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Competition Without Chaos

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This article is an expanded version of a speech given by Mr. Rowe to the Commercial Club of Chicago on March 14, 2001. Mr. Rowe is President and Co-Chief Executive Officer of Exelon Corporation, the parent company of Commonwealth Edison Company in Illinois, PECO Energy Company in Pennsylvania and Exelon Generation. Mr. Thornton is Assistant General Counsel of Exelon Business Services Company. Ms. Szczypinski is Special Assistant to John Rowe at Exelon Corporation.

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Executive Summary

California heralded the New Year with a wave of rolling blackouts, spiraling wholesale electricity prices, and at least one utility bankruptcy. California, which symbolizes the electronic age and represents an eighth of the U.S. economy and its population, faces electricity supply issues not seen since the Great Depression and the collapse of the great utility holding companies.

To what extent is California the bellwether for the restructured electric industry in the United States? We do not believe that the recent crisis in California is a signal that competition and deregulation have failed. Indeed, it remains our firm belief that market-oriented restructuring of the electric industry remains the best opportunity to provide consumer benefits and to develop reliable new sources of supply. After all, a major impetus for introducing competition into the generation and marketing of electricity has been the previous failures in long-term planning decisions made by public utilities and their regulators. The regulated monopoly regime simply did not provide the correct economic incentives for a company to provide electric service efficiently.

To what extent can other states that have restructured their electric industries expect to see California-like dramatic sustained price increases and supply shortages resulting in rolling blackouts? The root cause of California's problems was its long-term failure to build generating plants during the most sustained economic boom in the state's history. California's most significant restructuring problem was also a local issue. The California restructuring law required utilities collecting stranded costs to retain fixed price obligations to retail customers, while preventing them from hedging their price risk in the wholesale market by entering into long-term supply contracts.

The California market design flaws have been avoided in the restructuring legislation enacted by the twenty-four states and the District of Columbia that have restructured electricity markets. Among these states are Pennsylvania and Illinois—the states where Exelon conducts public utility businesses. The restructuring efforts in these other states are generally yielding results quite different from those in California and demonstrate that thoughtful, market-oriented, evolutionary restructuring can work well for all parties. This is not a reason, however, for complacency. Government agencies, utilities and all market stakeholders must work hard to make sure this answer remains valid a few years hence. This work includes establishing appropriate pricing and incentives to encourage the building of new supply and the development of demand-side management programs; establishing regional transmission organizations in order to support the expansion of and appropriate pricing for transmission; establishing appropriate rules and pricing regarding the utilities' provider of last resort or default supply obligation.

The default supply issue is one of the most significant challenges to the transition to competition. If the delivery companies retain primary responsibility for arranging supply and thus lock up most of the generation sources, the result is reliable service and stable rates for customers. However, new market entrants' access to supply sources will be limited and at high prices, making it difficult for them to compete. To resolve this dilemma, we propose a bifurcated approach to default service offerings and pricing. For large customers, who have the most desirable service characteristics to competitive suppliers and thus more opportunity to hedge their price risk, the utilities' only default service obligation would be unbundled energy at a market price. For mass market customers, who lack hedging ability because of limited, if any, market development, the utilities would provide a fixed price, multi-year energy supply offering. The price for both offerings must include a risk premium adequate to compensate the utility for the risk it assumes and to avoid rates that are too low to allow alternative suppliers to compete. We believe our default supply resolution will achieve the competing goals of price stability, reliability, and the development of a mature competitive market.

The California experience is not an accident or the product of bad luck. It is the product of choices––long-term choices about siting generation and transmission, and the more recent choice of a market design that imposed asymmetric risks on utilities to the ultimate detriment of all. If other states make similar choices, similar consequences can be expected to follow. In short, the California experience is no reason to reject restructuring; it is rather a forceful lesson on the importance of doing it right.

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The California Experience

The first focus of blame for the California debacle has been the state's utility restructuring bill—sometimes mislabeled its deregulation bill—which introduced competition into the retail marketing of electricity.[1] The California statute followed the federal Energy Policy Act of 1992, replacing the historic model in which utilities were government-regulated monopolies, controlling the generation, delivery and marketing of electricity within a given area, with a new a model in which the generation and wholesale supply of electricity are becoming competitive while the delivery remains regulated.[2] The Energy Policy Act and the Federal Energy Regulatory Commission's (FERC's) open access transmission policy restructured the wholesale market. California became the first state to propose the extension of the new competitive model to the retail supply of electricity and, indeed, developed a more radical separation of regulated and competitive operations than any other state has chosen.

While California's approach to restructuring has contributed to its energy problem, the root of the problem is the growing inadequacy of the physical supply of energy in the state and, to some extent, the western region. Between 1996 and 1999, only 672 MW of new generation came on line in California, while the peak demand increased by over 5,500 MW during that period.[3]

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[1] California Assembly Bill 1890 (AB 1890) Sess. (Cal. 1996).

[2] Pub. L. 102-486, October 24, 1992, 106 Stat. 2776. The Federal Energy Regulatory Commission took a more important step in 1995, issuing its Order No. 888, which required provision of open access transmission service. Promoting Wholesale Competition Through Open Access; Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Dockets RM95-8-000 & RM94-7-001, 75 FERC 61,080 (April 24, 1996).

[3] Report of the CaPUC and California Electricity Oversight Board to Gov. Davis ("CaPUC Report"), August 2, 2000, p. 36 (available on the Web at http://www.cpuc.ca.gov/word_pdf/REPORT/report.doc). *See* Staff Report to the Federal Energy Regulatory Commission on Western Markets and the Causes of the Summer 2000 Price Abnormalities ("FERC Staff Report"), November 1, 2000, pp. 41, 4-8 to 4-11 (available on the web at www.ferc.fed.us). For example, the San Jose-based Calpine Corp. faced substantial opposition when it sought to construct the 600 MW Metcalf power plant in Coyote Valley. Among others, Cisco Systems Inc. objected to siting such a large plant next to the company's planned Coyote Valley campus location. The San Jose City Council rejected Calpine's plan, although the Silicon Valley Chamber of Commerce has urged reconsideration of the decision. Controversy over the plant continues to engage politicians and the public. (See the community website: SouthSanJose.com.) On April 12, 2001, U.S. Senator Diane Feinstein added her support to the project,

At least in part, this shortage occurred because of difficulties in power plant siting occasioned by strict state environmental regulations and lengthy siting procedures. In addition, uncertainty about the regulatory structure and market rules, and thus about a generator's ability to recover its costs, likely discouraged new entrants in the generation market. Meanwhile, the booming economy of the nineties caused the peak demand for electricity in California to grow by about 4 per cent per year in 1996-98, higher than the national average.[4]

Because of its shortage of domestic generation, California has been heavily dependent on imports from other states, importing 25% of its energy in 1999.[5] These levels remained steady in 2000, but could not be increased, at least in part because low water levels limited the amount of hydropower available from the Northwest.[6] Moreover, attempts to control wholesale prices in California through imposition of progressively lower price caps paradoxically induced in-state suppliers to sell *outside* the state, to circumvent the caps. Thus *net* imports (imports net of exports), decreased substantially in 2000.[7] All of these factors contributed to low reserve margins and the price spikes seen in May and June of 2000; the average prices in August were even higher, despite the imposition of progressively lower price caps.[8] Similar factors have been at play in creating sky-high prices and even rolling blackouts during the winter of 2000-01, a season when prices would typically be expected to fall. From January 16 to February 16, 2001, the California Independent System Operator (ISO) declared thirty-two consecutive Stage-3 Emergencies, meaning that operating reserves were falling to 1.5 percent or less.[9] Moreover, the emergence of local shortages highlighted

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stating: "We're in a crisis. It's important to build it." *The Mercury News*, April 12, 2001. Another illustration of the problem is Pacific Gas & Electric's effort last summer to moor a floating power plant in San Francisco Bay as protection against future brownouts. The floating plant—the Rio da Luz—was acquired by PG&E from El Paso Energy and shipped from Texas to the coast of Mexico, with plans to bring its 95 MW of capacity to the San Francisco area. Opposition from environmentalists and delays in seeking necessary governmental permits caused PG&E to scuttle its plans. *San Francisco Chronicle*, August 5, 2000.

[4] See FERC Staff Report, p. 2-4 (3.9% average growth percentage 1996-98); See also California Energy Commission, Report on California Energy Demand 2000-2010 .

[5] California Energy Commission (http://www.energy.ca.gov); FERC Staff Report at p. 2-17.

[6] FERC Staff Report, p. 2-27.

[7] FERC Staff Report, pp. 2-15 to 2-16.

[8] *Id.*, p. 3-1. In addition to these factors, the price of natural gas approximately tripled in the West between January and September 2000 (FERC Staff Report, p. 3-20), and the price of NOx emission credits needed to run gas units increased even more drastically (*id.*, p. 3-20 to 3-21).

[9] California ISO, "Declared Staged Emergencies," revision date 02/23/01. Stage 3 Emergencies are declared any time it is clear that an Operating Reserve shortfall (less than 1.5%) is unavoidable or when in real-time operations the Operating Reserve is forecasted to be less than 1.5% after dispatching all available resources.

the limits of the state's transmission system: the rolling blackouts in northern California both in June 2000 and early this year could not be avoided through increased imports from southern California because of a transmission bottleneck in the Central Valley.[10]

California's physical supply shortages were significantly compounded by design flaws in the restructured market that brought Southern California Edison ("SCE") to the brink of bankruptcy, have more recently caused Pacific Gas & Electric ("PG&E") to make a Chapter 11 filing, and have required the state to use its credit to purchase billions of dollars of power for them. The state restructuring plan aimed to create a competitive electric industry in California. At the same time, however, government did not want to expose customers to the price and supply risks a developing competitive market could bring, so it required the utilities to keep serving retail customers at fixed prices—prices in fact 10 percent lower than they had been.[11] Regulators and legislators were persuaded by regulatory theorists and potential market entrants that jump-starting competition would best be accomplished if the utilities were no longer allowed to enter into long-term purchase agreements for power. Instead, the utilities—after divesting all their generation except for nuclear and hydroelectric—were to sell all their remaining power into a central market (the Power Exchange or PX) and to buy from the PX all the power they needed to serve their customers (which turned out to be a far greater amount than what they sold every day).[12] This requirement stemmed from a fear on the part of regulators and market entrants that the utilities would use their control over the wires to favor their own generation and defeat competition. They also believed such a scheme was necessary to create sufficient depth and liquidity in the PX market.[13]

The California market design made it easy for competitive suppliers to obtain power to serve new retail customers. Unlike the utilities, those that owned generation could sell the power directly to retail customers. Those that did not own generation could buy power from the PX on the same basis as the utilities. Markets take time to develop, however, and even this

[10] FERC Staff Report, pp. 2-31 to 2-32; California ISO News Release, "Rotating Power Outages Ordered In Northern California," January 17, 2001 (available on the web at www.casio.com/newsroom/releases/index.html).

[11] CPUC, Restructuring In California ("CPUC Restructuring Report") at 4 (available on the web at www.cpuc.ca.gov/Environment/restruct/chapter2.htm). ("A ten percent reduction is mandated in 1998 for the residential and small commercial customers for all California electrical corporations.")

[12] This requirement was initially imposed by the California PUC's Preferred Policy Decision, 64 CPUC 2d 1 (1994); it was later confirmed by statute. AB 1890, September, 1996.

[13] CPUC Restructuring Report at 8. ("The PX will allow power producers to compete on common ground using transparent rules for bidding into the exchange . . . . Participation in the PX will be voluntary for all buyers and sellers other than IOUs.")

market design did not induce the immediate birth of a vibrant competitive retail market. As might be expected, a fair number of large customers, but very few smaller customers, switched suppliers. After more than two years of full customer choice, about 15 to 20 percent of industrial customers and less than one percent of residential customers had switched suppliers. Since then a large number of the customers that switched have returned to utility service.[14]

Part of the problem of California's attempt to induce switching was that, at least for SCE and PG&E customers, new entrants found it hard to compete against the utility's fixed price offering. This meant that, following restructuring, the utilities were left with an obligation to serve the great majority of market demand at fixed prices that were 10 percent lower than those they had charged under the fully regulated market. However, unlike the days when they supplied their customers from their own generation, they now had essentially no control over the availability or the price of the energy that they were required to buy in the PX and deliver to their customers. The utilities accepted this market structure, but it exposed them to extreme risk from wholesale price swings or volatility.[15]

In trading any commodity, whether as a producer or a consumer, the trader must determine how much of the risk of future price changes it is prudent to assume. The more volatile the market, the greater the price risk the trader assumes by not entering into forward contracts or other hedging devices to lock in present prices and thus relying solely on the daily spot market. It turns out that the market for electricity is one of the most volatile of commodity markets. (This is perhaps not surprising because electricity is not a storable commodity, but must be created instantaneously on demand.) For example, in 1999 the average daily volatility of gold, soybean and silver prices ranged between 10 and 20 percent.

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[14] Kenneth Train and Anne Selting, *The Effect Of Price On Residential Customer Choice In Competitive Retail Energy Markets: Evidence From Specific Markets To Date* at 14 (prepared for Edison Electric Institute)(March 2000)("As of July 31, 1999, only 1.2% of residential customers had switched to a new supplier, even though direct access had been available for over a year.") As of 2000, less than 1 percent of residential customers and 15 to 20 percent of industrial customers have chosen new suppliers. *San Francisco Chronicle*, December 31, 2000. The number of customers switching suppliers peaked at 224,000, but by late January 2001 had declined to less than 180,000. *San Francisco Chronicle*, January 27, 2001. Supplemental Direct Access Implementation Activities Report – Statewide Summary – February 15, 2001/March 15, 2001 (available on the web at www.cpuc.ca.gov/static/electric/Direct Access/ToDateJanuary2001[February 2001]. . . web) (reflecting 172,565 total direct access customers as of January 31, 2001 and a further decline to 123,776 by February 28, 2001).

[15] Although the utilities had to sell all their generation into the PX and obtain all their requirements from the PX, in 1999 the PX began to offer some limited ability to purchase forward contracts. These were standard products,

By contrast, the average daily volatility for electricity prices was 400 percent, and for the month of June it was 1300 percent.[16]

The result was that the California utilities, while retaining the obligation to supply customers energy at moderate fixed prices, were forced to buy energy at prices that fluctuated and spiked to extremes, primarily due to severe supply shortages.

Commodity supply shortages are more likely to occur when there is little price elasticity in a market, meaning little inclination on the part of customers to increase or decrease consumption in response to price changes. Retail markets for electricity have demonstrated very limited price elasticity because retail prices in general have been fixed (though some rates for large customers reflect changes in the cost of energy). The efficient expansion of price-elastic demand for electricity will require more extensive customer exposure to underlying market costs. In addition, it will require two other features: the customers must "see" the spot price signal and the utility must be able to track customers' hour-by-hour or day-by-day changes in consumption. Today, interval meters that provide this information are typical for large customers, but not for small customers. California originally proposed to install an interval meter in every household in the state as part of the restructuring plan, but reversed course after a study concluded that the multi-billion dollar investment that would be required was not justified.[17]

In prohibiting the utilities from hedging their risks through forward contracts or by serving customers from their own generation, California regulators appear to have counted on low natural gas prices and an adequate supply of electric energy keeping producer prices in line and resulting in a deep and liquid market for electricity. This turned out to be a losing bet, and the consequences have been disastrous. In 2000, wholesale prices began to increase significantly, not only because of the growing supply-demand imbalance, but also because of serious increases in the cost of inputs to electric generation, especially natural gas and

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however, lacking the flexibility of contracts in the bilateral market, and did not provide a full range of hedging features. FERC Staff Report, p. 5-10.

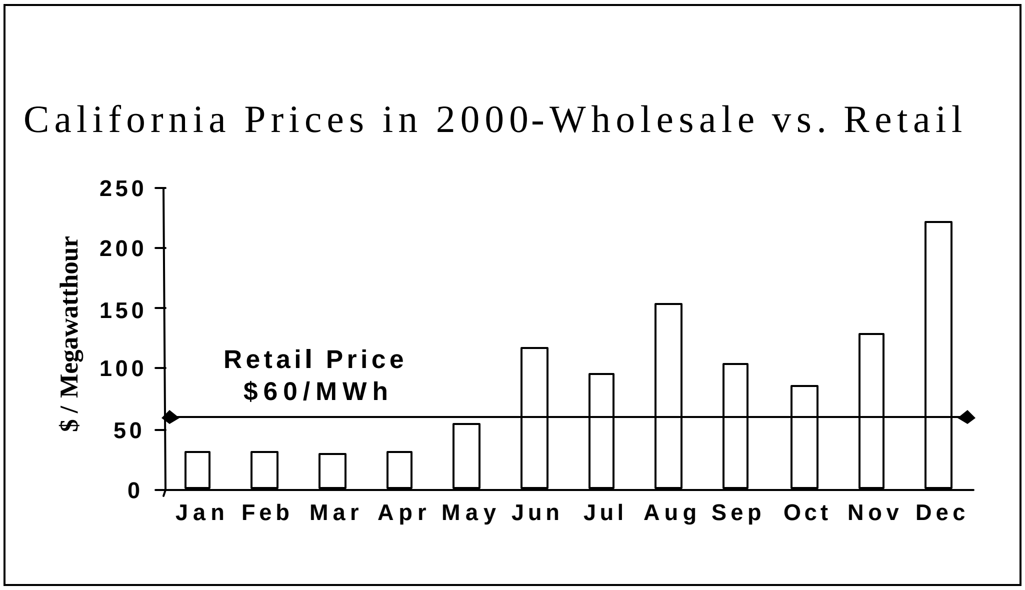
[16] Sources: Chicago Board of Trade Research Department, Exelon Generation Trading (1999 and 2000 data).

[17] See In re Proposed Policies Governing Restructuring California Electric Services Industry and Reforming Regulation, Decision 95-05-045, 161 P.U.R. 4th 217 (May 24, 1995)(". . . the proposal establishes a schedule for installation of real-time price meters, which are needed to enable customers to derive virtual direct access benefits. . . . The proposal would phase-in real-time metering to all customers within 6 years, starting on January 1, 1997."; *Id.*, Decision 95-12-063, as modified by D96-01-009, 1996 WL 47921 (January 1, 1996)(customers in domestic, GS-1 and TC-1 groups "will not be required to purchase or install such meters but may do so on a voluntary basis."

environmental compliance. In 1999, natural gas provided the fuel for 3l percent of the power consumed in California (as opposed to 3 percent in Illinois).[18] From January to August of 2000, natural gas prices in California increased from about $2 per MMBtu to about $5 per MMBtu. Meanwhile, the price of NOx credits needed by gas-fired generating units rose from about $6 per pound in May 2000 to $35 per pound in August and $45 per pound in September.[19]

Before 2000, daily prices for electricity in Western market hubs had never risen much above $100/MWh. In 2000 the California ISO imposed a price cap of $750/MWh, and in June the hourly price hit the cap three times, with the *average* price in that month reaching a record level of $120/MWh. The ISO lowered the price cap to $500/MWh in July 2000, and then to $250 in August 2000. Although these caps prevented price spikes above the capped level, the average price in August was $166/MWh, even higher than the record levels of June.[20] To everyone's surprise, average prices rose still higher in December 2000 – to $221/MWh in southern California and $308/MWh in northern California.[21] After paying these wholesale prices to acquire the energy, the utilities were required to deliver it to their customers at a retail price of approximately $60/MWh.[22]

[18] Electric Power Annual 1999, Vol. I, App. A, Tables 7, 10 (U.S. Energy Information Administration, August 2000).
[19] FERC Staff Report, p. 3-1.
[20] FERC Staff Report, p. 3-1.
[21] Source: California Energy Commission at http://www.energy.ca.gov.
[22] See California Assembly Bill 265 signed by Governor Davis on September 6, 2000; California Public Utilities Commission, D-00-09-040, September 7, 2000 (establishing ceiling price of 6.5 cents/kWh); Pacific Gas & Electric Form 8-K March 30, 2001 ("The CPUC determined that [PG&E's] company-wide average generation-related rate component is 6.471 cents per kWh. . . .").



Beginning in June 2000, SCE and PG&E were forced to pay billions of dollars for power in the wholesale spot market that they could not recover from their retail customers under their fixed rates. By early 2001, this price gap came to more than $11 billion for the two utilities combined,[23] eventually destroying the creditworthiness of both utilities and making suppliers unwilling to sell to them, or to the ISO, which itself relies on the ability of the utilities to pay their bills. The federal government and courts stepped in and required energy sales to California to continue on a temporary basis through emergency orders of various sorts.[24]

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[23] Pacific Gas & Electric, Form 8-K, Item 5, February 1, 2001 ($6.6 billion under-collection as of December 31, 2000); Southern California Edison, Form 8-K, December 22, 2000 (estimated $4.9 billion under-collection as of December 31, 2000)

[24] On December 14, 2000, Energy Secretary Richardson issued an emergency order under Section 202(c) of the Federal Power Act requiring certain generators and marketers to make sales to the California ISO of available power in excess of the amounts needed to serve their firm loads. (available on the web at www.energy.gov) Extensions of the order were in effect through February 6, 2001. (www.energy.gov/HQPress/releases 01/janpr/pr01028.htm) On February 6, 2001, Federal District Judge Frank Damrell in Sacramento granted a request by the California ISO for a temporary restraining order requiring Reliant Energy to continue to sell power despite the expiration of the emergency order. California ISO v. Reliant Energy Services, et al., No. S-01-238 FCD/JFM (E.D. Calif.) The order was broadened to extend to three other suppliers, AES, Williams Energy Marketing and Dynegy Power Corporation, on February 8, 2001. On March 16, 2001, AES, Williams and Dynegy agreed to continue to follow the California ISO's emergency dispatch instructions pending a ruling by the FERC on an emergency request to compel the ISO to comply with the Commission's March 14, 2001 order on creditworthiness. Reliant declined to enter into a similar agreement and on March 21, 2001 the court entered a preliminary injunction requiring it to respond to emergency dispatch instructions until the FERC ruling. (Decisions available on the web at www.caed.uscourts.gov)

San Diego Gas & Electric found itself in a somewhat different situation from SCE and PG&E. Because it was further along in the transition to a competitive industry than the other utilities, San Diego was not required to deliver energy to its retail customers under fixed-price tariffs, as SCE and PG&E were. Instead, San Diego was allowed to pass on to its retail customers the price of the power that it had to acquire to serve them. Considering that all of its customers had the right to choose alternative suppliers—which in effect was a hedging opportunity for customers—San Diego concluded that spot prices were appropriate for default service.

San Diego's reliance on the ability of customers to exercise choices that provide protection against price increases is consistent with the theory underlying the separation of generation and delivery services. However, when energy prices spiked in the summer of 2000 and San Diego's customers were exposed to the full brunt of them, there were cries of outrage, creating enormous pressure on California regulators to provide relief. San Diego's average residential commodity price rose from slightly over 4 cents/kWh in mid-May to about 6.5 cents on June 18, 2000. [25] In the next week, prices rose to 9.2 cents and by September 3 had reached 21 cents/kWh. [26] Passing these large price increases through to customers proved to be politically unacceptable, and resulted in the imposition of a temporary ceiling on the commodity portion of San Diego's electric rates. [27]

At this time, the financial future of all three California utilities remains clouded. Early in 2001, the California Commission granted a temporary rate increase of about 9 percent to Southern California Edison and Pacific Gas & Electric. [28] This was plainly inadequate to relieve their financial problems and they began defaulting on debt payments. [29] The State of

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[25] San Diego Gas & Electric, Form 8-K, Exhibit 99.1, January 24, 2001.
[26] Id.
[27] On September 7, 2000, one day after Governor Davis signed Assembly Bill 265 establishing the price cap, the California Public Utilities Commission placed a 6.5 cents/kWh ceiling (retroactive to June 1, 2000) on the electricity rate component for specified San Diego Gas & Electric customer classes, primarily consisting of residential, small commercial, and lighting customers. San Diego Gas & Electric, Form 8-K, Exhibit 99.1, January 24, 2001. In December 2000, San Diego Gas and Electric's ceiling price of 6.5 cents/kWh was substantially less than its average cost of about 22.5 cents/kWh. ***Id.***
[28] Interim Order, Decision 01-01-061, California PUC, January 31, 2001.
[29] In addition to defaults on maturing commercial paper, Pacific Gas & Electric reported on February 1, 2001 that it had payments of $437 million due to qualifying generators and $611 million to the California Power Exchange that it was unable to pay in full. Pacific Gas & Electric Form 8-K, Item 5, February 1, 2001. Similarly, Southern California Edison failed to pay maturing commercial paper, principal and interest on certain senior unsecured notes and approximately $34 million due to the California Power Exchange on February 1, 2001, and also had about $743 million of deferred payments for purchased power and related services. Southern

California and its Department of Water Resources began using their credit to purchase large amounts of power on behalf of the utilities, at a cost of billions of dollars.[30] On March 27, 2001, the California Commission approved prospective rate increases of up to 46%, but did not address the utilities' deficits for past power purchases. Despite the rate increase, on April 6 PG&E filed for bankruptcy under Chapter 11, citing unreimbursed energy costs increasing by over $300 million per month and other reasons.[31] The bankruptcy filing probably raises more questions than it settles because the court's authority to compel administrative action by the state is unclear. The governor has meanwhile been attempting to keep the utilities solvent with a cash infusion, at the price of taking over the California transmission grid itself.[32] On April 9, the state entered into a Memorandum of Understanding with SCE, under which it would acquire SCE's 12,000 mile transmission system for $2.76 billion.[33] Although this development appears to avoid SCE's following PG&E into bankruptcy for the present, the agreement faces opposition in the legislature, which must approve it.[34] Moreover, no industry analyst has regarded the state takeover of the transmission system as a positive development, and the FERC almost surely shares this sentiment. In addition to the muddled financial picture, most analysts are predicting supply shortages leading to rolling blackouts in California, perhaps on a frequent basis, during the summer of 2001.

Lessons Learned from California

California provides a spectacular example of the perils inherent in moving from an industry where customers are served by a government-approved monopoly at prices set by the state to an industry where the competitive market sets prices. The most important root cause of the California problems was not avoidable on a short-term basis. This was the long-term

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California Edison, Form 8-K, Item 5, February 1, 2001. Because of the current crisis and the difficulties facing Pacific Gas & Electric and Southern California Edison, San Diego Gas & Electric has encountered resistance from banks and generators who are reluctant to extend credit to it. San Diego Gas & Electric, Form 8-K, Exhibit 99.1, January 24, 2001.

[30] *Electric Power Daily,* March 6, 2001. Transcript of Press Conference, Office of the Governor, March 6, 2001 (available on the web at www.governor.ca.gov/state/govsite) (announcing "40 different agreements with 20 different companies for long-term power.")

[31] *Electric Utility Week,* April 2, 2001; *Electric Power Daily,* April 9, 2001.

[32] Press Release, Office of the Governor, February 16, 2001 (available on the web at www.governor.ca.gov/state/govsite) (announcing plan for "State purchase of the transmission grid owned by the state's three largest utilities.")

[33] *Electric Power Daily,* April 10, 2001.

[34] *Electric Utility Week,* April 16, 2001.

failure to build generating plants during the most sustained economic boom in the state's history. The market effect of the resulting shortages was exacerbated by an equally unavoidable surge in natural gas prices that helped cause electricity prices to spike. But other contributing causes were in fact avoidable. Requiring utilities to retain fixed price obligations to retail customers, while preventing them from hedging their price risk in a volatile wholesale market by entering into long-term supply contracts, seriously compounded the problems that would have developed in any case. This was the most significant regulatory problem, but other commentators have pointed out the contributory role played by other design flaws in the complex California restructuring regulations. [35]

The California market design flaws can be avoided, and many of them have been avoided in the restructuring legislation enacted by the other twenty-four states that have restructured. Other problems may not be so easily avoided, in particular California's failure to encourage supply development adequate to meet its growth in peak demand for electric service. In the traditional regulatory system, that responsibility fell on the incumbent integrated utility. The bedrock lesson of the California experience is that in any restructured market – in which there is no longer a monopoly utility to guarantee supply – government and transmission providers must encourage the development of generating capacity by private developers sufficient to keep up with growth in demand. Adequate supply development is one of the preconditions for robust wholesale electricity markets. Another precondition is the ongoing restructuring of the operation of the transmission grid. FERC's initiative to have Regional Transmission Organizations (RTOs) operate the grid on a regional basis must be carried through to a successful conclusion. [36] The best structure for an RTO is that of a for-profit entity receiving rates for transmission service adequate to provide it financial incentives to maximize throughput and access, as well as to expand the grid, which will further reinforce a robust wholesale market.

California also provides an object lesson, however, in the conundrum that faces any market transitioning from regulation to competition. California regulators sought to avoid having utilities "control" the available supply through long-term contracts, which they

[35] See, e.g., S. Harvey & W. Hogan, "Issues in the Analysis of Market Power in California," October 27, 2000, filed October 31, 2000 in FERC Docket No. EL00-95-000.

[36] Order No. 2000, Regional Transmission Organizations, III FERC Stats. & Regs. ¶ 31,089 (1999), order on reh'g, Order No. 2000-A, III FERC Stats. & Regs.¶ 31,092 (2000).

thought would discourage competitive supplier entry at the retail level. Accordingly, regulators effectively required the utilities to acquire their supply in the spot market. At the same time, however, regulators discouraged competitive retail entry by requiring SCE and PG&E to serve retail customers at low fixed-price rates. The result was a lose/lose solution: competition did not develop to the extent anticipated and the utilities were substantially ruined by having to serve a huge default customer base at a loss.

The Experience in Illinois and Pennsylvania to Date

To date, the restructuring experience in Illinois and Pennsylvania has been very different from California's, primarily because their respective restructuring legislation differs significantly from that adopted in California. Our discussion of Illinois and Pennsylvania restructuring will draw from the specific experience of the Exelon Corporation regulated utilities: ComEd, which serves 3.4 million electric customers in northern Illinois, including Chicago, or 70% of the state's population; and PECO Energy, which serves 1.5 million electric customers in the Philadelphia area.

Illinois Restructuring

Under the Illinois restructuring legislation enacted in 1997, customers obtained the right to choose their electric supplier on a phased-in timetable, with all non-residential customers having obtained that right by December 2000. Larger customers were given the right to choose their suppliers earlier, while residential customers received a rate cut in exchange for a later place in the phase-in of competition. For most of the state, including ComEd's service territory, this rate cut is 20 percent, (15 percent in August 1998 and another 5 percent in August, 2001). All residential customers in Illinois will have the right to choose their electric supplier in May 2002. In addition, under the "PPO option," non-residential customers have the right to buy energy from ComEd at market rates and pay ComEd to deliver it.[37] The effect of this option is that in order to win customers, competitive suppliers have to meet or beat the market price ComEd is required to charge. As of December 2000,

[37] 220 ILCS 5/16-110.

4,100 MW of demand in ComEd's service territory, accounting for 40 percent of the eligible sales, had chosen unbundled retail supply.[38]

Several features of the Illinois legislation have helped avoid California-style problems. In part, California may have suffered from a transition to competition that was simply too short to allow market institutions to mature. Rigid market structures were ordained in advance by the California legislature, so that developing experience could not inform their evolution. In contrast, the Illinois restructuring legislation did not impose rigid market rules, and direct retail access is being phased-in over a four-year period to allow the development of systems and infrastructure for a smooth transition to competition. By drafting the legislation with these features, Illinois stakeholders recognized that competition does not develop overnight or in a uniform pattern. The Illinois transition period gives market participants time to offer products and gain experience with the operation of a competitive retail market before full-scale direct access is implemented for all customers.

The Illinois restructuring scheme includes other features that shield retail customers from the impact of wholesale price volatility: Illinois law mandated a rate freeze for all retail customers through 2004 and a 20 percent phased-in rate reduction for most of the state's residential customers.[39] These features shelter retail customers from price spikes in the wholesale markets, such as those that occurred briefly in the Midwest in 1998. In addition, ComEd is required to continue offering bundled retail service at cost-based rates until a fully competitive market develops. After that, customers will still be able to receive service from ComEd under options that we will discuss in more detail later. The Illinois restructuring scheme thus offers very significant protection for consumers. This is in contrast with the California restructuring law which allows utilities to pass through the price of power to customers after the utilities have ceased collecting stranded costs.

At the same time it protects customers, the Illinois law allowed the Illinois utilities to hedge their risks of continuing to supply power at fixed rates to retail customers. Illinois has not imposed California's significant divestiture requirement, nor its requirement to buy and sell in a central spot market, nor has it prohibited utilities from entering into buy-back arrangements when generating plants are divested. In 1999, in the largest generation sale in

[38] Source: ComEd Retail Access Group.
[39] 220 ILCS 5/16-111(a) and (b).

the nation at the time, ComEd voluntarily sold all of its fossil generation to unaffiliated owners. In 2001, ComEd also voluntarily transferred its nuclear generation to its affiliate, Exelon Generation. ComEd took these steps because of ComEd management's belief that: (1) all generation should be on the same competitive footing in a competitive market; (2) a generation market that is half-regulated and half-competitive could distribute risks and rewards in an asymmetric fashion; and (3) retention of all control area generation in the hands of the incumbent utility could be a deterrent to full competition. The result of ComEd's divestiture has been to significantly reduce concentration in the important northern Illinois generation market, in which Exelon Corporation now owns less than half of the generation.

In selling its generating stations, ComEd was able to enter into power purchase agreements with the new owners that assure an adequate supply of electricity at reasonable prices through the year 2004 and, under different terms, beyond that. Similarly, when ComEd transferred its nuclear generation to its generation affiliate, ComEd entered into power purchase agreements through 2004 and beyond. Thus, ComEd has been able to ensure that neither it nor its customers are exposed to shortages or price spikes while the competitive market is developing over the coming years. How much capacity ComEd should contract for over the longer term while still allowing a competitive market to develop is a difficult question that we will address later.

ComEd has also tried to ensure supply-demand balance in northern Illinois by encouraging Independent Power Producer development, as we will discuss below, and by implementing demand-side management to reduce peak loads. Exelon Corporation has four types of programs that serve this latter purpose. Exelon pays large customers to curtail their usage at prices that are linked to market rates for power; we have about 650 MW under these programs. Exelon also has more traditional interruptible rates, under which large customers allow ComEd to interrupt their usage a certain number of times in exchange for a year-round discounted rate. Moreover, ComEd has rates under which large customers pay a price linked to the spot price of power and are given hourly forecasts of that price, which gives them an economic incentive to curtail load during peak price times. In addition, for residential customers ComEd has a residential direct load control program. In 2000, ComEd had a total of over 1200 MW of load on all these programs, which is the size of a large nuclear generating unit.

Pennsylvania Restructuring

Pennsylvania's retail restructuring began earlier and is thus more advanced than in Illinois. Pennsylvania's restructuring began in December 1996, and all retail customers have had the right to choose their electric supplier since January 2000.[40] To date, about 18 percent of PECO Energy's customers have chosen a supplier other than the distribution company; because the larger customers have a higher rate of switching, this amounts to about 35 percent of PECO Energy's peak demand from customers. PECO has more customers in the competitive market than any other Pennsylvania electric distribution company.[41] In part, this is attributable to the fact that PECO agreed to assign 20 percent of its residential customers, nearly 300,000 customers, to a competitive supplier as a result of a program that the Pennsylvania Public Utility Commission required the company to adopt.[42]

Competition throughout Pennsylvania has also been advanced by the institution of the "shopping credit," a price reduction a customer receives from the distribution company if that customer obtains its electric supply from a competitive supplier. Knowing the amount of the shopping credit allows the customer to evaluate competitive offerings intelligently, because any competitive price less than the shopping credit will save the customer money. The Pennsylvania experience teaches that if the shopping credit exceeds the wholesale generation price, a competitive supplier can underbid it while obtaining an adequate profit margin. This scenario will foster a competitive retail market because it is a win-win situation—customers save money and competitive suppliers earn a profit. As an aside, PECO's experience is that certain customers are less price sensitive and are willing to pay more than the shopping credit for "green" power generated from renewable resources. However, PECO's experience also suggests that the "green" power market is relatively small.

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[40] Electricity Generation Customer Choice and Competition Act, HB 1509, Pennsylvania Consolidated Statutes, Title 66, Chapter 28, Section 2806 (December 1996).

[41] Pennsylvania Electric Shopping Statistics, PA Office of Consumer Advocate (January 2001)(available on the web at http://sites.state.pa.us/PA_Exec/Attorney_General/Consumer_Advocate/cinfo/stat0101.pdf).

[42] PECO's Competitive Default Supply Program was initially established by the Joint Petition for Settlement approved by the Pennsylvania Public Utility Commission on April 29, 1999. Order, Docket No. R-00973953 and P-00971265 (April 29, 1999). The program was replaced by the CDS Lite program outlined in the Joint Petition for Settlement in PECO's Application for Approval of Corporate Restructuring. Order, Docket No. A-110550F0147 (June 22, 2000).

Pennsylvania also has significant market structure advantages that will allow it to avoid the California experience. Wholesale electric markets in Pennsylvania and neighboring states, and the institutions that manage those markets to date, have shown themselves sufficiently flexible to avoid the price spikes experienced in some other areas. PECO Energy's service territory is located in a regional grid and power pool known as the Pennsylvania-New Jersey-Maryland Interconnection, or PJM, which is likely to be approved by the FERC as a Regional Transmission Organization. PJM is the most mature, liquid, and efficiently functioning wholesale electricity market in the country. In large part, its success has resulted from the fact that PJM provides a reasonable and stable environment for companies to make investment decisions about generation. A set of stakeholders, representing customers as well as generators and transmission owners, works together to craft negotiated compromises that reflect all interests. Regulators have allowed this cooperative process to function without externally imposed rules, and the result has been a high level of confidence by all parties that creates the stable environment needed for investment decisions.[43]

Like Illinois, Pennsylvania's rules for the transition to competition were designed with the goal of protecting retail customers while the retail market continues to evolve to maturity. In PECO Energy's service territory, there will be a transition period until 2010 during which time PECO will be required to provide retail electric service at capped rates, and PECO's rates for energy delivery will be capped through 2006. As in Illinois, this transition period provides significant protection for all electric retail customers in Pennsylvania.

Supply Development in Illinois and PJM

The single most important factor in avoiding California-style problems in Illinois and in Pennsylvania is the currently healthy state of the development of new supplies of electricity in both of those regions. This development has kept generation supply in relative balance with demand in both states.

In Illinois, ComEd has taken a proactive stance on encouraging the development of new generating capacity by independent power producers in northern Illinois, and to date development has been significant. By last year, about 2,000 MW of new generating capacity

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[43] Electricity Generation Customer Choice and Competition Act, HB 1509, Pennsylvania Consolidated Statutes, Title 66, Chapter 28, Section 2804(4)(i) (December 1996).

had become operational in ComEd's service territory. For 2001, over 3,600 MW of capacity is expected to come online, all of which is permitted and currently under construction. For 2002, another 5,500 MW are scheduled to come on line, of which 3,600 MW are currently in a definitive stage, that is, either construction has begun or the equipment has been ordered. For the longer term, over 10,300 megawatts are projected for 2003, though none of these projects are as yet in a definitive stage.[44]

PJM has also been successful in encouraging adequate development of new capacity. Over 4,000 MW of new generation is scheduled to come on line in 2001 in PJM, with over 12,000 MW in each of the years 2002-2004. Of that large amount, 4,200 MW is under construction, 3,700 MW consists of upgrades of existing generating facilities (both indicators of definiteness), and 9,100 MW consists of projects on which construction is about to begin.[45]

While the development of new generation supplies in pace with the growth in demand is essential to maintaining market price stability, a growing concern nationwide is that most of the new generation being developed today is fueled by natural gas. With natural gas prices at historically high levels, a natural question is whether the new generation will result in significant overall increases in the price of electric energy and whether the development of new generation by independent producers will itself be choked off. The indications so far are that neither of those contingencies will occur in the Midwest. There is no question that higher natural gas prices increase the cost of gas-fired generation, and some projects planned for 2002 and later have already been delayed or cancelled. However, most of the plants being built so far are "peakers," that is, plants designed to run for only about 1000 hours a year when demand is highest and consequently when energy prices are highest. This limits the effect of currently high natural gas prices, which are in any case expected to moderate over the next few years.[46]

As to prolonged development of new generation supply in northern Illinois, developers continue to see a large and desirable customer base and a robust transmission system capable of delivering their power. Moreover, because of extensive pipeline construction in the upper Midwest in the last few years, the Chicago Hub has become an

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[44] Source: ComEd IPP Interconnection Group

[45] Source: PJM. See data available on the web at www.pjm.com. (Click on Generation Interconnections).

increasingly important market center for natural gas. This means that from a fuel availability and cost point of view, the Chicago area remains attractive to independent power producers.[47]

The Ongoing Transition

The combination of consumer protections in Illinois and Pennsylvania law and robust climates for investment in new generating capacity will ensure that customers in Exelon's service areas are not threatened for several years to come by either price spikes or physical supply shortages leading to rolling blackouts. This does not mean, however, that we can afford to be complacent about our current successes, because the one thing we can be sure of is that nothing stands still. We want to address, therefore, how we must go about assuring for the longer term adequate transmission capacity and appropriate transmission pricing, adequate supply of electricity, and a final transition to a fully competitive marketplace for electricity.

The Future—Developing Regional Transmission Organizations

A current limitation on the development of full competition is the transmission charges a competitive supplier must pay to transmission owners to transport energy to the supplier's customers. The market in which a competitive supplier can find energy to serve a customer in a delivery company's control area is limited by the fact that the farther afield it looks, the more cumulative transmission charges it must pay to deliver the energy to its customer. All else being equal, this gives generation within each control area a price advantage over generation located outside the control area.

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[46] Although gas prices in the West roughly tripled from January 2000 to September 2000 from about $2/MMBtu to $6/MMBtu, FERC Staff Report , pp. 3-19 to 3-20, average costs over the next five years are projected to be about $6/MMBtu.

[47] "Although the Henry Hub in Louisiana remains the major natural gas market center in North America, the Chicago Hub can be expected to grow significantly as new Canadian import capacity targets the area as a final destination or transshipment point." (American Gas Association, Hubs Issue Summary, 3/28/01, www.aga.org/AdvocacyIssues/IssuesSummaries/Deliverability/942.html.) The Northern Border Pipeline Co. has built a line extension from Iowa to Chicago, which is now in service; and the Alliance Pipeline from Alberta, Canada to Iowa has completed the Tampico compression station to support this line extension. (www.capp.ca/pipeline.html; www.alliance-pipeline.com/our_system/0100_Interactive_System_map.asp.) The Vector Pipeline from Joliet, Illinois to the East Coast and Ontario is in service, and the Independence Pipeline Project from Joliet to the East Coast is obtaining regulatory approvals. (www.vector-pipeline.com/news_releases/pdf/nr-2001201.pdf; www.independence.twc.com/releases/NR10.htm.) There are also proposed pipeline expansion projects to promote competition in Wisconsin from the Chicago area. (www.isonline.com/bym/news/oct00/guard11101000a.asp.)

The multiple transmission charge limitation on competition, however, will soon be significantly reduced. FERC has strongly encouraged the development of Regional Transmission Organizations (RTOs), and such organizations are now under development in every area of the country. These RTOs will provide all electric suppliers with a multi-state market within which they can deliver energy for a single transmission charge.

While we have discussed it as a market above, PJM also currently operates as a regional transmission operator. By contrast, at present there is no RTO in the Midwest. However, subject to regulatory approval, ComEd has agreed to participate in the Alliance RTO (ARTO), which will be functioning by the end of this year. The ARTO will be an independent entity that will operate the combined transmission systems of a group of utilities that stretches from Virginia to Illinois, and this greatly expanded market should provide a significant boost to competition.

The Future—Ensuring Adequate Supply

All states—whether restructured or not—must support the development of new generation supply to ensure adequate supply to meet demand. States must avoid imposing unduly restrictive regulations and lengthy permitting and siting procedures, which have hurt supply development in California. Moreover, as the independent power market matures, not all new supply can continue to consist of peaker plants. Eventually growth in average demand, not just peak demand, will require construction of cycling and base-load capacity. Addition of combined-cycle gas generation is part of the solution, but states will also have to come to grips with siting some large new coal-burning plants or next generation nuclear units. An important factor in selecting the mix of new generation may well be the need to control and reduce emissions of greenhouse gases to address global warming and other environmental concerns. Although significant controversy has surrounded reliance on nuclear power in the past, it is important to remember that nuclear generation has avoided emissions of billions of tons of carbon dioxide.

ComEd currently has long term power purchase agreements that assure adequate supply of electricity at reasonable prices for its customers through the end of 2004. After that time, ensuring that adequate amounts of new generating capacity continue to come on line will be of paramount importance - not only to maintaining reliability as load continues to grow, but also to developing a fully competitive market. It will be essential that Illinois and Pennsylvania continue to support development of new generation sources by independent power producers.

As development of independent power producer generation continues, more extensive upgrades to transmission systems may be necessary to facilitate delivery of energy from new generation to markets where it is needed. It will also be important for Illinois, Pennsylvania, and other states to facilitate siting of new transmission facilities, so as not to constrain the power supply.

In addition to supporting additions and upgrades of generation and transmission facilities, all industry stakeholders need to consider carefully how the reserve margins that we have so carefully preserved as regulated vertically-integrated utilities will be preserved in a fully competitive market. The industry has generally considered that preserving the reliable service that customers expect requires planning reserve margins in the range of 15 to 20 percent. When utilities were regulated monopolies, they planned for and constructed generating capacity to satisfy these reserve levels.

In the fully competitive market, who will assure that competitive suppliers have adequate reserve margins? This is a case in which competitive market forces alone may not assure that our current level of reliability is preserved. In particular, the free market cannot be expected to encourage electric suppliers to build adequate reserve margins into their load-serving capability because the physical nature of the energy delivery system creates the market inefficiency known as the free rider problem. For example, if my neighbor's security lighting illuminates my property adequately, I have no economic incentive to install my own security lighting. In the case of the electric industry, if every competitive supplier faced the realistic prospect that its customers would be blacked out unless it maintained adequate reserve margins, there would be adequate market incentives. In fact, however, when numerous competitive firms supply different customers connected to the same electric system, there is no adequate means for the system operator to selectively cut the power supply to customers of a competitive supplier that runs out of energy. Thus the competitive supplier does not pay for reliability risks that are imposed.

For northern Illinois, reliability issues related to reserve margin should not emerge for some years. It is important, however, that we begin thinking hard about solutions adapted to the Illinois market. PJM has adopted a straightforward solution to the reserve margin problem, but it is not clear that this solution would be easily adaptable in the Midwest. PJM has a so-called "installed capacity requirement": any entity selling to an end-use customer located in PJM must either own or purchase a reserve margin of 19 percent to back up its sale. To allow competitive suppliers to meet this obligation, PJM runs an installed capacity market. Payments from this market provide a steady stream of income to generators that is helpful in maintaining continuing development of generation supplies. The suppliers receiving the payments must sell their energy to customers in PJM under long term contracts or make it available to the central energy pool there. This mechanism appears to work well in PJM, though there has been controversy about the level of the charge. It is less clear, however, that an installed capacity market could be run efficiently in an area like the Midwest, where there is not a central energy pool. There are alternatives to the installed capacity requirement to ensure maintenance of adequate reserve margins. Such options might include having the control area operator purchase reserves and pass the cost through to transmission customers as a service analogous to the balancing energy service for non-conforming load under open access transmission tariffs.

The Future—Making Competition Work

In its pure model, the fully competitive generation market would have competitive electric suppliers responsible for ensuring provision of enough energy to meet their customers' needs at a competitive price, while entirely separate from them would be a single delivery company in each area, owner of the wires and responsible only for moving the energy to the customers' locations. The provision of delivery service would remain a cost-based regulated service, while the pricing of energy would ultimately be up to unregulated suppliers. This was the implicit goal of the California model. In reality, however, the physics and politics of electricity dictate that the delivery company will be a default supplier. Because the system operator (*i.e.*, the delivery company) cannot selectively drop customers whose suppliers default on their obligations, the delivery company cannot ultimately shed its default supplier role from a physical reliability point of view. In addition, the practical considerations involved in moving all retail customers, including residential customers, out of the regulated utility and into the hands of competitive retail suppliers is daunting, considering the slow pace of development of competitive retail suppliers who are interested in serving the residential market. This has led to a debate about how the delivery company's default service should be priced.

Indeed, the pricing of default supply is one of the most difficult problems for regulators, utilities, competitive suppliers, and customers to resolve. The difficulty resides in the chicken-and-egg dilemma of the transition to competition. If regulators assign primary responsibility to the delivery company for arranging supply and permit it to enter into and recover the cost of long-term agreements to hedge against price increases, new entrants in the market will have much less access to generation sources needed to compete. Moreover, although delivery company rates for supply in such a system may be more stable because of the utility's hedging activities, the result will be that competitors who rely on limited remaining generation sources, including the spot market, may have difficulty meeting or beating them. An alternative system that eliminates the delivery company's obligation to arrange supply and to engage in hedging transactions would expose customers to very high price spike risk unless competitors can be required or encouraged to make similar price protection available.

One method of limiting the delivery company's supply obligations while directly stimulating competition would be for regulators simply to assign a certain percentage of customers to competitive electric suppliers. This method need not eliminate customer choice because, as in Pennsylvania, the customer could be allowed to opt out of being assigned to the competitive supplier. The method nonetheless to some degree substitutes regulatory mandates for free customer choice, inserting the regulator into the competitive market. It also does not eliminate the delivery company's ultimate responsibility to supply power to these customers in the event that their assigned suppliers fail to deliver. The Pennsylvania Public Utility Commission has recently decreed that PECO Energy must again supply tens of thousands of customers of a competitive supplier that has decided it no longer wants to serve them.[48]

Beginning in 2005, under the Illinois restructuring law, the rates for electric supply by delivery companies will be set by the Illinois Commerce Commission. The Illinois statute

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[48] Utility.com, which described itself as "the world's first internet utility company" offering "reliable electricity service" recently announced that "[d]ue to unanticipated impacts of deregulation laws in California and the uncertainty in resolving these impacts, wholesale energy markets are experiencing unreasonably high prices" and "accordingly, Utility.com can no longer offer online electricity services to consumers." Utility.com therefore stated that "[w]e will not be signing up new residential electricity customers and are turning our current electricity customers back to the incumbent utilities." (www.utility.com.)

allows the Commission to set the rate at the market price plus ten percent, but does not require any specific methodology. Because of the complexity and importance of the issues and the long lead times involved in assuring adequate supply, it is time now for Illinois utilities, customers, and regulators to develop a method for reaching the end-state fully competitive market.

We propose a market-oriented method of limiting the delivery company's supply obligations and stimulating competition, one that takes advantage of the important differences between large customers and mass market customers to find a way around the chicken-and-egg dilemma.

In order to make competition work at both the retail and the wholesale level, it is essential that substantial numbers of large customers migrate from the delivery company to competitive suppliers. These large customers have the most desirable service characteristics and therefore are the ones at whom competitive suppliers aim their products. The continued availability of fixed-price bundled service from the utility will constitute a significant deterrent to large-scale migration of these customers, as well as leave the utility with virtually undiminished supply obligations, which can also deter competition. These considerations lead us to the conclusion that the delivery company's only default service obligation to large customers should be to supply their electricity at a market price that includes some risk premium to compensate the delivery company for its default obligation. This should not impose an undue price risk on large customers, because they are likely to have their own means of hedging the risk of bearing spot prices in the electric markets, including products offered to them by competitive suppliers. If the delivery company is required to offer a price more attractive than this to large customers, it may be difficult for competition to make headway against it.

Mass market customers, on the other hand, lack hedging ability. To date, for example, no vibrant competitive market for supplying residential customers has developed anywhere. Such customers need some protection from price volatility, and failure to provide it will rebound against the delivery company. The events of 2000 in San Diego showed that when the price risk of the wholesale market was passed directly through to small customers, their reaction to the summer price spikes quickly became political. With demands for rate-rollbacks and refunds raining down on regulators, the potential financial risk to the utility from such an arrangement is open-ended. It would thus appear that, both from the customer's and the delivery company's point of view, some kind of fixed-price, multi-year energy supply offering is necessary for small customers. Because such long commitments would insulate the small customer from wholesale price volatility for a period of years, it would involve more price risk for the delivery company. The price would therefore have to include a risk premium adequate to compensate for the utility's hedged risks. Such a risk premium would also ensure that the delivery company's rates are not set too low for competitors to beat. Unless this happens, no competitive market for small customers will ever develop.

Such a bifurcated approach to default service pricing offers the promise of escaping from the dilemma that we outlined above. It can achieve goals that might otherwise be seen as competing by: (1) providing price stability for customers who need it, while allowing more energy-intensive customers to engage in buying strategies to minimize their costs; (2) maintaining the delivery company's financial soundness, thereby safeguarding reliability; and (3) encouraging the entry of competitive suppliers at all levels, thus ensuring the development of a mature and fully competitive market.

Conclusion: "A Republic, If You Can Keep It"

Despite the serious problems that have developed in California, there is no way to go back to the old world of monopoly integrated utilities, and temptations to do so must be resisted. In the anxiety about adequacy of supply raised by California, it is too easy to forget why the old regime was abandoned in the first place. Monopolies in general did a good job of assuring adequate supply. They did a much less good job of assuring the right amount of supply and pricing it efficiently. The result was widespread customer revolt at paying for generating capacity that was perceived as excess. In some quarters, the perceived solution to this problem was the institution of integrated resource planning, but that regime simply put the state in the position of a central planner for a vital industry. If the twentieth century taught anything, it was that state central planning does not allocate resources with the efficiency of competitive markets. Indeed, the inefficiencies of integrated resource planning were such that the states which relied on it most extensively—including Massachusetts, California and Rhode Island—were among the first to embrace the new competitive model.[49]

As he left Independence Hall at the close of the Constitutional Convention in 1787, Benjamin Franklin described the challenge facing the new nation. When asked what kind of government the country now had, Franklin responded "A republic, if you can keep it." The Founders had established the framework for the new system, but, worried about a tendency toward monarchy. Franklin cautioned that much work remained to be done to make it a lasting reality. In all of the restructured states, including Illinois and Pennsylvania—the states where Exelon Corporation does regulated utility business—the restructuring legislation establishes frameworks for competitive electricity marketplaces with reliable sources of supply. But, as with our republic, it will require constant work by all stakeholders to achieve these promises.

[49] For example, the California Energy Commission's 1994 Electricity Report commented that "[f]or the past six years, the California Public Utilities Commission (CPUC) has engaged in a controversial proceeding known as the Biennial Resource Plan Update (BRPU) to determine each IOU's need for resources, the potential costs of those resources and the rules under which each utility would be compelled to acquire power from independent power producers to meet some portion of those needs. In a competitive market, the rationale for this well-intentioned but difficult, highly contested and, so far, still unsuccessful effort could be completely eliminated." California Energy Commission, Pub. No. P300-95-002 (November 1995) at 8 (available on the web at www.energy.ca.gov/reports/ER94.html.