THE U.S. ELECTRICITY SECTOR: WHAT AFTER CALIFORNIA?
Shifting Risks And Opportunities

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The seas have changed. Some of the dreadnought utilities are taking on water. What is going on with the utility sector?

Certainly, the premises for evaluating equity investments in those businesses we used to know as electric utilities have changed dramatically. The vertically integrated electric utility had long been perceived as a safe harbor for equity investors during the squeamish period of a potentially waning bull market. Utilities were protected from the unforeseeable vagaries of the unregulated, competitive markets – markets in which perfectly reasonable decisions can be rewarded with failure. But the basics of electric industry stocks, and the principles for the electric energy industry generally, have changed and are in a dynamic state of flux.

The old perception of a predictable safe harbor in large electric utilities can no longer obscure the rocks and shoals that are emerging for electric energy industry players. Dangerous rocks and shoals that were beneath the surface are now much more visible after the tide went out in California in the Summer of 2000. What happened in California? Will it happen elsewhere?

The California Experience

California pursued electric industry restructuring for several reasons, some of them based on economic principles, but all of them were rooted in politics. Electric rates in California (and in Massachusetts, Illinois, Pennsylvania and other early states in the deregulation game) had become, from a political standpoint, intolerably high.* Whether or not these high rates resulted from unreasonable utility management decision making, they surely were the result of the need to build and plan for generating plants in the period 1970-1990 when some states experienced rapid demographic growth and forecast substantial increases in electric demand.

Political Will

Utilities, under the old regulatory compact, had no choice but to build the plants necessary to meet forecast demand. Some of the plants, after the fact, turned out to be expensive options. High-priced Independent Power Producer ("IPP") electric off-take contracts were forced upon utilities in some states by the federal Public Utility Regulatory Policy Act of 1978 (PURPA)* and state requirements in places like California and New York* (which had legislatures or PUC's enthusiastic about promoting non-utility generation by those entities now accused of "profiteering"). These factors caused utility cost-of-service-based rates to be, from a political standpoint, indigestibly high. Fingers now point at the utilities. But what about the policymakers who created this new world? In some states the policies seem better conceived than in others. Or maybe the difference in results relates to the existence of adequate electric generation reserves – or the political will to allow adequate reserves to be constructed – in some jurisdictions as compared to others.

A Devil of a Deal

The political objective of reducing high electric rates (a political imperative, since all voters are also ratepayers) caused primarily by high fixed costs, left only two solutions. One – the disallowance of a material part of the high fixed costs (the "stranded costs") could lead to the bankruptcy of some of the biggest U.S. utilities in California, Illinois, New York, etc.* These utilities quickly became champions of the only other option to reduce rates – break up the vertical monopoly utilities, sell off some of the pieces at substantial gains, refinance (re-leverage) the capital devoted to generation to pass through lower capital costs in rates, and trust that the resulting unregulated generation market would respond with excess capacity, improved technology, and cheaper purchased power.

The political deal in California had something to please everyone. The omnibus deregulation bill passed with barely a dissenting vote in the California legislature (who was that prescient vote?).* The legislation was too good to be true. Most deals with the devil are. It reflected the rank fear of the utilities about stranded costs being inflicted due to the politics of high rates; the greed of Wall Street about the rush of recapitalizations which would have to result; and the glutinous political appetite to defy basic principles of economics to serve up lower utility rates to the voters.

The landmark legislation ignored numerous lessons of history and basic principles of economics. Electricity, in today's world, is one of civilization's most fundamental necessities. It cannot be in shortage without the most dire social and political consequences. Electricity is produced primarily out of commodity fuels (coal, oil, gas), which have inherent price volatility. The most efficient electric production facilities are very large, apparently environmentally unappealing, politically unpopular facilities. The electricity is shipped over environmentally unattractive transmission super highways. Electricity cannot be stored. It must be generated at the same moment that it is being consumed. It cannot be shipped by boat, truck or train, but can only be transmitted in the grids which are geographically limited by the political and social will to build substantial transmission highways.

Historic Approach

During the development of the electric industry, these same realities developed, but they were answered with:

- Utility powers of eminent domain (exercised under the oversight of state regulation) to build the generation and transmission capacity necessary for (but not in excess of) that needed to assure adequate, reliable service at reasonable cost;* and

- Utilities were required to build the vertically integrated infrastructure necessary to accomplish adequate service, but were protected from the risk of financial failure posed by competition, and the price for this was comprehensive, cost of service-based price regulation. Customers paid an insurance premium for avoiding the risk of electric shortage by paying rates which included the cost of reliability, assuring, electric system excess reserves of 15% to 18%.

Deregulation came as the political answer to the question of how to get three pounds out of a two pound bag. The total costs involved with producing electricity were too high – and a fundamental reason involved very high cost generating facilities. Selling generating plants to third party producers at prices over the book value just meant someone else might be left holding the bag. Either those buyers would recover their costs (and raw electricity prices would go up) or the plant buyers would lose their bets. The plant buyers won their wager. Electricity shortages made electric generation plant owners the big winners.

Risks, Latent Risks and Political Will

It is an economic axiom. There is a finite amount of risk involved with producing electricity, transmitting and selling it. That risk is allocated between those who build facilities; those who own them; those who finance them; those operate them; those who sell the electricity; and those who purchase it. Deregulation didn't eliminate risks, or increase them. It just reallocated them. In that reallocation, more of the latent risk associated with a short supply has become apparent. It's like the difference between the potential energy in the bowling ball sitting on the counter, and the kinetic energy of the ball falling off the counter. You don't perceive that energy until it falls.

And customers bear the risk of the consequences of shortage. In the past customers were asked to bear the cost of avoiding shortage in some orderly manner (system reserves). Now we are seeing the economic consequences of actual shortages. It proves the high cost (value) of electric system reliability. And whether the latent risk is realized has to do with the political will to assure (or just to allow) adequate electric infrastructure be constructed. The political process has more trouble perceiving the latent risk of electric shortage. In the past, this led to paternalistic system planning regulation by state PUC's.* Once the actual shortage materializes, it is too late. The half life of building needed new capacity involves years.*

Demand and Supply

A basic principle of economics, and a prime lesson of economic history, is that shortages of commodities cannot be solved by fueling the demand for that commodity with more buying power. And if that commodity is a necessity, amplifying the buying power is like pouring gasoline on a fire. The rule in commodity markets, at least those with a very low price elasticity of demand, is: supply, supply, supply.

The demand for electricity is, in the near term, price inelastic. So is the supply. For the distribution utility that must buy electricity to meet retail firm requirements – the demand for electricity at the margin, in the spot market, is absolutely price inelastic. When the buyer of electricity in the wholesale market must buy electricity regardless of the wholesale price, because of an absolute obligation to sell electricity at retail on a firm basis at a firmly capped retail price – the sky is the limit on the wholesale purchase price. No amount of market subsidization, without price controls in the wholesale market, will avoid financial ruin – without an adequate supply of electricity (generation). The answer to California's problem must start with solving the electric supply shortage.

Boom, or Else

The statutory deregulation scheme in California reflects either the absolute desperation of the distribution utilities in the mid-1990's, or the ebullience of California optimism – that the downside scenario simply won't happen. Not boom, or bust; but boom, or else. The California reforms set an absolute retail price cap* – with no pressure release valve to adjust for purchased power costs. And that legislation also forbid long term off-take contracts between the distribution company selling the facility and the new owners.* This placed the electric distribution utilities at the whim of the electric wholesale spot market – a formula for disaster in a commodity shortage situation with an absolute obligation to meet a growing demand in the retail market, at a fixed retail price cap. The situation would work fine for the distribution companies in a supply surplus; but in a commodity shortage, financial ruin happens on a predictable basis – just as the citrus market turned on Dan Ackroyd in a predictable manner in "Trading Places." Being unhedged in a commodity market by being restricted to the spot market is roulette – Russian roulette. But that is where the California political process put the California utilities. Are they to blame for letting the legislation pass? Did they have any real choice?

What now? Understanding what lies ahead requires a better understanding of the lessons of history, and an evaluation of the political imperatives.

The Political Imperatives

The brownouts and blackouts in California rival natural disasters in the scope of their impact. Just imagine the political consequences if governmental regulations or corporate conduct could be blamed for earthquakes.

Distance

The recent blackouts and the predicted shortages for the California electric system are the equivalent of political stink bombs. The immediate political instinct in the face of the apparent California electric system dysfunctionalism is distance. Politicians obtain distance by laying low, or laying blame. Laying low can work for a short time, but if the crisis fails to resolve itself, politicians who are not perceived as being part of the solution will be seen as part of the problem. Thus, the California legislature will move increasingly towards activism. But, as discussed, there are few if any easy or low cost solutions, and essentially none which solve the problem in the critical political planning horizon of one term in office.

Distance was obviously the first policy vantage point chosen by the Bush Administration.* But California represents a significant percentage of the national GNP. The energy issue there could be viewed as causal for a next recession. Federal action and support of some kind is undoubtedly a growing imperative.

Distance is definitely the likely political posture for state politicians in the states just considering the possibility of electric industry restructuring. The political imperatives for deregulation in most of the 20-plus states which pursued some level of deregulation were well above-average utility rates to the voters, and the financial risk to utilities posed by stranded costs. Both imperatives are lacking in the states which have yet to act. As compared to national averages, South Dakota, Kansas, Vermont, and Florida have the highest electric rates amongst the states which have not deregulated* – and yet their rates are not materially different from other rates in their region. Without political imperatives to force the deregulation issue, the dangers of lighting the fuse on the political bomb that has gone off in California might seem overwhelming.

Laying Blame

Laying blame is another strategy. A risky one. Particularly in a state which unanimously adopted a failed restructuring program. The long finger of blame can turn back on the accuser just like the rifle muzzle of Wil E. Coyote, blackening his facial fur with powder burns. And laying blame on the distribution utilities reduces the political options. If the local utilities are blamed, what about the legislation that so clearly put them between a rock and a hard place? While the utilities might have volunteered for the trip, it was the California reform legislation that sent the utilities up the deregulation creek without a paddle.

If the local utilities are to blame, then providing them with state financial support or allowing rate increases will become impossible as unpopular "bailouts." If support cannot be provided, then the large utilities go bankrupt – and the politicians will have to replace the incumbent utilities. With what? New, investor-owned utilities would not likely fare any better than those they replace without relief from the rate cap and a solution to the supply shortage. The financial markets will not support them. If public entities are installed to replace the incumbent investor-owned utilities, politicians will face the blame for all of the future energy problems. That kitchen looks very hot to politicians.

Bankruptcy has other political risks. Trustees in bankruptcy are required to be junkyard dogs in their pursuit of value for the creditors. They might well ask questions in court about the constitutionality of the California rock and hard place deregulation scheme which so clearly put the utilities into the jaws of insolvency. Ever since the Hope and Bluefield cases, it is clear that state price regulatory processes must give the regulated utility a reasonable opportunity to earn a fair return.* If they prevail, was the regulatory system enacted so unfair as to constitute a condemnation and confiscation of the shareholders' and creditors' property? In retrospect, it sure looks that way. How much could that court controversy cost the politicians? Would that process wrest control of the California situation out of the legislature and into the court's hands? Will receivers end up unsorting the problem in California, and reinstating the incumbent utilities?

Blame the "profiteering" IPPs? But the incumbent legislators installed them with the 1995 deregulation. And bringing them under price regulation is a federal issue, and one which could also involve fundamental confiscation issues.

No Alchemy

There really are no political options other than accelerating the construction of new power plants. Alchemy does not work. Putting money into the balance sheets of the utilities by buying their transmission systems at a gain will buy but just a little bit of time. That money will be gone in a short time if retail prices stay below wholesale prices. Selling off transmission is like burning the furniture and floor boards to heat the house. And of course electric customers (or taxpayers –aren't they the same in a state that imports power?) will have to pay for the transmission system premium either with rates or government subsidies.

No Quick Fix

The answer is new power plants – fast. But the plants which can be built most quickly are expensive to operate, and use now-expensive natural gas, cf, combustion turbines. Meeting demand in this fashion will require that utility rates go up, or that utility financial losses increase. Not a popular solution. The California solution will involve higher costs to citizens of California, either in their capacity as taxpayers or ratepayers. Ultimately, the rate freeze promise will prove illusory because of the shortage. Efficient, large coal plants take years to build and have to overcome political opposition to siting, or opposition to the new transmission lines to transmit the power from places where siting resistance is low to where electricity is used.

Black and Brown Trumps Green

The problem faced in California now is the result of the experience in the late 1980's and early 1990's. During that time, utilities had been required to build generating facilities to provide 15% to 18% reserves in excess of projected peaks throughout long-term planning horizons. Recessions and actual increases in conservation practices increased the amount of excess generation capacity at the margin, much of the time. Many utilities found they could successfully rely on the purchased power market instead of building new plants. These excess reserves, and uncertainty about stranded costs and other regulatory issues, resulted in very few new power plants being constructed in the 1990's.*

Political Atrophy

The political system began to take adequate electric service for granted. The political process to support electric infrastructure development, like efficient, large generation and high voltage transmission, atrophied. Meanwhile, the green movement took hold in a number of states like California and Wisconsin. Latent or merely predicted shortages of electricity could not overcome NIMBY,* or the more global NOPE* movements. Green became a reigning color in the political spectrum. That is, until there are blackouts or brownouts. Then, Black and Brown are colors which probably trump Green in the political scene.

That is the test we face right now. What is the political will to support the construction of an adequate electric infrastructure now, and on an ongoing basis when shortage is still a latent risk, before brown and black appear? When shortages are latent, will the political process overcome NIMBY and NOPE so that reliability-enhancing electric reserves can be constructed? In an unregulated generation market? Is eminent domain and coercive governmental authority necessary to assure adequate electric infrastructure? Does eminent domain require renewed, comprehensive regulation of electric generation? Will the marketplace be allowed by all the various jurisdictions to build the electric generation infrastructure? Is continued government planning and oversight by paternalistic PUCs the only way to assure generation capacity will keep shortage at bay as only a latent risk?

What Other Likely Government Action?

In the past, when the government has wanted to stimulate capital investment, as for electric generating plants, it has used stealth subsidies like investment tax credits, special tax credits to reward environmentally attractive options (§ 29 tax credits), accelerated depreciation options, and broadened use of tax exempt financing (changes in the "private use" definitions). Some or all of these steps aimed at electric generation are likely to be considered soon at the federal level. The EPA is likely to be asked to reconsider, in a difficult political process, how much of the air cleanup burden should be borne by electric generation (of course, the main competition for bearing air emission controls burdens is the automobile). And the FERC will get increased pressure to more closely regulate electric wholesale prices charged by exempt wholesale generators which have been allowed to charge market-based prices because they were found not to have market power.

Free and Slave States, Patchwork or Tapestry

After California, the prognosis for the states which have not deregulated is probably different. Whereas the prevailing assumption had been that all states would deregulate, and the question was just when? Now, it is whether? The situation is a bit like the cruel joke about the lame man who prayed for his one leg to be like the other, and ended up in a wheelchair. The situation looks something like a map of the U.S. in 1862, with a number of "free" states, and others not. The "free," deregulated states, include a material percentage of the country's population, but by no means all.

The deregulation is a patchwork of systems which is working well in most jurisdictions* – but, as always, the drama in California is overshadowing successes elsewhere. California's problems are frequently seismic, and develop along fault lines. In this instance, of deregulation, the fault line is quite obvious. It was the rigid retail price lid, coupled with a prohibition on long-term power off-take agreements by the distribution utilities.

If states sitting on the deregulation fence stay there, of course the result will be uncomfortable. It could paralyze the political and corporate will (due to uncertainty) to build an adequate electric infrastructure in advance of the black and brown political crisis of electric shortage. And, a national patchwork will surely affect the rate of development of effective, new generation technologies and more efficient national markets.

Certainty about how electric systems will be regulated is much better than uncertainty. Properly deregulated generation markets seem to hold a lot of promise. Will the bomb that went off in California scare the politicians in the rest of the country into paralysis? Do they understand the discomfort and risk they face by sitting on the deregulation fence too long? How atrophied is the electric infrastructure process in the various states where shortage is still a latent problem? These questions are especially important where the Green movement has developed while the electric infrastructure processes have atrophied. This was the political situation in California, and it could be the case in other electrically isolated markets like Wisconsin, Florida and Michigan. The questions about deregulation and which type of deregulation won't be answered until shovels hit dirt, and the next round of needed electric capacity is constructed. Does the political will exist to allow/assure the level of actual and planning reserves of electricity that are necessary to maintain electric shortage as a latent risk? The fundamental issues revolve around siting and construction approvals for generation, and freedom for electric market participants to use various market tools to hedge their risks. And, basic fairness must apply to the price regulation of the distribution utility, so long as price regulation is applied.

The Past

Some rules and trends have helped shape the restructuring of the new reality electric industry and the various business strategies adopted by industry players. Electric industry companies can be recognized and need to be valued based on new fundamentals, rather than old assumptions.

1. The Challenge: Valuation of an Industry In Flux

Are equity investments in the electric industry still a safe harbor for the squeamish? The answer is – it depends. And what it depends upon is a much more careful, analytical evaluation of each energy company and the unique attributes of its strategy and its regulatory jurisdiction. How has it changed from the traditional, vertically integrated utility model, and what do those changes mean for the valuation of the ongoing enterprise?

Risks on the Regulated Side

After California, there are a host of new issues to be considered before answering that question. Are a company's electric generation plants regulated, or selling into an electric commodity market? How long is electric generation likely to have its risks and opportunities proscribed by regulation? What is the technology of the electric generation, and its probable life to obsolescence? What is the expected investment required to keep the plant in compliance with environmental regulations? How mature and predictable is the electric commodity market in which those plants operate? What rate of equity return will the unregulated components fetch, in what time frame, and with what level of associated financial risk (debt)? How protected is the regulated component of the business against earnings volatility – and is the probable earnings level commensurate with those business risks? This is the issue which has turned the California utilities into very poor investment bets. Whereas in most jurisdictions the business risks faced by investors due to deregulation seemed to center on losses in the unregulated sector, in California the speed bumps and potholes have all appeared for the regulated businesses. Characteristically, for California, the potholes have been resized, based on seismic scale activities, into major fault lines.

Other issues include: what is the likely time frame for material technological innovations, or environmental regulations, which might materially affect the economics of the generation facilities? Is the generation book value consistent with the economics of each unit in the unregulated commodity markets? Will the political jurisdiction allow utility assets to be sold, and will shareholders be allowed to share the gains realized from divestiture? What is the projected dividend payout ratio for the blend of regulated and unregulated businesses? What is the likely strategy for the business in the face of the deregulation of its business lines, and what is the likely pace of deregulation?

And an ultimate question to be answered about the direction of the utility industry is: what is the political will to allow adequate electric generation and transmission infrastructure to be constructed? Will the political allow private enterprise to build and own facilities viewed by some in the political spectrum as environmental insults, or will that power be reserved for political, or at least politically regulated, enterprises? The answer to this question is central to the future of the electric industry. If is the answer is "no," re-regulation will occur. In that case, the recent history of deregulation in the generation market might be just a phase, an interesting historic footnote. And as obvious as the emerging need for more generation and transmission capacity is to the public, it is interesting how slow the political process is to get solidly behind the approvals or other affirmative actions needed to expedite construction of large power plant and transmission line projects – regardless of who builds them.

All of these issues will seriously affect the "safe harbor" attributes of an energy company's common stock. And because every company is affected by and has responded to these issues in a variety of ways, there are far more differences between electric energy equity investments today than there have been in the past.

2. Historical Development

The old electric industry's reputation for being a safe harbor was well earned. Historically, the regulatory process for the establishment of utility earnings provided reasonable protection from inflation, while the utilities paid real cash dividends which grew predictably over time. That historic, comprehensive regulatory process was a product of state political systems which gave constitutionally-based protections to management (and their shareholders) who acted reasonably, given their state of knowledge.

a. Traditional Valuation and the Old Company Strategies

In the past, the financial markets could comfortably gauge the business risks faced by the typical electric utility. Earnings of a utility were largely the result of political rate setting policies in each state, and the ability of management to predict and manage against its regulatory agency-approved budgets for the next year. The business risks associated with both of these variants could be reasonably evaluated based on the historical record. The financial markets rarely received ugly surprises, except with unexpected cost overruns or price volatility (say, with the construction of nuclear plants; or fossil fuel volatility during the Arab oil embargo).

This comfortable world was the product of a predictable industry. The electric utility business involved the conversion of primary energy sources (coal, oil, gas and enriched uranium) into a commodity – electricity. But electricity was not sold in a commodity market – it was sold as a public good in a regulated market. Regulation treated all of the vertical phases of the electric industry as natural monopolies. And 75 years ago when regulation commenced, the generation, transmission and distribution of electricity were natural monopolies. Society was best served with just one electric delivery infrastructure, sustained by eminent domain powers. With essentially local electric systems, the amount of electric generation capacity needed to match demand – and there was no easy way to accommodate over capacity or shortage. Essentially all 50 states had similar electricity regulatory processes. Each part of a state had but one electricity provider, franchised by state law as a monopoly – the only entity allowed to generate electricity for sale, transmit it and distribute it to end users in that franchise area.

The policy trade-off for this avoidance of competition and duplication of capacity was two-fold: a requirement to meet reasonably foreseeable demand with adequate service, and a requirement to sell electricity only at the average cost-based price set by government regulation. Rates were set for the companies by regulatory bodies. These rates were set by projecting sales for a year (essentially an actuarial exercise) and projecting operating costs for that same period. Again, these were essentially statistical regressions from the recent past. Large components of the budget subject to price volatility (fuel costs and purchased power costs) tended to have cost passthrough (to customers) mechanisms, or other risk mitigation devices. The regulatory body had to draw conclusions about the reasonableness of the projected costs (typically through an audit process), and the reasonable required return to be authorized for the equity invested in the utility. The required return and operating cost projections determined by the regulator determined the prices to be set which would most likely generate the required return. The actual return was neither guaranteed nor subject to true-up, but the business risks of realizing the returns centered around the accuracy of actuarial-type cost and sales forecasts, and the ability to forecast and manage costs against a budget.

The understandable response of electric utilities to this regulatory framework was to adopt a conservative business strategy focused almost exclusively on reliability and not on keeping costs low. Regulatory pass-through to customers of the costs for fuel and purchased power limited the risks and opportunities for owners arising out of conversion efficiency. Utilities were more concerned about plant reliability than they were conversion cost breakthroughs. Early plant retirements caused more shareholder risk then higher-than-optimal running costs.

Further, utilities were protected through regulation from losses due to plant obsolescence while shareholders did not stand to gain from cost-reducing technological breakthroughs. Utilities could, however, be financially injured through reliability problems causing unforeseen maintenance costs or premature shutdown (before the capital cost of the plant was fully amortized and recovered in rates). The companies making electric generators reacted to this market pressure. R&D was devoted to making generation more reliable, and plans for generating plants presumed 30-year useful lives to match the depreciation schedules reflected in rates.

But to understand how all of this has changed, we first need to look further back into the historical development of the industry, and then see the changes brought by restructuring.

b. Roots of the Industry

(1) Early Days

For many utilities, the most significant regulation occurs at the state level - where rates for all electric sales at retail are regulated. (At the resale or wholesale level, sales are regulated by the FERC). For the past 75 years, and prior to restructuring, regulation of utilities by state commissions had evolved into a rather consistent regime. To avoid duplication of electric facilities and to promote the investment in essential electric infrastructure, utilities obtained franchise monopolies for all the distribution wires and systems, the electric transmission systems, and the electric generation plants necessary to serve the "native" load in defined geographic "service territories."

The political compact necessary to permit utility franchise monopolies was state and federal electric service price regulation. In exchange for being sure that electric system infrastructure investments could be made without the threat of failure due to competition, and to avoid the negative social effect from insufficient electric service or waste due to duplicate facilities, utilities are required in each state to provide "adequate electric service at reasonable prices."

Paternalistic Regulation

State commissions evolved as the central regulatory planners for electric system infrastructure. Such regulation was necessary and appropriate when the electric infrastructure circuit was essentially local in nature. The transmission, distribution and generation systems were natural monopolies. The provision of adequate electric capacity required the construction of sufficient generating capacity, but the local nature of the transmission system and the franchise customer base would not support excess capacity. Thus, the justification and need for rate and construction approval regulation for power generating plants, transmission lines and local service costs.

The state regulatory commissions in the past typically decided whether and when new power plants and new transmission lines may be constructed. Specialized regulators watched over, and worried about, the level of investment needed to avoid the (latent) risk of shortage without excessive levels of investment. The state commissions have exercised regulatory power by deciding about the recovery of utility capital and operating costs through the retail rates it sets. Only costs reasonably incurred are to be recovered. Any entity that generates power and offers to sell that power to third parties has been deemed to be a utility which requires state and usually federal regulation. This was necessary to protect the franchise monopoly. This franchise monopoly status was deemed necessary to avoid undesirable duplication of facilities and to assure that sufficient facilities to provide adequate service, without undue risk of failure, would be constructed.

For almost 60 years, this system worked well. Utilities suffered few financial reversals; the U.S. electric infrastructure developed admirably and was an exemplar to the rest of the world; utility corporations were traditionally bedrock investments promising near certain dividends coupled with inherent growth potential. Utility costs were moderate.

(2) Recent History

So what happened? The wave of restructuring that characterized the latter half of the 1990's did not come out of nowhere. In fact, it was triggered by a confluence of accidents, happenstance and the whiplash of ground-breaking government regulation.

For one, the national electric system became, of necessity, more interconnected. From its origin and through World War II, electric energy was produced by relatively small, scattered local power plants, with power transmitted relatively short distances to the load centers. Technological advances and economies of scale prompted the size of electric generators to increase (first large hydro projects; then larger coal plants; then nuclear generation in the 1960s and 1970s). As a result, growing geographic areas were being serviced by individual plants. And, because the loss of a single and very large generator could not be easily replaced with local "backup" capacity, transmission line links to other large plants were necessary so that load centers could be protected against the contingency of an unexpected outage.

Several accidents also intervened. The Northeast blackout of 1965 demonstrated that the grid of interconnections between utilities presented risks to reliability on a grand scale. This gave rise to a national, and several regional, reliability council(s), and a national focus upon creating a more reliable and effectively interconnected transmission system.

In 1973, the Arab Oil embargo woke the American political system up to the oil/energy conservation issue and the prospect of ever rising energy prices. This shortage prompted utility planners to forecast increasing oil and gas prices, which pushed generation planners towards nuclear plants, or large coal plants, as "least cost" solutions. Those electric utilities which, in the 1970s, forecast the most rapid growth in their regional demographics faced the greatest electric capacity planning pressures, and many opted for the apparently least cost generation option of nuclear power. Fast growing areas, like California and the Northeast, moved away from oil-fired power and toward nuclear.

Congress reacted in a variety of ways to the perceived energy crisis. These included passage of the Public Utility Regulatory Policy Act of 1978 (PURPA). The legacy of PURPA which impacts the industry today is its requirement that all utilities stand ready to purchase electricity from any electricity producer utilizing certain defined and environmentally-friendly electric generation facilities (a qualified facility, or QF) at a price reflecting the cost that utility would otherwise incur to obtain that amount of electricity, *i.e.*, its avoided cost. The non-utility generator ("NUG") industry made up of IPPs was spawned by the legislation, to the enthusiastic applause of the financial community, which was charged up by the potential to undertake project financing anchored upon long-term, life of financing, off-take agreements with blue chip electric utilities. Long-term forecasts, at least in rapid growth utility service areas, were for material increases in avoided cost.

Meanwhile nuclear generation, which had been originally hailed as a long term, low cost option, also faced the prospect of unexpected rising costs. Construction cost overruns began to plague the industry in the 1970's, and then the 1979 Three Mile Island accident led to new, highly stringent and very expensive design, retrofit and operating standards from the federal Nuclear Regulatory Commission. From the date of that accident, the cost of nuclear power increased by orders of magnitude above the costs projected earlier, and many nuclear projects planned to meet growing electricity demand were abandoned or completed at costs way above those anticipated.

The result of all these pressures and developments was an increasing disparity in electric service prices from region to region, since electric retail customers were required to cover the costs reasonably incurred by utilities (i.e., reasonable in light of the circumstances when decisions were made).* Faced with projections of ever rising costs to generate electricity, certain states reacted enthusiastically to the opportunities provided by PURPA, particularly those in the Northeast and West Coast with high population growth forecasts. At the strong urgings of their regulators, utilities in these regions entered into a spate of long-term power purchase contracts, including with NUGs. The avoided cost assumptions built into these NUG contracts were high, both because those regions had an historic reliance on higher cost oil fuel and because high growth rates forecasted for electric demand would require expensive new generation projects. From the knowledge that these utilities and regulators had at the time, these contracts were arguably a rational response to ever-growing electric demand dependent upon fuels with ever rising prices.

The Unexpected

But then happenstance, or at least the unpredictable, occurred. Instead of long-term fuel cost escalation at rates in excess of inflation, electric generating fuel costs fell, with Western coal prices going nearly through the floor. Conservation worked better than expected, and many new power plants projected for construction did not need to be built. Utilities burdened with fixed costs premised upon assumptions of higher fuel costs and expensive new power plants found themselves with costs that were way out of line.

As a result, power purchase agreements entered in the 1980s, and nuclear power plants justified by fuel cost projections from the 1970s, reflect costs way above the prevailing market cost. In fact, electric rates across the country began to vary in ways that could not be explained by geography or the operations of any economic market force. Electric prices in the Northeast and West Coast were way out of line with the rest of the country. Even electric prices in Milwaukee were just a fraction of those in Chicago, 80 miles to the south. It was becoming clear that jurisdictional boundaries, the impact of regulation, and the existence of stranded asset costs were the difference between average and high cost electricity.

The way was thus paved for restructuring. An independent power industry, separate from the regulated utilities, had begun to develop and proved itself capable of providing reliable power. The FERC, through its Orders 888 and 889, revamped the rules of the road of the electric grid, allowing a genuine market in wholesale transactions to develop. Load centers could now be served by generators located hundreds of miles away. PURPA had spawned a nascent generation market of IPP generators. The natural monopoly over generation that had characterized the industry in its early days was now largely extinct, and with it the need for a vertically integrated utility providing generation, transmission, and distribution. The regulatory compact itself, under which utilities were required to provide adequate and reliable service in exchange for guaranteed recovery of prudently expended costs, had produced, in certain areas, politically untenable results. Due to stranded costs and possible monopolistic inefficiencies, electric customers in some large and powerful states (e.g., California, New York, Massachusetts, Pennsylvania and Illinois) did not believe they were receiving adequate service at reasonable cost. Electric service price reductions became a primary political goal. This price focus put pressure on the cost of maintaining the system reserves – a cost to avoid only a latent risk.

With the recognition that the old regulation did not work in the new circumstance, the current tension developed. The stage was set for states to restructure Thomas Edison's industry.

3. The Restructuring Era

a. The Drive To Restructure

Almost half the states have restructured to date. The key factor determining whether or not a state has restructured is clearly demonstrated on Exhibit 1: how each state's price of electricity compared with the rest of the country. Exhibit 1 shows the average revenue per kWh in each state during 1994. Of the 18 states (including Washington D.C.) with the highest rates in 1994, 14, or 77.8% have restructured. If Hawaii and Alaska are excluded from this group, then 14 of the 16 states with the highest rates in 1994, or 87.5% (saving only Vermont and Washington D.C.), have restructured.

As indicated by Exhibit 2, however, states with restructured electric industries have not faired much better than the rest when it comes to reducing average rates from 1994 to 1999. Exhibit 2 shows that only 7 of the 12 states with the biggest rate reductions between 1994 and 1999 have restructured. At the other end of the spectrum, 5 of the 12 states with the biggest rate increases from 1994 to 1999 have restructured, including 2 of the 3 states with the biggest rate increases during this time period.

If the states (including Washington D.C.) are ranked, from 1 to 51, on the basis of their rates in 1994 (with 1 being the highest rates) and on the basis of the decrease in their rates from 1994 to 1999 (with 1 being the biggest decrease), and these rankings are added, the result is depicted on Exhibit 3. One might expect these simplistic rankings to indicate that states with the highest rates have restructured and have experienced a rate decrease since restructuring and, in fact, the 8 states with the combined (i) highest rates in 1994 and (ii) biggest decrease in rates from 1994 to 1999 have all restructured.

These results generally indicate that the states with the highest rates in 1994 have been the most likely to restructure, and those with the highest rates in 1994 have experienced the biggest decrease in rates. That is to be expected, of course, as the restructuring laws have frequently mandated a transition period during which rates had to be lowered or capped. The results during the next five years, as these mandated transition periods end, could of course show a very different picture. States whose rates were not as high to begin with have experienced a relatively smaller reduction in rates, and some have even seen rates increase despite restructuring. In fact, as indicated by Exhibit 4, of the 20 states that saw rates decrease from 1998 to 1999, only 9 have restructured; on the other hand, of the 23 states which saw an increase in rates from 1998 to 1999, 13 have restructured.

b. Electric Restructuring Models

Spurred by economic fears related to high electric prices, or through a variety of other factors, the legislation adopted as individual states have moved to electric restructuring can be broken down into four different models, based on how they have dealt with generation divestiture. A question that each state has faced is how to deal with stranded costs. The answer frequently depends on the extent of such stranded costs, and how far from the national norm retail electric rates had risen (two issues which were not entirely separate). State commissions had approved what later proved to be excessive electric generation plant costs as prudent expenditures when they were incurred, but they now represented a significant portion of the above market retail electricity prices customers in some states were paying. In most of the models discussed below, stranded cost recovery by the utility is intimately connected with plans for generation divestiture, and is paid for (at least in part) by a non-bypassable charge on all users of the distribution system.

Typically, each state's legislation has been adopted with the support of local utilities. As part of the overall "legislative bargain," utilities have received significant stranded cost relief. The relief typically allows for securitization of an exact amount of stranded costs which is approved by the state commission. These bonds are the securitization of a revenue stream derived from a charge, sometimes called a "competitive transition charge," assessed on all electric users, whether they remain with the utility or use a competitive retail provider.

In exchange for this stranded cost relief, most states' restructuring legislation in one way or another encourages utilities to divest some or all of their generation assets. Proceeds from these sales are typically used to offset the amount of stranded costs on the books.

The method each state has adopted to encourage this generation divestiture varies. As noted, they can be divided into four models. On one extreme, divestiture of generation assets to a party unrelated to the utility is mandated. On the other extreme, some states have restructured without any requirement for generation divestiture. As usual, most of the interesting stuff happens in between these extremes.[1]

(1) Model 1 – The Maine Model

The first model includes a mandate in state legislation that all investor-owned utilities sell their generation assets to unrelated third parties. By including in such a mandate a requirement that the utility become a transmission and distribution entity and that its competitive retail service be provided under a name unrelated to the previous utility's name, Maine can be said to have gone the farthest to mandate (through legislation) the exact outlines of how its competitive electricity marketplace will be shaped.

(2) Model 2 – Carrot & Stick

A large number of states have adopted restructuring which includes various incentives, some more heavy handed than others, to encourage vertically-integrated utilities to

[1] See Appendix 1 for further discussion of these models.

divest their generation assets. For example, in Arizona, Massachusetts and Connecticut, the vertically-integrated utility is barred from recovering any stranded costs unless the utility divests its generation.

(3) Model 3 – Empowering the PUC

A number of states have given their state commission full discretion to order generation divestiture. Some states limit this discretion to situations where market power concerns are evidenced. Others do not specifically require or prohibit divestiture, but leave the state commission with enough authority over stranded cost recovery to negotiate for generation divestiture with individual utilities. Such states include Arkansas, Illinois, Nevada, New Mexico and Maryland.

(4) Model 4 – No Divestiture Required

The state of Virginia has perhaps gone farthest to the other extreme in not requiring any divestiture and stating explicitly that the state commission does not have authority to order divestiture. Further, Virginia created a rate cap through 2007, that allows the utility to recover any stranded costs so long as its rates remain under the rate cap. Similarly, Ohio has not required divestiture, but allows divestiture without PUC approval.

c. Early Results of Restructuring

Exhibits 2 and 4 displays one measure of the results of electric restructuring: what happened to the retail price of electricity. The information, however, is an early snapshot, based on the latest annual figures from the Electric Information Administration. It thus does not show, for example, the shock wave of the price spikes in San Diego or utility losses during the summer of 2000. The San Diego phenomena has, more than any single event, brought the entire restructuring enterprise into question in the eyes of some policymakers. In addition, it does not reflect what has been reported more recently – the potentially devastating effect on the earnings of California's biggest, dreadnought distribution utilities required to provide electricity at capped prices in the spiking market.

Perhaps what occurred should not have surprised anyone. Utilities were strong armed into selling off their generation assets; companies buying those assets paid a premium price, and expected to make profits; the marketplace for energy trading was neither developed nor robust, and there was a limited supply. In such situations, price increases could be easily forecast.

<u>Pennsylvania Experience</u>

Contrast that to the situation in Pennsylvania. There the PJM energy market had slowly developed years before restructuring was enacted. While there was a demand for new generation, the need was not as extreme as in California. Many of the buyers in the energy market are also sellers and load serving entities, meaning they are not completely at the mercy of the new breed of generation owners possessing such a keen eye for the bottom line.

Another way to measure the early results of restructuring is to examine the results of the generation asset auctions. Exhibit 5 compares the book value of the assets sold to the price set by auction. For those auctions where information is available, only three winning bids have been below book value. The vast majority have sold at a substantial premium.

Depending on the gainsharing provisions of each states' restructuring program, those premiums have been used to reduce stranded costs or jump start investments in replacement businesses (IPPs for some, telecommunications for others). As one California legislator saw it, the whole purpose of restructuring was to bring in out-of-state money to help reduce in-state stranded costs. As San Diego may have demonstrated, however, the new generation owners did not include a free lunch in any of their plans for entering the California market. Consistent low prices may not return until such time as there is enough generation to marginalize high cost units (a result which could be achieved through a combination of new development, new distributed generation technologies, improved and more reliable demand side management systems and increased robustness in the transmission system) and a market which adequately disciplines energy sellers to bid within reasonable margins of their cost of production.

d. Technology

Another result of restructuring, perhaps the most important, is that the old disincentives which impeded technological development have been removed. As discussed above, in the old days companies would rightly shy away from untested technology in the face of the tried and reliably true. A coal plant designed primarily for dependability and to last for the 30 years of its cost amortization was just fine -- even if its operating costs became somewhat high, they could be recovered – but the main thing was to keep those generators humming and everybody's lights turned on.

But now the electric commodity market is losing its regulatory shield, and unregulated electric generation businesses are facing the price volatility risks and technological obsolescence risks inherent in capital intensive, commodity conversion industries (cf. gasoline refining, paper manufacturing, etc.) In the competitive electric commodity market, the near term spoils will go the low cost generator. Note the stock market's enthusiastic response to Calpine, perceived to be a low cost electricity provider. Electricity markets verge on perfect competition. When properly operating, save for electric transmission system constraints, electric generators with running costs of production (measured minute-to-minute) at or below the market price operate; those with costs above do not.

Manufacturer R&D has already responded to this shift in focus from long term reliability to lowest cost operations with an accelerated pace of reductions in operating costs. Distributed generation technologies and fuel cells are just part of the R&D happening today. Whether or not well-maintained plants will continue to last 30 years, there is a substantial risk they will be technologically obsolete far short of that time. The risk of obsolescence is different depending upon the effective heat rate (the efficiency of converting a Btu of fuel to a KW hour of electricity) and the air emission rate of an electric generating plant – and how such characteristics compare to similar measurements for other electric generators (to be) located in the pertinent regional electric market. Newly constructed, cutting edge technology plants have a longer potential life than older, less efficient units.[2] With current technology, green field plants have less risk of obsolescence.

And forecasts for gas fired plants more than about 10 years in the future will be treated as blue sky – because of fuel uncertainties and technology risks.

4. Company Strategies

In the face of this changing world, numerous utilities have opted, or been forced, to substantially change the nature of their balance sheets; they have adopted a variety of strategies, all of which involve certain risks. This section will describe the strategies of some of the big companies and the risks they face.

The ironies in some of these shifts are striking. The initial company shifts were often dictated by the political compromises already discussed which each state adopted to solve two problems of the electric industry – relatively high electric prices and stranded assets. PG&E and other California utilities have sold essentially all of their fossil-fired electric generation (with varied chronological and technological vintages). Under similar circumstances in New England, so has New England Electric System. In fact, PG&E Generating Company, an affiliate of PG&E, bought the New England units sold by NEES – a mixed bag fleet of older plants. Similar economic issues apply in Illinois, and Commonwealth Edison and several other Illinois utilities have sold their generation. In Minnesota, rates are lower, and stranded costs not such a pronounced risk. Northern States Power of Minnesota has, to date, retained its regulated utility fleet of electric generation – but its unregulated affiliate NRG has acquired very substantial MWs of unregulated generating plants, mostly existing facilities acquired in divestiture auctions. So too, Southern Company holds its regulated plants and has a rapidly growing portfolio of unregulated plants. NEES has not made material acquisitions of unregulated electric generation.

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[2] The electric system demands fluctuate over each day, by the week and over the year. A base level of electric demand is there around the clock, and all year. That is the system "baseload." Some of the peak demand is there at only limited periods of peak demand, less than 5% of the time. That is system "peak demand." Other electric load varies up and down over days and weeks. The most efficient plants to operate (those with the lowest running costs per KWH of output) have the highest capital costs of construction. The lowest cost plants to construct have the highest running costs to operate. The most expensive plants to construct (but cheapest to operate) must be run a great deal ("baseloaded") to overcome their capital costs. Peaker plants, because of their high running costs, need to be operated at a low percent of the time (at time of peak). All of the electric system is economically dispatched – as demand rises, the next least expensive plant to operate is turned on, and as demand falls, the most expensive plant to operate is turned off. Technological efficiency has everything to do with whether power plants operate, or not, and how much profit they earn by having their all-in costs be under the market-determined price. In today's world, the most efficient combustion, thermal plants are combined cycle gas-fired facilities which produce and sell an optimal amount of waste heat (waste to the electric generation cycle) to a third party for process use. Hydrodams, nuclear plants, certain large coal facilities, and certain geothermal plants are the lowest cost plants to operate – but difficult or expensive to construct. Gas-fired combustion turbines are the standard technology for peakers – today. The analyst testing the value of a composite of unregulated power plants needs to understand their probable rank order in the economic dispatch prevailing in their market area – now and over their probable life. This involves complex computer modeling of plants in the market. And, the analyst needs to understand whether the internal rate of return for a project is driven by assumptions about near-term electricity prices (which are subject to more accurate forecasting), or long term market price projections. Another more confounding influence is an assessment of the effect of deregulation, its pace of change, and the rate of technological obsolescence in the future.

Many companies have chosen to focus on expanding their domestic generation capabilities through acquisitions, though often not as an exclusive strategy. FP&L has acquired auctioned generation assets while also building wind projects. AES has made some generation acquisitions while also acquiring distribution utilities in foreign countries. AEP has similarly looked to acquire domestic generation assets while moving into foreign markets with an acquisition in Australia. PPL has an been active player in generation auctions, as has the NRG subsidiary of Northern States Power. PG&E Generating has actively acquired and constructed domestic generation and plans to focus its future expansion on the construction of state-of-the-art, gas-fired and other "green field" projects. Reliant has acquired generation throughout the U.S. and in the Netherlands. This national focus on generation is frequently coupled with a regional base in the transmission and distribution assets in the company's "home base," including those mentioned as well as Duke, Southern Company, and Exelon.

The risk of focusing on generation is multifold. While current forecasts show increasing demand and an expanding need for capacity, such forecasts have been wrong before. Will all the new plants being developed lead to a generation glut in 10 years? The risk is probably more regional than national, and thus one way to mitigate it is to have a generation footprint covering a variety of regions.

Further, the risk varies as to fuel. Calpine, lately a darling of Wall Street, has focused on becoming the lowest cost generator by building gas-fired power plants. It has shied away from auctions. Its risk is that natural gas prices might not always remain low, as in fact recent price spikes have demonstrated. Will natural gas costs return to the low price curves seen just a few months ago, or will costs drive the recent darling of peaking plant developers to the financial brink? Will the proud purchasers of base loaded coal plants find that the tightened screws of environmental regulation squeeze all the profit out of their economic forecasts?

Conversely, other companies have gotten out of the generation business altogether, or at least to a degree that would have been unthinkable ten years ago. Consolidated Edison has sold its generation assets to become a transmission and distribution company, and is joined in this strategy by Northeast Utilities and GPU. California's home utilities have been similarly stripped of generation. The risk to a "generation-less" distribution company, as has become clear in California, is that it and its retail customers can suffer at the mercy of a less than robust generation market.

Other companies have expanded beyond the electricity business. Montana Power sold its generation and has shifted its focus to the telecommunications industry. Other companies with a significant investment in telecom and internet industries include Utilicorp and the joint venturers in the "America's Fiber Network" alliance, which includes AEP. Will expertise in one industry translate into profits in another? Early returns seem favorable, but only time will tell.

Some have seen no reason to change. Idaho Power remains a fully integrated vertical utility, taking advantage of low cost hydro units and low transmission costs. Its risk is whether it can remain a small independent player in an industry where deregulation in other parts of the country have helped create large entities, and whether it can continue to operate under the old regulatory compact in an era where increasing federal activity may force change.

What is clear from the variety of strategies adopted is that there is no one-size-fits-all formula for responding and adapting to the changing electric industry environment. Consultants and pundits have had a field day. Wall Street analysts have been eager to lock onto a perceived winning play, but they emerge only in fits and starts. The fuel cell industry run-up, and the soaring share prices of Calpine, have shown that Wall Street will pay attention to a compelling story. What does seem clear, however, is that a compelling business plan based on a single aspect of the industry can produce winners like Calpine. More corporate restructurings can be expected to attempt to unlock shareholder value in generation assets, even as the distribution and transmission functions try to move back to the safer harbors of regulated rates of return. Players with new technology will become a more important and more valued part of the industry.

5. <u>Valuation Today</u>

a. In General

Evaluating electric industry companies has thus become a much more interesting enterprise, presenting risks but offering serious rewards to those earliest to recognize successful new value equations. It will take more art to evaluate a company like NRG, with a large portfolio of used plants acquired at auction, than it will to evaluate a green field developer. It will take more art to analyze an energy company with substantial unregulated holdings than it will to analyze a relatively pure, regulated utility business.

The recent history of PG&E presents starkly the challenges facing analysts today. On the unregulated side, its PG&E Generating subsidiary has been actively involved in purchasing and developing generation projects in markets with increasing demand. One would be tempted to base the company's value on electricity markets forecasts and the ability of this new fleet to capture a profitable slice of that business. But to the extent the company's value is still tied to the old utility, the home market cannot be ignored either. There, skyrocketing wholesale power costs, coupled with rate caps in place under California's restructuring legislation, have forced the utility to spend vast amounts of potentially unrecoverable dollars to serve the needs of its native load. How can the analyst comfortably predict what will happen? Will a regulatory change allow the wholesale spending to be recovered? Will the current regulatory straightjacket "force" these deficits to continue to build? Will the unregulated subsidiaries produce offsetting profits from wholesale sales in other regions? Will the dreadnought utility go bankrupt?

Faced with such vexing questions, it can be expected that financial markets will prefer purer "plays" – with traditionally regulated utility businesses held and traded as financial entities distinct from unregulated businesses. In the long run, this desire should cause a trend toward spin-offs or separations of the regulated businesses (distribution and transmission companies, regulated as common carriers) from unregulated enterprises (unregulated generation, unregulated energy merchant businesses). Until this happens, it will be up to the analysts to help the market understand the value of the parts, and the composite whole, of energy companies which own both regulated and unregulated components.

On the regulated side, to the extent an electric energy company's business remains subject to rate regulation, the safe investment characteristics (the safe harbor) continue to apply. Some states are shifting from the traditional "cost plus" rate making (where the plus is an approved projected rate of return or the book value of shareholder equity invested in the regulated utility business) to price or price or performance-based regulation. Either affords the investor insulation from up and downside earnings potential. If such ratesetting is adopted, the analyst needs to evaluate the probabilities and symmetry of the opportunities and risks, the magnitude of each, and the balance of risk and reward (equity return) that has been set.

b. Valuing a Company Faced with Restructuring

A lynchpin issue determining the potential seismic effect of deregulation upon valuing a traditional utility is generation divestiture. If generation divestiture is required, the energy companies are asked very directly the question – now how will you redeploy your investments? This question is posed in the most shrill manner if the jurisdiction permits substantial shareholder gain sharing from the sale of generation i.e. the gain from sales above book value remains as retained earnings. In any case, upon divestiture by sale the equity component of the book value of capital invested in the divested generation becomes available for redeployment. The question becomes, how will the business redeploy the fruits of the liquidation of this very large part of their balance sheets?

Even if the jurisdiction follows a model that does not mandate (or even permit) the divestiture of generation, it might pose the same strategic deployment question to the utility in a more subtle manner. This is occurring in Wisconsin, where the utilities have not been required/allowed to divest generation. However, the utility regulatory commission has effectively embargoed the construction of new generating plants by a regulated utility. Since generating plants have constituted in the range of 50% of the utility balance sheet (and it is the utility's balance sheet book value that is used to determine the equity value upon which a regulatory return is authorized), these energy companies are also faced with the issue of where to invest the substantial capital which is generated by earnings and would have been invested in generation. And, as the existing generation is depreciated to zero and the aging fleet of plants operated by utilities shrinks, scale economies and critical mass competence issues will cause the utilities to outsource the generation function, and look for other investment options.

Reinvestment Options for Protecting Stock Value

The energy company options for replacing the generation business come in about three general forms. First, the corporation can repurchase stock and reduce its equity outstanding to reflect its reduced capital requirements. If this is done with cash derived from asset sales, there are taxes on the realized gain at the corporate level, and in any case tax consequences upon payout to the shareholders.

Second, the management can, upon self-evaluation, conclude that their core expertise is as an ELECTRIC utility, and follow their electricity competency by pursuing investments in the unregulated side of the electric industry. These investments could be in: divested, used power plants; newly constructed, state of the art greenfield plants; energy merchant businesses (as marketer, broker, or service provider); or a mix of the three. Each of these three sectors requires different analyses. As discussed below, state regulations and tax avoidance objectives could further impact upon and prompt certain strategies.

Third, management's strategic self-analysis could conclude that its core strength is as an electric UTILITY. This evaluation would lead to redeployments of after tax dollars (if generation is divested) into other, price regulated business opportunities. As an example, capital might be redeployed to the regulated water utility business. This strategy would cause the least change in the business risk and financial profile of the utility – but would constitute a migration out of the energy sector.

If the strategy adopted is 1) not to return capital to shareholders (with its concomitant balance sheet shrinking and tax gain effects); and 2) to invest in unregulated energy opportunities, the energy companies choosing this strategic path will have the same set of questions to answer, but each could have a different mix of responses.

If generation can, or must, be divested from the regulated utility, then:

A. Should it be auctioned for cash, to the highest third party bidder?

   (1) State regulation could require this.

   (2) This will trigger issues of shareholder gain sharing and gain realization tax effects.

   (3) How will the rates of the regulated utility handle risks associated with purchasing power requirements in the power market (and not continuing to own generation) after the divestiture?

   (4) Can the generation be transferred to an affiliate of the utility, owned by the energy company?

   - Will this avoid adverse tax consequences of an auction sale?

   - Will this permit untaxed gain realization for shareholders through an IPO, spin-off or other means to obtain independent market valuation of unregulated generation?

   - Can the affiliate sell electricity at market, or under what terms, to its affiliated utility?

   - Are there market power concerns in the unregulated generation market which constrain the option of an inter-affiliate power plant transfer (and its beneficial tax avoidance)?

B. If investments will be made in unregulated generation, what is the shape of the projected revenue stream – and how speculative are the market price assumptions on which the earnings are based?

C. What is the business risk of the energy marketing business, or the business risk for electricity production sales into the electricity commodity market?

D. What financial risk level (debt) is presumed and what dividend pay-out and growth profiles are the redeployed assets likely to realize – and how different is that from the historic pay out and growth pattern for the energy company?

c. Valuation Today Is More Difficult

Deregulation and introduction of competition is often generalized as the panacea, a change which bodes well for utility stock value. Does it? It has in states where huge stranded cost risks tied to very expensive nuclear generation plants and expensive oil generation caused unreasonably high electric prices (a political risk) and where price deregulation motivated by high retail prices threatened utility insolvency by breaking the regulatory compact which promises the recovery of reasonable investments in generating plants. These perceived risks put the stock market valuations for a number of utilities in the proverbial toilet – and only a later political fix allowed them to get their head above water. For a number of utility stocks coming back from the brink, stranded cost recovery guarantees explain their recent equity market value gains. For utility stocks that currently have no such stranded cost problems, and are trading at, say, 1.5 times book value, deregulation might not offer very much upside without a material change in their business plans.

Deregulation might prompt the sale of generating facilities. Generation auctions could result in pre-tax divestiture prices of more than three times book value (better than the stock market multiple). But how much of the after-tax gain will the shareholder be allowed to keep? That will vary by regulatory jurisdiction and needs to be considered by the analyst.

If deregulation results in generation divestiture, the regulated utility will have to buy the power to replace the sold generation capacity. Will regulation of the regulated distribution utility adequately protect against the new electricity market price volatility risks (the California risk)? The analyst needs to consider this policy risk. Will the new regulations of the regulated utility include an adequate risk-adjusting authorized return for the investor?

How will the utility redeploy the after-tax proceeds derived from asset movements out of the utility, and will the projected returns be risk commensurate? Will the returns support current dividends and dividend trends, or will there be a necessary shift to growth status – and what does the analyst think of that change – and the growth prospects of the investment portfolio?

Another difficult issue is the valuation of unregulated generation – particularly used electric generation with less than state-of-the-art energy conversion characteristics. Commodity markets are hard enough to predict, but a mature electricity commodity market does not yet exist. The impact of a competitive electricity market on the rate of technological change has not yet been tested. Price stabilizing mechanisms are just being developed.

The electricity market's ability to deal (and the political system's willingness to tolerate without regulatory controls) with shortage or excess has not been tested. The summer of

2000 in California was more than a fire drill, and all parts of the new electric market seemed to fail. The price was volatile, and the regulators could not keep their hands off.

Regulated electricity is currently being sold at operating costs plus depreciation (of book value) and a market return on investment. Used generation facilities are being sold at more than three times book – so the price of the electricity sold by the unregulated purchaser of a generation plant sold from a machine with depreciation amortizing three times book-value may have to exceed what would have been the regulated price to clear all costs for the plant-buyer. How can this be? There is today a dislocation of expectations about the generation market. Will the electricity market be characterized by shortage or surplus? What is the life to obsolescence of unregulated plants? This is crystal ball stuff – and must be taken into account in evaluating the effects of deregulation. Today we have a market with participants who obviously have widely disparate views about the answers to these questions. This market dislocation creates opportunity, and risk.

Will the deregulated utility redeploy assets "liberated" by deregulation be deployed into regulated businesses; back to the investor with resultant after-tax effects; or into unregulated businesses? Will deregulation be stalled, or stopped, by California? Will the jurisdiction allow shareholders to keep, or share in at all, the gain from utility asset sales? How will the tax effects of the generation "liberation" be handled/minimized? What is the redeployment strategy? If generation will be acquired, will it be greenfield, "used," or a mix? What returns can be expected from generation investments, generally? Depending upon the answers to all of these questions, deregulation might or might not be good for utility equity investors. Will investment plays be pure?

Calpine and AES are pure generating companies with relatively clear investment strategies. The equity market seems to like this approach <u>very</u> much. The equity market seems to put much more than a three times book valuation on the right type of generation located in a generation company with a clearly perceived game plan. Can we expect more spin-offs of generation companies? Or does California presage the return of vertical integration for the "flock"?

6. <u>Conclusions</u>

In order to assess whether a utility stock represents a safe harbor for the squeamish equity investor, it will be necessary to analyze and project: the deregulation policy developed (or likely to be) in the pertinent jurisdiction; the management strategy likely to be adopted for the redeployment of utility capital; and if unregulated generation is a material part of that strategy, how the electric commodity market is likely to treat the type of assets acquired. If the safe harbor characteristic of energy industry stocks is based upon the certainty of dividends from a regulated "public good" business, then the analyst looking for such safe harbors needs to identify companies which are concentrating their business capital deployment strategies in the regulated sectors. If the investors' vision of a safe harbor is not driven by dividends, but by an investment in the electric infrastructure, that is another consideration. But the analysis of the value of an investment in the unregulated components of the electric commodity market is <u>much</u> different than the analysis of regulated industries. And the nature of regulation after California now needs to be examined very carefully. The distinctions need to be clearly identified and handled in the evaluation of electric industry investments.

It seems likely that the restructuring process, in some form, will continue in the United States. For states where utilities have sold off their generation and adopted retail choice, the genie is out of the bottle. Certain principles will continue to guide policy makers. The goal of robust and transparent generation markets will require continued efforts to streamline the process of plant and transmission siting and continued tinkering with the rules of power exchanges. The basic principle of separating transmission, distribution, and generation is likely to continue, perhaps with some recognition that the most effective energy buyers will possess enough of their own generation to hedge their market vulnerability. The need for consumer education will continue to be a high priority: it is one thing to have faith in economic theory, but quite another to teach old customers of a monopoly the benefits and risks of a new system.

Political will will be tested. Brown and Black will trump Green. Shortage in fact will not be tolerated. California could happen again in electrically isolated places like Wisconsin, Florida and elsewhere if the latent risk of shortage is ignored. If actual shortage recurs, the road to re regulation would be short.

APPENDIX 1

Discussion of Models

States which have adopted various forms of the carrot and stick approach of Model 2 are the most interesting. While all the states have envisioned some type of realignment among the operations of transmission, generation, and distribution, these states have done it in a way that forces some interesting (or perhaps inevitable) choices to be made by utilities that were vertically integrated prior to restructuring.

For example, the California legislation does not require divestiture of generation. However, in order to procure any stranded cost recovery, the state commission must first determine the valuation of generation assets, which could be done either by sale or by appraisal. The legislation also placed the burden on the utility to demonstrate why, after valuation, keeping generation in the corporation would be in the public's interest. Further, the legislation makes clear that stranded cost recovery would not apply to any "going forward" costs of generation, which could only be recovered through energy prices on the open market. Faced with a deck so stacked, the sale of so many generation assets in California is no surprise.

In Montana, while the legislation explicitly barred the state commission from requiring or prohibiting divestiture, the utility's generation assets were required to be functionally separated from distribution and had to be removed from its rate base. A utility choosing to divest could do so to an affiliate or, as occurred with Montana Power, a third party.

In New Jersey, while the state commission is authorized to order divestiture only in response to market power problems, utilities nonetheless are incented to divest the majority of their generation assets, as that is the only way to recover 100% of their stranded costs through the transition bond mechanism. Without such a divestiture, the legislation only permits a recovery of 75% of stranded costs.

In Arizona, generation divestiture is required only if utilities want to petition the PUC for recovery of 100 percent of their stranded costs. The legislation does, however, require the two major utilities in the state to divest their generation assets, but allows divestiture to an affiliate. Even after divestiture, however, a full recovery of stranded costs is not guaranteed; divestiture simply allows the utility to petition for full recovery. Recovery is then determined by the PUC's evaluation of several factors, including the impact of the recovery on competition; the impact of recovery on customers of the utility who choose to not switch suppliers, on other consumers who do elect to participate in the competitive market, and on interruptible customers; the impact on the utility's ability to meet its debt obligations; the degree to which the utility has mitigated its stranded costs; the degree to which the utility's assets are under or over valued; the treatment of negative stranded costs; and the time period allowed for the recovery.

In Massachusetts, utilities were given the option to either divest all non-nuclear generation assets and purchased power contracts, or transfer them to an affiliate generating company. Sales of generation assets to either affiliated or unaffiliated entities had to be at a reasonable price, while transfers to an affiliate generating company had to be at a rate determined and approved by the DTE. A utility that chose not to divest its non-nuclear generation facilities and purchased power contracts was ineligible to benefit from the electric rate reduction bonding (securitization) provisions of the Act, and its recovery of transition costs had to be net of any market value in excess of book value of the non-divested facilities.

To recover stranded costs by the legislated securitization process in Connecticut, utilities had to divest, at auction, their interests in non-nuclear generation assets by the effective date of retail competition, and their interests in nuclear generation assets within four years of such effective date – making Connecticut the first state to require nuclear divestiture as a condition of stranded cost recovery. An affiliate of the utility was permitted to bid on any generation asset at the auction, provided that such affiliated entity was otherwise qualified to bid.

In Rhode Island, there were two requirements imposed upon those utilities recovering transition charges. First, any wholesale power supplier recovering transition charges was required to subject at least 15% of its non-nuclear generating facilities to a form of market valuation through lease, sale, spin-off or other method. Second, any wholesale power supplier recovering transition charges with respect to power purchase contracts had to offer to sell, buydown or assign to others, through either public bid or private negotiation, at least the portion of such power purchase contracts attributable to its affiliated electric distribution company; such entities were allowed to retain 10% of any savings expected to be realized by customers as a result of such sale, buydown or assignment.

Some states restructuring laws combine elements of the Maine Model and the Carrot and Stick approach. Texas approached its market power concerns through a regional capacity auction requirement, as opposed to an outright divestiture requirement. Any utility or utility affiliate owning or controlling more than 20% of the installed generation capacity in a given power region, and owning more than 400 MW of installed generation capacity, must auction entitlements to at least 15% of such capacity each year until the earlier of five years after the date of full retail competition or when at least 40% of the power consumed by residential and small commercial customers within the affiliated utility's service area is provided by nonaffiliated retail electric providers. The 20% per region grouping of assets owned or controlled by is also followed in the determination of stranded costs, as the utility, its affiliated retail provider and affiliated generation company must file jointly for stranded cost recovery. While requiring less than full divestiture, the Texas restructuring legislation will certainly increase the number of players in the market.

In Michigan, the Act provides that if, after subtracting the average demand for each retail customer under contract that exceeds 15% of the utility's retail load in that market, a utility has commercial control over more than 30% of the generating capacity available to serve the relevant market (either the Upper or Lower peninsula), the utility must do one or more of the following with respect to any generation capacity in excess of that required to serve its firm retail sales load (including a reasonable reserve margin): (1) divest a portion of its generating capacity; (2) sell generating capacity under a contract with a nonretail purchaser for a term of at least 5 years; and/or (3) transfer generating capacity to an independent brokering trustee for a term of at least 5 years in blocks of at least 500 MW, 24 hours per day. While participation in the securitization process contemplated by the Act is not contingent meeting this mandatory requirement, those utilities which, due to their smaller number of customers, are not subject to this market share limitation may participate in the securitization process only if they abide by the rate fixes prescribed by the statute.

States following Model 3, "Empowering the PUC," have also varied slightly in their approaches to generation divestiture. The Illinois restructuring legislation does not address divestiture, although the state commission is authorized to order functional separation. Further rulemaking regarding divestiture is expected by early 2001.

In Oregon, divestiture is not uniformly mandated, but the state commission is authorized by the legislation to "allow" divestiture if it is in the "consumer's" interest. The PUC also is authorized to offer incentives to utilities to divest. Functional separation is required, and divestiture to an affiliate can be ordered by the PUC.

Similarly, New Mexico requires only functional separation and not divestiture. The state commission there has used its authority to delay implementation of restructuring.

In Oklahoma, the restructuring legislation passed in 1997 did little more than empower a Joint Electric Utility Task Force to undertake a study of all relevant issues relating to restructuring of the electric industry. The legislation did not expressly require or prohibit divestiture, although it did provide that "[g]eneration services may be subject to minimal regulation and shall be functionally separated from transmission and distribution services, which services shall remain regulated." In addition, while the legislation contemplated the recovery of stranded costs by the imposition of a transition charge, the right to impose such charge was not tied to whether a utility divested its generation assets to an unaffiliated entity.

As with Oklahoma, the New Hampshire legislation provides that "[g]eneration services should be subject to market competition and minimal economic relation and at least functionally separated from transmission and distribution services which should remain regulated for the foreseeable future." The PUC was given significant latitude is drawing up a Final Plan for restructuring, provided that stranded costs "be reconciled to actual electricity market conditions from time to time. The PUC apparently took this to mean that it should calculate stranded cost entitlements on a market-based rather than rate-based basis. Such a market-based calculation was applied to the Public Service Company of New Hampshire ("PSNH," which serves 70% of the state's customers), resulting in a federal court lawsuit (which delayed the commencement of retail competition for several years) against the PUC in which PSNH alleged that it would be forced into bankruptcy if were held to such calculations.

In the end, there do not appear to be any clear factors that could predict which state adopted each model, but some broad trends can be sketched. The models adopted seem to have been the product of the relative strength of the lobbying prowess of the in-state utilities, the degree of respect which the legislature had for its state commission, and the degree to which prices deviated from the national average. The higher the costs, the less persuasive the utility, and the more esteemed the state commission, the more likely the state was to adopt a heavy stick with the PSC in a position to order divestiture.

EXHIBIT 1

1994 Rank in Revenue/kWh from Highest to Lowest
(Restructured States in BOLD)

New Hampshire	**11.32**	Missouri	6.28
New York	**10.92**	**Virginia**	**6.20**
Hawaii	10.68	**Ohio**	**6.19**
Alaska	10.25	South Dakota	6.19
Rhode Island	**10.24**	Colorado	6.07
Connecticut	**10.18**	Louisiana	6.05
New Jersey	**10.06**	Mississippi	6.05
Massachusetts	**10.00**	Iowa	5.92
California	**9.78**	**Oklahoma**	**5.84**
Maine	**9.63**	North Dakota	5.77
Vermont	9.13	South Carolina	5.67
Arizona	**7.93**	Minnesota	5.63
Pennsylvania	**7.87**	Nebraska	5.49
Illinois	**7.41**	Alabama	5.48
District of Columbia	7.12	Wisconsin	5.46
New Mexico	**7.11**	Utah	5.36
Michigan	**7.09**	Indiana 5.25	
Maryland	**7.03**	West Virginia	5.25
Florida	6.96	Tennessee	5.23
Delaware	**6.78**	**Oregon**	**4.60**
North Carolina	6.62	**Montana**	**4.51**
Kansas	6.61	Kentucky	4.26
Georgia	6.57	Wyoming	4.26
Texas	**6.42**	Washington	4.02
Nevada	**6.37**	Idaho	4.00
Arkansas	**6.35**		

EXHIBIT 2

Comparison of Average Revenue per kWh for U.S. Electric Utilities (by state) 1994 versus 1999

1994 Average Revenue per KWh for U.S. Electric Utilities (Ranked by State) (in cents)		1999 Average Revenue per KWh for U.S. Electric Utilities (Ranked by State) (in cents)			Difference from 1994 to 1999 (in cents)	Difference from 1994 to 1999 (percent)
Pennsylvania	7.87	Pennsylvania	6.70	Pennsylvania	-1.17	-14.87%
Texas	6.42	Texas	5.70	Texas	-0.72	-11.21%
Washington	4.02	Washington	3.60	Washington	-0.42	-10.45%
Utah	5.36	Utah	4.90	Utah	-0.46	-8.58%
Wyoming	4.26	Wyoming	3.90	Wyoming	-0.36	-8.45%
California	9.78	California	9.00	California	-0.78	-7.98%
New York	10.92	New York	10.10	New York	-0.82	-7.51%
Mississippi	6.05	Mississippi	5.60	Mississippi	-0.45	-7.44%
North Carolina	6.62	North Carolina	6.20	North Carolina	-0.42	-6.34%
Rhode Island	10.24	Rhode Island	9.60	Rhode Island	-0.64	-6.25%
New Mexico	7.11	New Mexico	6.70	New Mexico	-0.41	-5.77%
Maine	9.63	Maine	9.10	Maine	-0.53	-5.50%
Kansas	6.61	Kansas	6.30	Kansas	-0.31	-4.69%
Oregon	4.60	Oregon	4.40	Oregon	-0.20	-4.35%
Louisiana	6.05	Louisiana	5.80	Louisiana	-0.25	-4.13%
Arkansas	6.35	Arkansas	6.10	Arkansas	-0.25	-3.94%
Florida	6.96	Florida	6.70	Florida	-0.26	-3.74%
Massachusetts	10.00	Massachusetts	9.70	Massachusetts	-0.30	-3.00%
South Carolina	5.67	South Carolina	5.50	South Carolina	-0.17	-3.00%
West Virginia	5.25	West Virginia	5.10	West Virginia	-0.15	-2.86%
Georgia	6.57	Georgia	6.40	Georgia	-0.17	-2.59%
Idaho	4.00	Idaho	3.90	Idaho	-0.10	-2.50%
Arizona	7.93	Arizona	7.80	Arizona	-0.13	-1.64%
Virginia	6.20	Virginia	6.10	Virginia	-0.10	-1.61%
Alaska	10.25	Alaska	10.10	Alaska	-0.15	-1.46%
Colorado	6.07	Colorado	6.00	Colorado	-0.07	-1.15%
Nevada	6.37	Nevada	6.30	Nevada	-0.07	-1.10%
Illinois	7.41	Illinois	7.40	Illinois	-0.01	-0.13%
Connecticut	10.18	Connecticut	10.20	Connecticut	0.02	0.20%
Alabama	5.48	Alabama	5.50	Alabama	0.02	0.36%
Indiana	5.25	Indiana	5.30	Indiana	0.05	0.95%
Iowa	5.92	Iowa	6.00	Iowa	0.08	1.35%
Wisconsin	5.46	Wisconsin	5.60	Wisconsin	0.14	2.56%
Oklahoma	5.84	Oklahoma	6.00	Oklahoma	0.16	2.74%
Michigan	7.09	Michigan	7.40	Michigan	0.31	4.37%
New Hampshire	11.32	New Hampshire	11.90	New Hampshire	0.58	5.12%
North Dakota	5.77	North Dakota	6.10	North Dakota	0.33	5.72%
Vermont	9.13	Vermont	9.70	Vermont	0.57	6.24%
Tennessee	5.23	Tennessee	5.60	Tennessee	0.37	7.07%
Delaware	6.78	Delaware	7.30	Delaware	0.52	7.67%
South Dakota	6.19	South Dakota	6.70	South Dakota	0.51	8.24%
New Jersey	10.06	New Jersey	10.90	New Jersey	0.84	8.35%
Nebraska	5.49	Nebraska	6.00	Nebraska	0.51	9.29%
Ohio	6.19	Ohio	6.80	Ohio	0.61	9.85%
Hawaii	10.68	Hawaii	11.90	Hawaii	1.22	11.42%
Minnesota	5.63	Minnesota	6.30	Minnesota	0.67	11.90%
Kentucky	4.26	Kentucky	4.80	Kentucky	0.54	12.68%
Missouri	6.28	Missouri	7.20	Missouri	0.92	14.59%
Maryland	7.03	Maryland	8.20	Maryland	1.17	16.64%
District of Columbia	7.12	District of Columbia	9.20	District of Columbia	2.08	29.21%
Montana	4.51	Montana	7.00	Montana	2.49	55.21%

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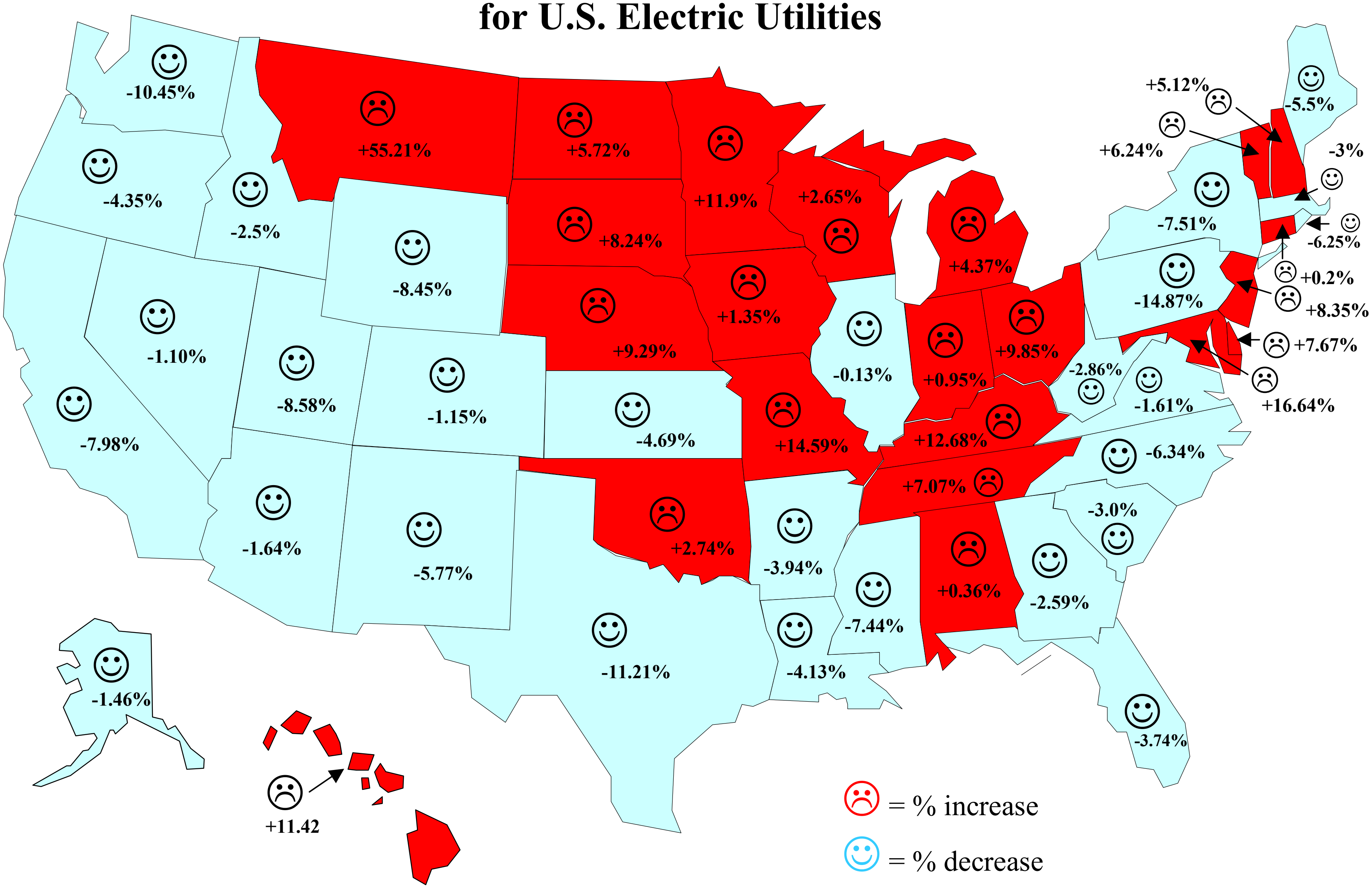
1994-1999 Percentage Change in Average Revenue/kWh for U.S. Electric Utilities



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1994 Average Revenue per KWh for U.S. Electric Utilities

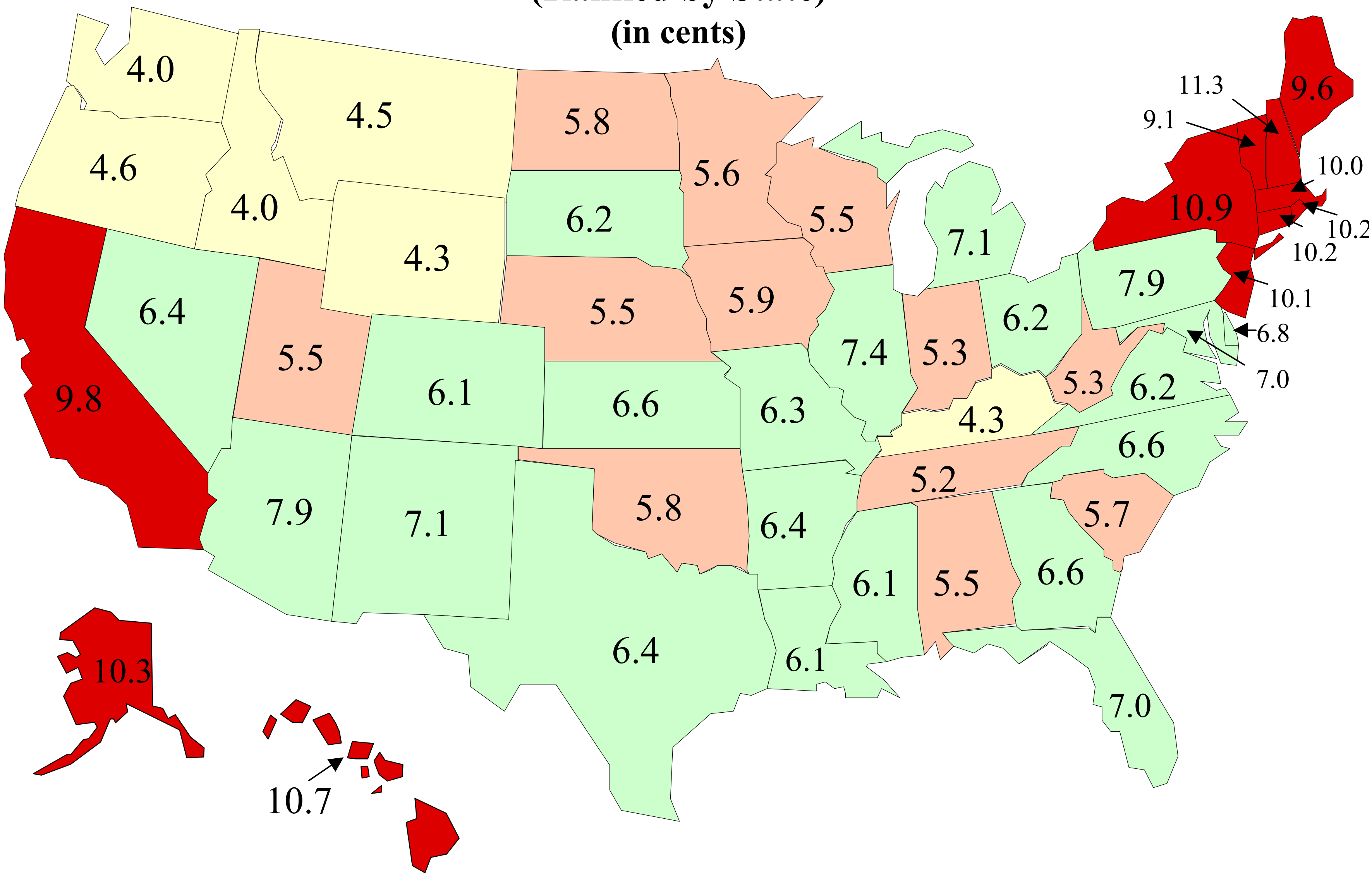
(Ranked by State) (in cents)

New Hampshire	11.32	New Jersey	10.06	Arizona	7.93
New York	10.92	Massachusetts	10.00	Pennsylvania	7.87
Hawaii	10.68	California	9.78	Illinois	7.41
Alaska	10.25	Maine	9.63	New Mexico	7.11
Rhode Island	10.24	Vermont	9.13	Michigan	7.09
Connecticut	10.18			Maryland	7.03
Florida	6.96	Iowa	5.92	Oregon	4.60
Delaware	6.78	Oklahoma	5.84	Montana	4.51
North Carolina	6.62	North Dakota	5.77	Kentucky	4.26
Kansas	6.61	South Carolina	5.67	Wyoming	4.26
Georgia	6.57	Minnesota	5.63	Washington	4.02
Texas	6.42	Nebraska	5.49	Idaho	4.00
Nevada	6.37	Alabama	5.48		
Arkansas	6.35	Wisconsin	5.46		
Missouri	6.28	Utah	5.36		
Virginia	6.20	Indiana	5.25		
Ohio	6.19	West Virginia	5.25		
South Dakota	6.19	Tennessee	5.23		
Colorado	6.07				
Louisiana	6.05				

1999 Average Revenue per KWh for U.S. Electric Utilities
(Ranked by State) (in cents)

Hawaii	11.9	Massachusetts	9.7	Maryland	8.2
New Hampshire	11.9	Vermont	9.7	Arizona	7.8
New Jersey	10.9	Rhode Island	9.6	Illinois	7.4
Connecticut	10.2	Maine	9.1	Michigan	7.3
Alaska	10.1	California	9.0	Missouri	7.2
New York	10.1			Montana	7.0
Ohio	6.8	Colorado	6.0	Utah	4.9
Florida	6.7	Iowa	6.0	Kentucky	4.8
New Mexico	6.7	Nebraska	6.0	Oregon	4.4
Pennsylvania	6.7	Oklahoma	6.0		
South Dakota	6.7				
Georgia	6.4	Louisiana	5.8	Idaho	3.9
Kansas	6.3	Texas	5.7	Wyoming	3.9
Minnesota	6.3	Mississippi	5.6	Washington	3.6
Nevada	6.3	Tennessee	5.6		
North Carolina	6.2	Wisconsin	5.6		
Arkansas	6.1	Alabama	5.5		
North Dakota	6.1	Indiana	5.3		
Virginia	6.1	West Virginia	5.1		

1994 Average Revenue per KWh for U.S. Electric Utilities
(Ranked by State)
(in cents)



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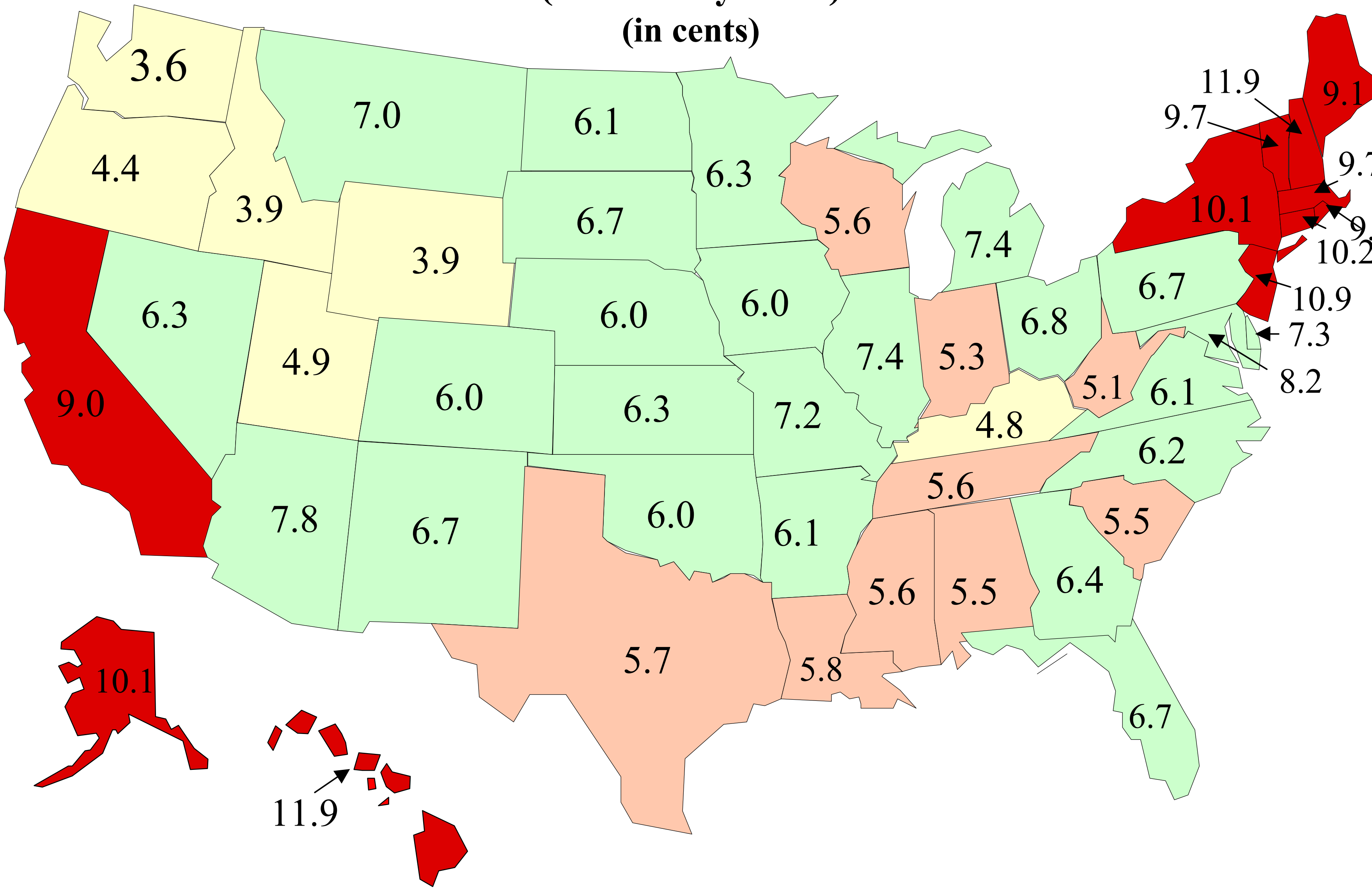
1999 Average Revenue per KWh for U.S. Electric Utilities
(Ranked by State)
(in cents)



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<u>EXHIBIT 3</u>

Combined Rank of Highest Rates in 1994 and Biggest Decrease in Rates 1994-1999

New York	**9**	**Virginia**	**52**
Pennsylvania	**14**	Washington	53
California	**15**	Wyoming	54
Rhode Island	**15**	South Carolina	56
Maine	**22**	Colorado	57
Massachusetts	**26**	**Delaware**	**60**
Texas	**26**	**Oregon**	**60**
New Mexico	**27**	West Virginia	64
Alaska	29	District of Columbia	65
North Carolina	30	Iowa	66
Arizona	**35**	**Maryland**	**67**
Connecticut	**35**	**Oklahoma**	**69**
Florida	36	Alabama	70
New Hampshire	**37**	South Dakota	71
Kansas	41	Idaho	73
Mississippi	41	North Dakota	73
Arkansas	**42**	**Ohio**	**73**
Illinois	**42**	Indiana	74
Georgia	44	Tennessee	74
Utah	46	Wisconsin	74
Louisiana	47	Missouri	75
Hawaii	48	Nebraska	82
New Jersey	**49**	Minnesota	84
Vermont	49	Kentucky	95
Michigan	**52**	**Montana**	**98**
Nevada	**52**		

EXHIBIT 4

Comparison of Average Revenue per kWh for U.S. Electric Utilities (by state) 1998 versus 1999

1998 Average Revenue per KWh for U.S. Electric Utilities (Ranked by State) (in cents)		1999 Average Revenue per KWh for U.S. Electric Utilities (Ranked by State) (in cents)			Difference from 1998 to 1999 (in cents)	Difference from 1998 to 1999 (percent)
Pennsylvania	7.70	Pennsylvania	6.70	Pennsylvania	-1.00	-12.99%
Washington	4.00	Washington	3.60	Washington	-0.40	-10.00%
Wyoming	4.30	Wyoming	3.90	Wyoming	-0.40	-9.30%
Texas	6.10	Texas	5.70	Texas	-0.40	-6.56%
Oregon	4.70	Oregon	4.40	Oregon	-0.30	-6.38%
Maine	9.70	Maine	9.10	Maine	-0.60	-6.19%
Utah	5.20	Utah	4.90	Utah	-0.30	-5.77%
Florida	7.10	Florida	6.70	Florida	-0.40	-5.63%
New York	10.70	New York	10.10	New York	-0.60	-5.61%
Mississippi	5.90	Mississippi	5.60	Mississippi	-0.30	-5.08%
North Carolina	6.50	North Carolina	6.20	North Carolina	-0.30	-4.62%
Indiana	5.50	Indiana	5.30	Indiana	-0.20	-3.64%
Iowa	6.20	Iowa	6.00	Iowa	-0.20	-3.23%
New Mexico	6.90	New Mexico	6.70	New Mexico	-0.20	-2.90%
Idaho	4.00	Idaho	3.90	Idaho	-0.10	-2.50%
Vermont	9.90	Vermont	9.70	Vermont	-0.20	-2.02%
South Carolina	5.60	South Carolina	5.50	South Carolina	-0.10	-1.79%
Illinois	7.50	Illinois	7.40	Illinois	-0.10	-1.33%
Rhode Island	9.70	Rhode Island	9.60	Rhode Island	-0.10	-1.03%
Connecticut	10.30	Connecticut	10.20	Connecticut	-0.10	-0.97%
Alabama	5.50	Alabama	5.50	Alabama	0.00	0.00%
California	9.00	California	9.00	California	0.00	0.00%
Colorado	6.00	Colorado	6.00	Colorado	0.00	0.00%
Georgia	6.40	Georgia	6.40	Georgia	0.00	0.00%
Kansas	6.30	Kansas	6.30	Kansas	0.00	0.00%
Louisiana	5.80	Louisiana	5.80	Louisiana	0.00	0.00%
Tennessee	5.60	Tennessee	5.60	Tennessee	0.00	0.00%
West Virginia	5.10	West Virginia	5.10	West Virginia	0.00	0.00%
New Hampshire	11.80	New Hampshire	11.90	New Hampshire	0.10	0.85%
Alaska	9.90	Alaska	10.10	Alaska	0.20	2.02%
Massachusetts	9.50	Massachusetts	9.70	Massachusetts	0.20	2.11%
Michigan	7.20	Michigan	7.40	Michigan	0.20	2.78%
Virginia	5.90	Virginia	6.10	Virginia	0.20	3.39%
Hawaii	11.50	Hawaii	11.90	Hawaii	0.40	3.48%
Wisconsin	5.40	Wisconsin	5.60	Wisconsin	0.20	3.70%
North Dakota	5.80	North Dakota	6.10	North Dakota	0.30	5.17%
Arizona	7.40	Arizona	7.80	Arizona	0.40	5.41%
Delaware	6.90	Delaware	7.30	Delaware	0.40	5.80%
Ohio	6.40	Ohio	6.80	Ohio	0.40	6.25%
South Dakota	6.30	South Dakota	6.70	South Dakota	0.40	6.35%
New Jersey	10.20	New Jersey	10.90	New Jersey	0.70	6.86%
Nevada	5.80	Nevada	6.30	Nevada	0.50	8.62%
Arkansas	5.60	Arkansas	6.10	Arkansas	0.50	8.93%
Oklahoma	5.50	Oklahoma	6.00	Oklahoma	0.50	9.09%
Minnesota	5.70	Minnesota	6.30	Minnesota	0.60	10.53%
Kentucky	4.20	Kentucky	4.80	Kentucky	0.60	14.29%
Nebraska	5.20	Nebraska	6.00	Nebraska	0.80	15.38%
Maryland	7.00	Maryland	8.20	Maryland	1.20	17.14%
Missouri	6.10	Missouri	7.20	Missouri	1.10	18.03%
District of Columbia	7.40	District of Columbia	9.20	District of Columbia	1.80	24.32%
Montana	5.10	Montana	7.00	Montana	1.90	37.25%

EXHIBIT 5

Seller/Buyer(s)	Capacity (MW)	Aggregate Purchase Price (MM)	Aggregate Book Price (MM)	Total Premium Over Book (MM)	Purchase Price ($ per kw)	Book Price ($ per kw)	Total Premium Over Book ($ per kw)
GPU/Edison Mission	942	900	219	681	955	232	723
Bangor Hydro /PPL Global	96	80	24	56	833	250	583
CMP Group/FPL Energy	1185	846	240	606	714	203	511
Commonwealth Energy/Southern Energy	984	462	79	383	470	80	390
Unicom (Commonwealth Edison)/Edison Mission Energy	9772	4813	1300	3513	493	133	360
GPU/FirstEnergy Corp.	83	43	16	27	518	193	325
Maine Public Service Co/WPS-PDI	92	37	12	25	405	127	278
Niagra Mohawk/Orion Holdings	661	425	250	175	643	378	265
Puget Sound Energy/PPL Global	735	549	354	195	747	482	265
Montana Power/PPL Global	1556	892	552	340	573	355	218
Sempra/NRG Energy & Dynegy	1218	356	94	262	292	77	215
GPU/Sithe	4117	1680	814	866	408	198	210
Energy East (NYSEG)/AES Corp.	1424	950	662	288	667	465	202
Consolidated Edison/NRG Energy	1456	505	220	285	347	151	196
Orange & Rockland/Southern Energy	976	345	179	166	353	183	170
Consolidated Edison/Orion Holdings	1855	550	250	300	296	135	161
Electric Uutilities Association/NRG Energy	160	55	30	25	344	188	156
Electric Utilities Association/Southern Energy	280	75	40	35	268	143	125
NEES/U.S. Generating Co.	3960	1590	1100	490	402	278	124
Consolidated Edison/Key Span Energy	2168	597	330	267	275	152	123
PG&E Corp./Southern Energy	3065	801	432	369	261	141	120
Sempra/San Diego Unified Port District	693	110	40	70	159	58	101
PPL Resources/WPS-PDI	467	106	64	42	227	137	90
Enron (Portland Gen.)/PPL Global	323	49	32	17	152	99	53
United Illuminating/Wisvest	1056	272	217	55	258	205	53
PG&E Corp./Duke Energy	2745	501	380	121	183	138	45
PG&E Corp./FPL Energy	1224	214	160	54	175	131	44
BEC Energy/Sithe	1983	536	450	86	270	227	43
Unicom/Southern Energy & Dominion Energy	1598	250	250	0	156	156	0
Niagra Mohawk/NRG Energy	1360	355	370	-15	261	272	-11
Consolidated Edison /Southern Energy & Dynegy	814	135	151	-16	166	186	-20
Edison International(Southern Calif. Edison)/Houston Industries	1500	43	125	-82	29	83	-54

(-) indicates the Book Price was greater than the Purchase Price