity to end-users.[26] For most of the 20th century, vertically integrated utilities dominated the electricity sector, and even today, despite the increase in independent power producers that generate electricity to sell to utilities,[27] vertically integrated IOUs continue to produce nearly 40 percent of all electricity delivered in the United States.[28]

Vertical integration of electric utilities prompted regulators to treat the electricity system as a natural monopoly.[29] Under a typical monopolistic system, a monopoly will initially lower its prices to drive out competitors.[30] Once all competitors have exited the market, the monopoly will have unlimited power to increase prices and lower production to maximize its profit.[31] To prevent monopolistic behavior, regulators have several possible responses.[32] Most commonly, regulators will use antitrust laws to "break up" the monopoly and restrict the monopoly's behavior to promote competition.[33] However, in some circumstances, regulators will determine that a particular industry will never be competitive and that monopolies within that industry are inevitable.[34] Where regulators determine such natural monopolies exist, they will increase regulation over

25. Sidney A. Shapiro & Joseph P. Tomain, *Rethinking Reform of Electricity Markets*, 40 WAKE FOREST L. REV. 497, 503-506 (2005).

26. *See* David B. Spence, *The Politics of Electricity Restructuring: Theory vs. Practice*, 40 WAKE FOREST L. REV. 417, 419 (2005) (describing vertical integration of utilities).

27. *See id.* at 424-25 (discussing increasing acceptance of competitive wholesale market for electricity).

28. Energy Info. Admin., Electric Industry Generating Capacity by Type, 2007, http://www.eia.doe.gov/cneaf/electricity/page/prim2/figure3.html (last visited Oct. 27, 2009).

29. *See* Shapiro & Tomain, *supra* note 25, at 506-07 (defining natural monopoly and describing legal precedent that led to recognition of natural monopolies and subsequent regulation).

30. RICHARD J. PIERCE, JR. & ERNEST GELLHORN, REGULATED INDUSTRIES IN A NUTSHELL 39-40 (4th ed. 1999).

31. *Id.* at 40 ("[T]he monopolist will maximize profits by restricting output and setting price above marginal cost.").

32. *Id.* at 47-48.

33. *See id.* at 48 ("If a firm does become a monopolist, it can be divided into several smaller firms in order to restore a competitive market.").

34. *Id.* at 48-53.

the monopoly's behavior and its prices.[35]

Regulators considered the electricity system a natural monopoly because the high costs associated with construction of power plants and transmission and distribution lines made it economically infeasible for competitors to enter a market where infrastructure already existed.[36] Moreover, additional power lines were considered unnecessary; once a utility had installed its power system, there would be no need for additional, redundant power lines.[37] Therefore, regulators thought it unlikely that competition in the electricity sector would ever develop.[38] Although many have challenged whether electricity remains a natural monopoly,[39] most regulators continue to view the electricity system as a monopoly requiring comprehensive regulation.[40]

To prevent abuses from a monopolistic electricity utility, a state PUC will enter into a regulatory compact with the utility.[41] Under this compact, the utility receives a franchise to provide exclusive service within a particular geographic area.[42] In exchange, the utility must provide service to all customers within the region and it must agree to cost-of-service ratemaking regulation by the PUC.[43] Through cost-of-service ratemaking, the PUC allows the utility to earn "just and reasonable" revenues while

35. *Id.* at 53-54.

36. *Id.* at 506-508. The electricity system in the United States initially consisted of dozens of small power stations and hundreds of self-contained power generators located within various cities. *See* HOWARD L. PLATT, THE ELECTRIC CITY (1991) *as reprinted in* BOSSELMAN ET AL., *supra* note 9, at 737-43 (describing that when Samuel Insull, a protégé of Thomas Edison, developed a centralized electricity and transmission system that was able to produce and transmit electricity over long distances, he became able to out-compete the smaller, less efficient, localized plants, and once a larger centralized system became established, economies of scale prohibited other electric companies from establishing their own competitive systems).

37. Shapiro & Tomain, *supra* note 25, at 506.

38. *See id.* at 506-07 (noting the connection between natural monopoly and need for government regulation).

39. *See* PIERCE & GELLHORN, *supra* note 30, at 51 ("As a result of this combination of changes in technology and costs, electricity generation is no longer a natural monopoly.").

40. *See* Shapiro & Tomain, *supra* note 25, at 507 ("[A] proposed price regulation must first show that the industry exhibits monopolistic tendencies and second that the industry is affected with a public interest. Electricity clearly satisfies both tests . . . .").

41. Jersey Cent. Power & Light Co. v. Fed. Energy Reg. Comm'n, 810 F.2d 1168, 1189 (D.C. Cir. 1987) (Starr, J., concurring), *footnoted in* Shapiro & Tomain, *supra* note 25, at 507, n.50. States have jurisdiction over all "retail" electricity sales, while the Federal Energy Regulatory Commission (FERC) has power under the Federal Power Act, 16 U.S.C. §§ 791a-828c (2006), over all interstate wholesale sales of electricity and interstate transmission. 16 U.S.C. § 824b(1) (2006). Wholesale electricity sales are sales of electricity to any entity that will then sell the electricity at resale to an end-user. 16 U.S.C. § 824d (2006).

42. Shapiro & Tomain, *supra* note 25, at 507.

43. *Id.* at 507-08.

protecting customers from exploitative rates.[44] In essence, the overarching goal for a PUC is to ensure the utility will provide cheap, abundant, and reliable electricity for ratepayers. As explained below, traditional utility regulation has encouraged utilities to meet these goals by building large coal-fired power plants.

A. *Traditional Utility Regulation Favors Large Capital Projects*

Historically, traditional utility regulation has incentivized the construction of capital-intensive power plants and infrastructure. The "duty to serve" requires utilities to provide electricity to all customers within the geographic area of the utilities' franchises.[45] This duty means that utilities must build infrastructure to supply power to customers located within and beyond city and commercial centers.[46] When communities expand beyond urban boundaries, utilities must expand infrastructure to provide electrical service.[47] As energy demand grows within utilities' service areas, utilities must obtain more power to serve their customers.[48] This typically means that utilities will build new power plants to respond to increased energy demand by businesses and residential consumers.[49] Although utilities may meet this demand by purchasing power from independent power producers, traditional regulation incentivizes construction of new power plants by the utilities.[50]

Traditional ratemaking practices employ a common formula[51] to calculate utilities' revenues, and this formula creates economic incentives for utilities to build infrastructure and power plants.[52] Under this formula, utilities may recover from ratepayers their operating expenses – which include expenditures for labor costs, fuel costs, administrative costs, and the like – and earn a profit (called a rate of return) on their capital

44. *Jersey Cent. Power*, 810 F.2d at 1172. *See also id.* at 1192 (Starr, J., concurring) ("FERC has already moved somewhat in the direction of balancing competing interests by permitting recovery of the costs of building the plant in the cost of service.").

45. Spence, *supra* note 26, at 419-20.

46. *Id.*

47. *See* Jim Rossi, *The Common Law "Duty to Serve" and Protection of Consumers in an Age of Competitive Retail Public Utility Restructuring*, 51 VAND. L. REV. 1233, 1251-57 (1998) (discussing the obligation to extend services over time).

48. *Id.*

49. *Id.*

50. *See id.* at 1278-79 (discussing the rise of independent power producers as electricity suppliers).

51. R = Br+O, where R = the utility's revenue requirement, B = the rate base, r = the rate of return, and O = operating expenses. TOMAIN & CUDAHY, *supra* note 7, at 130.

52. *See* Harvey Averch & Leland L. Johnson, *Behavior of the Firm Under Regulatory Constraint*, 52 AM. ECON. REV. 1052, 1059 (1962) (applying the formula to a hypothetical situation to demonstrate how firms operate in certain markets).

expenditures (called the rate base) – which include expenses associated with building new power plants, transmission lines, and other facilities.[53] Under this formula, utilities will earn a greater profit if their rate bases – i.e., their capital expenses – increase.[54] The ratemaking formula, therefore, incentivizes the construction of new power plants because capital projects provide utilities with a relatively secure way of increasing their rate base.[55]

B. Traditional Regulation Favors Coal

While it is clear that traditional utility regulation favors capital construction, it is not necessarily clear that it would favor coal over other sources of power. Nonetheless, traditional utility regulation has particularly favored the use of coal and incentivized the construction of coal power plants since World War II.[56] Several aspects of traditional utility regulation have contributed to coal's dominance. As noted above, utilities must demonstrate their capital expenditures will provide cheap, abundant, and reliable electricity.[57] Reliable baseload[58] electricity traditionally has come from coal, natural gas, and nuclear energy.[59] Of these sources, only coal has thus far avoided significant economic or ecological constraints. As a result, coal has remained the dominant source of U.S. electricity.[60]

Natural gas currently accounts for a little more than 20 percent of U.S. electricity production,[61] and it has never come close to competing with

53. *See* TOMAIN & CUDAHY, *supra* note 7, at 130-31, 36 (noting that in order to stay functional, firms must recoup operating expenses).

54. *See* Richard J. Pierce, *The Regulatory Treatment of Mistakes in Retrospect: Canceled Plants and Excess Capacity*, 132 U. PA. L. REV. 497, 500-01 (1984) (explaining how electricity demand forecasts in the early 1970s spurred increased construction of new plants).

55. *See id.* at 542-43 (discussing incentive effect of various rate treatment schemes). *See also* TOMAIN & CUDAHY, *supra* note 7, at 130-31 (discussing controversial nature of rate base determinations).

56. *See* ENERGY INFO. ADMIN., *supra* note 1, at 228 fig.8.2a (demonstrating the increase of the net generation of coal since 1950).

57. *See* Jersey Cent. Power & Light Co. v. Fed. Energy Reg. Comm'n, 810 F.2d 1168, 1172 (D.C. Cir. 1987) (Starr, J., concurring) (noting rates must be "just and reasonable" to consumers).

58. Energy Info. Admin., Glossary: B, http://www.eia.doe.gov/glossary/glossary_b.htm (last visited Oct. 27, 2009) (defining "base load" as "[t]he minimum amount of electric power delivered or required over a given period of time at a steady rate.").

59. *See id.* (defining a base load plant as one "usually housing high-efficiency steam-electric units, which is normally operated to take all or part of the minimum load of a system, and which consequently produces electricity at an essentially constant rate and runs continuously."). Coal, natural gas, and nuclear power plants fall within this definition.

60. *See* ENERGY INFO. ADMIN., *supra* note 1, at 228 fig.8.2a (comparing the net generation by all sectors).

61. *Id.*

coal as a base load source of electricity.[62] From the 1930s until the early 1980s, the Federal Energy Regulatory Commission (FERC) and its predecessor, the Federal Power Commission, regulated natural gas as a natural monopoly, similar to the way most PUCs regulate electricity now.[63] However, unlike the electricity system, the natural gas system always featured many independent natural gas producers and a competitive intrastate market.[64] FERC's regulation did not fit with the realities of the natural gas market, and it both stifled natural gas production and kept prices artificially high.[65] This period coincided with the development of many of the existing coal-fired power plants in the United States, and high gas prices prevented natural gas from becoming a financially reliable source of energy during the 1960s and 1970s.[66] Deregulation of the natural gas market in the 1980s spurred many utilities and, more importantly, independent power producers to build several more natural gas plants.[67] Despite this, natural gas has not become competitive with coal because natural gas prices track oil prices and are therefore subject to the price shocks common in the oil industry.[68] While some energy experts believe natural gas could become a more dominant fuel if the United States passes climate change legislation,[69] it has not yet proven competitive with coal.

Nuclear power seemed likely to displace coal as the dominant source of electricity in the late 1950s and 1960s, when utilities built dozens of nuclear power plants based on the promise that nuclear power would be "'too cheap to meter.'"[70] As a result of that construction boom, nuclear power currently accounts for 20 percent of U.S. electricity production.[71] But the costs associated with constructing nuclear power plants were never

62. *See id.* at 231 tbl.8.2b (showing that every year since 1949, coal has generated significantly more electricity than natural gas).

63. *See* Richard J. Pierce, Jr., *The Evolution of Natural Gas Regulatory Policy*, NAT. RESOURCES & ENV'T, Summer 1995, at 53-55 (describing the history and problems of natural gas regulation).

64. *See id.* at 54 (stating that the production of gas is "not a natural monopoly").

65. *Id.* at 55.

66. *See id.* at 54 (acknowledging that by the mid 1970s, "gas service was no longer available to most prospective new customers").

67. *See id.* at 84 (stating that "gas is being found, produced, stored, and transported at a much lower cost than was [previously] the case").

68. Bosselman, *supra* note 24, at 13-14.

69. *See* PODESTA & WIRTH, *supra* note 22 and accompanying text (stating that "natural gas can serve as a bridge fuel to a low-carbon, sustainable energy future"). *But see* Bosselman, *supra* note 24, at 11-13 (arguing that natural gas may not remain an abundant source of energy in the near future and that industry experts expect to increase imports of natural gas as production from domestic gas wells declines).

70. *See* Joseph P. Tomain, *Nuclear Futures*, 15 DUKE ENVTL. L. & POL'Y F. 221, 227-28 (2005) (discussing aggressive construction of nuclear power plants during this period).

71. ENERGY INFO. ADMIN., *supra* note 1, at 228 fig.8.2a.

competitive with coal,[72] and the 1979 accident at Three Mile Island effectively ensured that no more nuclear plants would come online to compete with coal during coal's ascendancy.[73] Although some commentators believe that climate change legislation could revive the nuclear industry as a source of carbon-free electricity,[74] others question whether nuclear energy will ever become economically competitive or publicly accepted.[75] To date, though, nuclear energy production has remained a weak competitor, and coal has retained its primacy in the electricity sector.

Climate change, however, threatens coal's dominance in the electricity sector. Although concerns about the direct impacts of coal production and combustion have never threatened coal's status before, the projected costs of carbon have led regulators to reject or restrict new coal plants.[76] As the next section explains, the PUCs may be attempting to prevent a repeat of the fiascos associated with the build-up and rapid demise of the nuclear industry.

III. PAYING THE COSTS FOR UNUSED NUCLEAR PLANTS

The rise and fall of the nuclear energy industry include several interesting parallels to the current situation of the coal-based electricity sector. Although nuclear energy never gained the market share that coal-based energy currently enjoys, its boom and bust has served as a cautionary tale for utilities and their regulators. This is not only due to public fears

72. *See* Tomain, *supra* note 70, at 229 (noting that the market for nuclear power would not have been able to operate without government support).

73. *See id.* at 225 (noting that all plants ordered since 1973 have been canceled and that no nuclear power plants have come online since 1978).

74. *See* Bosselman, *supra* note 24, at 37-52 (discussing relative environmental advantages of nuclear power). In August 2009, the Nuclear Regulatory Commission (NRC) stated that it planned to process twenty-three applications to license and build new nuclear power plants "over the next several years." U.S. NUCLEAR REGULATORY COMM'N, 2009-2010 INFORMATION DIGEST 43 (2009), http://www.nrc.gov/reading-rm/doc-collections/nuregs/staff/sr1350/v21/sr1350v21.pdf. At least one commentator views these new license applications, and the several pending requests for license renewals for existing nuclear plants, as an indication that the United States is "in the midst of the 'Second Coming' of nuclear power." Anthony Z. Roisman et al., *Regulating Nuclear Power in the New Millennium (The Role of the Public)*, 26 PACE ENVTL. L. REV. 317, 317 (2009). Despite this pronouncement, Roisman and his co-authors view the NRC's public participation processes as inadequate and do not believe nuclear power will play an increased role in providing electricity until the NRC improves the licensing processes. *Id.* at 363.

75. *See* Tomain, *supra* note 70, at 232-46 (noting that prospect of a nuclear-powered future will depend on public acceptance and relative cost).

76. *See infra* notes 135-196 and accompanying text.

regarding the safety of nuclear power plants.[77] Rather, the economic costs associated with nuclear plants which never came online have forced utilities and PUCs to act with great caution in the face of uncertainty.

A. *Nuclear Power's Rise and Fall*

Nuclear energy in the United States got its start with the passage of the Atomic Energy Act of 1946[78] and the creation of the Atomic Energy Commission.[79] Under the 1946 Act, however, only the military could develop or use nuclear energy, because Congress then believed that nuclear energy required strict controls.[80] By 1954, moods about nuclear power had changed, and the nuclear power industry successfully lobbied for the passage of the Atomic Energy Act of 1954.[81] The new Atomic Energy Act encouraged private ownership and commercial development of nuclear power plants.[82] The passage of the Price-Anderson Act of 1957[83] further promoted private development of nuclear energy by limiting the liability of utilities and nuclear reactor manufacturers should a nuclear accident occur.[84] These two laws quickly spurred a boom in nuclear power plant construction. In total, between 1955 and 1979, the Atomic Energy Commission issued construction permits to build 177 nuclear generating units.[85] As a result of this boom, nuclear energy accounted for approximately twenty percent of the nation's electricity production in 2008.[86]

However, the boom quickly ended with the accident at Three Mile Island in 1979, when a nuclear plant's core reactor malfunctioned and nearly experienced a complete meltdown.[87] That year marked the last one in which the Atomic Energy Commission or its successor, the Nuclear Regulatory Commission, issued a construction permit for a nuclear facility.[88] The accident also exacerbated other problems in the nuclear power industry. Several plants had incurred cost overruns in which

77. *See infra* notes 87 and 91 (discussing the Three Mile Island accident).
78. Atomic Energy Act of 1946, Pub. L. No. 79-585, 60 Stat. 755 (1946).
79. Tomain, *supra* note 70, at 226.
80. *Id.*
81. Atomic Energy Act of 1954, Pub. L. No. 83-703, 68 Stat. 919 (1954).
82. Tomain, *supra* note 70, at 227.
83. Price-Anderson Act of 1957, Pub. L. No. 85-256, 71 Stat. 576 (codified as amended in scattered sections of 42 U.S.C. (2000)).
84. Tomain, *supra* note 70, at 227.
85. ENERGY INFO. ADMIN., *supra* note 1, at 275 tbl.9.1.
86. *Id.* at 276 tbl.9.2.
87. *See* Barry Kellman, *Anxiety Over the TMI Accident: An Essay on NEPA's Limits of Inquiry*, 51 GEO. WASH. L. REV. 219, 227-32 (1983) (describing the details of the Three Mile Island accident).
88. ENERGY INFO. ADMIN., *supra* note 1, at 275 tbl.9.1.

construction costs increased two-, three-, and even fivefold over initial cost estimates.[89] In addition, energy forecasts from the 1950s and 1960s proved inaccurate, and it became clear that utilities no longer needed electricity from the nuclear plants.[90] Ultimately, revised cost estimates and concerns about plant safety arising from the Three Mile Island accident led to dozens of plant cancellations and abandonments.[91] In some cases, planned facilities never reached the construction phase; but in others, fully constructed plants never went online.[92] Yet all of the canceled plants involved significant expenditures of money,[93] and the question quickly turned to who should pay for the costs associated with these useless facilities.

B. Who Pays?: Prudent Investment v. Used and Useful

PUCs typically approached the question of who should pay for canceled plants by employing the "prudent investment" doctrine, the "used and useful" doctrine,[94] or a combination of the two.[95] The prudent investment doctrine allowed a utility to include the costs of a plant in its rate base so long as the utility's investment in the plant was prudent at the time of the decision to invest.[96] As noted above, the inclusion of the plant in the utility's rate base meant that the utility would earn a rate of return, or profit, on the plant.[97] The used and useful doctrine allowed a utility to include a plant in its rate base if the plant was "actually used and useful to the utility in providing regulated services."[98] The hybrid approach, which most PUCs applied to nuclear plants, allowed a utility to recover the costs of the plant but typically prohibited the utility from including the costs in its rate base.[99]

As the number of canceled nuclear plants grew, some legislatures passed laws prohibiting utilities from recovering *any* of their investment in

89. TOMAIN & CUDAHY, *supra* note 7, at 324.

90. Pierce, *supra* note 54, at 498-99.

91. *See id.* at 498-99 (noting that, in 1984, more than one hundred nuclear plants had been canceled, many of which would have provided "totally superfluous generating capacity").

92. *Id.* at 497-98.

93. *See id.* at 498-99 (noting that plant cancelations had already resulted in a loss of ten billion dollars, and they were expected to yield losses of many more billions).

94. *Id.* at 511.

95. *Id.* at 517.

96. *Id.* at 511.

97. *Supra* notes 52-53 and accompanying text. *See also* Pierce, *supra* note 54, at 511-12 (showing how the inclusion of a new plant to the ratemaking formula significantly impacts the rates of return).

98. Pierce, *supra* note 54, at 512.

99. *Id.* at 518-19.

the canceled plants from ratepayers.[100] In *Duquesne Light Co. v. Barasch*,[101] the Supreme Court upheld a Pennsylvania law declaring "'the cost of construction or expansion of a facility undertaken by a public utility producing . . . electricity shall not be made a part of the rate base nor otherwise included in the rates charged by the electric utility until such time as the facility is used and useful in service to the public.'"[102] The Pennsylvania Supreme Court had interpreted this law to prohibit utilities from recovering any of the costs of the plants in either their rate bases or through amortization.[103] On certiorari, the U.S. Supreme Court rejected the utilities' arguments that the Pennsylvania law resulted in an unconstitutional taking of the utilities' property.[104] The Court declared the Pennsylvania law, and others like it, beyond the federal courts' scope of review unless utilities could demonstrate that the laws would, by themselves, bankrupt the utilities.[105] As a result of *Duquesne*, PUCs retained great authority to decide how to allocate costs for failed investments in nuclear plants.

C. The Broader Consequences of Allocating Costs for Failed Facilities

In the end, none of the practices employed by PUCs yielded immediately satisfactory results. Politically, PUCs were in a no-win situation because any decision allocating the costs inevitably resulted in either the utilities or the ratepayers, or both parties, feeling cheated. Beyond that, as Professor Pierce has explained, each cost allocation decision necessarily affected the utilities' future business plans. PUCs that allowed utilities to include the full costs of the failed plants in their rate bases penalized ratepayers and signaled to utilities that they could expect to earn a profit on investment decisions that turned out to be imprudent.[106] PUCs that prohibited utilities from recovering from the ratepayers any investment in the canceled plants sent mixed messages to utilities and ratepayers. On the one hand, the denial of any recovery incentivized utilities to under-invest in new power plants so they could avoid exposure to failed investments at the outset.[107] On the other hand, a utility already in the process of construction would likely continue the project, even if the

100. *Id.* at 519-20.

101. 488 U.S. 299 (1989).

102. *Id.* at 304 (quoting 66 PA. CONS. STAT. § 1315 (Supp. 1988)) (omission in original).

103. *Id.* at 305.

104. *Id.* at 310-16.

105. *Id.* In reaching this conclusion, the Supreme Court applied longstanding precedent which empowers federal courts to review only the "end result" of a PUC's ratemaking decision. Fed. Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591, 603 (1944).

106. Pierce, *supra* note 54, at 542.

107. *Id.* at 542-43.

electricity was no longer required, to avoid the harsh treatment some states afforded plants that did not go into service.[108] While the hybrid approach some PUCs employed may have mitigated the most extreme consequences of a strict prudent investment or used and useful test,[109] it nonetheless left utilities, regulators, and ratepayers dissatisfied to some degree.

Beyond that, the rise and fall of the nuclear industry appears to have had lingering consequences as PUCs struggle to predict how potential climate change regulation will affect utilities' investments in new coal plants. As the next section explains, several utilities have attempted to invest in new coal-burning technologies that would reduce, and perhaps eliminate, carbon dioxide emissions from coal-fired power plants. Yet, as Part V shows, PUCs appear unwilling to expose ratepayers to the risk that these technologies, which are expensive and in some cases unproven, will fail to adequately reduce emissions to the levels Congress may ultimately demand. Thus, the lasting legacy of the nuclear plant cancellations may ultimately signal the end of coal's dominance in the electric sector.

IV. COAL, CARBON DIOXIDE, AND DEVELOPING TECHNOLOGIES

In 2007, coal-fired power plants accounted for eighty-two percent of all carbon dioxide emissions from the electricity sector[110] and over twenty-seven percent of the country's greenhouse gas emissions.[111] Not surprisingly, these emission levels have made coal-based electricity a primary target of enacted and proposed laws aimed at reducing greenhouse gas emissions.[112] In response, the coal industry has attempted to develop

108. *Id.*

109. *Id.* at 543-44. Professor Pierce argues that a policy allowing for recovery of out-of-pocket costs of an investment in a canceled plant, exclusion of some cost of capital associated with the failed plant, and a penalty to discourage over-investment could create the right incentives for future plant investment decisions. *Id.* at 543. Even so, he acknowledges that the specific formula to achieve the right incentives is difficult to establish or employ. *Id.*

110. Carbon dioxide emissions from stationary power plants that burn fossil fuels for electricity equaled 2,397.2 teragrams of carbon dioxide equivalents (Tg CO_2 Eq.). ENVTL. PROT. AGENCY, *supra* note 4, at 3-8, tbl.3-9. Coal-fired power plants accounted for 1,967.6 Tg CO_2 Eq., or slightly more than 82 percent, of the total carbon dioxide emissions from the electricity sector. *Id.*

111. Total U.S. greenhouse gas emissions equaled 7,150.1 Tg CO_2 Eq. *Id.* at 2-1. Coal-fired power plants emitted 1,967.6 Tg CO_2 Eq., or 27.5 percent of total greenhouse gas emissions, in carbon dioxide alone. *Id.* at 2-18, tbl.2-13. Although coal plants emit other greenhouse gases, carbon dioxide emissions dwarf all other greenhouse gas releases. *Id.* at 2-7 to 2-8, tbl.2-4 (stationary combustion of fossil fuels emits only 6.6 Tg CO_2 Eq. of methane and 14.7 Tg CO_2 Eq. of nitrous oxide).

112. *See, e.g.*, REG'L GREENHOUSE GAS INITIATIVE, MEMORANDUM OF UNDERSTANDING (2005), http://rggi.org/docs/mou_12_20_05.pdf (establishing a regional cap-and-trade program for carbon dioxide emissions from electricity generation); REG'L GREENHOUSE GAS

new coal combustion technologies that reduce carbon dioxide emissions or capture and permanently store carbon dioxide emissions. The obvious objective of these technologies is to enable the coal industry to maintain its prominence in the electricity sector. However, the industry's ability to do this will depend largely on the willingness of PUCs to allow utilities to invest in new coal technologies while the scope of climate change regulation remains unclear.

Typical coal-fired power plants use a standard technology to convert coal into electricity: they burn coal to create steam, which then drives a turbine to create electricity.[113] Most technological advances in coal-based electricity have focused on increasing efficiency to burn less coal and thus emit fewer pollutants.[114] For example, early "sub-critical" coal-fired power plants burned coal to boil water to create the steam.[115] Other early innovations, employing "supercritical" technologies, focused on ways to increase pressures and temperatures so that more steam could form using less coal.[116] Most existing coal plants use these standard technologies, but even those that employ "supercritical" coal combustion continue to emit millions of tons of carbon dioxide each year.[117]

As concerns about climate change have increased, electric companies have worked to develop new coal combustion technologies to reduce carbon dioxide emissions. The two primary technologies, "ultra-supercritical" technology and integrated gasification combined-cycle technology, seek to increase the efficiency of coal combustion.[118] Coal plants currently operate at about thirty-five percent efficiency, with the remaining energy released as waste heat.[119] American Electric Power has

INITIATIVE, MODEL RULE (2008), http://www.rggi.org/docs/Model%20Rule%20Revised%2012.31.08.pdf; H.R. 2454, 111th Cong. (2009) (proposing a federal cap-and-trade program); Act of Sept. 29, 2006, 2006 Cal. Legis. Serv. ch. 598 (establishing a statewide emissions performance standard requiring all long-term power purchases to come from plants that emit no more than a combined-cycle gas turbine power plant and thus prohibiting long-term power contracts for coal-powered electricity).

113. William L. Sigmon, *The Lure of Ultra-Supercritical: Exploring the Future of Coal-Burning*, ENERGYBIZ, Sept.-Oct. 2008, at 90, 90, *available at* http://energycentral.fileburst.com/EnergyBizOnline/2008-5-sep-oct/Tech_Frontier_Ultra-Supercritical.pdf.

114. *Id.*

115. *Id.*

116. *Id.* at 90-91.

117. *See id.* at 91 (noting that many new coal plants coming online will use supercritical technology); DEP'T OF ENERGY & ENVTL. PROT. AGENCY, CARBON DIOXIDE EMISSIONS FROM THE GENERATION OF ELECTRIC POWER IN THE UNITED STATES 3 tbl.2 (2000), http://www.eia.doe.gov/cneaf/electricity/page/co2_report/co2emiss.pdf (noting that coal plants emitted more than 1.7 billion metric tons of carbon dioxide in 1999).

118. Sigmon, *supra* note 113, at 90.

119. *See* VELLA A. KUUSKRAA, PEW CTR. ON GLOBAL CLIMATE CHANGE, A PROGRAM TO

developed an ultra-supercritical technology that will use increased pressures and temperatures to create steam, and theoretically increase the efficiency by about eleven percent.[120] Other companies have invested in integrated gasification combined-cycle (IGCC) technologies, which first convert coal into a synthetic gas that is then burned in a combustion cycle.[121] The waste heat from the combustion cycle then heats water to create steam, which then powers a steam-generated turbine.[122] This combined combustion/steam system has the potential to operate up to twenty percent more efficiently than traditional coal plants.[123] Even with these efficiency gains, however, coal-based electricity will still account for millions of tons of carbon dioxide emissions each year.[124]

A more aggressive technology under development would employ carbon capture and sequestration (CCS) technology to capture carbon dioxide emissions from coal plants, pump the carbon dioxide into underground storage areas, and sequester the carbon dioxide indefinitely.[125] Although CCS could theoretically apply to subcritical and supercritical coal plants, the costs to adapt the plants for CCS would likely be prohibitively expensive.[126] Technologically and economically, it should be easier to integrate CCS technology into IGCC plants, although the carbon capture

ACCELERATE THE DEPLOYMENT OF CO_2 CAPTURE AND STORAGE (CCS): RATIONALE, OBJECTIVES, AND COSTS 9 tbl.2 (2007), http://www.pewclimate.org/docUploads/CCS-Deployment.pdf (noting that plant efficiencies vary depending upon when the plants came online). Plants built before 1970 have an average efficiency of twenty-eight percent; those built between 1970 and 1989 have a thirty-six percent efficiency rate, and those built between 1990 and 2003 achieve thirty-nine percent efficiency. *Id.*

120. Sigmon, *supra* note 113, at 91.

121. DEP'T OF ENERGY, HOW COAL GASIFICATION POWER PLANTS WORK, http://fossil.energy.gov/programs/powersystems/gasification/howgasificationworks.html (last visited Nov. 2, 2009).

122. *Id.*

123. *Id.*

124. *See* David Biello, *How Fast Can Carbon Capture and Storage Fix Climate Change?*, SCIENTIFIC AMERICAN, Apr. 10, 2009, http://www.scientificamerican.com/article.cfm?id=how-fast-can-carbon-capture-and-storage-fix-climate-change (noting that a single coal-fired power plant using IGCC technology in West Virginia will emit 8.5 million metric tons of CO_2).

125. NAT'L ENERGY TECH. LAB., DEP'T OF ENERGY, CARBON SEQUESTRATION, http://www.netl.doe.gov/technologies/carbon_seq/index.html (last visited Oct. 25, 2009).

126. NAT'L ENERGY TECH. LAB., DEP'T OF ENERGY, COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS 11 (2007), http://www.netl.doe.gov/energy-analyses/pubs/Bituminous%20Baseline_Final%20Report.pdf [hereinafter NETL COST AND PERFORMANCE]. *See also* NAT'L ENERGY TECH. LAB., DEP'T OF ENERGY, WHAT ARE THE COSTS AND BENEFITS OF CARBON CAPTURE AND SEQUESTRATION?, http://www.netl.doe.gov/technologies/carbon_seq/FAQs/benefits.html (last visited Nov. 2, 2009) [hereinafter NETL COST AND BENEFITS] (explaining results of cost estimates and demonstrating that CCS applied to pulverized coal plants using sub- and supercritical technology would increase costs by 70 to 100 percent).

and sequestration process would use about one-fourth of all electricity generated from the plant.[127] However, the development of commercial-scale power plants with CCS technology is in its infancy and has proceeded to date in fits and starts due to cost concerns and technological challenges.[128] Most notably, the Department of Energy briefly canceled funding for the FutureGen project, a proposed commercial-scale ICGG power plant with CCS capacity, when it realized the plant would cost $1.8 billion, about $850 million more than it had anticipated.[129] Although the Department later renewed its support for the FutureGen facility, many other private investors backed out of the facility's development due to concerns about the stability of the project's funding.[130] Other commercial-scale CCS plants have yet to proceed as far as FutureGen.[131] Thus, while ICGG plants with CCS may provide a way to continue to use coal in a carbon-constrained world, the deployment of the technology appears to be distant.

The electricity sector thus faces a conundrum as it attempts to respond to climate change. It emits a significant amount of greenhouse gases, primarily from coal-based power, and existing technologies allow coal plants to operate more efficiently but do not significantly reduce overall carbon dioxide emissions. More innovative technologies will consume about one-quarter of any new plant's energy and may cost about $2 billion to deploy.[132] Although technologies may become cheaper over time, coal's dominance as a "cheap" form of energy may be nearing an end. At least, it seems that PUCs believe this to be the case. As discussed in the next section, this belief may in fact make coal's potential demise a certainty.

127. NETL COST AND BENEFITS, *supra* note 126; Trish Choate, *Sweetwater Coal Plant Ready for Cap and Trade Rules*, SAN ANGELO STANDARD TIMES, Mar. 30, 2009 (noting that proposed CCS facility would use about twenty-five percent of power plant's electricity), *available at* http://www.gosanangelo.com/news/2009/mar/30/sweetwater-coal-plant-ready-for-cap-and-trade/.

128. *See* Matthew L. Wald, *Refitted to Bury Emissions, Plant Draws Attention*, N.Y. TIMES, Sept. 21, 2009, at A1 (discussing the difficulties with implementing CCS technologies).

129. Martin LaMonica, *DOE Scraps FutureGen "Clean Coal" Project for New Tack*, CNET NEWS, Jan. 30, 2008, http://news.cnet.com/8301-11128_3-9861473-54.html.

130. Sonal Patel, *Revived FutureGen Faces Renewed Funding Obstacles*, POWER, Aug. 1, 2009, http://www.powermag.com/coal/Revived-FutureGen-Faces-Renewed-Funding-Obstacles_2077.html.

131. *See* Wald, *supra* note 128 (discussing other efforts to develop CCS facilities).

132. *See* Choate, *supra* note 127 (discussing the energy used to capture and compress carbon dioxide at a proposed plant); LaMonica, *supra* note 129 (discussing the $1.8 billion estimated cost of a proposed FutureGen project).

V. APPLYING TRADITIONAL ELECTRICITY REGULATION TO NEW COAL PLANTS IN THE AGE OF CLIMATE CHANGE

Although traditional electricity regulation has favored the use of coal thus far, the costs associated with climate change, combined with the electricity sector's experiences with nuclear energy, make it likely that coal will lose its dominance within the electricity sector. Even if Congress fails to pass climate change legislation within the immediate future, or enacts a mediocre law that requires very few reductions in greenhouse gas emissions in the short-term, the specter of climate change legislation will likely be enough to discourage construction of new coal plants. A handful of PUCs across the country have already rejected proposals for new coal plants because they expect climate change legislation will impose significant carbon costs on utilities and their ratepayers.[133] Other PUCs have rejected coal plants proposing to use innovative technology, like IGCC and carbon capture and sequestration, due to concerns regarding the expense and uncertainty involved in deploying new technologies.[134] Combined, these cases reveal an increasing wariness on the part of PUCs to allow construction of new coal plants.

A. *The PacifiCorp Projects*

Oregon was perhaps the first state to reject a utility's proposal to build new coal plants due, in part, to concerns about pending climate legislation.[135] In Oregon, utilities must prepare integrated resource plans (IRPs), which serve as long-range planning documents.[136] IRPs identify existing energy resources and propose an overall resource portfolio designed to achieve low costs and limit ratepayers' risks.[137] Once a utility

133. *See infra* notes 135-169 and accompanying text; *see also* Robert L. Glicksman, *Coal-Fired Power Plants, Greenhouse Gases, and State Statutory Substantial Endangerment Provisions: Climate Change Comes to Kansas*, 56 U. KAN. L. REV. 517, 538-52 (2008) (discussing various state denials of proposed new coal plants).

134. *See infra* notes 170-196 and accompanying text; *see also* Glicksman, *supra* note 133, at 546-47 (discussing North Carolina's "go-slow" approach regarding IGCC technology).

135. *See In re* PacifiCorp, 2007 WL 299389 (Or. P.U.C. Jan. 16, 2007) (denying approval of PacifiCorp's draft RFP).

136. *In re* Integrated Resource Planning, 255 P.U.R.4th 367, 385 (Or. P.U.C. Jan. 8, 2007); *see also* Sandra L. Hirotsu, Remembering the Bottom Line: Why the Oregon Public Utility Commission's Obligation to Protect Utility Ratepayers Requires Saying No to Coal 14-15 (Apr. 24, 2008) (unpublished comment, on file with the author) (describing the IRP process).

137. *In re* Or. Pub. Util. Comm'n., 2007 WL 534555 (Or. P.U.C. Feb. 9, 2007) (describing the rule for investigations into Integrated Resource Planning); Hirotsu, *supra* note 136, at 14.

develops an IRP, it must then present the IRP to the Oregon PUC for "acknowledgement."[138] If the PUC acknowledges a utility's plan to build new electricity generation plants, this acknowledgement provides support for a utility when it seeks to include the costs of the plant in its rate base.[139] In contrast, if a PUC denies all or part of an IRP, the utility will have a more difficult time receiving authorization to build a power plant or recover the costs of the plant in its rate base.[140]

PacifiCorp is a utility regulated by the Oregon PUC. In 2004, the Oregon PUC acknowledged in part an IRP prepared by PacifiCorp; however, the Oregon PUC declined to acknowledge PacifiCorp's stated need for two large power plants for the eastern side of its service area.[141] In its denial, the Oregon PUC concluded that PacifiCorp had failed to demonstrate an adequate need for the additional power plants and advised PacifiCorp to "delay a commitment to coal until IGCC technology is further commercialized."[142] Rather than wait, PacifiCorp filed an updated IRP claiming a need for one base load power plant.[143] Before the Oregon PUC had the opportunity to review or acknowledge the updated IRP, PacifiCorp submitted a draft "Request for Proposals," seeking authorization to solicit bids to construct new coal power plants.[144]

In 2007, the Oregon PUC rejected PacifiCorp's request. First, the PUC held that PacifiCorp had not demonstrated a need for two large power plants.[145] Second, to the extent PacifiCorp had demonstrated some need for additional electricity, it had shown a need for peaking power.[146] The Oregon PUC found large base load plants inappropriate to fill peak power demand, particularly since large plants could limit the utility's ability to respond to "uncertainties related to technology change and regulation of carbon dioxide (CO_2) emissions."[147] Third, the PUC concluded that PacifiCorp's construction of large coal-fired power plants would likely expose the utility to significant cost risks due to recent greenhouse gas emissions legislation passed by California.[148] California had established an emissions performance standard prohibiting utilities in California from entering into long-term contracts to purchase power from any power plants

138. Integrated Resource Planning, 255 P.U.R.4th at 370; Hirotsu, *supra* note 136, at 14-15.
139. Hirotsu, *supra* note 136, at 15.
140. *Id.*
141. PacifiCorp, 2007 WL 299389, at *3.
142. *Id.*
143. *Id.* at *1.
144. *Id.*
145. *Id.* at *5.
146. *Id.*
147. *Id.*
148. *Id.* at *6-7.

whose greenhouse gas emissions rates exceeded the emissions rates of a combined-cycle gas turbine power plant (i.e., a natural gas plant).[149] PacifiCorp's proposed coal-fired power plants would not have met the California standards, and, therefore, the Oregon PUC considered PacifiCorp's intention to sell electricity to California unduly risky.[150] In short, based on the uncertain prospects of future climate change legislation and the certain risks associated with California's emissions performance standards, the Oregon PUC rejected PacifiCorp's proposal to build new coal plants.

The Oregon PUC also discussed, but did not decide, how PacifiCorp should factor the costs of climate change into its proposal.[151] PacifiCorp had estimated that carbon costs would add eight dollars per ton of CO_2 to its projected costs, while other parties argued the costs should range from $8.50 per ton to $30.80 per ton.[152] Based on the potential costs, the Oregon Department of Energy concluded that PacifiCorp should be allowed to build only IGCC plants with carbon sequestration, if it were to build any coal plants at all.[153] Although the Oregon PUC did not adopt the Department of Energy's recommendation, it made it clear that carbon dioxide costs would become a significant factor in future decisions.

B. The Turk Plant

In 2007, Southwestern Electric Power Company (SWEPCO) filed an application for a certificate of convenience and necessity (CCN)[154] with the Public Utility Commission of Texas (Texas PUC) to build a 600-Megawatt ultra-supercritical coal-fired power plant.[155] Although the Texas PUC found that SWEPCO demonstrated a need for the plant,[156] it

149. CAL. PUB. UTIL. CODE § 8340 (2008).

150. In re PacifiCorp, 2009 WL 299389 at *7 (Or. Pub. Util. Comm'n 2007).

151. *Id.* at *9-10.

152. *Id.* at *9.

153. *Id.*

154. Most states require utilities to obtain pre-approval to construct new plants from PUCs. The approval is often issued as a certificate of convenience and necessity (CCN), which certifies that the plant is necessary to meet projected power needs and in the public interest. BOSSELMAN ET AL., *supra* note 9, at 62.

155. Order Conditionally Approving Application of Sw. Elec. Power Co. for a Coal Fired Power Plant in Ark. at 10 ¶ 1, PUC Docket No. 33891, SOAH Docket No. 473-07-1929, (Tex. Pub. Util. Comm'n Aug. 12, 2008) [hereinafter SWEPCO].

156. *Id.* at 3-4. The administrative law judge (ALJ) initially recommended denial of the CCN because he did not believe SWEPCO had adequately demonstrated a need for additional electricity to serve its ratepayers. *Id.* at 2. Specifically, the ALJ concluded that SWEPCO had improperly included wholesale power – power SWEPCO would generate and then sell to a non-regulated entity for resale – in its forecasts of energy needs. *Id.* The ALJ believed SWEPCO could only consider the needs of its regulated customers when forecasting future energy requirements. *Id.* The Texas PUC, however, held that SWEPCO

nonetheless restricted SWEPCO's ability to recover future carbon mitigation costs from ratepayers.[157] The Texas PUC noted that estimated costs for CO_2 emissions could range from $13 per ton to $70 per ton, and average CO_2 costs would range between $30 to $45 per ton, depending upon the number of allowances available during the early phase of any cap-and-trade program and the availability of carbon capture and sequestration in the future.[158] After recognizing the significant degree of uncertainty regarding the potential costs, the Texas PUC limited SWEPCO's ability to pass carbon mitigation costs onto consumers by declaring that any mitigation costs that exceed $28 per ton through the year 2030 "shall not be borne by Texas ratepayers."[159]

Although the Texas PUC's decision represents a moderate response to uncertainty regarding carbon regulation, it nonetheless signals an important shift within PUCs regarding climate change. The Texas PUC recognized the likelihood of future carbon regulation and sought to protect ratepayers from exposure to future costs. In so doing, the Texas PUC put the utility and its investors on notice that they would bear responsibility for unanticipated costs. At the same time, the decision raises several important questions, including who will pay carbon mitigation costs after the year 2030. This lingering uncertainty regarding future carbon costs may require utilities to proceed with even greater caution as they decide whether to invest in new coal plants.

C. The WP&L Plants

The Public Service Commission of Wisconsin (Wisconsin PSC) is perhaps the first PUC that based its denial of a CCN squarely on costs associated with carbon mitigation. Wisconsin Power and Light Company (WP&L) sought a CCN authorizing construction of a 300-Megawatt power plant using coal as its primary fuel.[160] WP&L presented the Wisconsin PSC with two options, both of which would employ traditional coal-burning technology to produce electricity.[161] WP&L's initial cost estimates for the projects ranged from $777 million to $795 million.[162] Within nine

could include wholesale power sales in its needs forecast. *Id.*

157. *Id.* at 8.

158. *Id.* It is unclear what timeframe applies to these estimates. *Id.*

159. *Id.*

160. Final Decision Denying Application of Wis. Power and Light Co., d/b/a Alliant Energy, for Auth. to Construct a New Coal-Fired Plant in Wis., No. 6680-CE-170 (Wis. Pub. Serv. Comm'n Dec. 11, 2008) [hereinafter WP&L].

161. *Id.* at 1. One plant would employ a "circulating fluidized bed boiler" that could burn coal, pet coke, and biomass, while the other would use a subcritical pulverized coal boiler to burn coal and up to four percent biomass. *Id.* at 1-2.

162. *Id.* at 2.

months, WP&L's cost projections had climbed to between $1.26 billion and $1.283 billion, representing a 62 percent increase over the initial cost estimates.[163] Based on the revised figures, the Wisconsin PSC determined that the WP&L plant, if built, would be "the most expensive conventional coal plant of its size . . . ever proposed in the United States."[164] With this statistic in mind, it is not surprising that the Wisconsin PSC denied WP&L's requested CCN. However, the Wisconsin PSC's cost analysis did represent a significant change in its historical approach to calculating electricity costs.

The Wisconsin PSC's cost determinations hinged on its inclusion of greenhouse gas mitigation expenses in the plant's cost estimates.[165] WP&L had argued that the PSC could not include greenhouse gas emissions in its consideration of the application for the CCN because a state statute prohibited the PSC from considering "the impact of air pollution" in deciding whether a proposed facility will meet the public interest requirement for a CCN.[166] The PSC, however, concluded that it could consider monetization of greenhouse gases in its cost assessment of the proposed plant.[167] The Wisconsin PSC then determined that, if greenhouse gas monetization were factored into the plant's cost, the expenses would increase between $551 million and $817 million.[168] Based on these anticipated costs, which would have made the plant "the most expensive conventional coal plant of its size," the Wisconsin PSC found the projects contrary to the public interest.[169]

The Wisconsin PSC also briefly entertained WP&L's suggestions that it could increase the value of the plants by retrofitting them for future carbon capture and sequestration technology.[170] The PSC found the technology for carbon capture and sequestration "so experimental and so far from commercial viability" that it refused to consider the proposed plant modifications as money-saving measures.[171] Indeed, the PSC speculated that carbon capture and sequestration would probably increase the costs of the plants significantly.[172]

The Wisconsin decision may signal a new wariness on behalf of PUCs regarding the traditional claim that coal-fired power plants can deliver cheap power. Although the Wisconsin PSC recognized that the

163. *Id.* at 2-3.
164. *Id.* at 3.
165. *Id.* at 7-9.
166. *Id.* at 9 (citing Wis. Stat. § 196.491(3)(d)3 (2002)).
167. *Id.* at 9-10.
168. *Id.* at 7-8.
169. *Id.* at 3, 13.
170. *Id.* at 11.
171. *Id.*
172. *Id.*

utility needed to add base load power to its energy generating resources,[173] it refused to allow coal plants to fulfill this need. And it based its refusal almost entirely on the added costs that carbon regulation will impose on power plants. As discussed in greater detail below, this case could represent a new future for energy policy as PUCs attempt to protect ratepayers from exposure to uncontrolled costs that climate change legislation may impose.

D. The Mesaba Project

While the other PUC decisions demonstrate regulators' increasing reluctance to allow new coal plants to go online due to projected carbon costs, a Minnesota PUC decision reveals a reluctance to expose ratepayers to uncertain costs of carbon mitigation technologies. In 2005, Excelsior Energy, Inc. (Excelsior) sought preliminary approval to begin construction of an IGCC coal plant, known as the Mesaba Project, in Minnesota.[174] The Minnesota legislature had passed a law in 2003 that provided several incentives for construction of IGCC facilities in the state, including exemptions from parts of the state PUC approval process for new power plants.[175] One of the most important incentives would guarantee that the regulated utility in Minnesota, Xcel Energy, would enter into a long-term power purchase agreement (PPA) committing to buy 450 Megawatts of power from the Excelsior site.[176] However, Excelsior required the Minnesota PUC's approval of the PPA and other preliminary authorizations before it could begin constructing the facility.[177] The Minnesota PUC refused to give Excelsior the authorizations it needed because the Excelsior plan would have exposed ratepayers to unacceptable risks.

Before seeking the Minnesota PUC's approval, Excelsior attempted to negotiate a mutually agreeable PPA with Xcel.[178] When these negotiations failed, Excelsior filed a petition with the Minnesota PUC, asking it to approve, amend, or modify its proposed PPA and to order Xcel to buy 13 percent of its retail energy from Excelsior's Mesaba Project.[179]

173. *Id.* at 4-5.

174. Order Disapproving Petition by Excelsior Energy, Inc., for Approval of a Power Purchase Agreement under Minn. Stat. § 216B.1694, Docket No. E.-6472/M-05-1993 at 3-4 (Minn. Pub. Util. Comm'n Aug. 30, 2007) [hereinafter Excelsior].

175. *Id.* at 1-2.

176. *Id.* at 1.

177. *Id.* at 1-2. Among the other requirements, Excelsior required a finding from the Minnesota PUC that the IGCC was a "least cost resource" under state law and sought an order directing Xcel to buy 13 percent of the power it needed for its retail customers from Excelsior. *Id.* at 4.

178. *Id.* at 4.

179. *Id.*

Administrative law judges (ALJs) assigned to review the petition concluded that the costs in the PPA were unreasonable.[180] Moreover, the ALJs concluded that the actual costs of the Mesaba Project were so high that it was unlikely Excelsior could develop any PPA with reasonable prices.[181] Excelsior appealed the ALJ's decision to the Minnesota PUC.

After acknowledging that both state and federal lawmakers "clearly consider IGCC technology – and this project – sufficiently promising," the Minnesota PUC rejected Excelsior's requests for approval of the power purchase agreement because it found the terms of the proposed PPA would be contrary to the public interest and would expose Xcel Energy and its ratepayers to unreasonably high rates and risks.[182] The Minnesota PUC explained that it would review the PPA based on its traditional regulatory criteria requiring it "ensure that retail consumers receive adequate and reliable service at reasonable rates, consistent with the financial requirements of public utilities and their need to build generating facilities" or otherwise secure adequate energy supplies.[183] The PUC could approve the PPA only if it met the traditional public interest criteria, which required it to protect ratepayers from the operational and financial risks of the project and to ensure the PPA would ensure Xcel's financial health.[184]

The Minnesota PUC first concluded that the PPA exposed Xcel and its ratepayers to unreasonably high prices and rates.[185] Rather than setting fixed prices for power purchased from the Mesaba Project, the PPA proposed to tie Xcel's power prices to the costs of building and operating the Mesaba Project, including any costs associated with installing carbon capture and sequestration technology.[186] The Commission determined that the Mesaba Project's costs, excluding carbon capture and sequestration, would be around $1.9 billion[187] – 30 percent higher than other proposed new coal plants.[188] Adding carbon capture and sequestration would increase the costs by more than one billion dollars and reduce the plant's efficiency by about ten percent.[189] Based on these projections, and the lack of any cap on the ultimate costs Xcel might pay, the Minnesota PUC found the proposed PPA inconsistent with the public interest because it "would result in unreasonably high prices for Xcel and unreasonably high rates for

180. *Id.* at 6.
181. *Id.*
182. *Id.* at 4, 13-23.
183. *Id.* at 13-14 (citing Minn. Stat. § 216B.01 (2003)).
184. *Id.* at 14.
185. *Id.* at 15.
186. *Id.* at 15.
187. *Id.* at 20.
188. *Id.* at 15-16.
189. *Id.* at 15.

Xcel's ratepayers."[190] The PUC did not rule out the possibility that Excelsior and Xcel could negotiate a contract setting reasonable rates,[191] but the costs of CCS technology make successful negotiations unlikely.

Although costs associated with the Mesaba Project served as the main reason for the Minnesota PUC's rejection of the PPA, the PUC also found that the PPA exposed Xcel and its customers to unreasonable operational and financial risks. The PPA would have required Excelsior to pay for more than $75 million worth of replacement power if the Mesaba Project were to experience breakdowns, shutdowns, or other operational problems.[192] Seventy-five million dollars would cover only about one year's expense for replacement power, while the PPA would extend for 25 years.[193] The Minnesota PUC concluded that this provision had the effect of shifting "nearly all the risk" of breakdown and shutdown onto the ratepayers, and thus found the term to be contrary to the public's interest.[194] The PUC also rejected as unreasonable the PPA's proposal to place all of the financial risks associated with engineering, contracting, and constructing the Mesaba Project on Xcel and its ratepayers.[195]

Ultimately, the Minnesota PUC ordered Excelsior and Xcel to resume negotiations to see if they could reach agreement regarding the terms of a PPA.[196] It is unclear, however, if these negotiations will resolve the significant disputes at issue in the petition proceedings. The disputes revolved around who should bear the risks for potential cost increases and operational failures associated with installing new technology. Excelsior appeared unwilling to expose itself to these risks, and it sought to use the PPA to push the risks onto the regulated utility, Xcel. The Minnesota PUC, however, made clear that Xcel and its ratepayers would not bear the risks of the expensive and unproven IGCC technology. With $1.9 billion – at a minimum – at stake, it may be the case that neither Excelsior nor Xcel has the stomach to assume the risks of new coal technology.

VI. COAL PLANT DENIALS AND THE RISE OF RENEWABLES?

Regulators' reluctance to permit new coal plants suggests that coal may not retain its status as the dominant source of electricity for much longer. The uncertainty surrounding the passage and contents of national climate change legislation[197] increases the risk that ratepayers could end up

190. *Id.* at 17.
191. *Id.* at 17, 23.
192. *Id.* at 17.
193. *Id.*
194. *Id.*
195. *Id.*
196. *Id.* at 24.
197. *See* Jennifer A. Dlouhy, *Climate Change Bill May Drift: A Wary Senate Might Not*

paying for carbon costs if PUCs approve new coal plants. To avoid this risk, PUCs have approached new coal plants with great caution, likely in an effort to avoid repeating the mistakes associated with the rise and fall of the nuclear power industry. Indeed, the mishaps with the nuclear energy industry continue to resonate today, since many ratepayers continue to pay for canceled or abandoned nuclear power plants from which they never received any electricity.[198] So long as carbon costs remain uncertain[199] and CCS technologies remain unproven, it is likely that PUCs will continue to treat new coal plant proposals with skepticism. Since it is very likely that uncertainties regarding climate change mitigation will perpetuate for the foreseeable future, new coal proposals will face more denials.[200]

As PUCs reject more new coal plant proposals, the question that arises is: what new energy sources will come online? Three major

Decide Measure's Fate Until Next Year, HOUSTON CHRON., Sept. 26, 2009, at Business 1 (recognizing that a new climate change law may take longer to pass than previously expected due to other domestic issues taking priority).

198. *See* Benjamin K. Sovacool & Christopher Cooper, *Nuclear Nonsense: Why Nuclear Power is no Answer to Climate Change and the World's Post-Kyoto Energy Challenges*, 33 WM. & MARY ENVTL. L. & POL'Y REV. 1, 27 (2008) (noting the energy consumers in the Pacific Northwest continue to pay for canceled nuclear plants).

199. Costs of carbon dioxide will be difficult to predict even if Congress passes national climate change legislation. For example, cost estimates of the recently passed House bill, the American Energy and Security Act of 2009 (H.R. 2454), vary widely depending upon how regulated entities will respond to certain incentives in the bill. The bill would, if enacted, establish a cap-and-trade system that sets caps on the total allowable emissions and lowers that cap over time, distribute emissions allowances to facilities covered under the cap, and allow companies to trade emissions allowances in an effort to meet their emissions requirements. CONGRESSIONAL BUDGET OFFICE, COST ESTIMATE, H.R. 2454, AMERICAN CLEAN ENERGY AND SECURITY ACT OF 2009, at 4-5 (2009). It would initially distribute more than 70 percent of the emissions allowances for free, but by 2031, it would require regulated entities to purchase, through an auction, about 70 percent of available allowances. *Id.* at 6. It would also allow covered entities to use "offsets," or credits produced through emissions reductions of uncovered entities, in lieu of up to two billion GHG allowances each year. *Id.* at 16.

The Congressional Budget Office prepared an economic analysis of the bill, in which it estimated that the cap-and-trade requirement "would amount to tens of billions of dollars annually for private-sector entities and about $1 billion annually for public entities." *Id.* at 35. Yet, it also repeatedly noted that it could not provide a cost estimate for various requirements under the proposed bill. *Id.* at 36-37. Since the actual costs will depend, among other things, on the number of offsets covered entities use and the degree to which covered entities can reduce their own emissions, cost estimates will necessarily remain speculative. ENERGY INFO. ADMIN., ENERGY MARKET AND ECONOMIC IMPACTS OF H.R. 2454, THE AMERICAN CLEAN ENERGY AND SECURITY ACT OF 2009, at vii (2009) ("While the ceiling on offset use is clear, their actual use is an open question.").

200. *See* Cassandra Sweet, *Otter Tail Unit Scraps Plans for South Dakota Coal Plant*, WALL ST. J., Sept. 11, 2009, http://online.wsj.com/article/BT-CO-20090911-712041.html (reporting that a Minnesota utility recently withdrew from its sponsorship of a South Dakota coal plant due to concerns about finances and uncertainty regarding climate change legislation).

categories of sources could serve as likely substitutes: natural gas, nuclear energy, and renewable sources including hydropower, wind, solar, and wave.

In the short term, it seems likely that natural gas will serve as a good "bridge" fuel as the electricity sector adjusts to the decline of coal.[201] Natural gas plants are relatively inexpensive to build, and they can turn on and off quickly to respond to peak energy needs.[202] In addition, natural gas power plants emit about one-half of the carbon dioxide that coal plants emit and will therefore serve as an acceptable transitional energy source in a carbon-constrained world.[203] However, as mentioned above, natural gas prices are extremely volatile and will likely become even more volatile as more countries increase their use of natural gas.[204] Therefore, while natural gas will ease the transition away from traditional coal, it will likely not become a dominant energy source for the future.

The fate of nuclear energy remains unclear. Despite claims of a nuclear renaissance and efforts of Congress and the Nuclear Regulatory Commission (NRC) to develop more incentives for nuclear power, nuclear plant construction costs remain prohibitively high.[205] As Professor Tomain has argued, nuclear energy seems unlikely to ever be competitive on its own, and it will require continued subsidies, liability waivers, and tax breaks for it to gain more market share within the electricity sector.[206] Even if Congress continues to support the nuclear industry with these incentives – as it seems likely to do – the nuclear industry will still need to address other unresolved problems, including the public perception that nuclear energy is unsafe and uncertainty about waste disposal.[207] Even then, utilities seeking to build new plants will need to convince PUCs to authorize the construction. After the experience with nuclear plants in the 1970s and 1980s, and the de facto moratorium on new plant development since 1979, utilities may have a difficult time making the case for more

201. PODESTA & WIRTH, *supra* note 22; *see also* ENERGY INFO. ADMIN., ANNUAL ENERGY OUTLOOK 2009, 72 (2009) [hereinafter ANNUAL ENERGY OUTLOOK 2009], *available at* http://www.eia.doe.gov/oiaf/aeo/pdf/0383(2009).pdf (showing that the amount of coal-fired plants to be added between 2009 and 2025 will continue to decrease each year).

202. ANNUAL ENERGY OUTLOOK 2009, *supra* note 201, at 72.

203. PODESTA & WIRTH, *supra* note 22, at 1.

204. ANNUAL ENERGY OUTLOOK 2009, *supra* note 201, at 72 (noting that high oil prices may lead to fewer natural gas plants due to price increases); *see also supra* note 23 and accompanying text (describing the positive correlation between natural gas and oil prices and indicating the volatility of the price of both fuels).

205. *See* Sovacool & Cooper, *supra* note 198, at 28-29 (providing estimates that nuclear plants will cost between $8 billion and $14 billion each to construct); ANNUAL ENERGY OUTLOOK 2009, *supra* note 201, at 73 (noting that new nuclear plants will not be economical during a period of low economic growth).

206. Tomain, *supra* note 70, at 238-43.

207. Sovacool & Cooper, *supra* note 198, at 35-38.

nuclear facilities.[208]

This leaves renewable energy sources, which have their own flaws but also great potential. Indeed, if PUCs continue to reject new coal plants and resist new nuclear facilities, a window of opportunity could open for renewable energy sources to finally enable them to compete on a fairer level with coal, natural gas, and nuclear energy.

Thus far, most utilities have either sought to employ relatively discrete policies, such as net metering laws,[209] to incentivize limited, small-scale construction of renewable energy sources by private land owners or to build their own larger base load plants in relatively remote areas of the country.[210] The first strategy, promotion of small-scale distributed generation, is good but has limited potential because it relies on home and building owners to purchase and install their own renewable energy systems.[211] The second strategy similarly has promise, but licensing procedures and efforts to connect remote wind and solar farms to the interstate transmission grid are time-consuming and costly.[212] In addition, large solar installations have been proposed in sensitive desert habitats,[213] and it will likely take a considerable period of time for these large arrays to

208. *See Progress Energy Takes Turn Before the PSC*, THE JACKSONVILLE OBSERVER, Sept. 23, 2009, http://www.jaxobserver.com/2009/09/23/progress-energy-takes-turn-before-the-psc/ (describing the likely hurdles a Florida utility will face in order to receive a $500 million rate increase necessary to fund investment in a proposed nuclear power plant).

209. Net metering laws repay consumers for any electricity they produce from their own, usually small-scale, renewable energy sources. *See* Steven Ferrey, *Power Paradox: The Algorithm of Carbon and International Development*, 19 STAN. L. & POL'Y REV. 510, 540 (2008) (describing how under net metering systems, customers exchange power they produce and sell with power that they take from the utility).

210. *See* Joseph Romm, Biggest CA Utility Contracts for World's Biggest Solar Deal – 1300 MW Solar Thermal, ClimateProgress.org, Feb. 11, 2009, http://climateprogress.org/2009/02/11/southern-california-edison-sce-brightsource-biggest-csp-concentrated-solar-thermal-power/ (examining a new solar power contract between Southern California Edison and BrightSource Energy, Inc., which will create new solar power plants totaling 1,300 megawatts of concentrated solar-thermal power).

211. *See* Craig Morris & Nathan Hopkins, *Home-Grown Juice*, WORLD WATCH, May-June 2008, at 20, 23-24 (arguing that feed-in-tariffs, which guarantee small-scale energy producers a rate of return above the cost of energy production, would better serve the renewable energy market).

212. *See* Kelsey Jae Nunez, *Gridlock on the Road to Renewable Energy Development: A Discussion about the Opportunities & Risks Presented by the Modernization Requirements of the Electricity Transmission Network*, 1 J. BUS. ENTREPRENEURSHIP & L. 137 (2007) (recognizing that while the United States strongly needs to develop more sources of renewable and clean energy, it will be very costly and that utilities, taxpayers who are energy-users, and power generators all need to bear the costs of the upgrade).

213. *See* Colin Sullivan, *RFK Jr., Enviros Clash Over Mojave Solar Proposal*, NY TIMES, Sept. 9, 2009, http://www.nytimes.com/gwire/2009/09/08/08greenwire-rfk-jr-enviros-clash-over-mojave-solar-proposa-98645.html (examining a dispute in California over the proposed building of large solar-thermal power plants in the Mojave Desert).

come on line, if they ever do.[214] Finally, subsidies awarded to the fossil fuel industries outnumber subsidies to the renewable energy sector by orders of magnitude.[215] This disparity has delayed some technological improvements in the renewable energy sector and kept it from gaining a more significant market share.[216]

However, a decline in coal may open new opportunities for the renewable energy sector and create new incentives for regulated utilities to invest in renewable energy. The traditional electricity regulatory model already provides some of these incentives, since it allows utilities to profit from their capital investments.[217] If utilities know that they will no longer receive approval for new coal plants, they may seek to increase their profits by turning to renewable energy sources. And unlike the case with nuclear plants, construction costs for most renewable energy sources are comparatively low and thus not likely to face the same opposition as nuclear energy.[218] The traditional electricity regulatory model could also spur utilities to build their own forms of distributed generation and recover the costs of construction and installation in their rate base. For example, in urban areas, instead of encouraging ratepayers to install privately owned photovoltaic cells on their roofs, utilities could perform the installation and retain ownership of the solar array, while providing the ratepayer a discounted electricity rate in exchange for allowing the utility to site the solar array on the ratepayer's roof.[219] If the utility could recover expenses

214. *See* Bureau of Land Management, BLM Initiates Environmental Analysis of Solar Energy Development (May 29, 2008, updated June 12, 2008), http://www.blm.gov/wo/st/en/info/newsroom/2008/may_08/NR_053008.html (announcing a process for developing an Environmental Impact Statement for 125 proposals to build solar energy on public lands).

215. *See* Mona Hymel, *The United States' Experience with Energy-Based Tax Incentives: The Evidence Supporting Tax Incentives for Renewable Energy*, 38 LOY. U. CHI. L.J. 43 (2006) (acknowledging that while over the past 30 years Congress has enacted subsidies through tax incentives to encourage the development of renewable energy, historically the fossil fuel industry has been the only recipient of these incentives).

216. *Id.* at 74-75.

217. *See supra* notes 50 to 53 and accompanying text.

218. ANNUAL ENERGY OUTLOOK 2009, *supra* note 201, at 74-75. Indeed, the Energy Information Administration predicts growth in the renewable energy industry even if construction costs remain high. *Id.* at 75.

219. Companies in the United States already rent solar arrays to homeowners in various states. Alano Herro, *U.S. Homeowners Can Now "Rent" Solar Panels, Saving Money*, WORLDWATCH INSTITUTE, Jan. 10, 2007, http://www.worldwatch.org/node/4828. The companies can take advantage of net metering laws and thus earn money both through rental income and any repayment the customer would receive under the net metering laws. Utilities arguably lose out under these net metering and rental agreements, because they cannot profit from the solar investment. *See* Posting of Jennifer Kho, Rooftop Solar Setback in California, to Green Inc., Energy, the Environment and the Bottom Line, NY Times.com, http://greeninc.blogs.nytimes.com/2009/09/18/rooftop-solar-setback-in-california/ (Sept. 18, 2009, 09:17) (discussing utility company opposition to net metering of homeowner solar

associated with the installation and construction of the infrastructure necessary to implement the distributed generation system, it would have ample incentives to revolutionize the electricity system. Because the technology to develop distributed generation already exists,[220] utilities could undertake the process almost immediately. As electricity storage and other renewable energy generation technologies improve, the utility could make upgrades to its system where necessary. In the near term, distributed generation and energy conservation efforts could supply adequate electricity to replace any lost electricity from rejected coal plants.[221] In the more distant future, as renewable energy technologies advance, renewable energy sources could begin to replace existing coal plants and augur a transition to a clean energy economy.[222]

While these ideas may seem overly optimistic, there is little reason why they cannot become reality.[223] For the past seventy or so years, the abundance, reliability, and, above all, cheapness of coal has allowed it to dominate over all other electricity sources. Now that PUCs have begun to reject the idea that coal is cheap, it may well be time for renewable energy sources to dominate the electricity sector.

power). However, if utilities owned the solar arrays, they could arguably recover the cost of purchasing the solar arrays in their rate base while incentivizing installation of the panels through net metering laws or other incentives.

220. *See* Herro, *supra* note 219 (discussing solar arrays); *see also* Sovacool & Cooper, *supra* note 198, at 103-04 (discussing available technologies).

221. *See* Richard J. Lazarus, *Super Wicked Problems and Climate Change: Restraining the Present to Liberate the Future*, 94 CORNELL L. REV. 1153, 1192 (2009) (noting that energy conservation could reduce greenhouse gas emissions by 60 percent in the near-term); *see also* Michael P. Vandenbergh & Anne C. Steinemann, *The Carbon-Neutral Individual*, 82 N.Y.U. L. REV. 1673, 1699-1703 (2007) (explaining that 37 percent of individual emissions result from appliance use and identifying easy measures to reduce energy consumption).

222. *See* ANNUAL ENERGY OUTLOOK 2009, *supra* note 201, at 74-75 (describing a scenario where renewable energy costs continue to decline, resulting in rapid capacity growth).

223. The specific strategies necessary to develop a robust distributed generation system that utilities would embrace are beyond the scope of this article. In a different article, I intend to examine why utilities have not yet invested significantly in distributed generation. That article will also explore whether new energy legislation and potential climate change regulation will provide utilities with incentives to pursue distributed generation over large-scale renewable energy projects. While these policy questions merit much more review, it is nonetheless fair to say that distributed generation provides many opportunities for utilities to transition away from fossil fuels and toward renewable energy sources.