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ABA SECTION OF ENVIRONMENT, ENERGY AND RESOURCES

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MESSAGE FROM THE CHAIR OF THE GAS AND ELECTRICITY MARKETING COMMITTEE

Lyle D. Larson

The consolidated Energy Committees Newsletter is published approximately quarterly, and a single Energy Committee will sometimes take sole responsibility for preparing an issue of the newsletter. The Gas and Electricity Marketing Committee has produced this issue, which contains articles on (1) state-level responses to recent retail electricity rate spikes, (2) energy trading bankruptcies, (3) oversight of the over-the-counter energy trading markets, and (4) the new master renewable energy certificate (REC) trading agreement. We want to recognize and thank our committee's vice chair of Publications and Technology, Jeff Gray of Howard & Howard in Ann Arbor, MI, who assembled and edited this issue of the newsletter.

Our committee includes over 250 members serving various areas of the energy industry. We seek to address and communicate on-going changes in energy law and practice of particular value to our members, with a focus on gas and electricity marketing and trading. Our focus is not, however, merely on the marketing and trading of physical products, but extends to financial derivatives and risk management products relating to the marketing and trading of energy and energy-related commodities. If you already are a member of our committee, thank you. If you are not a member, we hope you will join us. We also hope you will take an active role in our committee as we establish a community where leading and complex issues can be addressed in ways that enhance our individual practices, and that serve the broader needs of the industry.

Perhaps the best way to illustrate the focus of our committee is to provide an overview of the organizational structure. Details about the committee can be found on the ABA's Web site at http://www.abanet.org/environ/committees/elct/. Our leadership team includes the traditional vice chair roles of Programs (John Shepherd of Skadden Arps), Publications & Technology (Jeff Gray of Howard & Howard), Outreach (Kathleen Magruder of Citigroup Energy), and Membership (Casey McFaden of Hunton & Williams). In addition to these standing vice chair positions, each year we evaluate current trends to identify a group of specialist vice chair positions that focus on subject matters meriting particular attention. During the 2007 ABA year, these areas of focus and the specialist vice chairs are (1) Standardized Energy Trading Contracts (Melissa Lauderdale of Edision Electric Institute), (2) Energy Creditors' Rights and Bankruptcy (Paul Turner of Sutherland Asbill & Brennan), (3) Financial and Energy Derivative Products and Trading (Harlan Murphy of Sutherland Asbill & Brennan), (4) Compliance and Enforcement (George Billinson of Morgan Lewis & Bockius), and (5) Policy and Legislation (Sean Cunningham of Hunton & Williams).

We invite you to participate in our committee as a newsletter contributor, *Year in Review* contributor, event organizer, or perhaps even as a future specialist

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This newsletter is a cooperative effort of Energy and Natural Resources Litigation, Energy Facilities and Siting, Gas and Electricity Marketing, Hydro Power, International Energy and Resources Transactions, Petroleum Marketing, Global Oil and Gas Exploration and Production, and Renewable Energy and Resources Committees, and the Special Committees on Restructuring the Electric Industry and on Energy and Environmental Finance.

On behalf of the energy committees, Jeffrey M. Gray was editor of this issue. The other Energy Committee newsletter vice chairs are James E. Hickey, Jr., Marla E. Mansfield, Lauren McGregor, Peter D. Mostow, Andrew Ratzkin, Jamie Rhymes and Roger Stark.

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This newsletter is a publication of the ABA Section of Environment, Energy, and Resources, and reports on the activities of the committee. All persons interested in joining the Section or one of its committees should contact the Section of Environment, Energy, and Resources, American Bar Association, 321 N. Clark St., Chicago, IL 60610.

vice chair. We look forward to hearing from you, and hope that you enjoy this issue of the Energy Committees Newsletter.

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OVERVIEW OF RECENT STATE ELECTRICITY RATE INCREASES AND LAWMAKERS' RESPONSES

Jeffery S. Dennis

For decades, retail electricity service was provided by regulated electric utilities in franchised monopoly service areas. Retail rates were set by state regulators under a cost-of-service formula. A monopoly electric utility was allowed to collect rates that recovered the costs it incurred in providing electricity service to end users, plus a reasonable return on its investment. To adjust its rates to reflect the current cost of service, a utility periodically filed a rate case with the state regulatory agency.

In many states, this ratemaking paradigm changed over the past decade as legislatures passed laws to restructure the electric-utility industry and introduce retail competition. Many of those laws included rate freezes and other transitional measures intended to foster competition and ensure that the former monopoly utilities could not keep out new suppliers.

Over the past several years, retail electricity rates have increased nearly across the board, while some states that passed electric-utility restructuring legislation have experienced sharp increases. The resulting rate shock in those states has outraged ratepayers and caused political and regulatory upheaval. The most notable examples are in Maryland and Illinois, where rate increases became a hot-button political issue for lawmakers and a burden for utility regulators.

In these and other states, legislators and regulators have already responded, and are contemplating further measures to address the steep rate increases. Still other states, seeing the chaos caused by electricity rate spikes in Maryland, Illinois, and elsewhere, are proactively considering regulatory reforms to avoid such scenarios.

This article presents an overview of the recent rate spikes and responses by state governments. These responses provide some indication of how state regulatory models may again be changing.

I. Restructuring and Rate Freezes

Numerous factors contribute to cost increases for any form of energy, including electricity, and all of those factors cannot be addressed here. However, in those states that enacted some form of electric-industry restructuring and have recently experienced rate spikes, certain factors associated with their restructuring laws can be identified.

First, nearly every state restructuring program included a transition plan with measures intended to protect consumers and foster competition. The most notable measures adopted by nearly all of the states that restructured were retail rate freezes, which locked in the rates that incumbent utilities could charge during the transition period. In many instances, electricity rates were capped at levels below the then-current rates to guarantee savings to customers during the transition period. For example, Illinois' restructuring law prohibited regulators from approving any rate increase during the transition period, and mandated that existing rates be reduced 15 to 20 percent, depending on the size of the utility and other factors.[1] Maryland's restructuring statute expressly capped rates and mandated residential rate reductions of between three percent and 7.5 percent of current rates.[2] Policymakers adopted these caps not only to ensure that customers could achieve early savings, but also with the intent to establish a benchmark "price to beat" that would inform customers about whether to switch suppliers.[3]

Second, many state restructuring laws required or strongly encouraged the incumbent utilities to sell their power plants and become "wires" companies responsible only for delivering electricity to end users. For example, Connecticut law forbade electric utilities from recovering their stranded costs, or costs incurred as a result of restructuring, unless they divested their power plants.[4] Illinois law was less proscriptive, instead expressly allowing utilities to divest generating assets, and permitting regulators to disallow divestiture only if the sale or transfer would render the utility unable to provide safe and reliable service, or would create a strong likelihood that the utility would seek a rate increase during the transition period.[5] These measures were intended to promote competition and ensure that the incumbent utilities, which already had recovered most of the capital costs for their existing power plants, could not dominate the market.

Third, an incumbent electric utility generally retained the obligation to supply electricity to any consumer in its franchised territory who did not switch to an alternative electricity supplier, or who had chosen an alternative electricity supplier but then returned to the incumbent utility, perhaps because the alternative supplier had ceased its service. This obligation is sometimes called "standard-offer" or "default" service.[6] Because the incumbent utilities holding this obligation often had sold or transferred their power plants, they were forced to procure electricity in the wholesale markets to meet their standard-offer and default service obligations. These standard-offer and default service obligations typically were significant, in part because few customers switched to alternative suppliers during the transition periods.[7]

II. Rising Cost of Fuel

From the mid-1990s to today, during the time that most of the state restructuring transition mechanisms and retail rate freezes were in effect, prices of the common fossil fuels used to generate electricity—coal, natural gas, and oil—rose significantly. According to Energy Information Administration (EIA) reports, the average cost of fossil fuels used for electricity generation was 114 percent higher in 2005 than in 2002.[8] Going back further, in financial terms, the average cost of fossil fuels rose from 152 cents/10^6 British thermal units (BTUs) in 1996 to 326 cents/10^6 BTUs in 2005.[9]

Moreover, most of the new generation constructed or planned in recent years has been natural-gas fueled.[10] The price of that particular fossil fuel increased the most of any, rising 130.6 percent between 2002 and 2005.[11] In financial terms the price of natural gas for electricity generation rose from 264 cents/10^6 BTUs in 1996 to 821 cents/10^6 BTUs in 2005.[12] This sharp rise in natural gas prices is significant, not only because of the number of new gas-fueled power plants, but also because those plants often set the wholesale market price for electricity, particularly in the Northeast.

III. Rate Increases—Some Examples

Average retail electricity rates have increased over the past several years, due in no small part to the fuel-cost increases noted above. The EIA reports that average retail prices increased by 7 percent in 2005 compared to 2004.[13] Moreover, average retail prices increased from 6.86 cents/kilowatt-hour in 1996 to 8.14 cents/kilowatt-hour in 2005.[14] But the combination of fuel-cost increases and the expiration of rate caps led to far more dramatic rate increases in some restructured states, taking the form of "rate shock."

Maryland is one example. In early 2006, auctions were conducted to procure wholesale electricity to satisfy the standard-offer service obligations of Baltimore Gas & Electric Company (BG&E) and the other Maryland utilities, all of which held no generation of their own. Maryland's rate caps adopted as part of restructuring had already ended for two of the state's incumbent utilities, and would end in mid-2006 for BG&E. The auctions' impact on rates was staggering, with residential customer bills projected to increase between 35 and 72 percent.[15] BG&E's rates were at the high end of those projections, because BG&E would be procuring 100 percent of its standard-offer service obligation for the first time since its rate caps expired.[16]

Rate increases in Illinois were also significant. There, legislatively mandated rate caps ended on Jan. 1, 2007. Because the state's incumbent utilities with standard-offer service obligations had sold or spun off their generation under the restructuring statute, the Illinois Commerce Commission (ICC) had determined in earlier proceedings that competitive auctions should be conducted to procure electricity supplies to satisfy utility obligations. September 2006 auction results for the post rate-cap period translated into rate increases of 21 to 53 percent for residential customers.[17] Rate impacts were also significant for many classes of non-residential customer.[18]

In both Maryland and Illinois, regulatory agency staff issued reports comparing post-auction, post rate-cap retail rates to the rates that existed prior to the implementation of rate caps under restructuring, taking into account the increased cost of fuel. A report by ICC staff found that the new rates were 3 percent less to as much as 45 percent more, depending on utility.[19] A report by Maryland Public Service Commission staff found that percentage rate increases for electricity in the post rate-cap period were substantially less than percentage cost increases for fuel over the same period.[20]

While the situations in Maryland and Illinois received the most public attention, other examples exist. In Delaware, incumbent utility Delmarva Power & Light announced in early 2006 that after its rate caps expired, electricity rates would jump 59 percent for the typical residential customer.[21] In Connecticut, regulators reached a settlement in late 2006 with United Illuminating for standard-offer service, allowing the utility to phase in a 52 percent rate increase for residential customers during 2007, with a higher non-phased increase for commercial and industrial customers.[22]

IV. State Responses

All of the states noted above have enacted new legislation in response to increased electricity rates and the end of their restructuring transition periods. These responses, and legislative and regulatory activity in other states, provide some insight into what changes might be made to state regulatory frameworks in the future.

A. Rate Increase Phase-Ins

A common response has been to mandate that electricity rate increases be phased in over a period of years. For example, the Maryland state legislature passed, over the governor's veto, a law that included provisions requiring BG&E to phase in rate increases, which were projected to be as high as 72 percent.[23] Specifically, it limited BG&E's rate increase to 15 percent for the period July 1, 2006 to June 30, 2007, and thereafter allowed customers to begin paying full market rates or opt in to a further deferral of the full increase. Full market rates will go into effect beginning Jan. 1, 2008, and the law allows BG&E to recover the deferred rates, and its costs to implement the deferral, over a ten-year period.

Delaware also enacted legislation in response to the rate increases facing its residents, including provisions requiring Delmarva Power & Light to phase in those rate increases.[24] In an important difference from Maryland's phase-in plan, customers were permitted to opt out of Delaware's phase-in plan. For customers that did not opt out, rates increased 15 percent on May 1, 2006, another 25 percent on Jan. 1, 2007, and will increase 19 percent on June 1, 2007. A true-up will occur on Jan. 1, 2008, allowing Delmarva to collect all deferred amounts.

B. Rate Freeze Extensions

Mandated rate-freeze extensions have been used in the past, and while they have been considered in response to the most recent rate increases, they have not been widely employed. Illinois legislators continue to debate an extension of the retail rate freeze that recently expired in that state.[25] During the ongoing debate, utility executives have argued that an extension of rate freezes would put them in financial jeopardy and threaten their ability to provide reliable service. Commonwealth Edison's chairman and CEO stated that the company's cost to procure wholesale electricity would exceed by $1.4 billion what it could recover in frozen retail rates.[26] Maryland, Delaware, and other states have not extended their rate freezes, perhaps because of the same difficult questions of cost recovery and financial stability that can arise for their incumbent utilities.

C. Overhauls of Regulatory Frameworks

Aside from rate-increase phase-ins or rate-freeze extensions, various states are considering overhauls of their electric-industry regulatory frameworks. Some states took this approach in the wake of the 2000-2001 California energy crisis. Arkansas and New Mexico, among others, acted quickly after the crisis to scrap or indefinitely postpone implementation of their electric-industry restructuring laws. Moreover, legislation is now moving through the Montana Legislature that would repeal Montana's restructuring laws. If approved, the measure would, among other things, return the state's electric-utility industry to a cost-of-service form of regulation.[27]

Virginia has replaced its restructuring laws with a new regulatory scheme, even though its rate freeze will not expire until 2010. In the wake of recent rate spikes experienced by its neighbors, Virginia enacted legislation during the 2007 session that repeals the ability of most consumers to shop for alternative electricity suppliers.[28] The new legislation establishes a modified form of cost-of-service regulation that requires regulators to set the rate of return for an electric utility no lower than the average returns of other electric utilities in a peer group.[29] This rate of return can be adjusted downward or upward based on the utility's efficiency and performance. If regulators find during a required biennial review that the utility is earning an amount above the average rate of return for the peer group, the regulators can either order rate reductions or direct the utility to share the excess earnings with customers by crediting 60 percent of the excess to customer bills.

D. Targeted Changes to Regulatory Frameworks

1. Power Plant Ownership

In contrast to a repeal or re-write of state electric-industry restructuring laws, some states have made targeted changes to those laws or to their regulatory approaches. One example relates to the feature in many electric-industry restructuring programs that required or encouraged incumbent utilities to divest their power plants to help develop competitive markets. Some states have already eased ownership restrictions, and may continue to back off this policy and allow incumbent utilities to own power plants and include those plants in their cost-of-service rates.

In Connecticut, legislation passed in 2005 allows incumbent utilities that were previously required to divest their power plants to develop, own, and operate up to 250 megawatts of generating capacity.[30] However, that provision dictates that any incumbent utility constructing new capacity must sell the power plant or auction off its output no later than five years after commercial operation. Maryland also now allows incumbent utilities to construct or acquire and own power plants to meet their standard-offer service obligations, subject to regulatory approval.[31]

In Arizona, a 2005 rate settlement approved by regulators allowed incumbent utility Arizona Public Service Company (APS) to acquire and include in its cost-of-service rates five power plants previously held by its parent, Pinnacle West Energy Corporation.[32] Regulators approved this acquisition and rate treatment despite their earlier support of APS' divestiture of its generation to encourage wholesale competition, finding that the acquisition would provide significant benefits to ratepayers over other options, such as building new power plants or issuing competitive solicitations.

2. Wholesale Procurement Practices

Another example of targeted change is setting standards or mandating certain procedures for the procurement of electricity by incumbent utilities to serve standard-offer or default customers. Maryland's 2006 legislation adopted wide-ranging provisions requiring the use of a "competitive process" to obtain supply at "the best price . . . in light of market conditions" for residential and small commercial standard-offer customers.[33] The new law allows regulators to establish a wholesale bidding process to (1) obtain a blended portfolio of short, medium, and long-term supply, (2) require or allow the procurement of energy efficiency or conservation measures, and (3) stagger or alter the dates for competitive wholesale auctions to limit price volatility and take advantage of favorable market conditions.[34]

An administrative law judge in Pennsylvania recently recommended that state regulators approve a plan by PPL Corporation (PPL) to procure supply through six staggered auctions held through 2009, when PPL's rate freeze expires, which could hedge costs and prevent price spikes like those experienced in Maryland and Illinois.[35]

Virginia's proposed re-write of its electricity laws, discussed above, would require that rates be reviewed on a biannual basis.[36] More states, including those that have not restructured, may follow this approach and require more frequent rate-case filings by utilities to smooth out the retail effects of short-term fluctuations in wholesale markets.[37]

3. Supply Diversity

Delaware's 2006 legislation, in addition to phasing in Delmarva Power & Light's rate increase, mandated that the utility engage in integrated resource planning (IRP) when securing supply to meet its standard-offer and default service obligations.[38] IRP, which has been used in traditional cost-of-service regulation in several states since the 1980s, will require Delmarva to develop a plan to acquire "sufficient, efficient and reliable resources to meet its customers' needs at minimal cost" and, in so doing, to take into account several factors, explicitly including generation source diversity. Delaware's new IRP statute also notes that demand-side management programs can be considered in Delmarva's planning, which could include programs to encourage customers to reduce consumption.

Similar demand-side measures to reduce reliance on traditional fossil-fuel plants were included in recent legislation in Virginia, Maryland, and Connecticut. Virginia's legislation sets a goal of reducing electricity consumption by 10 percent by 2020.[39] Maryland's new law setting standards for the procurement of electricity supply to serve standard-offer or default service customers allows regulators to require or allow incumbent utilities to procure energy efficiency, conservation, or other services to reduce electricity demand.[40] Connecticut's 2005 legislation contains provisions to encourage consumers to reduce demand, including a requirement that incumbent utilities implement time-of-use and seasonal rates to reflect the costs of electricity during peak and off-peak demand periods, and a requirement that utilities offer interruptible or load-response rates to large customers.[41] The Connecticut law also requires regulators to establish grant programs to encourage the development of distributed generation resources, or small generating units that can supply a customer's own needs and send excess power to the grid.[42]

V. Conclusion

The responses of states to the recent sharp increases in retail electricity rates include phase-ins, stop-gap measures, overhauls of the regulatory framework, and targeted changes to law. As restructured states continue to address rising energy costs, they must grapple with whether to (1) maintain an industry structure that allows customers to shop for alternative electricity suppliers, (2) return to the old cost-of-service model, or (3) adopt a new regulatory paradigm.

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Notes:

1. 220 Ill. Comp. Stat. Ann. 5/16-111(a)-(b) (LexisNexis 2007).
2. Md. Code Ann., Public Utility Companies § 7-505(d) (LexisNexis 2006).
3. Kenneth Rose and Venkata Bujimalla, National Regulatory Research Institute, *2002 Performance Review of Electric Power Markets* (Aug. 30, 2002) at 2-3.
4. Conn. Gen. Stat. § 16-244f (LexisNexis 2006).
5. 220 Ill. Comp. Stat. Ann. 5/16-111(g) (LexisNexis 2007).
6. *See, e.g.*, Md. Code Ann., Public Utility Companies § 7-510(c) (LexisNexis 2006); Del. Code Ann. tit. 26, § 1008 (LexisNexis 2007).
7. *See generally,* Rose and Bujimalla, *supra* note 3 (noting that low prices guaranteed by transition period rate caps and rate reductions left little "headroom" within which alternative suppliers could compete).
8. Energy Information Administration, *Electric Power Annual 2005* (Released Oct. 4, 2006) at 5.
9. *Id.* at Table 4.5, 37.
10. *Id.* at 3.
11. *Id.* at 5.
12. *Id.* at Table 4.5, 37.
13. EIA, *supra* note 8, at p. 7.
14. *Id.* at Table 7.4, 50.
15. Maryland Public Service Commission Staff's Report/Observations on the Standard Offer Service Bidding Process and Results (Mar. 7, 2006) at 4-6.
16. *Id.* at 4.
17. Post-Auction Public Report of the Staff of the Illinois Commerce Commission (Dec. 6, 2006) at 19.
18. *Id.* at 23.
19. Post Auction Public Report, *supra* note 17, at p. 19.
20. Maryland Public Service Commission Staff Report, *supra* note 15, at p. 6.
21. *Delmarva Power Plans to Phase in 59% Rate Increase*, Foster Electric Report, Mar. 8, 2006, at 13.
22. *In re Application of United Illuminating Company to Increases its Rates and Charges*, Docket Nos. 05-06-04RE02 *et al.*, 2006 Conn. PUC LEXIS 203 (Dec. 19, 2006).
23. Md. Code Ann., Public Utility Companies, §§ 7-547 and 7-548 (LexisNexis 2006).
24. Del. Code Ann. tit. 26, § 1006 (LexisNexis 2007).
25. At the time of this writing, the Illinois House had passed legislation to extend the previous rate freeze. *See* H.B. 1750, 95th Gen. Ass., 1st Sess. (Ill. 2007). News reports indicate that the prospects for the bill are uncertain in the Senate, which had earlier rejected a similar measure. Erik Potter, *Illinois House Votes to Roll Back Electric Rates*, St. Louis Post-Dispatch, Mar. 7, 2007.
26. Press Release, ComEd, Rate Freeze Would Trigger Severe Energy Crisis, Devastate Economic Growth in Illinois (Feb. 27, 2007).
27. *See* H.B. 25, 60th Leg., 1st Sess. (Mont. 2007).
28. 2007 Va. Acts ch. 933.
29. *Id.* at § 56-585.1.
30. Conn. Gen. Stat. §§ 16-243m(h) and (o)

(LexisNexis 2006).
31. Md. Code Ann., Public Utility Companies § 7-510(c)(6) (LexisNexis 2006).
32. *In Re. Arizona Pub. Serv. Co.*, Docket No. E-01345A-03-0437, 241 P.U.R. 4th 181 (Apr. 7, 2005) at 8-12.
33. Md. Code Ann., Public Utility Companies § 7-510(c)(4).
34. *Id.*
35. *See* David DeKok, *Judge Backs Plan to Ease PPL Rate Hikes*, The Patriot-News (Harrisburg, PA), Feb. 27, 2007.
36. *See supra* note 27.
37. Philip S. Cross, *A Survey of Recent Retail Rate Cases for Electric and Gas Utilities*, Public Utilities Fortnightly, Nov. 2005, at 47.
38. Del. Code Ann. tit. 26, § 1007 (LexisNexis 2007).
39. *Supra* note 27 at § 3.
40. Md. Code Ann., Public Utility Companies § 7-510(c)(4)(ii).
41. Conn. Gen. Stat. § 16-243n (LexisNexis 2006).
42. Conn. Gen. Stat. §§ 16-243(i) and (s) (LexisNexis 2006).

ENERGY TRADING BANKRUPTCIES AND THEIR LINGERING EFFECTS

Paul B. Turner
Mark Sherrill

Bankruptcy and related concerns continue to play an important role in the ongoing development of the energy trading markets. Although energy trading bankruptcy activity has slowed over the past year, counterparty credit concerns and bankruptcy risk continue to be central issues. A number of energy trading bankruptcies continue to work their way through the restructuring or liquidation process and have led to developments that impact the energy trading business. One of the most significant changes relating to energy trading bankruptcies has been the enactment of certain amendments to the Bankruptcy Code that provide additional protections to forward contract merchants with respect to bankruptcies filed after October 2005. We briefly discuss these changes and provide a summary of some of the legal issues that have arisen from the recent energy trading bankruptcies.

I. Bankruptcy Abuse Prevention and Consumer Protection Act of 2005

On Oct. 17, 2005, the Bankruptcy Abuse Prevention and Consumer Protection Act of 2005 (Bankruptcy Amendments) went into effect. More specifically, most of the provisions in the Bankruptcy Amendments apply only to bankruptcy cases commenced after that date. The Bankruptcy Amendments include several provisions that could affect energy traders.

One provision relates to the timing for valuation of rejection damages. The Bankruptcy Amendments create a new provision, Section 562 of the Bankruptcy Code, which provides that damages from the termination or rejection of a safe harbor contract are to be measured at the time of such termination or rejection. This change eliminates some of the risk for trading counterparties with respect to bankrupt companies' forward contracts and swap agreements that were not terminated under the bankruptcy filing.

Second, the Bankruptcy Amendments clarify, at least in part, the enforceability of master netting agreements in bankruptcy by adding a new Section 561 to the Bankruptcy Code. Section 561 allows parties to exercise their contractual rights to terminate, liquidate, accelerate, or offset termination values under a master netting agreement and across contracts. In addition, master netting agreements are added to the list of agreements and transactions generally exempt from a trustee's or debtor-in-possession's avoidance powers.

A third area of interest pertains to municipal bankruptcies, which are governed by Chapter 9 of the Bankruptcy Code. The Bankruptcy Amendments correct a Code deficiency that failed to extend safe-harbor provisions to counterparties of municipal debtors. By specifically extending to Chapter 9 the protections of Sections 556 regarding forward contracts and 560 regarding swap agreements, the Bankruptcy Amendments ensure that energy traders having contracts with municipalities will enjoy the same protections as in Chapter 11 cases. They would be authorized to terminate forward contracts and swaps with a municipality and liquidate those positions, notwithstanding the automatic stay.

Finally, the Bankruptcy Amendments address a deficiency in the Bankruptcy Code's definitions. In 2003, the *Mirant* court ruled that the Bonneville Power Administration, a unit of the U.S. Department of Energy, was not eligible for the protections given to "forward contract merchants" under the Bankruptcy Code because the Code's definition of a forward contract merchant does not extend to governmental units. The Bankruptcy Amendments modify the definition of forward contract merchant so that governmental units no longer are excluded.

II. Calpine Corporation

Calpine filed its voluntary petition for bankruptcy relief on Dec. 20, 2005. Calpine's bankruptcy is among the largest in the United States, and currently is the most active bankruptcy among large energy companies. Thus far, Calpine has engaged in a number of asset sales and other cost-cutting measures. Calpine's exclusivity period for filing a plan of reorganization expires on June 20, 2007, and it is expected to file its plan in advance of that deadline.

A. Jurisdictional Conflicts

Almost immediately upon commencing its bankruptcy case, Calpine faced a jurisdictional issue that has arisen in most of the major energy company bankruptcies. In such cases, a conflict has arisen between the bankruptcy courts and the Federal Energy Regulatory Commission (FERC) regarding the proper forum to adjudicate a bankrupt party's efforts to reject unprofitable wholesale power contracts. As parties have discovered in the course of several energy bankruptcy cases and various appeals, the policy goals of the bankruptcy courts (giving a debtor breathing room to reorganize its affairs and shed unprofitable pre-petition contracts) and FERC (ensuring wholesale customer protections for power at just and reasonable rates with not unduly discriminatory terms and conditions for service) do not necessarily coincide.

The *Calpine* case has seen the most recent instance of the foregoing jurisdictional conflict. In January 2006, the U.S. District Court for the Southern District of New York determined that it lacked jurisdiction to adjudicate Calpine's motion to reject eight wholesale power contracts that, according to Calpine, were significantly out-of-the-money. *California Dept. of Water Res. v. Calpine Corp. (In re Calpine Corp.)*, 337 B.R. 27 (S.D.N.Y. 2006). Reasoning that (1) wholesale power contracts are subject to FERC's regulatory jurisdiction and (2) rejecting the contracts would be tantamount to Calpine ceasing to provide power to its counterparties, the district court held that only FERC could determine whether Calpine could cease performance under the contracts.

The foregoing district court decision appears to conflict with the Fifth Circuit's opinion in *Mirant Corp. v. Potomac Elec. Power Co. (In re Mirant Corp.),* 378 F.3d 511, 517 (5th Cir. 2004). In *Mirant*, the Fifth Circuit determined that bankruptcy courts have jurisdiction to adjudicate a debtor's request to reject wholesale power contracts, albeit possibly under a somewhat heightened legal standard than typically applies to rejection motions involving other types of contracts. *Id.* The *Mirant* court did not perceive a conflict with FERC jurisdiction because, under the rejected contracts, the customer would have a claim against the debtor, calculated based on FERC-approved rates.

Calpine has appealed the district court's decision to the U.S. Court of Appeals for the Second Circuit. The parties have briefed and argued their appeal, but no decision has issued. The eventual decision could have a significant effect on energy traders. The disparity between the district court's *Calpine* rule and the Fifth Circuit's *Mirant* holding could lead to different treatment for counterparties to wholesale power contracts as compared to other creditors, depending upon where a debtor files. In addition, the ability of a bankrupt energy trader to reject some of its most burdensome contracts is at stake.

B. Other Calpine Developments

Beyond the jurisdictional disputes, Calpine has spent much of its time in bankruptcy selling assets and shedding unprofitable contracts. It has recently secured a replacement debtor-in-possession (DIP)-financing package of $5 billion, which may be the largest DIP financing ever. The financing contains provisions that allow it to be converted to exit financing, facilitating Calpine's eventual emergence from bankruptcy.

III. Mirant Corporation

Mirant filed its bankruptcy petition on July 14, 2003. The bankruptcy court confirmed Mirant's plan of reorganization on Dec. 9, 2005, and Mirant emerged from bankruptcy protection on Jan. 3, 2006. Despite Mirant's emergence, the bankruptcy court continues to administer the estate and generate opinions of interest.

A. Discount Rate for Present Value of Claims

Mirant and Kern River Gas Transmission Corp. entered into a contract for transmission capacity on Kern River's pipeline running from Wyoming to California. After Mirant filed its voluntary petition for bankruptcy protection on July 14, 2003, it rejected the contract.

Kern River filed a proof of claim for approximately $154 million in rejection damages. Mirant objected to Kern River's claim, asserting that Kern River's discount rate of 4.25 percent was an inappropriate mechanism to reduce the claim to present value.

The U.S. Bankruptcy Court for the Northern District of Texas held a hearing on the proper amount of Kern River's rejection claim, which required determining the proper discount rate. The court noted that the Bankruptcy Code requires a claimant to discount its claim to net present value, but does not provide guidance as to the appropriate discount rate. The court stated that applying a discount rate to a claim that includes a future stream of revenue serves two purposes: it accounts for the time value of money, and it adjusts the revenue stream in accordance with risk.

At the hearing, Kern River argued that the appropriate discount rate should fall between 1.07 percent and 5.14 percent. Mirant contended that the appropriate rate was 15.92 percent.

The court rejected Kern River's rationale for a lower discount rate, which did not take into account counterparty and other risks. For example, the court concluded that the federal judgment rate (1.07 percent) and the FERC refund rate (4.25 percent) were irrelevant benchmarks because the purpose of each was to compensate solely for the loss of the use of funds.

The court also criticized Mirant's proposed discount rate, which was based on the risks associated with doing business with a bankrupt entity. The court emphasized that the appropriate rate should be based on the risk of non-performance by the defaulting party at the time the parties entered into the contract, not during the parties' dealings after the bankruptcy filing. Such an analysis, the court noted, "is a fair measure of the market's assessment of the risk associated with dealing" with Mirant. The court further commented that the result would ensure that the Kern River claim would be treated in a like manner to other claims.

The bankruptcy court then looked to the interest rate on various types of Mirant debt that existed around May 2001, when the parties executed the contract.

The court found that interest rates on prepetition debt ranged from 7.4 percent to 9.125 percent. Based on that range, and without much further discussion, the court determined that a rate of 8.00 percent was an appropriate discount rate for the Kern River claim.

The *Mirant* opinion provides an analysis for determining discount rates to reduce claims to net present value. Given the relatively small number of opinions in this context for determining discount rates, other courts may take note and adopt a similar approach.

IV. National Energy & Gas Transmission, Inc.

National Energy & Gas Transmission, Inc. (NEGT, formerly PG&E National Energy Group, Inc.) and various subsidiaries, including its energy trading subsidiaries, filed voluntary petitions for relief on July 8, 2003. NEGT confirmed its plan of reorganization on May 3, 2004, and a plan of liquidation for the energy trading subsidiaries was confirmed on April 19, 2005. Since confirmation, the NEGT entities primarily have been engaged in resolving litigation and claims objections. Although many disputes have been resolved, the wind-down and liquidation of the energy trading businesses continue.

As in several other energy trading bankruptcies, the jurisdictional struggle between FERC and the bankruptcy courts surfaced in the *NEGT* case. Immediately before NEGT's bankruptcy filing, Vermont Public Power Supply Authority filed a complaint with FERC alleging that NEGT discontinued its performance under a contract without authority from the FERC. NEGT asked FERC to dismiss the complaint based on the contractual language and NEGT's bankruptcy filing. FERC granted the request and dismissed the complaint based on the contract's inclusion of an "automatic termination" clause, also known as an *ipso facto* clause. FERC determined that due to the automatic termination clause and the bankruptcy, the contract no longer was in force. Therefore, FERC reasoned, the parties got what they contracted for: termination of the contract upon one party's bankruptcy filing. *Vermont Pub. Power Supply Auth. v. PG&E Energy Trading Power, L.P.*, 104 FERC P 61,185, at ¶ 8 (Aug. 1, 2003).

V. Enron Corporation

The bankruptcy case of Enron Corp. dates back to Dec. 2, 2001 when Enron filed its voluntary petition—at the time, the largest bankruptcy in U.S. history. Many of the most contentious issues in the case have been resolved, and Enron confirmed its plan on July 15, 2004.

A. Trading Cases

In recent months, Enron has been active in resolving a number of adversary proceedings against energy trading counterparties. At one time, Enron estimated that $1.75 billion was at stake in its various trading cases. Nearly all were resolved before trial. One of the defendants remaining is Public Utility District No. 1 of Snohomish County (Snohomish). Snohomish is a defendant in an action in which Enron Power Marketing, Inc. (EPMI) seeks recovery of a $116.8 million termination payment. The issues for Snohomish and EPMI include a jurisdictional battle between FERC and the bankruptcy court over which tribunal should adjudicate matters concerning the termination payment, currently pending before the U.S. District Court for the Southern District of New York.

B. Cantwell Amendment

In a related decision involving EPMI by the U.S. District Court for the Southern District of New York, the court determined that the Cantwell Amendment, passed as part of the Energy Policy Act of 2005, did not fundamentally alter the jurisdictional line between FERC and the bankruptcy court regarding the termination of wholesale power contracts, termination payments, and related state-law claims. *Enron Power Mktg., Inc. v. Luzenac Am., Inc.*, 2006 WL 2548453 (S.D.N.Y. Aug. 31, 2006). According to the court, the Cantwell Amendment merely provides that FERC has exclusive jurisdiction under the Federal Power Act to determine the permissibility of termination payments in Enron contracts executed in the Western Interconnection prior to June 20, 2001.

As a result of the district court's ruling, the bankruptcy court would determine the many state-law claims, such as fraud in the inducement, relating to FERC-jurisdictional contracts involving Enron and western trading counterparties. Prior to the court's ruling, FERC had issued several decisions resulting from the Cantwell Amendment: (1) one asserting its exclusive jurisdiction, *City of Santa Clara v. Enron Power Mktg., Inc.*, 112 FERC ¶ 61,280 P 27 (Sept. 15, 2005); (2) another finding that EPMI was not entitled to a termination payment due to state-law fraud in the inducement, *Public Utility District No. 1 of Snohomish Co., Wash.*, 115 FERC ¶ 61,375 P 78 (June 28, 2006); and (3) a third initiating proceedings for counterparties desiring to bring claims pursuant to the Cantwell Amendment. *Public Utility District No. 1 of Snohomish Co. v. Enron Power Mktg., Inc.*, 115 FERC ¶ 61,037, P 6 (Apr. 11, 2006).

C. Timing of Rejection Damages

In a pair of cases arising out of the *Enron* bankruptcy, the bankruptcy court determined that under the pre-existing Bankruptcy Code (*i.e.*, for bankruptcies filed before Oct. 17, 2005) calculation of rejection damages for swaps and forward contracts should be based on market conditions as of the time of the bankruptcy filing. *See In re Enron Corp.*, 2005 WL 3874285 (Bankr. S.D.N.Y. Oct. 5, 2005) (involving swap agreement); *In re Enron Corp.*, 330 B.R. 387 (Bankr. S.D.N.Y. 2005) (involving forward contract). The reach of the decision is limited, however. As discussed above, the Bankruptcy Amendments provide for such damages to be calculated as of the earlier of the date of rejection or the date of termination.

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CONGRESS CONTINUES TO SCRUTINIZE OTC ENERGY MARKETS

Harlan Murphy

The past year saw a flurry of legislative activity in connection with the regulation of energy derivatives, but no new legislation, and the 110th Congress appears to be picking up where the 109th Congress left off. In 2006, legislators' scrutiny of over-the-counter (OTC) market regulation, and the regulation of energy OTC markets in particular, increased substantially. Legislative interest was piqued by, among other things, (1) the implosion of Amaranth Advisors, a Connecticut-based hedge fund that reportedly lost over $6 billion on financial transactions in the natural gas markets, (2) significant growth in the use of OTC derivatives, (3) criminal trials against energy traders, and (4) continued energy price volatility combined with high energy commodity-based profits. OTC market regulation for energy-based derivatives has been relatively light with respect to the transactions themselves, instead focusing primarily on parties' qualifications for entering into such transactions. To some legislators, that approach is inadequate. Accordingly, several bills were introduced in the 109th Congress that would have impacted how swap participants and electronic exchanges are regulated. Although none of the proposed legislation became law while the 109th Congress was in session, interest in expanded regulation remains, and may be rising closer to the top of the legislative policy agenda for the new congressional leadership. However, like 2006, no consensus exists among the necessary parties regarding the extent to which the OTC markets should be regulated, which is likely to continue to thwart efforts to pass legislation in this area.

On Feb. 13, 2007, Sen. Dianne Feinstein of California reintroduced legislation in the Senate aimed at preventing manipulation and fraud in OTC energy markets such as oil, natural gas, coal, and electricity. She cited Enron and Amaranth Advisors and opined that the Commodity Futures Trading Commission (CFTC) lacks the tools to detect and prevent manipulation and fraud. The bill, S. 577, calls for enactment of the Oil and Gas Traders Oversight Act of

2007, which would amend the Commodity Exchange Act to proscribe reporting and recordkeeping requirements for large positions involving energy commodities, thereby creating an audit trail of sorts and bringing the OTC energy markets to light. Specifically, the bill sets forth record-keeping requirements for persons holding or controlling any position in (1) a contract involving an energy commodity executed on an electronic trading facility, or (2) a contract executed in the United States, using technology providing access to a contract traded on a foreign board of trade, for future delivery of an energy commodity with a physical delivery point in the United States.

S. 577 would require energy traders to keep records of their transactions for five years or longer, and give the CFTC access to those records if asked. These same reporting requirements already apply to New York Mercantile Exchange (NYMEX) traders. S. 577 is designed to close the so-called "Enron loophole," which exempts energy traders from reporting large positions on electronic trading platforms and was allegedly engineered by Enron into the Commodity Futures Modernization Act of 2000. For example, S. 577 would allow the CFTC to collect data from traders holding large positions on the Intercontinental Exchange (ICE), which is a widely-used electronic trading platform for OTC energy contracts and futures. Nine other members of the Senate joined Sen. Feinstein in co-sponsoring the bill, including Sen. Olympia Snowe, a Republican from Maine, and Sen. Carl Levin, a Democrat from Michigan.

In a related move, on Feb. 7, 2007, Senate Energy Committee Chairman Jeff Bingaman, a Democrat from New Mexico, asked the CFTC and the Federal Energy Regulatory Commission (FERC) to describe their oversight of U.S. energy markets. More specifically, citing Amaranth Advisors as a cautionary tale, Sen. Bingaman asked for information about the CFTC's surveillance of natural gas trading on both the NYMEX and ICE, and whether speculative trading activity may be affecting the cost of natural gas to commercial, industrial, and residential consumers.

Similarly, on Jan. 19, 2007 H.R. 594 was introduced in the House of Representatives, which calls for enactment of the Prevent Unfair Manipulation of Prices Act of 2007. Rep. Bart Stupak, a Democrat from Michigan, citing high energy prices and the need for increased penalties for manipulation, introduced the bill to implement reporting and record-keeping requirements for OTC transactions in energy markets. In addition, the bill would repeal Section 2(g) of the Commodity Exchange Act, the so-called Enron loophole, which excludes from certain disclosure requirements transactions in energy commodities on electronic exchanges. Most significantly, the Stupak bill would authorize fines of up to $1 million for manipulation or attempted manipulation of energy markets. The bill was co-sponsored by House Energy Committee Chairman John Dingell, a Democrat from Michigan, and seventeen other members of the House.

The Federal Reserve appears to take a different view of the need for increased regulatory scrutiny of the energy markets. On Feb. 14, 2007, Federal Reserve Chairman Ben Bernanke reiterated his opposition to additional regulation of energy derivatives and warned against taking steps that would increase regulatory costs on the OTC energy markets. Mr. Bernanke's opposition appears to be based on the premise of the existing legislation: that the market participants are sufficiently sophisticated and well-capitalized to appreciate the risks involved. He also noted that the OTC energy markets are liquid enough to provide for a level of price discovery sufficient to allow market participants to protect themselves against manipulation. As was evident in 2006, a clear consensus regarding the appropriate degree of regulatory oversight of the OTC energy markets has yet to evolve. Whether Congress intensifies such oversight is likely to be a function of (1) the extent to which extrinsic political agendas overshadow the perceived need for increased scrutiny, (2) the ability of the Congressional leadership to develop a consensus approach to crafting a solution, and (3) whether 2007 yields another energy trading scandal or unusually high prices for energy commodities.

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NEW MASTER RENEWABLE ENERGY CERTIFICATE TRADING AGREEMENT

Jeremy D. Weinstein

In February 2007, culminating a two-year effort, a working group organized by the Environmental Markets Association (EMA), the American Council On Renewable Energy (ACORE), and committees of the American Bar Association Section of Environment, Energy, and Resources (namely, its Renewable Energy Resources Committee and its Special Committee on Energy and Environmental Finance), published a standard form master agreement for national trading of Renewable Energy Certificates (RECs, or "green tags"). It is available online at http://www.acore.org/programs/rectrading.php and http://environmentalmarkets.org.

The master agreement is legal infrastructure to (1) help buyers and sellers transact, (2) foster market mechanisms to promote renewable resource development, and (3) stave off potential balkanization of U.S. REC markets. It combines the efforts of volunteers from renewable resource developers, energy marketers and traders, utilities, NGOs, law firms, brokerages, and government agencies active in renewable resource development and REC markets. The working group co-chairs at publication were Jeremy Weinstein of the Law Offices of Jeremy D. Weinstein, Christopher Berendt of PACE Global Environmental Services, Baird Brown of Ballard Spahr Andrews & Ingersoll, Roger Feldman of Andrews & Kurth, Richard Saines of Baker & McKenzie, and Michael Eckhart of ACORE. The document reference library, located online at the EMA's Web site, provides insight into the development process, the invaluable contributions by many others to the drafting of the document, and the many policy and other debates in which the working group engaged.

RECs represent aspects of the renewable energy nature of generation from renewable resources, which are separated from the electricity itself. Active REC markets maximize cost-effective resource allocation and allow states to implement aggressive renewable portfolio standard (RPS) targets, while minimizing increases in electricity costs for consumers and businesses. How RECs are separated from the electricity, and the components of what constitutes a REC, can vary across state programs due to varying political and other agendas.

RPSs in twenty-three states and the District of Columbia now mandate that load-serving entities procure a minimum percentage of retail energy from renewable resources. The adoption of state standards in the absence of a federal standard has caused concern among some observers about the risk of different state programs creating barriers, either deliberate or not, to national REC trading across state borders. The need for a working group to promote a national master agreement became apparent as states sought to implement RECs that could (1) be fungible across state programs, (2) provide mutual reciprocity, and (3) provide a legal infrastructure to complement a developing physical infrastructure of information systems that track renewable resource generation.

The master agreement is technology neutral, usable across the voluntary and compliance markets, and legally robust regardless of state jurisdiction. The "Introduction for Users and Guidance Notes," posted on the Internet, contains a detailed explanation of how the master agreement is used, and defines the terms that are unique to RECs. The REC master agreement works much like a typical master trading agreement and includes a cover sheet with identifying information and core elections for payment, credit, and other terms, and contains flexibility to incorporate custom terms.

For the unique needs of a REC as an enviornmental commodity, the master agreement uses a disclosure-driven model. Much debate has transpired over what a REC represents and what it should contain. Rather than take sides in the debate, the master agreement does not mandate what is in a REC, but provides mechanisms that enable full and accurate disclosure of what is in the specific RECs bought and sold by the parties to the agreement. The master agreement provides a range of definitions. Between two bookend definitions of RECs, one with all attributes and another with generation-only attributes, sits the specific REC for which a seller discloses the REC's attributes and any applicable verification methodology. The Disclosure Document, which does not include the economics of the transaction, travels downstream with the REC in further transactions. Use of the Disclosure Document by the parties is optional, but it is a powerful tool for unlocking the potential value in RECs as REC and Carbon markets develop.

As for meeting the requirements of the various state programs for RECs, the disclosure model requires the parties to indicate the state programs with which the RECs comply, rather than trade using each state's separate REC definition. The working group considered but rejected the concept of adding to the master agreement the REC definitions for each state. Instead, the trading parties define the product they are trading and make representations about compliance with applicable state programs. The risk of fostering balkanization with many disparate definitions was overwhelming, and the document's definitions instead emphasize commonalities of the RECs and their components, and specify under which RPS programs they qualify.

Unless otherwise agreed, the buyer of a REC is assumed to bear the risk of a change in law or regulation that causes the REC to cease to qualify for recognition by regulators before it is delivered. Allocation of "change in law" risk was addressed with a designation called "Regulatorily Firm." Normally, when a REC is sold in a compliance market, the seller represents that it complies with the requirements of a particular program as of the date of the agreement, and the buyer accepts the risk of change in law after the date of sale. But if the product is sold as "Regulatorily Firm," the change in law risk is shifted to the seller, who promises that the product will comply with the program when delivered. However, a regulatory change that makes a REC more valuable, like enactment of a state RPS, does not obligate the buyer to pay more or excuse delivery by the seller. Parties are also given options to assign responsibility for verifying the attributes of the REC. Options may include self-certification or verification by independent organizations such as the Center for Resource Solutions, which administers the well-known "Green-e" program.

RECs and RECs markets are likely to be impacted significantly, if not subsumed, by the development of Carbon markets, as adoption of greenhouse gas mitigation legislation in the United States accelerates at the state, regional, and federal levels. The drafters of the REC master agreement recognized this, and gave the agreement multiple entry points for RECs into future Carbon markets. In fact, the working group's leadership, building upon the work done for the REC master agreement, is exploring the possibility of re-engaging the working group to develop a master agreement for trading verified Carbon emissions reductions.

The next step will be to review market response to the REC master agreement. The working group will keep the document current and review comments from users. Those who are interested in the group are encouraged to contact the author or any of the group's co-chairs listed on the Environmental Markets Association's Web site.

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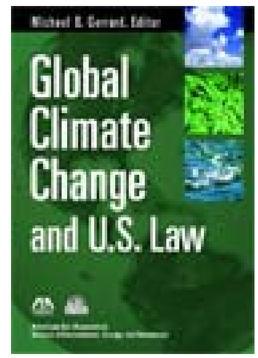
NEW FROM ABA PUBLISHING AND THE SECTION OF ENVIRONMENT, ENERGY, AND RESOURCES

Global Climate Change and U.S. Law

Michael B. Gerrard, Editor



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