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THE ENVIRONMENTAL IMPACTS OF ELECTRICITY RESTRUCTURING: LOOKING BACK AND LOOKING FORWARD

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I. INTRODUCTION

In the mid-1990s, when the Federal Energy Regulatory Commission (FERC) was preparing to release Order 888[1] requiring open access to the transmission grid, FERC, environmental groups, the Environmental Protection Agency (EPA), and others raised the question of how open access and greater competition in wholesale electricity markets might affect the environment. If open access worked as expected, underutilized, older coal-fired generators in the Midwest and elsewhere might open new markets for their power, which would lead to associated increases in air pollution emissions.

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1. Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, 18 C.F.R. § 35.15, §§ 35.26–.28, and § 385.2001 (2005), 75 F.E.R.C. ¶ 61,080 (Apr. 24, 1996), *available at* http://www.ferc.gov/legal/maj-ord-reg/land-docs/order888.asp (last visited Sept. 29, 2005) [hereinafter Order 888].

Restructuring might also lead to the retirement of inefficient nuclear facilities. If replaced by fossil generation, emissions would further increase. On the other hand, some suggested that in the long run the anticipated increase in investment in new gas-fired generators might accelerate a switch from coal to gas that could cause emission reductions. Lastly, if restructuring produced the desired result of lower electricity prices, many observers suggested that an increase in electricity demand would lead to greater generation and emissions.

In addition to potential direct effects on emissions from electricity generators, electricity restructuring could also contribute to changes in the effectiveness and costs of environmental policies. Incentives for regulatory compliance, particularly flexible incentive-based regulations, will vary depending on whether or not an electricity supplier is subject to price regulation. Because the country is currently divided between states that are restructured and those that are not, variations across these states in the effect of regulations such as pollution cap-and-trade approaches on electricity prices could have important implications for the political economy of new environmental initiatives facing the electricity sector.

This article discusses all of these important issues. Following a brief summary of the major policy initiatives related to electricity restructuring at both the wholesale and retail levels, this article reviews the prior literature on how electricity restructuring was expected to affect emissions from the electricity sector. The article then compares the actual experience of restructuring to prior expectations and, where possible, draws conclusions about likely effects on the environment. Changes in upstream fuel markets, energy policy, and environmental regulations are discussed with respect to the role that each plays in the efforts to evaluate the environmental effects of restructuring. Today, the movement toward restructuring has stalled, leaving the country divided into competitive and regulated regions. This article looks forward and discusses the implications of this division for the future of environmental policy and the complicated relationships between the policy agendas concerning mitigation of climate change and further restructuring of the electricity industry.

II. OVERVIEW OF ELECTRICITY RESTRUCTURING

It is difficult to pinpoint when the restructuring of U.S. electricity markets began. Some have argued that a major milestone in the process of electricity restructuring was the passage of the Public Utilities Regulatory Policies Act of 1978,[2] which included the requirement that regulated utilities purchase electricity from certain types of renewable generators and other so-called "qualifying facilities" at prices that were at or below the avoided cost of generating that electricity internally.[3] The importance of the provision as a precursor to restructuring is that it offered the first significant departure from the legitimate monopoly franchise of electricity generation by regulated utilities. The practical implications of this provision varied across the states. For example, in states where the avoided cost of generation was set during periods of high fuel costs, a number of qualifying facilities were constructed and utilities began acquiring power from these independent generators in earnest. Contrary to prior fears about the loss of coordination associated with separating the ownership of generation from the ownership of utilities, the integration of purchased power into the mix of generation supplied by the vertically integrated utilities generally worked well. The success of this power purchasing activity, albeit sometimes at prices that turned out to be too high by market standards, demonstrated that separating generation from the power delivery system could work.

During the 1990s, the Energy Policy Act of 1992 was the major impetus for subsequent FERC orders requiring transmission-owning utilities regulated by FERC to provide open and nondiscriminatory access to their transmission lines to facilitate wholesale power transactions.[4] Open transmission access is a necessary condition for competing generators to get their power to either wholesale or retail customers. FERC implemented this law in a series of three regulatory orders. Orders 888 and 889, issued in 1996, set forth the rules defining and governing open transmission access and the requirement for a centralized electronic bulletin board for sharing information about transmission availability and cost with potential customers.[5] Order 2000, issued in 1999, built upon Order 888 by

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2. Public Utilities Regulatory Policies Act of 1978, 16 U.S.C. §§ 2601–45 (2005).

3. *See* TIMOTHY BRENNAN, KAREN PALMER & DALLAS BURTRAW ET AL., A SHOCK TO THE SYSTEM: RESTRUCTURING AMERICA'S ELECTRICITY INDUSTRY (Resources for the Future, 1996).

4. Energy Policy Act of 1992, Pub. L. No. 102-486, 106 Stat. 2776 (codified in scattered sections of 16 and 42 U.S.C.). For a discussion of the Environmental Policy Act's substantive content, see Bernard Black & Richard J. Pierce, *The Choice Between Markets and Central Planning in Regulating the U.S. Electricity Industry*, 93 COLUM. L. REV. 1339 (1993); *and* Jeffrey Watkins & Douglas Smith, *The Energy Policy Act of 1992 – A Watershed for Competition in the Wholesale Power Market*, 10 YALE J. ON REG. 447 (1993).

5. Order 888, *supra* note 1; Open Access Same-Time Information Systems, 18 C.F.R. § 37 (2005), 75 F.E.R.C. ¶ 61,078 (Apr. 24, 1996), *available at* http://www.ferc.gov/

requiring utilities to actively consider participating in a Regional Transmission Organization (RTO), an independent entity that would operate the transmission grid and seek to prevent discrimination by the transmission owner against competing electricity generators.[6] The structure and rules of any RTO (except the one in Texas, which is outside FERC jurisdiction) are subject to FERC approval and oversight.

Despite these FERC rulings, utilities in several states including those in the Southeast do not yet participate in an RTO, and wholesale competition in these areas is still more of an aspiration than a reality.[7]

At the same time that FERC was paving the way for more effective wholesale competition, several states were actively seeking ways to provide real choice of electricity supplier to retail customers.[8] The push for retail competition started in those states where prices were relatively high, including California, New York, and Massachusetts.[9] Competition was seen as a means of lowering prices. In both California and Massachusetts, retail competition was enabled by legislation and took effect in 1998.[10] In New York, retail competition was implemented through separate agreements between the state utility regulator and individual utilities. Pennsylvania started to allow competition in 1999, and it was phased in to include all classes of customers by January of 2001. Texas passed a law in 1999 that required retail competition to begin in 2002.[11] In all of these

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legal/maj-ord-reg/land-docs/order889.asp (last visited Sept. 29, 2005) [hereinafter Order 889].

6. Regional Transmission Organizations, 18 C.F.R. § 35.34 (2005), 89 F.E.R.C. ¶ 61,285 (Dec. 20, 1999) *available at* http://www.ferc.gov/legal/maj-ord-reg/land-docs/RM99-2A.pdf (last visited Mar. 5, 2005) [hereinafter Order 2000].

7. *See* ENERGY INFO. ADMIN., STATUS OF STATE ELECTRIC INDUSTRY RESTRUCTURING ACTIVITY–AS OF FEBRUARY 2003, *available at* http://www.eia.doe.gov/cneaf/electricity/chg_str/restructure.pdf.

8. Although retail restructuring in practice has been a state jurisdictional issue, during the Clinton Administration there was an effort to make retail competition a national policy. THE COMPREHENSIVE ELECTRICITY COMPETITION ACT introduced by Senator Murkowski in 1999, would have required all states either to adopt retail competition by January 2003 or formally and publicly demonstrate why this would not be a wise policy in their state. S. 1047, 106th Cong. (1999). This proposal was a creation of the Clinton Administration and it died when that administration left office.

9. For a discussion of the factors that lead states to be early movers on electricity restructuring, see AMY W. ANDO & KAREN L. PALMER, GETTING ON THE MAP: THE POLITICAL ECONOMY OF STATE-LEVEL ELECTRICITY RESTRUCTURING (Resources for the Futures, Discussion Paper 98-19-REV, May 1998), *available at* http://www.rff.org/Documents/RFF-DP-98-19-REV.pdf.

10. CAL. PUB. UTIL. CODE §§ 328, 330–99 (West 2005); MASS. GEN. LAWS. ch. 164 § 1A (2005).

11. TEX. UTIL. CODE ANN. §§ 11.001–64.158 (Vernon 1998 & Supp. 2003).

states, except Pennsylvania and Texas, the restructuring legislation or regulation required a substantial fraction of electricity generation previously owned by integrated utilities to be sold to independent merchant generators. In Texas, only fifteen percent of existing capacity had to be sold.[12]

During the debates over electricity restructuring, existing utilities showed an interest in being able to recover the sunk costs, commonly called "stranded costs," of past utility investments that might not be profitable in competitive markets. Utilities argued that because they had often made these investments at the behest of regulators and typically with their approval, it would be unfair for their shareholders to have to bear the costs due to a policy change. Compensating utilities for the vast majority of their stranded costs proved key to moving restructuring forward. In New Hampshire, one of the first restructuring laws was passed in 1996 and then stalled in court for several years because it allowed for only partial recovery of stranded costs.[13] To facilitate stranded cost recovery, states typically imposed a nonbypassable charge on electricity distribution service that applied to all customers. Mechanisms for cost recovery were typically temporary and were eliminated once stranded costs were recovered. In many cases, these costs were actually recovered more quickly than initially anticipated due to a combination of high sales prices obtained for divested generating assets and higher than expected wholesale electricity prices.

During the transition period between price regulation and open competition, regulators set retail price caps or default service rates to protect customers from high prices and to provide a backup source of electricity should a competitive provider go out of business or decide to leave the market. The prices for these transition services were typically lower than the regulated electricity price prior to restructuring. In some cases this default service price proved too low to cover the wholesale market price of generation, which in many cases exceeded expectations due to higher fuel prices.

By the end of 2001, seventeen states plus the District of Columbia had passed laws or regulations introducing retail competition to their electricity markets and most were well on their way to implementing these changes.[14] Missing from this set

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12. TEX. UTIL. CODE ANN. § 39.153 (Vernon 2004).

13. N.H. REV. STAT. ANN. § 374-F:1-4 (1998). *See In re* New Hampshire P.U.C. Statewide Elec. Util. Restructuring Plan, 722 A.2d 483 (N.H. 1998).

14. ENERGY INFO. ADMIN., *supra* note 7, at 1.

of seventeen states was California, one of the first states to introduce restructuring.[15] After a summer of high prices and rolling blackouts in 2000 and widespread anticipation of more blackouts in the summer of 2001, the California Public Utility Commission of California declared an end to retail choice in September of 2001.[16] As Brennan points out, many factors contributed to the problems experienced in 2000, but much of the blame has been laid at the door of electricity restructuring and the problems with specific design features of the California energy market.[17]

The failure of the California market has helped stall enthusiasm for electricity restructuring in other states. Since 2001, no additional states have adopted restructuring, and plans to advance restructuring in states like Oklahoma and West Virginia were put on indefinite hold.[18] Thus, the United States remains a country divided between those seventeen states plus the District of Columbia that have retail choice and the remaining thirty-three that do not.[19]

III. EX ANTE PREDICTIONS OF THE ENVIRONMENTAL EFFECTS OF RESTRUCTURING

In the mid-1990s, as the rules for wholesale restructuring were taking shape at FERC, and some states were charting the course for retail electricity restructuring within their boundaries, there was much interest in assessing the potential environmental effects of these major regulatory changes. Most of the interest focused on how restructuring might impact air pollution. Electricity generation accounts for sixty-eight percent of the nation's emissions of sulfur dioxide (SO_2), which contributes to acid rain, particulate pollution, and reduced visibility in national parks.[20] Electricity generation also contributes twenty-five percent of the nation's nitrogen oxides (NOx), which has effects similar to SO_2 and additionally is a precursor of atmospheric

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15. Oregon passed a law in 2000 requiring customer choice for all industrial and commercial customers, but not for residential customers. For more information, *see id*.

16. Cal. Pub. Util. Comm'n, Decision 01-09-060 2 (Sept. 20, 2001), *available at* http://www.cpuc.ca.gov/word_pdf/FINAL_DECISION//9812.pdf.

17. TIMOTHY J. BRENNAN, THE CALIFORNIA ELECTRICITY EXPERIENCE, 2000–2001: EDUCATION OR DIVERSION (Resources for the Future, Oct. 2001), *available at* http://www.rff.org/rff/Documents/RFF-RPT-calielect.pdf.

18. ENERGY INFO. ADMIN., *supra* note 7, at 3–5.

19. *Id.*

20. U.S. ENVTL. PROT. AGENCY, NATIONAL AIR POLLUTANT EMISSIONS TRENDS: 1990–1998, ch. 2-2 (Mar. 2000), *available at* http://www.epa.gov/ttn/chief/trends/trends98/index.html (last visited Sept. 29, 2005).

ozone.[21] Electricity generation also results in about forty percent of the nation's emissions of mercury, a hazardous air pollutant that accumulates in the food supply and contributes to neurological disorders in children. Finally, power generation is also responsible for thirty-six percent of all U.S. emissions of carbon dioxide (CO_2), one of the most important greenhouse gases.[22]

The relationship between electricity restructuring and emissions of air pollutants depends on multiple factors that may have countervailing influences.[23] These factors can be classified into two groups: supply-side and demand-side influences. Most analyses of the potential effects of restructuring have tended to focus on a limited number of selected factors while a few studies have attempted to analyze all factors combined. The next two sections review what the literature claimed about the likely effects of these factors on the environment as the process of restructuring was beginning. A subsequent section discusses what post-restructuring experience suggests about the effects of restructuring on the roles of different technologies and fuels and on the size and shape of the overall electricity market.

A. Supply-Side Factors

1. Effects on Trade and Utilization of Older Coal-Fired Facilities. Before issuing the final versions of both Orders 888 and 889 in 1996 and Order 2000 in 1999,[24] FERC undertook environmental impact studies to analyze how greater opportunities for interregional electricity trade under these rules might affect air emissions from electricity generators.[25] During the debate over these regulatory rules, environmentalists raised concerns that emissions from the electricity sector might rise with open transmission access.[26] By providing greater access to

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21. *Id*.

22. *Id.* ch. 8-3.2.

23. For more discussion of the many ways that electricity restructuring could affect air emissions from the electricity sector, *see* Karen Palmer, *Electricity Restructuring: Environmental Impacts*, F. FOR APPLIED RES. & PUB. POL'Y, Fall 1997, at 28–33; TIMOTHY BRENNAN, KAREN PALMER & DALLAS BURTRAW ET AL., A SHOCK TO THE SYSTEM: RESTRUCTURING AMERICA'S ELECTRICITY INDUSTRY (RFF Press 1996).

24. Order 888, *supra* note 1; Order 889, *supra* note 5.

25. Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities; Availability of Final Environmental Impact Statement, 61 Fed. Reg. 17,263 (Apr. 19, 1996), 75 F.E.R.C. ¶ 61,208 (May 29, 1996), *available at* http://www.ferc.gov/legal/maj-ord-reg/land-docs/environmental.pdf.

26. *See generally* RICHARD ROSEN ET AL., NAT'L ASS'N OF REGULATORY UTIL.

markets in the east, the open access rules might cause older and under-utilized coal-fired generators in the Ohio Valley, most of which were built before implementation of new source performance standards under the 1970 Clean Air Act, to increase their generation and thus increase their emissions of NOx, SO_2, mercury, and CO_2.[27] This possibility led some to suggest that the open access rules should be accompanied by additional regulations to mitigate potential emissions increases.[28]

Analyses and simulation studies suggested a range of possible impacts of electricity restructuring on the role of coal-fired generation and emissions.[29] These studies focused largely on emissions of NOx and CO_2, because emissions of SO_2 are capped under Title IV of the Clean Air Act Amendments of 1990.[30] Additionally, monitoring of mercury emissions in the 1990s was uncertain.[31] Several studies found potentially large effects from increased interregional power trading on coal plant utilization and emissions of NOx and CO_2.[32] In two analyses of the proposed environmental impacts of its two transmission orders, FERC found a much more limited effect of increased power trading on air emissions.[33] The Energy Information Administration also found that open transmission access increased NOx emissions minimally, by one to three percent above the baseline scenario, with the largest effects in the early years.[34] Palmer and Burtraw

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COMM'RS, PROMOTING ENVIRONMENTAL QUALITY IN A RESTRUCTURED ELECTRIC INDUSTRY (1995).

27. *Id.* at 15–16.

28. *See generally id.*

29. *See* 42 U.S.C. §§ 7651–7651e (2005)

30. *Id*.

31. In 1997, the Environmental Protection Agency issued its first report to Congress on the effects of mercury in the environment. U.S. ENVTL. PROT. AGENCY, MERCURY STUDY REPORT TO CONGRESS (1997), *available at* http://www.epa.gov/mercury/report.htm (last visited Oct. 1, 2005).

32. Henry Lee & Darani Negeen, *Electricity Restructuring and the Environment*, ELEC. J., Dec. 1996, at 10; CENTER FOR CLEAN AIR POLICY, COMMENTS OF THE CENTER FOR CLEAN AIR POLICY ON THE DRAFT ENVIRONMENTAL IMPACT STATEMENT ON OPEN ACCESS FOR TRANSMISSION SERVICE (1996); CENTER FOR CLEAN AIR POLICY, EMISSION IMPACTS OF INCREASED ENERGY EXPORTS FROM THE AMERICAN ELECTRIC POWER (AEP) SYSTEM (1996); CENTER FOR CLEAN AIR POLICY, EMISSIONS IMPACTS OF COMPETITION FURTHER ANALYSIS IN CONSIDERATION OF PUTNAM, HAYES AND BARTLETT, INC.'S CRITIQUE, (1996); *see also* ROSEN ET AL. *supra* note 26.

33. FED. ENERGY REGULATORY COMM'N, PROMOTING WHOLESALE COMPETITION THROUGH OPEN ACCESS NON-DISCRIMINATORY TRANSMISSION SERVICES BY PUBLIC UTILITIES (RM95-8-000) AND RECOVERY OF STRANDED COSTS BY PUBLIC UTILITIES AND TRANSMITTING UTILITIES (RM94-7-001). FERC/EIS-0096 (1996).

34. ENERGY INFO. ADMIN., AN ANALYSIS OF FERC'S FINAL ENVIRONMENTAL IMPACT STATEMENT FOR ELECTRICITY OPEN ACCESS AND RECOVERY OF STRANDED COST (1996) (*prepared for* Senator James Jeffords, Vice Chair, Subcommittee on Energy Production and Regulation, Senate Energy and Natural Resources Committee, U.S. Senate).

found emission increases roughly in the middle of the range projected by other studies.[35]

One of the reasons for the differences between the findings of the government studies of the FERC orders and the other studies is the difference in scope. The studies of the FERC rules focused on the narrow question of how the rule was likely to affect emissions and assumed no change in final demand for electricity and no change in transmission capacity.[36] The other studies took a broader perspective and looked beyond the effects of the open access orders to the effects of restructuring at both the wholesale and retail levels, finding more significant effects of restructuring on the use of coal-fired power plants and thus on emissions.[37]

A key factor in predictions about the likely effects of restructuring on emissions of NOx is the underlying assumptions about NOx regulations. Virtually all of the studies done prior to the open access rules did not anticipate the role of the seasonal cap on summertime NOx emissions created as a result of the Ozone Transport Region NOx Budget cap-and-trade program that began in 1999, and the subsequent much larger NOx SIP Call cap-and-trade program that created a five-month summertime cap on NOx emissions from electricity generators in a twenty-eight state region in the eastern United States.[38] The SIP Call program ultimately came into force the summer of 2004.[39] Palmer and co-authors conducted a simulation study that looked at the effects on emissions in 2008 of moving from a position where roughly one-third of the country has restructured electricity markets to a position where all of the retail electricity markets in the country are restructured.[40] The Authors found that, in the absence of the NOx SIP Call, coal-fired generation in the NOx SIP region would rise by fourteen percent and total emissions of NOx and CO_2 would rise by twelve percent and two percent respectively.[41] When the NOx SIP Call was imposed in both the baseline and national restructuring scenarios, the increase in NOx emissions in the region fell by roughly half.[42]

35. Karen Palmer & Dallas Burtraw, *Electricity Restructuring and Regional Air Pollution*, 19 RESOURCE & ENERGY ECON. 139–74 (1997).

36. *See, e.g.*, *supra* note 33.

37. *See, e.g.*, *supra* note 32.

38. U.S. ENVTL. PROT. AGENCY, NOX BUDGET & TRADING PROGRAM: 2003 PROGRESS & COMPLIANCE REPORT 2 (2004).

39. *Id*.

40. KAREN PALMER ET AL., ELECTRICITY RESTRUCTURING, ENVIRONMENTAL POLICY, & EMISSIONS (Resources for the Future, 2002), *available at* http://www.rff.org/Documents/RFF-RPT-elecrestruct.pdf.

41. *Id.* at 26.

42. *Id*. at 34.

Moreover, when the seasonal restrictions on NOx emissions under the NOx SIP Call were modeled as year-round (as they would be under a recently adopted regulation), the increase in NOx emissions resulting from restructuring virtually disappeared.[43]

2. Effects of Investment in Natural Gas Generation. In the mid-1990s, natural gas-fired generation accounted for roughly thirteen percent of total electricity generation in the United States.[44] Natural gas and dual-fueled capacity (capacity that could burn either natural gas or coal) accounted for almost twenty-five percent of total capacity.[45] This difference in generation and capacity shares is attributable to the fact that existing gas-fired generators were used primarily to meet peak loads and thus had low capacity factors.[46]

An important objective of restructuring was the creation of competitive wholesale electricity markets with open access for all generators, including independent power producers.[47] Many observers expected that by reducing or eliminating transmission barriers, restructuring might hasten the introduction of new gas generation built by independent power companies. In this way, restructuring might result in a switch away from coal-fired electricity generators and toward natural gas.[48] Regulators exhibited some risk aversion with regard to potentially volatile natural gas prices and the possible effect of that volatility on electricity prices if the natural gas share of generation

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43. Rule to Reduce Interstate Transport of Fine Particulate Matter and Ozone (Clean Air Interstate Rule); Revisions to Acid Rain Program; Revisions to the NOx SIP Call (proposed Mar. 10, 2005) (to be codified at 40 C.F.R. pts. 51, 72, 73, 74, 77, 78 and 96), *available at* http://www.epa.gov/CAIR/pdfs/cair_final_preamble.pdf; *see also* Clear Skies Act of 2005, S.131, 109th Cong. (2005) (sponsored by Sen. Inhofe [OK]); Clean Power Act of 2003, S. 150, 109th Cong. (2005) (sponsored by Sen. Jeffords [VT]); Clean Air Planning Act of 2003, S. 843, 108th Cong. (2003) (sponsored by Sen. Carper [DE]).

44. ENERGY INFO. ADMIN., U.S. NATURAL GAS MARKETS: RECENT TRENDS AND PROSPECTS FOR THE FUTURE, 6–7 (2001), *available at* http://www.eia.doe.gov/oiaf/servicerpt/naturalgas/pdf/oiaf00102.pdf.

45. ENERGY INFO. ADMIN., HISTORICAL SPREADSHEETS (1990-PRESENT), *available at* http://www.eia.doe.gov/cneaf/electricity/epa/epa_sprdshts.html (last visited Apr. 29, 2005).

46. A capacity factor is the ratio of the amount of electricity generated at a facility during a year to the total amount of electricity that could be generated if the facility were run at full summertime capacity one-hundred percent of the time.

47. *See 1978 to 1998: FERC Calls Utilities to Deregulate, Restructure*, Jeff Hein (CLOSED CIRCUIT), Nov. 21, 2003, *available at* http://www.wapa.gov/newsroom/cct/2003/nov21/25no246.htm (last visited Oct. 1, 2005) (explaining FERC Order 888 and 889).

48. *See, e.g.*, *supra* note 2; *see also* Shi-Ling Hsu, *Reducing Emissions From the Electricity Generation Industry: Can We Finally Do it?*, 14 TUL. ENVTL. L.J. 427, 433-34 (Summer 2001) (*citing* ENERGY INFO. ADMIN., U.S. DEP'T OF ENERGY, ANNUAL OUTLOOK 2001, at 4, 29, 32 (Dec. 2000), *at* http://tonto.eia.doe.gov/FTPROOT/forecasting/0383(2001).pdf.

increased.[49] Indeed, in England electricity restructuring was accompanied by a large switch away from coal and toward natural gas as the fuel of choice.[50] However, in England the move to competitive electricity markets was accompanied by a deregulation of coal prices and a subsequent rise in coal prices that made gas generation more attractive, independent of the changes in electricity markets.[51]

The anticipated transition from coal to gas was not expected to be instantaneous, but rather to happen over time, with increases in coal-fired generation and associated emissions predicted as a short-term result. Acceleration of the introduction of new gas facilities into the generation mix was forecasted to lead to a mid-term to longer-run negative effect on emissions of uncapped pollutants, including NOx, mercury, and CO_2.[52] The emissions per unit of electricity generation differ significantly between coal- and gas-fired electricity generation, and especially between existing coal and new combined-cycle natural gas units.[53] Gas-fired generation results in no emissions of mercury and SO_2, and emissions of NOx that are about twenty percent of those of an existing coal plant without post-combustion controls.[54] A gas-fired facility produces CO_2 emissions that are about thirty-eight percent of those of an existing, relatively efficient coal facility.[55]

3. Nuclear. Nuclear power contributes roughly twenty percent of total U.S. electricity generation, making it the second

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49. Renz Jennings*, Foreword to* JAN HAMRIN ET AL., NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS, AFFECTED WITH THE PUBLIC INTEREST: ELECTRIC INDUSTRY RESTRUCTURING IN AN ERA OF COMPETITION, at v (1994).

50. BRENNAN, PALMER & BURTRAW ET AL., *supra* note 23.

51. *Id*.

52. David B. Spence, *Coal-Fired Power in a Restructured Electricity Market*, 15 DUKE ENVTL. L. & POL'Y J. 187 (Spring 2005).

53. ENERGY INFO. ADMIN., NATURAL GAS ISSUES AND TRENDS (1998) *at* http://www.naturalgas.org/environment/naturalgas.asp#emission. Emission levels are in pounds per billion Btu of energy input. Emission rates per megawatt hour of electricity generation will reflect generally lower heat rates (BTUs of heat input per megawatt of electricity) for natural gas generation.

Pollutant	Natural Gas	Coal
Carbon Dioxide	117,000	208,000
Nitrogen Oxides	92	457
Mercury	0.000	0.016
Sulfur Dioxide	1	1,122

54. *Id*.

55. *Id*.

largest source of electricity supply.[56] Nuclear plants have no emissions of conventional air pollutants and do not emit CO_2 or other greenhouse gases. They are thus considered relatively clean from a traditional air pollution perspective.[57] In the mid-1990s electricity restructuring was expected to hasten the retirement of a sizable fraction of existing nuclear capacity in the United States because of the anticipated inability of these plants to compete at market-determined prices for electricity. The high cost of meeting Nuclear Regulatory Commission (NRC) safety requirements and the relatively poor performance of several nuclear plants that spent many months off-line for various reasons suggested that nuclear plants would not be able to cover their operating and future capital costs at market prices. As a result they were expected to retire before the expiration of their operating licenses. These retirements would not occur under cost-of-service regulation because such regulation allows generators to recover all of their costs in electric rates.

Estimates of the amount of annual nuclear generation that might be lost to early retirement have covered quite a range. Rothwell estimated that as many as thirty-three nuclear generating units, roughly one third of the total fleet, were at risk of retiring early.[58] Most of these retirements were expected to occur in regions with predicted low system-wide marginal costs of generation and thus low expected competitive prices.[59] This early retirement of nuclear capacity would have meant a loss of up to 200 terawatt-hours of generation in 2005 or thirty percent of total nuclear generation predicted for 2005 under average cost price regulation.[60] This potential drop in generation would be associated with a substantial increase in CO_2 emissions because fossil fuel generators would be run more intensively and new units brought on line to replace the lost generation.

These ex ante estimates of potential nuclear plant retirements assumed that the costs and performance of existing

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56. ENERGY INFO. ADMIN., U.S. NUCLEAR GENERATION OF ELECTRICITY, tbl. 8.1 (Mar. 2005), *available at* http://www.eia.doe.gov/cneaf/nuclear/page/nuc_generation/gensum.html (last visited Apr. 15, 2005).

57. Fuel processing and transportation leads to small emissions of CO_2. Nuclear generators do emit small amounts of radionuclides into the atmosphere and the production of nuclear power raises a major challenge of how to manage the high-level radioactive waste produced by these plants that will remain dangerous for centuries to come.

58. Geoffrey Rothwell, *The Risk of Early Retirement of U.S. Nuclear Power Plants Under Electricity Deregulation and CO_2 Emission Reductions*, ENERGY J., JUNE 2000, at 61, 79, *available at* http://www.allbusiness.com/periodicals/article/612500-1.html.

59. *Id*. at 64.

60. *Id*. at 82.

nuclear plants would remain the same. The estimates ignored the potential for greater competition to lead nuclear plants to improve their performance and increase their capacity. Such a development would make early retirements of nuclear plants less prevalent and reduce the potential increases in emissions associated with substituting away from nuclear power.

4. Non-Hydro Electric Renewables. In the electricity sector, renewable energy technologies include wind power, geothermal power, hydropower, biomass, landfill gas, and solar power. Currently, hydroelectric power is by far the largest component of renewable electricity generation, but, with few exceptions, new investment in hydropower is not expected in the future. Renewable sources of energy, excluding hydroelectric power, currently constitute less than two percent of annual generation in the United States. With the exception of biomass and landfill gas, renewables typically have no emissions or air pollution. Even biomass generators can be part of integrated fuel production systems that produce essentially zero net emissions of CO_2.[61]

Commentators in the literature report mixed effects of restructuring on investment in new renewables and the use of renewables to generate electricity.[62] On the one hand, some view the move toward greater consumer choice as a way to allow consumers to express demand for green power in the market place. Some consumer surveys suggest that as many as fifty to ninety-five percent of electricity consumers are willing to pay a premium to purchase renewable energy.[63] Analysts caution that the share of customers actually willing to pay more for green power may be closer to ten to twenty percent.[64] In any case, this

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61. This ignores emissions associated with transport of the fuel from where it is grown to the electricity generator. These emissions are typically ignored for other fuel cycles as well.

62. There also has been speculation about how restructuring in the electricity sector in developing countries would affect the environment in general, and the fate of renewable technologies in particular. *See* KEITH KOZLOFF, RENEWABLE ENERGY RESEARCH PROJECT, ELECTRICITY SECTOR REFORM IN DEVELOPING COUNTRIES: IMPLICATIONS FOR RENEWABLE ENERGY, Washington: Renewable Energy Research Project (Mar. 1998), *available at* http://www.repp.org/repp_pubs/articles/index_kozloff.html (last visited Apr. 15, 2005).

63. BARBARA C. FARHAR, NATIONAL RENEWABLE ENERGY LABORATORY, WILLINGNESS TO PAY FOR ELECTRICITY FROM RENEWABLE SOURCES: A REVIEW OF UTILITY MARKET RESEARCH, (July 1999), *available at* http://www.eere.energy.gov/greenpower/resources/pdfs/farhar_26148.pdf.

64. PUBLICPOWER.COM, ALTERNATIVE ENERGY MARKETING: UNRAVELING THE MYSTERY OF GREEN TAGS 25 (Sept.–Oct. 2003), *available at* http://talgov.com/you/electric/pdf/2003_relay_alt-energy.pdf.

view sees investment in renewables growing under restructuring in response to successful green power marketing.[65]

On the other hand, the fact that renewables are typically a relatively expensive source of electricity generation compared to existing coal or new natural gas sources means that renewables might not fare as well as they would have under regulation. In many states, renewable generators were built under state regulatory programs designed either to encourage the use of low emitting sources or in response to PURPA requirements that utilities purchase power from renewables at prices below avoided cost. As a growing component of the electricity supply sector becomes deregulated, programs such as these would become less viable and the associated incentives to invest in new renewables would diminish.

B. Demand-Side Factors

1. Price Level and Demand Response. A primary motivation for electricity restructuring is the reduction of both wholesale and retail electricity prices. The theory is that competition will lead generating firms to become more efficient, leading to reductions in the cost of generation. Such a reduction in the cost of generation will translate into lower electricity prices. As price falls, total demand for electricity is expected to rise and, holding the mix of generation technologies constant, emissions would also increase.[66]

Price declines on average do not mean price declines everywhere. In some regions of the country, electricity rates have been relatively low under regulation, either due to efficient regulation or to the availability of low-cost generating resources such as hydroelectric dams. In those regions, prices could rise if restructuring provided generators with the option of selling their electricity into broader regional markets where prices set

65. RICHARD F. HIRSH & ADAM H. SERCHUK, RENEWABLE ENERGY POLICY PROJECT, POWER SWITCH: WILL THE RESTRUCTURED ELECTRIC UTILITY HELP THE ENVIRONMENT? (Sept. 1991); RUDD MAYER ET AL., RENEWABLE ENERGY POLICY PROJECT, THE GRASSROOTS ARE GREENER: A COMMUNITY-BASED APPROACH TO MARKETING GREEN POWER (June 1999).

66. This argument does not necessarily imply an increased need for regulation. Brennan shows that the size of the economic social welfare loss associated with unregulated or underregulated emissions from electricity generators could increase or decrease as the cost of generating electricity falls depending on the relative slopes of the demand and supply curves for electricity. TIMOTHY BRENNAN, DO LOWER PRICES FOR POLLUTING GOODS MAKE ENVIRONMENTAL EXTERNALITIES WORSE? (Resources for the Future, Discussion Paper 99-40, 1999), *available at* http://www.rff.org/ Documents/RFF-DP-99-40.pdf.

competitively at marginal cost would likely exceed the low average cost of the native generators. Thus, the effect of restructuring on electricity prices depends on the relative performance of generators prior to restructuring.

The predicted effects of restructuring on electricity prices have ranged from a two percent[67] to a forty percent[68] decline in the average national price, with the higher estimate being somewhat of an outlier. Assuming a relatively conservative elasticity of demand of -0.15 percent would suggest that the associated increases in electricity demand would range from 0.3 percent to six percent. Demand increases at the higher end would surely have adverse effects on emissions of noncapped pollutants, although the extent of those increases would depend on the relative roles of gas, nuclear, coal-fired, or renewable generation in meeting this increment in demand. Even in the presence of emission caps, demand increases could result in regional shifts in pollution with potential environmental consequences.

2. Price Structure and Demand Response. Many industry observers predicted that electricity restructuring would lead to greater use of real-time pricing of electricity in retail markets. Greater reliance on spot market transactions at the wholesale level coupled with greater desire to differentiate products for competitive purposes could provide a stronger incentive to offer real-time electricity prices. Consumers would then be in a position to manage the risk of price fluctuations in exchange for lower rates. The environmental effects of a change from time-invariant electricity prices to greater time differentiation depend on the fuel mix of peak versus baseload generation and would likely vary across regions of the country.[69] If peak-load pricing tends to shift demand from peak periods to base periods, and baseload generators are mostly coal-fired, then this shift could lead to an increase in emissions. However, some of the environmental consequences of higher emissions at night might be less severe than for emissions during the day. This is especially true for emissions of NOx, which is a precursor to ground-level ozone when combined with sunlight.[70]

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67. KAREN PALMER ET AL., *supra* note 40.

68. MARK BERKMAN & PETER GRIFFES, ENVIRONMENTAL POLICY AND UTILITY DEREGULATION (May 25, 1995) (paper presented at the Fourteenth Annual Advanced Workshop in Regulation and Public Utility Economics).

69. Stephen P. Holland & Erin Mansur, *Is Real-Time Pricing Green? The Environmental Impacts of Electricity Demand Variance* (U.C. Energy Institute CSEM, Working Paper No. 136, 2004).

70. Nighttime emissions of NOx may be roughly one-third as potent as daytime emissions in contributing to ozone formation. RANJIT BHARVIRKAR ET AL., NOX EMISSIONS

An analysis of the effects of real-time pricing for industrial customers only finds that eliminating real-time pricing for such customers reduces the increase in NOx emissions that would result from more widespread restructuring by twenty-five percent and reduces the increase in CO_2 emissions by almost fifty percent.[71] Eliminating real-time pricing shifts more demand from off-peak periods back to peak periods, thus shifting the mix of generation more towards gas and away from coal with associated reductions in the size of the emissions impacts of restructuring.

3. Demand-side Management and Conservation. In the mid-to-late 1980s and early 1990s, utility regulators in several states were actively encouraging the electric utilities under their jurisdiction to pursue cost-effective programs to reduce electricity demand or to shift demand away from peak periods. In some states, decisions about which demand-side management (DSM) or conservation programs to pursue were integrated with decisions about investment in new generating capacity under the rubric of integrated resource planning. Under this planning process, utilities would evaluate investments that promised reductions in current (or future) electricity use against investments in new generation capacity to find the most cost-effective approach to satisfy new demand. By reducing the need for generation, these programs were also seen as a way to reduce the adverse environmental effects of the electricity sector.

With the move toward restructuring and deregulation of the generation and retail sales parts of the electricity supply business, many commentators anticipated the demise of integrated resource planning and utility DSM programs. Absent the push from regulators, independent generators or retail electricity suppliers would not have sufficient incentive to continue these programs and future conservation efforts would fall short of those in the past.

However, others anticipated that instead of mandated programs for DSM, the restructured industry could see an influx of energy services companies that would help large electricity consumers find ways to save electricity in exchange for a portion of those savings.[72] Thus DSM would become more of a private enterprise and less of a regulatory program. How fast this would occur would depend on what happened with electricity prices and

TRADING AND EPISODIC AIR QUALITY VIOLATIONS IN MARYLAND (May 2003) (prepared for the Maryland Power Plant Research Program).

71. *See* PALMER ET AL., *supra* note 40, at tbl. 13.

72. DOUGLAS BOHI & KAREN PALMER, *The Efficiency of Wholesale Versus Retail Competition in Electricity*, 9 ELEC. J. 12 (1996).

the costs of energy-saving equipment.

IV. EVIDENCE ON THE EFFECTS OF RESTRUCTURING

More than ten years have passed since the signing into law of the Energy Policy Act of 1992.[73] FERC Order 888 is ten years old.[74] Many states, including Maryland and New Jersey, have completed the initial multi-year transition period envisioned in their restructuring laws and enabling regulations. Thus, it is timely to look back at what has happened in this early phase of restructuring and get some sense of how restructuring has affected the electricity sector and air quality.

This section of the article discusses the evidence to date regarding the effects of electricity restructuring on the many supply and demand-side factors identified above, as well as the role of additional factors that have complicated the landscape during the age of restructuring. The evidence presented here takes the form of a descriptive analysis. The analysis is preliminary in nature because, in most regions that have undergone restructuring, the transition to competitive markets is still underway. Arguably the transition to open transmission access and truly competitive wholesale markets is continuing as well. The analysis relies largely on simple descriptive statistics and graphs in lieu of a more formal statistical analysis of the role of restructuring and other factors in the data trends presented. In some cases, formal statistical analyses do exist and those findings are presented.

A Coal Plant Utilization

Have the predictions that restructuring could lead to increased utilization of coal-fired generators, particularly older, high-emitting, coal-fired generators in the Midwest been realized? This is a difficult question to answer using readily accessible data, but some trends are evident. First, Figure 1 shows that the average capacity factor for the entire fleet of coal-fired generators in the United States rose from roughly sixty percent in 1992 to seventy percent in 2002.[75] Moreover the rate of increase rose after 1995, coincident with the genesis of restructuring activity at FERC and in several states. Figure 1 shows a virtually identical trend in average capacity factors at

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73. Energy Policy Act, *supra* note 4.

74. Order 888, *supra* note 1.

75. ENERGY INFO. ADMIN., ENERGY INFO. ADMIN., U.S. NUCLEAR REACTOR LIST–SHUTDOWN, *at* http://eia.doe.gov/cneaf/nuclear/page/nuc_reactors/shutdown.html.

coal-fired units in the Ohio Valley region, the home of many of the oldest coal-fired generation facilities in the nation.[76]

However, the figure also shows that the national average capacity factor at coal plants rose between 1981 and 1992. A simple trend regression analysis of the 1981 to 1992 national average capacity factor data, forecasted forward to 2002, suggests that the post-1992 growth trend is roughly identical to the pre-1992 trend.[77] This finding suggests that restructuring may not be contributing to an increase in capacity factors at coal plants. However, other factors differentiate the earlier decade from the later one and must be taken into account. Some of the upward trend during the 1980s was likely due to the influx of newer coal-fired generators into the mix; close to sixty gigawatts of new coal-fired capacity came on-line. This influx tended to raise the average capacity factor of the coal fleet as a whole as represented in the graph. The building of new coal plants slowed dramatically during the 1990s; thus, newer facilities were not being infused into the mix of vintages of coal plants during that decade. Nonetheless, capacity factors did rise, particularly after 1996, the year FERC issued Orders 888 and 889.[78]

In addition to restructuring, another factor that likely has contributed to the increase in generation and capacity factors from coal-fired facilities is the rise in the price of natural gas. Figure 1 shows that the increase in average capacity factor at coal-fired plants is also coincident with a rather dramatic run-up in the wellhead price of natural gas. This increase in the price of an alternative fuel could be a major contributing factor to the increase in generation from existing coal plants in recent years.[79]

B. Nuclear Retirement and Generation

One of the unexpected consequences of electricity restructuring and greater competition in wholesale electricity markets is the substantial improvement in performance at the nation's nuclear plants. Contrary to predictions that many nuclear plants were at risk of retiring prior to their license expiration, nuclear units, for the most part, have thrived under

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76. *Id.*

77. *Id.*

78. ENERGY INFO. ADMIN., *supra* note 45.

79. High natural gas prices contributed to a continued increase in coal-fired generation in 2003 and, according to the EPA, also contributed an increase in annual emissions of SO_2 relative to 2002 and facilitated by the use of banked allowances from Phase I. U.S. ENVTL. PROT. AGENCY, 430-R-04-009, ACID RAIN PROGRAM: 2003 PROGRESS REPORT (Sept. 2004).

competition.

Since the passage of the Energy Policy Act in 1992,[80] only eight nuclear reactors totaling just less than six gigawatts of capacity have been shut down.[81] These commercial reactors are listed in Table 1. Notably, these plants accounted for only about six percent of total nuclear capacity in 1992, far below the upper limit of the predictions that thirty percent of existing capacity might retire as a result of restructuring.

Instead of faring poorly under restructuring, existing nuclear plants are thriving and producing more than ever.[82] Figure 2 shows that despite the fact that no new nuclear generators have been brought on-line since the early 1990s, total generation at U.S. nuclear plants has risen by close to one-third between the early 1990s and 2003, with most of that increase occurring in the most recent years.[83] Moreover, preliminary data through November 2004 suggest that nuclear generation achieved an all-time high in that year.[84] Figure 3 shows the substantial increases in capacity factors at the nation's nuclear plants in recent years.[85]

These findings are consistent with the incentives created by greater competition. Given the large, quasi-fixed costs associated with nuclear technology, it makes sense for a plant operator to try to reduce per megawatt-hour generation cost by increasing the amount of generation at the plant. Under cost-of-service regulation, incentives to increase productivity at nuclear plants were muted, as revenues were a function of cost. Reductions in cost would lead to an increase in net revenues (profits) only during time periods when rate case adjustments to electricity prices did not occur. In other words, the reward to reducing costs depended on so-called "regulatory lag," or the delay in adjusting revenues to match costs.[86] However, reductions in cost would not be rewarded to the same degree that they would be under competition.

Recent increases in nuclear generation have come about

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80. Energy Policy Act, *supra* note 4.

81. ENERGY INFO. ADMIN., U.S. NUCLEAR REACTOR LIST–SHUTDOWN, *at* http://eia.doe.gov/cneaf/nuclear/page/nuc_reactors/shutdown.html.

82. ENERGY INFO. ADMIN., NUCLEAR ENERGY OVERVIEW, MONTHLY ENERGY REV., MARCH 2005, *available at* http://www.eia.doe.gov/emeu/mer/pdf/pages/sec8_3.pdf.

83. *Id*.

84. *See* ENERGY INFO. ADMIN., U.S. NUCLEAR GENERATION of ELECTRICITY, *available at* http://www.eia.doe.gov/cneaf/nuclear/page/nuc_generation/gensum.html (last visited Apr. 10, 2005).

85. ENERGY INFO. ADMIN., *supra* note 82.

86. Paul L. Joskow, *Inflation and Environmental Concern: Structural Change in the Process of Public Utility Price Regulation*, 17 J.L. & ECON. 291 (1974).

through a combination of reductions in scheduled and forced outages at U.S. plants and through investments that have led to incremental increases in capacity at existing plants. These investments range from changes to instrumentation settings to replacement of major components such as high pressure turbines, pumps, and generators. Such investments increase the capacity rating of existing facilities and are, therefore, referred to as nuclear uprates.[87]

The relationship between electricity restructuring and increases in both capacity factors and new equipment investments at nuclear plants has been investigated by Zhang.[88] The Zhang analysis suggests that between1992 and 1998, the extent of restructuring or market deregulation within a state had a positive effect on both plant capacity factors and on the level of additional investment at existing plants.[89] These findings are consistent with the hypothesis that restructuring has been a positive force for productivity improvements at the nation's nuclear plants.

Growth in electricity generation at U.S. nuclear plants has clearly had some positive effects on the environment. If the observed increases in nuclear generation had not taken place, then generation from fossil facilities would have made up some of the difference, resulting in higher emissions. To some degree, at least, it is apparent that the incentives provided by restructuring did not lead to the retirement that some anticipated and have contributed to expanded generation by nuclear plants.

C. *Gas Investment*

Since 2000, there has been a dramatic increase in investment in new gas-fired capacity including both new single-cycle turbines and new combined-cycle units. The amount of new gas capacity added in 2001 and in 2002 dwarfs new natural gas capacity installed in any prior year. The amount of gas capacity that was planned in 2002 to be brought on-line in both 2003 and 2004 exceeds total additions of capacity of all types in all prior years as shown in Figure 4.[90] This massive entry of natural gas

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87. ENERGY INFO. ADMIN., NUCLEAR POWER: 12 PERCENT OF AMERICA'S GENERATING CAPACITY, 20 PERCENT OF THE ELECTRICITY, *available at* http://www.eia.doe.gov/cneaf/nuclear/page/analysis/nuclearpower.html (last visited July 17, 2003).

88. Fan Zhang, *Does Deregulation Work? Evidence from the U.S. Nuclear Energy Industry*, Address at the Harvard Kennedy School of Government Work-in-Progress Seminar (Apr. 22, 2005).

89. *Id*.

90. ENERGY INFO. ADMIN., ELECTRIC POWER ANNUAL 2004, *available at* http://www.eia.doe.gov/cneaf/electricity/epa/epa_sum.html.

capacity in response to the opening up of electricity markets can be characterized as an overbuild or an uncoordinated influx of investment that exceeded market opportunity. The large amount of new natural gas generation capacity has led to very high capacity margins in certain parts of the country, with summer reserve margins in the northeastern United States exceeding twenty-three percent in 2003 and exceeding twenty percent in the Ohio Valley and in Texas.[91] Not only has restructuring increased investment in new gas capacity, but it has also changed the nature of investment in gas turbines. According to Ishii, the expansion of restructuring has brought about a shift in technology choice away from smaller gas turbines toward higher capacity turbines that are better suited for combined-cycle, baseload applications that would operate over more hours of the year and compete with baseload coal and nuclear units.[92]

As a result of the overbuild, total gas-fired capacity exceeds current generation needs by a substantial margin and, therefore, many of the new plants are operating at low capacity factors. The high price of natural gas, which makes generating with natural gas relatively less attractive than using coal for baseload generation, also contributes to low capacity factors at new gas plants. In peak periods, gas turbine technology is the marginal technology. Electricity price is tied to short-run variable costs at these units, and, therefore, tightly dependent on natural gas price. Were it not for the overbuild in natural gas capacity, the peak-period price would provide revenue to offset the capital cost of new combined-cycle generation. Because of low capacity factors, though, these units are not earning expected revenue over all times of day. Furthermore, the environment of overcapacity means that there is no room for recovery of the capital cost of gas turbines even during the peak. Were capacity constrained, electricity price would be expected to rise above short-run variable cost for new efficient gas turbines to begin to reflect long-run marginal cost, or equivalently, the variable cost of older and less efficient gas and oil-fired turbines.

Two offsetting factors resulting from the overbuild in natural gas generation affect the environment. One is the accelerated expansion of natural gas-fired capacity, attributable

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91. ENERGY INFO. ADMIN., ELECTRICITY POWER ANNUAL 2003, at 21 tbl. 3.3, *available at* http://www.eia.doe.gov/cneaf/electricity/epa/epa.pdf (displaying a capacity margin in the ratio of total capacity installed to peak demand levels).

92. JUN ISHII, CENTER FOR THE STUDY OF ENERGY MARKETS, TECHNOLOGY ADOPTION AND REGULATORY REGIMES: GAS TURBINE ELECTRICITY GENERATORS FROM 1980–2001, Paper CSEMWP-128 (Mar. 2004), *available at* http://repositories.cdlib.org/cgi/viewcontent.cgi?article=1031&context=ucei/csem.

to a significant degree to restructuring and the perceived opportunity to earn profits in excess of regulated levels. Because of this perception, what had been characterized as a mid-term or long-term transition in generation capacity was realized much faster than expected. In isolation, this trend would have led to lower emissions and unambiguous environmental gains. The offsetting factor was the largely unanticipated run up in natural gas price since 1999 (Figure 1), which extended the economic advantage of existing coal-fired facilities. By and large, it is difficult to assert that the run-up in natural gas price is attributable to the increase in gas-fired generation capacity in the electricity sector because the electricity sector represents only twenty-five percent of total demand for natural gas in the United States. Rather, the increase in natural gas price appears to be largely due to factors outside of electricity restructuring, and the associated increase in coal-fired generation and related effect on emissions would have been felt even in the absence of restructuring.

D. Renewables

The increase in market demand for green power that some predicted would result from restructuring has yet to materialize. Bird and Swezy find that the green power market is only a small portion of the total electricity market.[93] They look at both green power offerings by utilities and green power offerings by competitive electricity suppliers. They find that, on average, just over one percent of all utility customers participate in some form of utility-offered green-pricing program and the vast majority of these are residential customers.[94] A second source of green power comes from nonregulated companies, such as Green Mountain Energy, which aggregate electricity supply and offer to electricity customers portfolios that have specific environmental attributes. Bird and Swezy estimate that adding in their estimates of total green-power customers from surveys of green-power marketers raises the percentage of total utility customers participating in some form of green pricing program to less than 1.9 percent of all customers.[95] Thus, most of the increase in "voluntary" green power sales has been in response to utility-sponsored choice programs, many of which have been required by regulators,

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93. LORI BIRD & BLAIR SWEZEY, NATIONAL RENEWABLE ENERGY LABORATORY, GREEN POWER MARKETING IN THE UNITED STATES: A STATUS REPORT, (7th ed. 2004), *available at* http://www.nrel.gov/docs/fy05osti/36823.pdf.

94. *Id.*

95. *Id.*

rather than being a result of retail market forces that emerged as a consequence of restructuring.

Despite the very limited success of green power marketing, renewables have gained some ground in the era of restructuring. Most of the states that have moved forward with restructuring (and several that have not) have adopted new policies to promote use of renewable-generating technologies during this time of transition to competition. One of the most popular policies is what is known as a renewable portfolio standard or RPS. Under an RPS policy, a certain minimum percentage of electricity, either generated or sold within the utility or at the state level, must be generated using a renewable technology. Typically, this minimum percentage starts out small and grows over time. Since the mid-1990s, twenty-one states and the District of Columbia have adopted RPS policies.[96]

Whether as a result of an RPS or private green-power marketing initiatives, the environmental benefits of increased renewable generation are not as large as some have predicted. Simple estimates of the emission-reduction effects of greater renewables generation use the average emissions rate across the entire fleet of generation within the relevant jurisdiction to estimate emission reductions. This approach explicitly assumes that, holding total generation constant, all fossil generation is reduced in proportion to its share of the generation mix with the introduction of increased renewables. However, renewables do not displace fossil generators in this manner. Palmer and Burtraw show that new renewables largely tend to back out generation from gas-fired facilities, especially new facilities, and thus the emissions reductions for CO_2 and NOx will be smaller than others have estimated.[97] Increased renewables will not reduce emissions of capped pollutants such as SO_2, either nationwide or within states that have state caps such as New York, unless the magnitude of the renewable requirement is so large that it causes aggregate emissions to actually fall below the allowable cap.

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96. In Pennsylvania, the standard is actually an alternative energy portfolio standard which includes waste coal generation. *See* Fact Sheet from Union of Concerned Scientists, Renewable Electricity Standards at Work in the States, *available at* http://www.ucsusa.org/assets/documents/clean_energy/res_in_the_states_-_01-05_update.pdf.

97. KAREN L. PALMER & DALLAS BURTRAW, RESOURCES FOR THE FUTURE, ELECTRICITY, RENEWABLES, AND CLIMATE CHANGE: SEARCHING FOR A COST-EFFECTIVE POLICY (May 2004); *see also* KAREN L. PALMER & DALLAS BURTRAW, RESOURCES FOR THE FUTURE, COST-EFFECTIVENESS OF RENEWABLE ELECTRICITY POLICIES, ENERGY ECONOMICS (2005) [hereinafter PALMER, COST-EFFECTIVENESS].

E. Electricity Price Levels and Demand

The changes in electricity prices in the early years of electricity restructuring have varied across states and across customer classes and generally have not been as dramatic as some had predicted. Figures 5 through 8 provide an overview of how average, nominal retail electricity prices in selected restructuring states have moved over time between 1990 and 2002.[98] In many cases these graphs mask large differences across regions of the state or across time periods in a year, but they give a general idea of how prices have changed over time during the initial phase of electricity restructuring in several key states. The graphs also provide data for Florida, one state that has not restructured, as well as for California and the United States as a whole.

These graphs provide some insights into why several of these states may have chosen to restructure. With the exception of Texas, all of the pictured states that did move ahead with restructuring had retail electricity rates for each class of customers and for all customers taken together that were typically well above the national average price.[99] In some cases, such as Pennsylvania and Connecticut, that price gap started to close after restructuring. For other states, the reduction in the price gap was more fleeting. Also, in most of the restructured states portrayed in the graphs (with the exceptions of Pennsylvania and Texas), retail electricity prices have tended to vary more over time both pre- and post-restructuring than did prices in Florida or across the nation as a whole.

In most cases, the initial price declines shown in these graphs for the restructured states in the late 1990s were the result of retail price caps, low regulated prices for standard-offer service imposed by regulators or by law on utility providers at the time of restructuring. For example, Connecticut imposed a cap on residential prices for standard offer service at 1996 regulated levels for the first few years of the transition. This cap was followed by a ten percent rate reduction to be put into place until 2004, at which time prices would be allowed to rise to encourage market entry with a cap on the ultimate price increase allowed by the end of 2007. These caps were seen as a way of "front loading" the energy cost savings expected to follow

98. The states included in these graphs were chosen to illustrate a range of price levels and to cover a range of policies toward price evolution during the early years of restructuring.

99. Some states not reflected in the graph, most notably Montana, also had retail rates that were below the national average.

naturally from the move to competition. In many states, such as Massachusetts and Maryland, these price caps were expected to be phased out in a few years, as more and more customers shifted to competitive suppliers and competition took the place of price-cap regulation as a mechanism for regulating prices.

Unfortunately, the low prices imposed in many states at the outset of restructuring may have served to delay the spread of true retail competition. First, in many states, most notably California but also northeastern states such as Massachusetts, the retail price caps proved too low to accommodate either increases in wholesale electricity prices that accompanied some tight capacity situations in the early days of restructuring or that were brought about, at least in part, by high prices of natural gas. Many utilities were stuck with a new type of stranded cost, as they were unable to recover in capped retail prices the costs of the power procured at rising wholesale rates. With electricity prices set so low, it became difficult for new suppliers to enter the market profitably as they were unable to cover their fuel costs and compete with the low price of standard-offer service from incumbent providers.[100] Many new entrants declared bankruptcy or left the market before doing so. Many retail customers who might have been inclined to switch providers were unlikely to do so because of the low prices for standard-offer service. As a consequence, the dynamic allocation of customers to providers, the dynamic price competition, and the entry of new providers did not materialize.

Eventually, prices for standard offer or default electricity service had to be adjusted upward to allow electricity retailers to cover increases in fuel costs reflected in wholesale market prices. This happened fairly quickly in Massachusetts, where a fuel adjustment clause was added to the default service pricing rule. The resulting effect of the run up in natural gas prices in 2001 on wholesale electricity prices is evident in the retail price spike in 2001 shown in Figure 8.[101] A milder form of this price spike seems to have also occurred in New York where prices also trended up in 2000 and 2001 (with the increase particularly pronounced in the commercial sector) and then back down in 2002. In California, increases in residential, commercial, and industrial rates that began in 2001 continued through 2002 as restructuring was abandoned and regulators tried to set rates

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100. Kenneth Rose, *The State of Retail Electricity Markets in the U.S.*, ELEC. J., Jan.–Feb. 2004, at 26.

101. ENERGY INFO. ADMIN., ELECTRIC POWER ANNUAL 2004, *available at* http://www.eia.doe.gov/cneaf/electricity/epa/epa_sum.html (last visited Feb. 20, 2006).

that helped secure the economic health of both electricity suppliers and their customers.[102]

What these price trends suggest for electricity demand and emissions is not uniform across the different states. While prices did fall in the early days, they also tended to rise again after 2000 (although the size of those price increases varied substantially across states and across customer classes within states). With the exceptions of Pennsylvania and Connecticut, where residential electricity prices have remained fairly low since restructuring, the post-2000 increases in electricity prices have not given consumers a reason to expect sustained low electricity rates in the era of restructuring.[103] As a result of the minimal effect on electricity price from restructuring, demand response to initial price drops is likely to have attenuated a bit, thereby muting any adverse effect on emissions results from higher demand that was anticipated to result.[104]

F. Electricity Conservation and DSM

Utility investments in DSM programs and associated energy savings fell dramatically during the early years of restructuring as utilities sought to shed costs in order to compete more effectively with non-utility competitors who did not have such programs.[105] According to data collected by the Energy Information Administration, annual utility expenditures on DSM programs fell by roughly fifty-five percent between 1993 and 1999 and incremental annual energy savings fell by about sixty-five percent.[106] Upon restructuring their electricity markets, a number of states established public benefits funds to fund numerous programs, such as research and development of new technologies and energy efficiency investments that many feared would be lost as a result of restructuring.[107] These public benefits funds were collected by charges assessed on all electricity users

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102. BRENNAN, *supra* note 17, at 22.

103. Figures 5 through 8 show the Average Retail Electric Prices for customers from years 1990 to 2002. ENERGY INFO. ADMIN., ELECTRIC POWER ANNUAL 2004, Tbl. 5.1, *available at* http://www.eia.doe.gov/cneaf/electricity/epa/epa_sum.html

104. PALMER, *supra* note 40, at 43.

105. KENNETH GILLINGHAM, RICHARD NEWELL, & KAREN PALMER, RESOURCES FOR THE FUTURE, RETROSPECTIVE EXAMINATION OF DEMAND-SIDE ENERGY EFFICIENCY POLICIES, Discussion Paper 04-19 Rev. (2004), *available at* http://www.rff.org/Documents/RFF-DP-04-19REV.pdf.

106. *Id*. at 21–22, 77.

107. *Id*. at 22; Steven Nadel & Marty Kushler, *Public Benefit Funds: A Key Strategy for Advancing Energy Efficiency*, ELEC. J., Oct. 2000, at 74.

who interfaced with the local distribution grid.[108] Beginning in 1999, DSM spending by utilities started to increase again as a result of these programs.[109] However, in several cases these programs were funded by state energy agencies or directly by regulators, so traditional utilities played a reduced role in administering these programs.[110]

G. Electricity Price Structures

The effect of electricity restructuring on electricity prices has not been as dramatic as expected either. Real-time pricing, which requires the installation of real-time electricity meters at customers' sites, has only been adopted by a small number of electric utilities with relatively mixed success. For example, real-time pricing has been employed at Duke Power for large customers and by Georgia Power Company where roughly 1600 large commercial and industrial customers pay real-time prices.[111] These two programs have been relatively successful, and the Georgia Power program has very low attrition rates.[112] However, another well-publicized experiment with time-of-use pricing for residential customers at Puget Sound Energy was ended in 2002, less than a year after it started.[113] The Puget Sound Experiment was not a real-time pricing program but a more moderate scheme whereby prices varied in a predetermined manner between predetermined peak and off-peak time periods.[114] Time-of-use pricing is designed to create incentives for load shifting away from peak-demand times and toward base periods, but without exposing customers to potentially large fluctuations in electricity prices on an hourly basis. However, the program ended up not saving customers' money and several ended up preferring to return to flat rates so the system was abandoned.[115] None of these major programs in real-time or time-

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108. GILLINGHAM, *supra* note 105, at 22; M. Sami Khawaja et al., *System Benefits Charge: Economic Impacts and Implications*, ELEC. J., June 2001, at 25.

109. GILLINGHAM, *supra* note 105, at 22.

110. Nadel, *supra* note 107, at 81-82. For example, in New York State, the system benefits program is administered by the New York State Energy Research and Development Authority (NYSERDA).

111. Michael T. O'Sheasy, *Is Real-Time Pricing a Panacea? If So, Why isn't it More Widespread?,* ELEC. J., Dec. 2002, at 24.

112. *Id.* at 24–34.

113. Mark Glyde, *Time of Use Pricing Plan Raises Concerns*, 20 NW ENERGY COALITION REP. 4, at 6 (Apr. 2001), *available at* http://www.nwenergy.org//publications/report/01_apr/apr.pdf.

114. *Id*.

115. Press Release, Puget Sound Energy, PSE proposes to end pilot time-of-use program ahead of schedule (Nov. 6, 2002), *available at* http://www.pse.com/news/

varying pricing took place as part of restructuring in those states. Some states chose to impose real-time pricing on large customers as they entered the second phase of the transition to full restructuring. For example, in New Jersey, the default service price for large commercial and industrial customers who fail to choose a competitive provider by the end of the initial transition period is based on hourly PJM spot market prices.[116] In the case of California, real-time pricing was a consequence of the market disruption in 2001 and was implemented by the state.[117]

The failure of the proliferation of real-time pricing should not necessarily be taken as a sign that it is a bad idea. Borenstein has used a simulation model to show that the benefits from greater use of real-time pricing tend to outweigh the costs.[118] However, the fact that it has not become more widespread to date means that this type of change in pricing structure has not had a big role in shaping the impact of electricity generation on the environment in restructured states or elsewhere.

H. Emissions and the Effects of Environmental Policies

Table 2 provides an overview of annual emissions trends for three key pollutants in the electric power sector between 1992 and 2003.[119] This table shows that, with the exception of CO_2, emissions from the electricity generation sector have been declining over this roughly ten-year time horizon.[120] SO_2 emissions have fallen by roughly one third and NOx emissions by over forty percent. The decline in SO_2 emissions will continue into the future as generators draw down the accumulated bank of SO_2 emission allowances. Prior to the adoption of the Clean Air Act Interstate Rule (CAIR) in 2005, the sector was expected to reach the annual cap on SO_2 emission allowances specified in Title IV of the 1990 Clean Air Act Amendments of 8.9 million tons per year by 2010.[121] CAIR will lead to dramatic further reductions over the next fifteen years. The cap on annual NOx

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2002/pr20021106a.html.

116. Rose, *supra* note 100, at 32.

117. *Id*.

118. SEVERIN BORENSTEIN, UNIVERSITY OF CALIFORNIA ENERGY INSTITUTE, THE LONG-RUN EFFECTS OF REAL-TIME ELECTRICITY PRICING, CSEM Working Paper No. 133 (June 2004), *available at* http://www.aeaweb.org/annual_mtg_papers/2005/0108_1015_1102.pdf.

119. ENERGY INFO. ADMIN., ELECTRIC POWER ANNUAL 2004, tbl. 5.1, *available at* http://www.eia.doe.gov/cneaf/electricity/epa/epa_sum.html (last visited Feb. 20, 2006).

120. *Id.*

121. Clean Air Act Amendments of 1990, Pub. L. No. 101-549, tit. 7, 104 Stat. 2399 (codified as amended at 42 U.S.C. §§ 7651-7651d (2005)).

emissions is currently limited to electricity generators in the eastern states. Prior to CAIR, it only applied in the summer months. CAIR added another cap over a larger region that applies annually. Total annual emissions of NOx from this sector still could rise in the future as electricity generation increases outside of the capped region. Emissions of CO_2, which are unregulated at the federal level, are also expected to rise as electricity demand increases.[122]

Unfortunately, these aggregate time-series emissions data tell us virtually nothing about the effects of restructuring on emissions from electricity generators due to the confounding effects of environmental regulation. Prior years do not provide a good counterfactual of what emissions levels or emissions rates would have been like in the absence of restructuring. In the case of both SO_2 and, to a lesser extent, NOx, the emissions caps have virtually guaranteed reductions in emissions over this time period.[123] If restructuring had resulted in increased utilization of existing coal facilities, a faster draw down of the SO_2 allowance bank than the 2010 date originally forecasted might have been expected.[124] However, prior to CAIR the EPA continued to forecast that the large bank of allowances would be exhausted by 2010.[125]

Total emissions of CO_2, which is unregulated at the federal level, track the coal plant capacity factor results shown in Figure 1 very closely. As shown in Table 2, emissions grew through 2000 and then dropped when coal plant utilization dropped in 2001. The pattern of emissions changes over this decade is likely due to a mix of electricity restructuring and fluctuations in the price of natural gas with the relative contribution of the two factors largely unknown.

I. Effects of Restructuring and the Efficiency of Pollution Cap-and-Trade Programs

Much has been written about how public utility regulation of electric utilities has limited the use of SO_2 allowance markets to achieve cost effective compliance with the national SO_2 emissions

122. David B. Spence, *Coal-Fired Power In a Restructured Electricity Market*, 15 DUKE ENVTL. L. & POL'Y F., 187, 190 (2005).

123. *Id*. at 194, 218.

124. Curtis Carlson, Dallas Burtraw, Maureen Cropper & Karen Palmer, *SulfurDioxide Control by Electric Utilities: What Are the Gains from Trade*?, 108 J. POL. ECON. 1292, 1310–25 (2000).

125. U.S. ENVTL. PROT. AGENCY, EPA ACID RAIN PROGRAM: 2003 PROGRESS REPORT, EPA 430-R-04-009 (Sept. 2005), *available at* http://www.epa.gov/airmarkets/cmprpt/arp03/2003report.pdf.

cap established under Title IV.[126] Differential regulatory accounting treatment of scrubbers versus allowance purchases served to reduce interest on the part of regulated utilities in using allowances for compliance.[127] Other research suggests that state regulation led to excess reliance on fuel switching instead of allowance trading as a means of compliance.[128] By eliminating some of these regulatory barriers or disincentives to the use of allowance markets, the move from regulation to competition was expected to increase the efficiency of pollution cap-and-trade programs applied to the electricity sector.[129]

Evidence concerning how restructuring has affected the performance of emission allowance trading is still sparse. EPA finds that annual transfers of Title IV SO_2 allowances between economically distinct entities increased dramatically through 2000, the beginning of the second phase of the program, and have declined since then, presumably because compliance plans were largely in place.[130] This data suggests that use of the market did increase as experience with allowance markets grew, but the role of restructuring in influencing this trend is difficult to ascertain.

One situation where the relationship between restructured electricity markets and pollution allowance markets has received wide attention is the effect of the California electricity crisis in the summer of 2000 on the behavior of NOx allowance prices in the Regional Clean Air Incentives Market (RECLAIM) program in southern California.[131] In 1994, to combat ozone pollution in Southern California, the South Coast Air Quality Management District had launched RECLAIM, the first large urban cap-and-trade program for NOx,.[132] In the summer of 2000, when

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126. *See generally* Dallas Burtraw, David Evans, Alan Krupnick, Karen Palmer & Russell Toth, *Economics of Pollution Trading for SO_2 and NOX, Annual Review of Environmental Resources*, *in* 30 ANNUAL REVIEW OF ENVIRONMENT AND RESOURCES 253–290 (2005) (reviewing much of the literature).

127. Doug R. Bohi & Dallas Burtraw, *SO_2 Allowance Trading: How Do Expectations and Experience Measure Up?*, ELEC. J., Aug.–Sept. 1997, at 67; Paul M. Sotkiewicz, The Impact of State-Level Public Utility Commission Regulation on the Market for Sulfur Dioxide Allowances, Compliance Cost, and the Distribution of Emissions (Jan. 2003) (unpublished Ph.D. thesis, University of Minnesota).

128. Toshi Arimura, *An Empirical Study of the SO_2 Allowance Market: Effects of PUC Regulations*, 44 J. ENVTL. ECON. & MGMT. 271 (2002); Kenneth Rose, *Implementing an Emissions Trading Program in an Economically Regulated Industry: Lessons from the SO2 Trading Program*, *in* MARKET-BASED APPROACHES TO ENVIRONMENTAL POLICY: REGULATORY INNOVATIONS TO THE FORE (Richard Kosobud & Jennifer Zimmerman eds., Van Nostrand 1997).

129. Carlson, *supra* note 124, at 1320–21.

130. U.S. ENVTL. PROT. AGENCY, *supra* note 125.

131. BRENNAN, *supra* note 17, at 21; *see also* Burtraw, Evans, Cropper & Palmer., *supra* note 126, at 253–290.

132. Burtraw, Evans, Cropper & Palmer., *supra* note 126, at 253–290.

electricity capacity was tight in California and older high emitting generators were called into service to meet peak-level demands, demand for NOx allowances also rose and the price of NOx allowances peaked at about sixty dollars per pound, substantially above historical levels.[133] Emissions during that summer exceeded the total allowance allocation.[134] This inability to cope with large increases in demand for NOx allowances may be due in large part to the lack of allowance banking in the RECLAIM program that would have provided a cushion of allowances to help fill the gap in supply during periods of high demand.[135]

Another strand of literature focuses on the potential relationship between allowance markets and the exercise of market power in electricity markets. In many cases, deregulated electricity generation markets function more as oligopolistic markets with small numbers of competitors than as perfectly competitive markets. In oligopolistic markets, individual suppliers can have some influence over the market price. The incentives for suppliers to behave strategically in order to raise price could have implications for emissions and for outcomes under emission cap-and-trade programs. Mansur investigates the reasons behind a substantial drop in regional emissions of both SO_2 and NOx in the Mid-Atlantic States between 1998 and 1999.[136] He finds that only sixty-four percent of the drop in NOx emissions is attributable to the environmental regulation of NOx; roughly thirty-six percent of the drop in NOx emissions can be explained by the exercise of market power by electricity generators.[137] He finds similar results regarding the drops in regional emissions of SO_2 and CO_2.[138] He also finds that strategic behavior in wholesale electricity markets helps to lower the price of NOx allowances and thus has positive effects on social welfare.[139]

V. PROSPECTS FOR THE FUTURE

Expectations about the large benefits to society from greater

133. *Id.* at 27.

134. *Id.* at 29.

135. *Id*. at 37–39.

136. ERIN MANSUR, ENVIRONMENTAL REGULATION IN OLIGOPOLY MARKETS: A STUDY OF ELECTRICITY RESTRUCTURING, POWER (U. Cal. Energy Inst., Working Paper No. 088, Sept. 2004), http://www.nber.org/~confer/2004/ si2004/ee/mansur.pdf

137. *Id.* at 2.

138. *Id*. at 2, 37–38.

139. *Id.* at 37–38.

competition in electricity markets remain largely unmet, although some gains in efficiency related to generation are evident, particularly for nuclear power.[140] Retail price reductions in states that moved to restructuring were largely a function of regulated, transitional price caps for electricity supplied by distribution utilities or of effective price caps in the form of regulated prices for standard-offer service. These low prices limited entry on the part of competitive suppliers and many suppliers who did enter subsequently withdrew from the market, unable to make a profit.[141] As initial transition periods end during a time of relatively high natural gas prices, retail electricity prices are tending to rise and people are questioning the wisdom of restructuring in the first place. Still it may be premature to judge the effects of moving to competition because policies may have limited the scope for retail competition during the transition and the real opportunities for market forces to affect retail electricity prices may still lie ahead.

Likewise, it may also be too early to tell how restructuring will affect the environment, both because the data is not yet complete and because the initial transition period is just now drawing to a close. The general sentiment is that, due in part to lack of supplier options for smaller customers, regulators will continue to impose rate freezes or caps on rates paid by smaller customers into the future.[142]

A. *Other Things Matter More to the Environment than Competition*

The lessons from our experience with restructuring to date and our efforts to simulate the potential effects of restructuring in the future suggest that other factors affecting the electricity sector may have bigger effects on the environment and on electricity consumers than the move to competition. In this section we review the likely effects of the different factors.

Many of the simulation studies that look at the potential effects of more widespread electricity competition and different types of regulatory policies on emissions from power generators suggest that policies other than restructuring may play a larger role in influencing the future course of emissions from the sector than will electricity restructuring. These policies include new or

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140. KIRA MERKIEWICZ, HAS RESTRUCTURING IMPROVED OPERATING EFFICIENCY AT US ELECTRICITY GENERATING PLANTS?, (U. Cal. Energy Inst., POWER Working Paper No. 135, July 2004), http://www.ucei.berkeley.edi/PDF/csemwp135.pdf.

141. Rose, *supra* note 100, at 30.

142. *Id*. at 36.

anticipated restrictions on emissions of multiple pollutants from the electricity sector, the presence or absence of caps on carbon emissions and efforts to promote greater use of renewable technologies to supply electricity. Across all of these policy initiatives, the price of natural gas will have an important influence on effectiveness and cost-effectiveness. In this section we address each of these issues in turn.

1. Multi-Pollutant Policies. The Clean Air Act Amendments of 1990 ushered in a new era of using cap-and-trade approaches to address emissions from electricity generators.[143] The 1990 legislation and subsequent regulations have focused on emissions of SO_2 and NOx, primarily to address acid rain concerns and ozone pollution.[144] While these regulations brought about substantial reductions in emissions, they have fallen short of bringing about attainment with national ambient air quality standards for ozone and particulates or to arrest the problems of acidification. Further reductions in both pollutants are clearly justified on cost-benefit grounds from the perspective of the human health benefits alone.[145]

Several proposals have been introduced over the past few sessions of Congress to impose stricter nationwide caps on emissions of SO_2 and NOx in the electricity sector and to cap emissions of mercury and, in some cases, CO_2 as well.[146] Three bills that would have regulated multiple pollutants were introduced into the Senate during the 108th Congress (2003–2004).[147] All of these bills use an emissions cap-and-trade program as the primary mechanism for achieving emissions reductions.

The most aggressive plan, The Clean Power Act, introduced by Senator Jeffords (I-VT) proposes to cap annual emissions of SO_2 at seventy-five percent below the Title IV emissions cap and annual NOx emissions at twenty-five percent of their 1997 levels by 2009.[148] The bill also caps annual emissions of mercury at ten percent of 1999 levels by 2008 and includes a national cap on CO_2 set at 1990 levels beginning in 2009.[149] The bill allows for

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143. Burtraw, Evans, Cropper & Palmer., *supra* note 126, at 253–290.

144. *Id.* at 25.

145. Spencer Banzhaf, Dallas Burtraw & Karen Palmer, *Efficient Emission Fees in the U.S. Electric Sector*, 26 RESOURCE AND ENERGY ECON. 317, 317–341 (2004).

146. Clean Skies Act of 2005, *supra* note 43 (proposed amendments to the Clean Air Act).

147. *Id*.

148. *Id*.

149. *Id*.

emissions trading for all gases except mercury.[150]

The Bush administration's Clear Skies proposal, which was introduced by Senators Inhofe (R-OK) and Voinovich (R-OH), caps annual emissions of SO_2 at fifty percent of the Title IV cap of nine million tons in 2010 with the cap declining to thirty percent of the Title IV cap by 2018.[151] Annual emissions of NOx are capped at roughly one third of 1997 levels beginning in 2009 and the cap declines to roughly twenty-eight percent of 1997 levels by 2018.[152] The bill also calls for reductions in annual emissions of mercury of about fifty percent compared with 1999 levels by 2010 and seventy percent by in 2018.[153] This proposal permits the trading of emission allowances for all three pollutants and imposes no cap on CO_2.

In between these two proposals is the Clean Air Planning Act, sponsored by Senator Carper (D-DE).[154] This bill imposes emissions caps for SO_2, NOx and mercury and timetables for achieving those caps, falling in between the other two proposals.[155] This bill also includes a phased-in cap on CO_2 emissions from electricity generators, but allows for the use of emissions offsets from outside the electricity sector.[156] Mercury emission trading is allowed, although generators must meet facility-specific emission reduction targets.

Multi-pollutant legislation has not advanced in Congress as of the end of 2005; however, the EPA has taken steps to require greater reductions in emissions of SO_2, NOx and mercury. The Clean Air Interstate Rule, adopted in 2005, establishes annual caps on emissions of SO_2 and NOx in twenty-nine eastern states and the District of Columbia.[157] The ultimate percentage reductions in emissions imposed within the CAIR region are comparable to those that would be required nationwide under the

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150. *Id*.

151. Clean Power Act of 2003, *supra* note 43.

152. *Id*.

153. The Clear Skies initiative does not include a cap on CO_2 emissions, but instead proposes to cut greenhouse gas intensity on an economy-wide basis by eighteen percent over the next ten years using mostly voluntary initiatives and providing a formal mechanism for recognizing cuts that are made voluntarily.

154. Clean Air Planning Act of 2003, *supra* note 43.

155. *Id*.

156. *Id*.

157. On March 10, 2005 the EPA Administrator signed the Clean Air Interstate Rule (CAIR) issued pursuant to Clean Air Act § 110(a)(2)(D). *See* U.S. Envtl. Prot. Agency, Clean Air Interstate Rule (2004), *at* http://www.epa.gov/cair. The background for CAIR is fully described in the preambles to the final rule, the notice of proposed rulemaking, 69 Fed. Reg. 4,565 (proposed Jan. 30, 2004) (to be codified at 40 C.F.R. pt. 51, 72, 75, and 96), and the supplemental notice of proposed rulemaking, 69 Fed. Reg. 12,398 (proposed Mar. 16, 2004) (to be codified at 40 C.F.R. pt. 60, 72, and 75).

Clear Skies legislation, except that they happen on a somewhat accelerated schedule. The EPA has also issued a rule to limit emissions of mercury, the Clean Air Mercury Rule, using a nationwide mercury cap-and-trade program that would achieve reductions in mercury emissions of seventy percent over a longer time frame.[158]

While legislative and regulatory debates over multi-pollutant policies continue at the federal level, several states have taken decisive action to address emissions of one or more pollutants from electricity generators beyond the requirements of federal law. These state policies are summarized in Table 3.[159] Most of these laws or proposals, such as new regulations in Connecticut and Massachusetts that limit non-ozone season emissions of NOx, are formulated as emission rate standards. The largest state action is in North Carolina, which has recently placed emissions caps on its largest coal-fired plants. A similar plan has been adopted in New Hampshire for all existing fossil-fuel generators. New York also has caps on emissions of SO_2 and NOx from large generators within the state.

When the new federal regulations take effect, these multi-pollutant programs will substantially offset any increases in emissions that might result from further expansion of competition and electricity trading. Key features of these policies include the stringency of the standard for mercury and the form of that standard. Stringent policies to control mercury using a cap-and-trade approach could result in substantial ancillary reductions in SO_2 emissions beyond those required under the CAIR policy for example.

2. Carbon Policy. One of the most important factors influencing how a multi-pollutant policy affects investment decisions at electric companies is whether or not the policy

158. Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units, (proposed Mar. 15, 2005) (to be codified at 40 C.F.R. pts. 60, 63, 72, and 75), *available at* http://www.epa.gov/air/mercuryrule/pdfs/camr_final_preamble.pdf.

159. Connecticut: CONN. GEN. STAT. § 22a–174j (2004) and Conn. Clean Air Regs; Massachusetts: 310 MASS. CODE REGS. 7.29(5)(a) (2005), *available at* http://www.mass.gov/dep/bwp/daqc/files/regs/729final.doc; Missouri: MO. CODE REGS. ANN. tit. 10, § 10-5.010 to -5.550 (2005), *available at* http://www.sos.mo.gov/adrules/csr/current/10csr/10csr.asp; New Hampshire: N.H. REV. STAT. ANN. §§ 125-O:1 to 125-O:10 (2005); New York: N.Y. COMP. CODES R. & REGS. tit. 6, §§ 201-7, 237-1 to 237-9, 238-1 to 238-8, *available at* http://www.dec.state.ny.us/website/regs/ch3.htm; North Carolina: N.C. GEN. STAT. § 143-215.107D (2004); Texas: *See, eg.*, 30 TEX. ADMIN. CODE § 101(H)(3) (2005) (for the Houston/Galveston nonattainment area); Wisconsin: WIS. ADMIN. CODE NR § 417, 428, 446 (2005), *available at* http://www.dnr.state.wi.us/org/aw/air/reg.

includes a cap on emissions of CO_2.[160] In the absence of a CO_2 policy, firms will invest significant resources in post-combustion controls at existing coal-fired and gas-fired facilities in order to reduce emissions of conventional pollutants. Once in place, these long-lived investments will further cement opposition to capping or taxing CO_2 emissions from electricity generators until the capital has depreciated.

If a multi-pollutant policy includes a cap on CO_2 emissions, the electricity sector will broaden the range of options it considers for reducing the entire basket of pollutants and begin to pay more attention to switching away from coal and toward greater use of natural gas and renewables. The inclusion of CO_2 will also, depending on the level of the cap, have a greater impact on the price of electricity paid by consumers, which in turn will encourage more energy conservation and efficiency as a way to reduce emissions of greenhouse gases.

Efforts to regulate emissions of CO_2 from the electricity sector have been concentrated at the state and regional level. Massachusetts and New Hampshire have adopted limits on CO_2 emissions from electricity generators.[161] In December of 2005, seven northeastern states covering a territory from Delaware to Maine (excluding Massachusetts and Rhode Island) announced an agreement to implement the Regional Greenhouse Gas Initiative (RGGI).[162] The governors of these states have signed a memoranda of understanding to develop a cap and trade program for CO_2 emissions from electricity generators within the region.[163] One challenge these states face is how to limit increases in generation and emissions of CO_2 outside the RGGI region.

3. RPS and Other Policies to Promote Renewables. The renewables portfolio standard is another policy tool that has become increasingly popular with states wanting to reduce emissions. As discussed *supra*, the emissions-reducing effects of an RPS are not as large as some had previously predicted.[164] However, the CO_2 emission reductions from an RPS set at about ten percent will more than offset the CO_2 emissions increases

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160. DALLAS BURTRAW & KAREN PALMER, ENVIRONMENTAL REGULATION OF ELECTRIC POWER GENERATION IN NEW APPROACHES ON ENERGY AND THE ENVIRONMENT (Richard Morgenstern & Paul Portney eds., 2005).

161. 310 MASS. CODE REGS. 7.29 (2006); NEW HAMPSHIRE CLEAN POWER STRATEGY, NEW HAMPSHIRE DEPARTMENT OF ENVIRONMENTAL SERVICES (2001), *available at* http://www.des.state.nh.us/ard/pdf/nhcps.pdf.

162. Regional Greenhouse Gas Initiative Memorandum of Understanding to Signatory States, *available at* http://www.rggi.org/docs/mou_12_20_05.pdf.

163. *Id*.

164. *See* PALMER, COST-EFFECTIVENESS, *supra* note 97, at 20.

predicted by Palmer and Burtraw to result from a transition to more widespread restructuring.[165] While an RPS is not a national policy, the federal renewable energy production credit (REPC), recently renewed and expanded to include more sources of generation, will continue to be in effect through 2007.[166] The REPC policy has emission-reducing effects similar to the ten percent RPS. If the REPC were continued indefinitely into the future, it could also serve to more than offset the emission increases which Palmer and Burtraw found likely to result from electricity restructuring.[167]

4. Gas Prices. The effect of high gas prices on emissions from the electricity sector presents a mixed bag of benefits and disadvantages. On the one hand, higher natural gas prices make coal-fired generation more attractive relative to natural gas units, so coal units tend to be dispatched more than natural gas, which tends to raise emissions. At the same time, renewables generation also increases, which has an emission-reducing effect. Also, higher gas prices tend to lead to higher electricity prices which can have a dampening effect on electricity demand.

The net effect on emissions will depend, among other things, on the size of the gas price increase. In one analysis, Palmer and Burtraw found that a fifteen percent rise in natural gas prices above the long-run levels predicted in the reference case to the EIA's 2003 Annual Energy Outlook would result in a three percent increase in electricity prices and a one percent reduction in electricity demand.[168] This price increase also would result in a ten percent reduction in gas generation with almost offsetting increases in coal and renewables generation. In their analysis, the net effect on CO_2 emissions from the electricity sector was zero.[169]

B. Other Things Matter More to Consumers than Competition

While the effects of electricity restructuring on retail prices have been mixed and the ultimate result of markets setting retail prices is yet to be achieved in many restructuring states,

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165. PALMER & BURTRAW, ELECTRICITY, RENEWABLES, AND CLIMATE CHANGE, *supra* note 97, at 30 tbl. 4 col. 6.

166. *See* Energy Policy Act of 2005, Pub. L. No. 109-58, § 1301, 119 Stat. 987–990 (2005) (expanding scope of eligible resources under Renewable Energy Production Credit and extending it through Dec. 31, 2007).

167. PALMER & BURTRAW, ELECTRICITY, RENEWABLES, AND CLIMATE CHANGE, *supra* note 97, at 30 tbl. 4 col. 6.

168. PALMER, COST-EFFECTIVENESS, *supra* note 97, at 50.

169. *Id.* at 48.

consumer savings have generally not met expectations. Initial price declines of ten percent or more have not generally been sustainable over time as fuel costs have risen and markets have been thin. Because most of the high-cost states have gone through restructuring, additional savings from having more low-cost states restructure are likely to be even smaller than the savings experienced to date, with simulation analysis suggesting price reductions on the order of two percent from making retail competition nationwide.[170]

These small effects pale in comparison to the potential effects of other policy initiatives or changes in fuel prices on electricity prices and consumer welfare. Two factors in particular merit further discussion: allocation of CO_2 emission allowances and changes in natural gas prices.

While the spread of retail electricity restructuring to additional states seems unlikely, the prospects for some sort of binding CO_2 constraint being imposed on the electricity sector may be higher. Regional initiatives such as RGGI in the northeast and ongoing discussions among west coast governors about the possibility of a binding climate policy for their states suggest that regional constraints are likely.[171] These initiatives aim to provide model systems that could be the foundation for a national CO_2 policy.

One important design question associated with any cap-and-trade program is the question of how to initially allocate the emission allowances. Three basic approaches have been suggested.[172] One is to allocate allowances to firms at no cost, based on some historic measure of performance, either generation or emissions, and to use that unchanging formula indefinitely.[173] (This approach was used to allocate SO_2 allowances under Title IV.[174]) A second approach is to allocate allowances to firms at no cost, based on recent rather than historical measures of performance such as generation.[175] Firms in some states have used this approach to allocate NOx allowances under the NOx SIP Call program.[176] A third approach

170. PALMER ET AL., *supra* note 40, at 39–42.

171. Rose, *supra* note 100.

172. DALLAS BURTRAW ET AL., THE EFFECT OF ALLOWANCE ALLOCATION ON THE COST OF CARBON EMISSIONS TRADING (Resources for the Future, Discussion Paper 01-30, 2001), *available at* http://www.rff.org/Documents/RFF-DP-01-30.pdf.

173. *Id.*

174. Clean Air Act, 42 U.S.C. §§ 7651–7651o (2005).

175. BURTRAW ET AL., *supra* note 172, at 2.

176. EPA's Clean Air Markets—NOx Budget Trading Program (2004), *available at* http://www.epa.gov/airmarkets/fednox/.

is to auction emission allowances to the highest bidder.[177] Typically, states have opted not to use this last approach, although the State of Virginia sells a small portion of NOx SIP Call allowances in an auction.[178]

When allowances are given away for free based on a historic measure, the approach used in most programs, the impact on electricity prices varies between regulated states and competitive states. In competitive states generation prices are based on the marginal cost of the marginal unit supplying electricity at a given time, and if that unit must surrender emission allowances to generate, then the competitive price will reflect the opportunity cost of using those allowances. Regulated states set prices based on average cost and treat the free allowances as having zero cost for rate-setting purposes. This difference can have a big effect on electricity prices. For instance, the analysis by the Energy Information Administration of the McCain-Lieberman economy-wide carbon-cap proposal is sensitive to the assumption about cost-recovery rules.[179] In regulated regions, the analysis assumes that ratepayers receive ninety percent of the benefits of freely distributed allowances and that company shareholders receive ten percent, meaning that only a small part of allowance value is reflected in the electricity price.[180] However, in competitive regions, when a fossil-fired unit is on the margin and sets the price in the region, the electricity price fully reflects the opportunity cost of emission allowances.[181] This difference in prices dwarfs the magnitude of the savings that have been realized so far from restructuring or are expected from further restructuring. On the other hand, if allowances are auctioned, the difference in electricity prices between regulated and unregulated regions disappears because firms must purchase emission allowances, and thus electricity prices everywhere reflect the opportunity cost of those allowances.

The relationship between electricity prices and natural gas

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177. BURTRAW ET AL., *supra* note 172, at 2.

178. DALLAS BURTRAW, KAREN PALMER & DANNY KAHN, RESOURCES FOR THE FUTURE, EMISSIONS ALLOWANCES IN THE REGIONAL GREENHOUSE GAS CAP-AND-TRADE PROGRAM at 2 (June 2005).

179. ENERGY INFO. ADMIN., ANALYSIS OF S.139, THE CLIMATE STEWARDSHIP ACT OF 2003, at 133 (June 2003), *available at* http://www.eia.doe.gov/oiaf/servicerpt/ml/pdf/sroiaf(2003)02.pdf.

180. ENERGY INFO. ADMIN., ANALYSIS OF S.139, THE CLIMATE STEWARDSHIP ACT OF 2003: HIGHLIGHTS & SUMMARY, at 13 n.21 (June 2003), *available at* http://www.eia.doe.gov/oiaf/servicerpt/ml/pdf/summary.pdf.

181. *Id.* at 13. Moreover, the social cost from using an auction can be one-third that of using historic allocation to distribute emission allowances in a nationwide CO_2 trading program. *See* TIMOTHY BRENNAN, ET AL., *supra* note 3.

prices becomes even more significant when electricity price-setting occurs in competitive markets. Increases in the price of natural gas affect electricity prices in both regulated and unregulated states, but in different ways. In regulated states, the increase in gas costs will raise the cost of using natural gas generators, and these higher costs, to a first approximation, will affect electricity generation prices in direct proportion to the share of natural gas generation in the mix.[182] However, in competitive markets the increase in generation costs with natural gas will increase the market price of electricity whenever gas generators are on the margin, and the market price will go to all kilowatt-hours sold at that time in the market, whether generated using natural gas or some other fuel. This means that during peak periods, when gas-fired units are typically on the margin, the impact of a gas price increase on electricity price is much greater under competition than it would be under regulation.

VI. CONCLUSIONS

Electricity restructuring has had both predictable and unanticipated effects on the mix of fuels and technologies used to generate electricity. Despite the dearth of new coal-fired facilities brought on line in the 1990s, capacity factors at coal-fired plants have increased substantially since 1996, helping to maintain coal's roughly fifty percent share of total generation. Investments in new gas-fired facilities have reached unprecedented levels in the last few years, exceeding expectations that many had for new investment and exceeding demand for output from those new facilities. No additional nuclear plants have gone off-line permanently since 1998, and generation at existing nuclear plants has grown significantly over the past ten years. The availability of green-power offerings, particularly from traditional utilities, has increased substantially, but their share of the market has remained quite low. Instead, renewable energy is being promoted through other means, such as renewable portfolio standards, which are more prevalent in states that have undergone restructuring than in those that have not.

The contribution of restructuring to these many changes in electricity supply is difficult to discern from aggregate time-series data, particularly given the concurrent changes in environmental regulations and input fuel prices. Most notably,

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182. This simple statement ignores any reduction in the share of gas generation that might result as utilities shift away from gas toward greater use of coal. It also ignores any increase in the price of coal that could result from greater demand for this fuel.

increases in natural gas prices have played a role in the growth in coal-fired generation. To the extent that these price increases are driven by supply-side effects, such as lower productivity at existing and new gas wells, and not demand shifts, this phenomenon is largely separate from restructuring itself.

It is even more challenging to estimate the effect of restructuring on electric sector emissions. Ex ante analyses suggested that effects on emissions of NOx and CO_2 of restructuring were likely to be small, while no changes in emissions of SO_2 emissions were expected due to the role of the aggregate emissions cap. Research shows that the imposition of the SIP Call cap-and-trade program would limit substantially any increases in NOx emissions related to restructuring. Restructuring-related increases in aggregate NOx emissions in the East are likely to be undone by the annual NOx cap-and-trade program found in the EPA's CAIR rule. A four-pollutant bill that caps emissions of NOx, CO_2, SO_2 and mercury from the electricity sector, using a cap-and-trade approach, would eliminate all restructuring-related increases in aggregate emissions of these pollutants nationwide. An economy-wide cap on carbon emissions would also mitigate increases in that pollutant as well.

The main environmental effect of restructuring may stem more from its effect on the future of new environmental policies than its effect on emissions directly. Emissions cap-and-trade programs with freely distributed allowances can have dramatically different effects on electricity prices between states where electricity markets are regulated and those where markets have been restructured. In restructured states, prices reflect the full opportunity cost of emission allowances used by the marginal firm, whereas in regulated states, the electricity price does not reflect the cost of freely allocated allowances. This difference can be very substantial for CO_2 allowances and may create a geographic divide in willingness to accept these regulations. The difference could also have serious implications for the ability to provide incentives to conserve electricity in regulated states.

Finally, the most important factor affecting electricity prices over the last few years has not been the direct result of public policy. Rather, the wild card affecting electricity price and the choice of technology for electricity generation has been the price of natural gas. If natural gas prices had remained relatively low, as they did in the 1990s when the movement toward restructuring took hold, the environmental consequences of restructuring might be more easily discerned. The massive investment in natural gas-fired technology that occurred at the end of that decade, coupled with lower natural gas prices, would have led to an expanded role for gas at the expense of coal-fired generation, with associated reductions in emissions of those pollutants not under emission caps. The unexpected magnitude of investment in natural gas generation set the stage for an accelerated transition to a long-term restructuring based on a large role for gas with its associated environmental advantages. But alas, the rise in gas prices early in this decade preserved the role for coal. On balance, the environmental impact of restructuring seems to be small in nature, though probably ultimately positive, given that the one most tangible consequence of restructuring is the large investment in natural gas facilities that are part of the technology mix we have today.

TABLES

Reactor Unit Name	Net Capacity (Mwe)	Location	Initial Commercial Operation	Date of Shutdown
Big Rock Point	67	Michigan	March 1963	August 1997
Haddam Neck	560	Connecticut	January 1968	December 1996
Maine Yankee	860	Maine	December 1972	August 1997
Millstone- 1	641	Connecticut	March 1971	July 1998
San Onofre- 1	436	California	January 1968	November 1992
Trojan	1095	Oregon	May 1976	November 1992
Zion 1	1040	Illinois	December 1973	January 1998
Zion 2	1040	Illinois	December 1974	January 1998

Table 1. Nuclear Reactors Shut Down Since 1992

Emission	CO_2 (million metric tons)	SO_2 (thousand short tons)	NOx (thousand short tons)
1992	1,951	16,534	8,501
1996	2,155	14,199	6,909
1997	2,223	14,876	6,956
1998	2,313	13,760	6,859
1999	2,327	13,690	6,305
2000	2,429	12,427	5,918
2001	2,380	12,063	5,550
2002	2,398	11,567	5,282
2003	2,409	11,653	4,836

Table 2. Annual Emissions from Electricity Generators for Selected Years 1992–2003[183]

[183] The emissions totals include emissions from all useful heat input at combined-heat-and-power plants. ENERGY INFO. ADMIN., ELECTRIC POWER ANNUAL 2003, tbl. 5.1 (2004), (emissions for SO2 and NOx converted to short tons), *available at* http://www.eia.doe.gov/cneaf/electricity/epa/epa_sum.html.

State	Pollutants	Form of Regulation	Effective Dates
Connecticut	SO_2, NOx	Emission rate standards	2003 for SO_2 2002–2003 for NOx
Massachusetts	SO_2, NOx, CO_2, Hg	Emission rate standards for SO_2, NOx and CO_2 Reduction from baseline emission levels for Hg	Phased in from 2004–2006 for SO_2 and NOx Phased in from 2005–2007 for CO_2, 2008 for Hg
Missouri	NOx	Tradable performance standard for summer emissions only	2004
New Hampshire	NOx, SO_2, CO_2	Emissions caps	2006
New York	NOx, SO_2	Emissions caps	2005 for NOx Phased in from 2005–2008 for SO_2
North Carolina	NOx, SO_2	Company-specific emissions caps	Phased in from 2007–2009 for NOx, Phased in from 2009–2013 for SO_2
Texas	NOx, SO_2	Regional emissions caps	2003
Wisconsin	NOx, SO_2, Hg	Emission rate standards	Phased in from 2007–2012 for SO_2 and NOx, Phased in by 2012 for Hg

Table 3. Selected States with Multi-Pollutant Rules Affecting the Electricity Sector

FIGURES

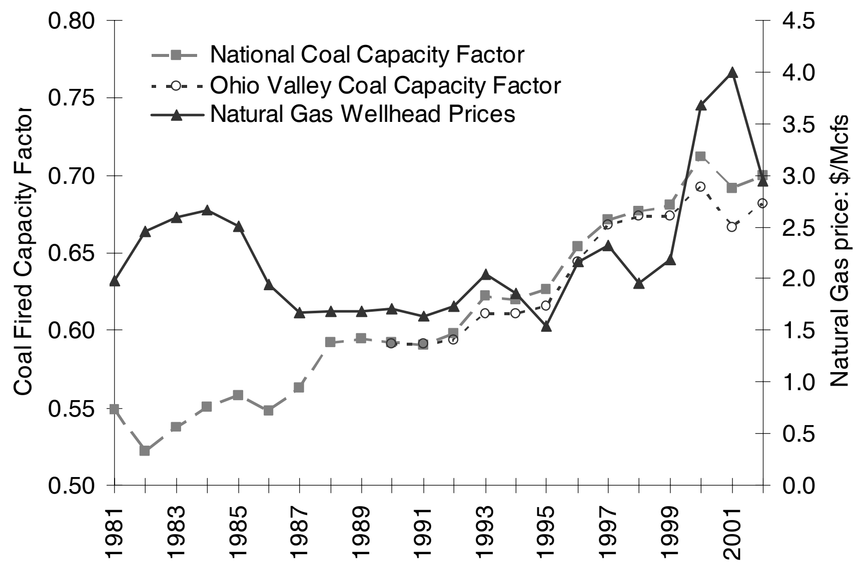

Figure 1. Capacity Factors for Coal-Fired Generators and Natural Gas Prices

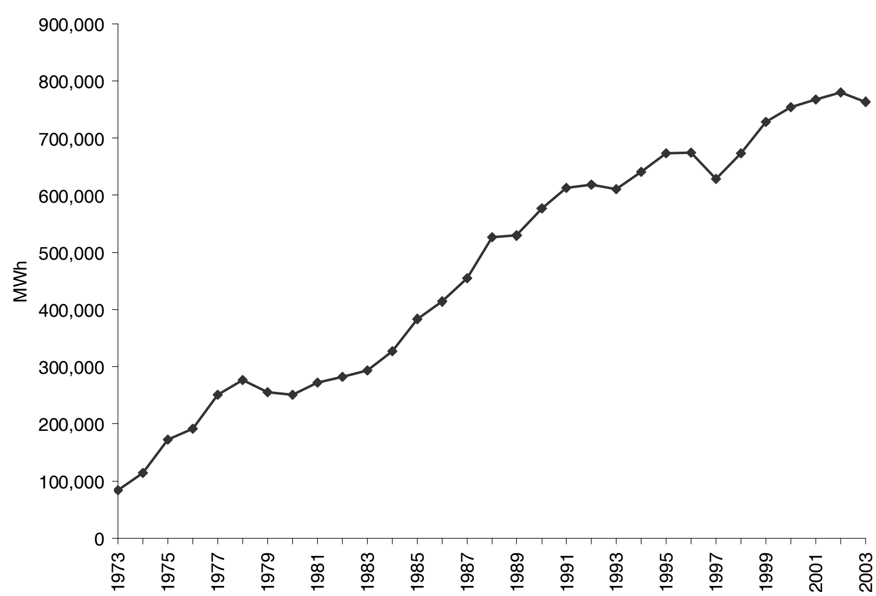

Figure 2. Nuclear Generation

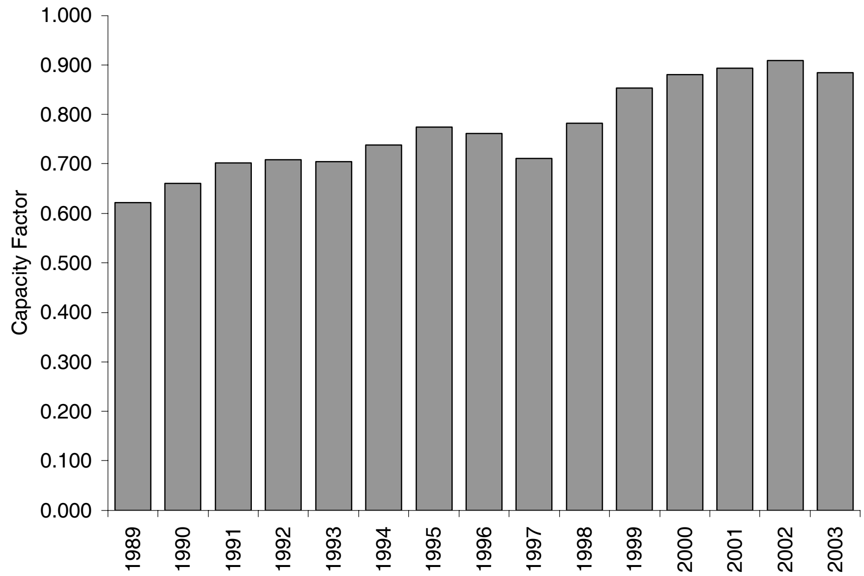

Figure 3. Nuclear Capacity Factor

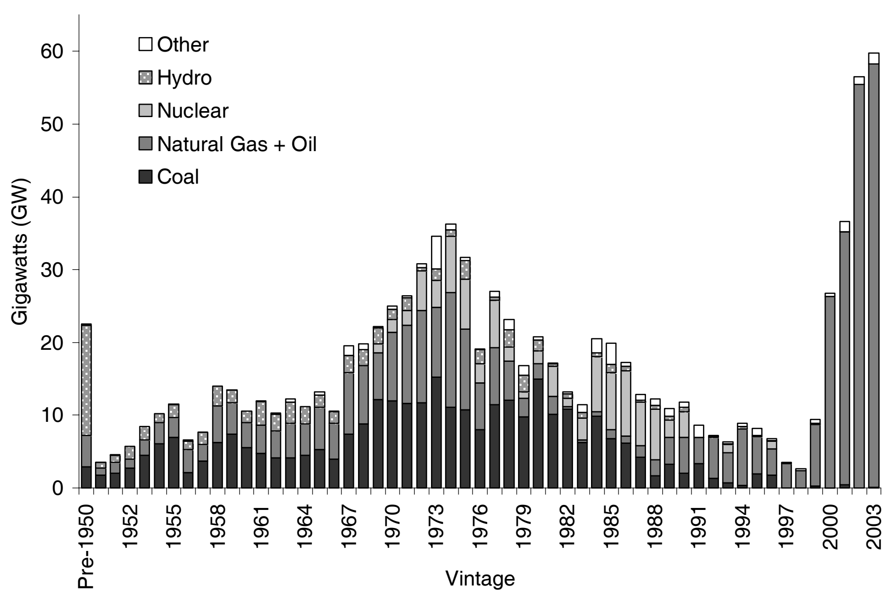

Figure 4. Capacity Additions by Year and Fuel

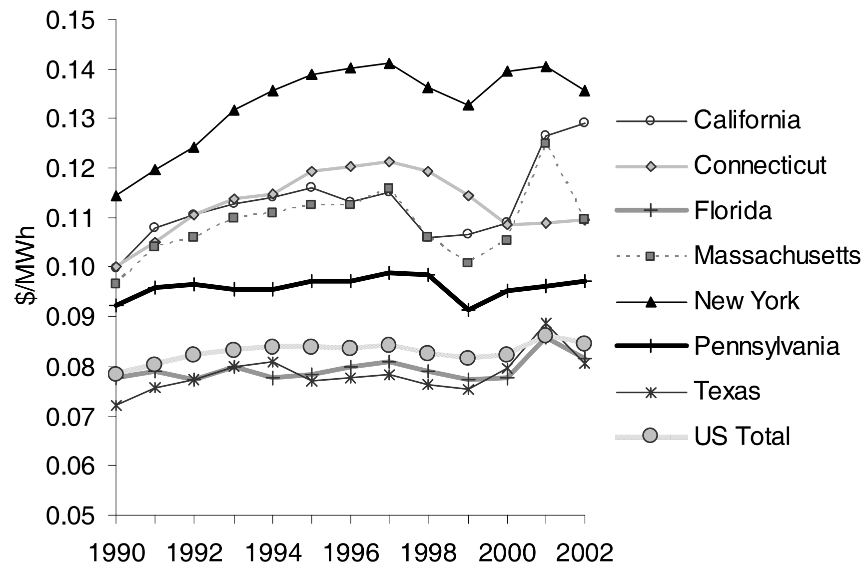

Figure 5. Average Annual Retail Electric Prices for Residential Customers in Selected States and Nationwide

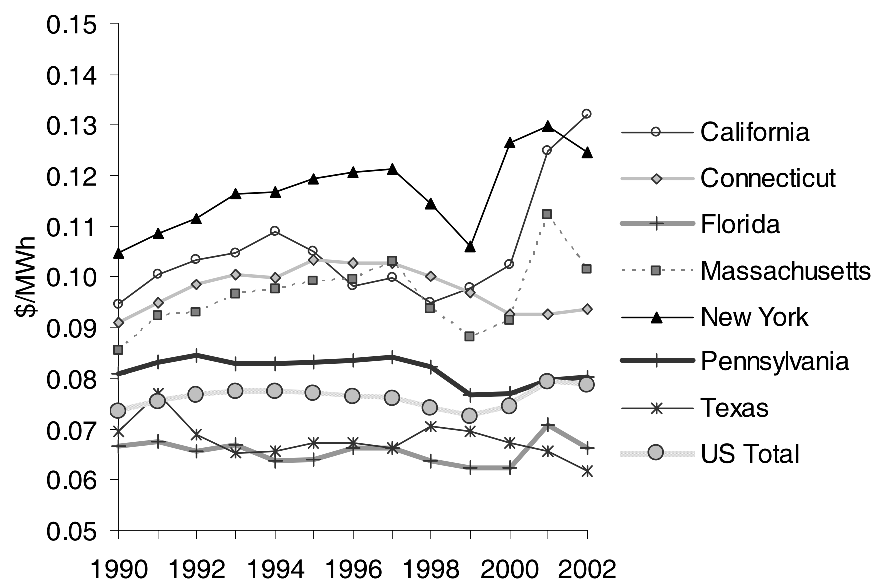

Figure 6. Average Annual Retail Electric Prices for Commercial Customers in Selected States and Nationwide

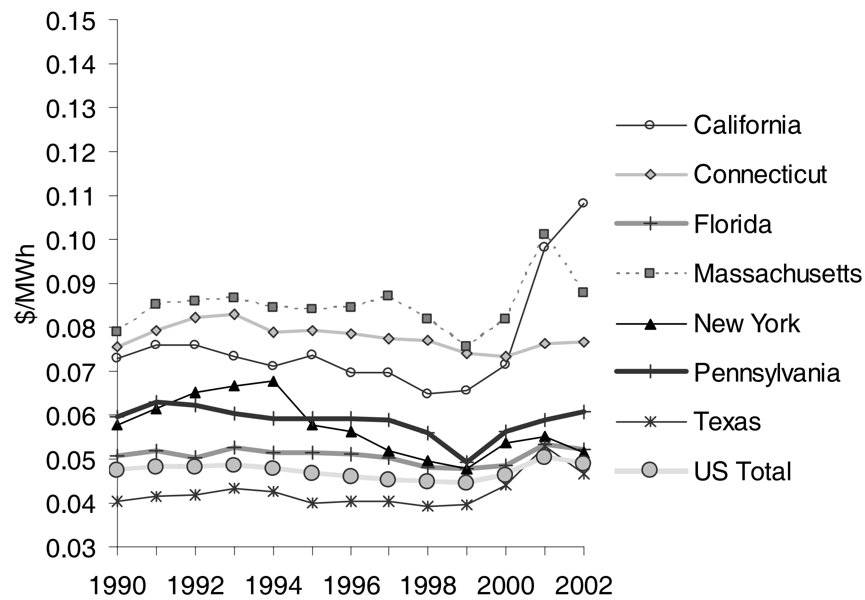

Figure 7. Average Annual Retail Electric Prices for Industrial Customers in Selected States and Nationwide

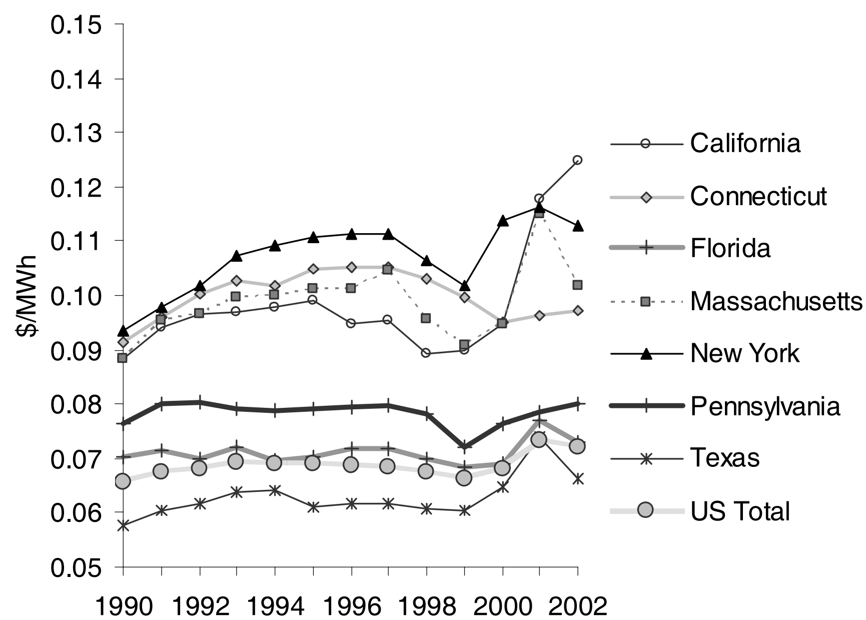

Figure 8. Average Annual Retail Electric Prices for All Customers in Selected States and Nationwide