ELECTRICITY RESTRUCTURING: SHORTCUT OR DETOUR ON THE ROAD TO ACHIEVING GREENHOUSE GAS REDUCTIONS?

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I. Introduction

For much of its 100-year history, the U.S. electric power industry has been organized largely as a collection of franchised monopolies that generate, transmit, distribute and sell electricity at regulated prices to captive customers. As a result of changes in technology and regulatory policies, however, the generation and sales of electricity are being opened up to competition (and, to some extent, being separated from the transmission or "wires" sides of the business). This transition from end-to-end regulation to greater competition is often referred to as “electricity restructuring."

Concerns over carbon dioxide emissions as well as conventional pollution are playing an important role in debates over the course of restructuring. Several studies have looked at the effect of retail competition on emissions, but the issue is far from resolved.

The effect of electricity restructuring on carbon emissions is of particular interest to U.S. government officials and others charged with developing strategies for achieving the U.S. greenhouse gas emission reduction targets established at Kyoto. How restructuring will affect carbon emissions will depend largely on the behavior of participants in the newly competitive electricity marketplace, which in turn will be determined in large measure by the policies that initiate and govern the transition from regulation. While many of the basic questions on the effect of restructuring cannot yet be definitively answered, there are nonetheless important lessons that we can draw from the current state of knowledge.

II. Background on Restructuring

Technology has evolved in the generation of electricity in ways that make competition more feasible. Particularly important in these technological developments has been the emergence of gas-fired generation technologies that can be efficiently operated at a small scale relative to the size of the plant needed to satisfy demand. Thus, it is technologically reasonable and economically efficient to have more than one company generating electricity in a market area.

Other competition-enhancing changes derive directly from public policy. While non-utility generators have been making inroads into wholesale generation markets for nearly twenty years, competition in generation was bolstered by the Federal Energy Regulatory Commission (FERC) decision in 1996 that ordered transmission-owning utilities to allow open access to their transmission lines to facilitate wholesale electricity transactions. The push for retail competition began with the passage of laws in California and New Hampshire in 1996. Under retail competition, electricity consumers are allowed to pick their electricity suppliers, but the delivery of that electricity to the customers’ premises will continue to be handled by the regulated local distribution utility. As of May 1, 1999, state utility regulators, state legislatures or both in 21 states had made the decision to implement retail competition within 5 years or less. Several bills seeking to promote retail competition in electricity markets nationwide, including the Clinton Administration's Comprehensive Electricity Competition Act, were introduced during the last session of Congress and new or revised bills, including the 1999 version of the Clinton Administration's restructuring bill, are being introduced into the current session.

III. Key Demand-Side Questions

1. How will restructuring affect the level and structure of electricity prices and, consequently, the level and shape of electricity demand?

Electricity restructuring is expected to result in lower average prices for electricity as competition from new entrants and low-cost suppliers drives down the market price in traditionally higher-priced markets. Lower prices are likely to generate higher demand from consumers which, holding the composition of the generating stock fixed, will produce higher carbon emissions from electricity generation.

How much electricity prices will fall as a result of restructuring depends on a number of factors. If the regulated utility was relatively inefficient and the new market is very competitive and provides options for all classes of customers, then restructuring could produce substantially lower electricity prices. On the other hand, if the local regulated utility is a low-cost supplier of electricity relative to its neighbors, then prices in the local area could actually rise under competition, particularly if new entrants are unable to beat the incumbent's price.

The price-lowering effect of competition will be muted by the provisions found in most electricity restructuring laws and proposed legislation to allow at least partial and often substantial recovery of "stranded costs" in retail electricity prices. Stranded costs are costs previously incurred by a utility that it will be unable to recover at market prices. The larger the amount of stranded costs that must be recovered through an electricity surcharge, the smaller the price reductions arising from competition in the short-run. Over time the impact of stranded costs on retail electricity prices will diminish as the contribution of stranded cost recovery to electricity prices becomes smaller and ultimately disappears.

Partially offsetting this effect is the guaranteed rate reduction provision of restructuring laws passed in many states. In these states, legislators or regulators or both have guaranteed rate reductions either by imposing a retail rate cap or by establishing a "standard offer" rate below the existing regulated price. This standard offer rate is available to customers who elect not to choose a competitive supplier. Like the stranded cost recovery provisions, these rate cap or guaranteed rate provisions expire after a period of time, making it difficult to predict the long-run price effects of competition.

The effect of expected price declines on electricity demand and on carbon emissions from the electricity sector depends on how sensitive demand is to changes in electricity prices. Estimates of the price sensitivity of demand vary depending on region of the country, time of year and type of customer, but in general, suggest that if prices fall by, say, 10-15% as a result of restructuring, demand could increase by anywhere from 1% to 6% or more in response to that price change.

Restructuring is also expected to produce more widespread use of time-differentiated pricing of electricity. With time-differentiated prices customers face higher than average prices during periods of peak demand and lower than average prices during off-peak periods. This form of pricing will lead to a shifting of demand away from peak periods to off-peak periods which also could contribute to higher carbon emissions, especially in those areas where off-peak, baseload generation tends to be coal-fired and peak generation tends to be gas-fired.

2. What will happen to demand-side management and energy conservation efforts in a more competitive electricity market?

As electricity markets become more competitive and utilities seek to shed excess costs, the number of utility-funded demand-side management (DSM) programs is already rapidly diminishing. Utilities argue that they cannot maintain these programs and effectively compete with independent power producers who are not required to fund such initiatives. In the absence of a new policy initiative, many argue that the carbon emission savings attributable to past DSM and conservation efforts by utilities will be lost in a competitive market.

The flip side of that argument is that greater use of time-differentiated pricing of electricity will result in stronger incentives for consumers to conserve electricity during peak periods, although some of this demand will merely be shifted to off-peak periods. Moreover, restructuring may create opportunities for energy service companies to compete on the basis of holding down the customers overall energy bill.

Many state restructuring laws and federal restructuring bills also explicitly include a mechanism for funding DSM initiatives that does not discriminate among electricity suppliers and could result in some energy and carbon savings. These initiatives usually take the form of a surcharge, often called a systems benefits charge, imposed on all electricity customers, regardless of whom their energy supplier is. Some portion of the revenues from the system benefit charge is used to fund demand-side management programs.

IV. Key Supply-Side Questions

1. Will generation from nuclear power increase or decrease in a more competitive electricity market?

Nuclear power plants produce roughly 20% of the electricity sold in the U.S. Nuclear generators emit no carbon dioxide, so maintaining or increasing the contribution of nuclear power to U.S. electricity production could be a key component of a strategy to prevent or delay increases in carbon emissions from the electricity sector. How important nuclear generation will be in the competitive electricity market of the future depends on the relative contributions of two opposing effects.

Competition may result in early retirement of a substantial portion of the existing nuclear capacity. In a regulated environment most nuclear power plants would be expected to remain on-line at least until the expiration of their current operating licenses. At market prices, many nuclear plants will be unable to cover the costs of fuel, operation and maintenance, and meeting safety requirements. Estimates of the annual amount of nuclear generation potentially subject to early retirement range from 40 billion kWh hours per year to over 110 billion kWh per year, or between 6.3 % and 17.5 % of current levels of nuclear generation.

Countering this effect, competition will likely improve efficiency at nuclear power plants. These improvements could take the form of fewer unplanned outages or shorter downtimes associated with refueling and, therefore, increased generation at existing plants over the course of the year. Efficiency gains could also result from reductions in operating and maintenance costs as nuclear operators actively seek to reduce their production costs and increase their operating returns. Higher returns will help to keep plants on-line longer.

2. Will renewables play a larger or smaller role in a competitive generation market?

Like nuclear generation, the class of renewable generating technologies, which includes hydropower, solar thermal and photovoltaics, biomass, geothermal and wind power, are all zero-carbon-emitting technologies. Renewables account for only about 12% of generation in the U.S. and non-hydro renewables account for only 2%. Non-hydro renewables have been slow to penetrate electricity markets because of their high cost. Non-hydro renewables also are generally non-dispatchable (the timing of their use cannot be controlled), which tends to diminish their value relative to other generating resources. If, as expected, increased competition in electricity markets leads to lower electricity prices, then in the absence of cost-reducing technological developments renewables will be less likely to penetrate the market.

Competition brings greater possibilities for diversification of services in the market that could provide a boost to renewables. In states that have moved to competition, renewable generators and power marketers are developing “green power” service packages. Under these packages customers contract for power that is, for example, 20, 50 or 100% renewable-based and generally pay a premium above the market price of conventional power. Some of these service packages are limited to non-hydro renewables, but many are not.

Whether green power marketing increases renewables generation depends on whether the size of the green power market exceeds the contribution of the existing renewable generators and on the selectiveness of green power purchasers. Some green power packages specifically indicate that a certain percentage of the power will come from new renewables, presuming that penetration above and beyond current levels is something that customers care about. Penetration of new renewables also does not necessarily preclude early retirement of existing renewables that find it difficult to compete in a more competitive market place.

In the traditional regulated environment, renewables have benefited from promotion policies such as the renewable purchase requirements under the federal Public Utilities Resource Policy Act (PURPA) and state public utility commission (PUC) orders that have often resulted in utilities offering or being required to build some new renewable generating capacity. With restructuring, PURPA is expected to become a thing of the past since it places requirements on utilities not faced by their non-utility competitors and PUC oversight of generation capacity planning is likely to be drastically reduced. In the absence of a new policy to promote renewables in restructured markets, they are likely to fare less well in a competitive environment than in a regulated environment.

Not surprisingly, new policies to promote renewables are part of virtually all existing and proposed restructuring laws and regulations. Some jurisdictions, such as California, have adopted surcharge-funded subsidies to renewable generation as a way to bring renewables into the market. Other jurisdictions, including Maine and Massachusetts, rely on a renewables portfolio standard (RPS) approach. The RPS typically requires that a minimum percentage of all electricity generated (or sold) within a region must come from non-hydro renewable sources (in Maine hydro sources are included under the RPS cap as well). Generally, this percentage exceeds the current contribution of renewable power by a substantial percentage. Under this policy, each MWh of renewable power generated creates a renewable generation credit. Generators (or retailers, depending on who is responsible for meeting the requirement) can meet their obligation through some combination of generating directly, purchasing renewable generation under contract, and purchasing sufficient renewable generation credits to fulfill their obligation. This program is designed to allow the market to identify the least cost set of renewable generators to satisfy the renewable obligation.

The impact of a RPS policy on carbon emissions will depend on how high the standard is set. Recent federal bills contain proposed levels of the RPS for 2010 ranging from 4% to 20% of either total electricity generation or total retail sales.

3. How will restructuring affect the level and composition of interregional electricity trade?

Open transmission access makes it possible for low cost utilities with excess generating capacity to sell their cheap electricity to retail electricity suppliers in higher priced neighboring regions. If the low cost suppliers are predominantly older coal-fired facilities and the generation being displaced comes from oil or natural gas facilities, then this increased inter-regional electricity trade will result in higher emissions of CO_2. There is some evidence that inter-regional trading of electricity, in particular the shipment of electricity from the Midwest to the Northeast, has increased with the establishment of open transmission access for wholesale power transactions. The amount of inter-regional electricity transmission is expected to increase even more with the move to retail competition. Under competition, exporting generators will also have incentives to improve plant availability, which could further increase the amount of electricity generated for export and, therefore, the level of emissions. On the other hand, generators will also have an incentive to economize on fuel use, perhaps by actually improving their heat rates, and this could contribute to reductions in the carbon emission rate per kWh.

The extent to which inter-regional power trade will increase under competition depends significantly on the amount of inter-regional transmission capacity that is available. Large differences in electricity prices between regions suggest at first glance that there will be greater incentives to expand transmission capacity under competition in an effort to exploit those price differences. In addition, the FERC open transmission access order requires transmission-owning utilities to expand transmission capacity if necessary to satisfy a demand for transmission service that can't be met with existing capacity. But the incentives to expand transmission capacity will depend importantly on how transmission service is priced. If transmission is priced in a way that allows transmission owners to earn excess profits whenever lines are congested, then they will have incentives to delay expanding transmission capacity. Alternatively, if transmission users have rights to congestion revenues, the incentive to delay investment in new capacity could be muted.

The potential for increased carbon emissions from greater electricity trading will diminish over time as older coal-fired generators are retired. While as a general rule coal-fired plants have tended to outlive their original 30-year expected life, these plants will not last forever. Indeed, some older plants will require capital investment to extend their lives and the costs of these investments may not be recoverable in a competitive market where new gas combined cycle plants can cover their fuel, operating and capital costs at prices under 3.5 cents per kWh. Increasing the output from older plants will also increase their maintenance costs making them uneconomic after a time. New environmental regulations to limit emissions that contribute to the formation of fine particulates could also accelerate retirement of these plants. Lastly, the economic lifetime of these older coal facilities will also depend on what happens to the relative prices of coal and natural gas in the future. If the difference between coal and gas prices grows faster than expected, then, all other things equal, generators may be reluctant to retire their older coal facilities. Exactly how all of these influences will come together to affect the remaining lifetimes of older coal plants is still highly uncertain.

4. How will increased competition affect the rate of penetration of new gas combined cycle units into the electricity markets?

When England simultaneously privatized and introduced competition into its power sector, it also was phasing out price supports for the British coal industry. The result was a substantial penetration of new gas-fired generation owned and operated largely by new independent power producers. This switch from coal to gas resulted in both a reduction in carbon emissions and a dramatic reduction in emissions of SO_2.

Many analysts suspect that a similar phenomenon will occur in the U.S. Driven by low natural gas prices and the advantages of gas-fired combined-cycle turbines (high-efficiency, low cost, modularity, and the short lead time for bringing these units on-line), energy market entrepreneurs will see many opportunities to make money selling electricity with this technology and will seize those opportunities. According to a recent article in Public Utilities Fortnightly (see Further Readings), plans to build over 50,000 MW of new generating capacity had been announced by project developers as of the end of 1998. The vast majority of this proposed new capacity will be either natural gas-fired combined-cycle plants or simple gas turbines. Most of the proposed plants are concentrated in two regions of the country, California and New England, the regions that have progressed the furthest toward implementing retail competition. New England is also a region where existing transmission constraints limit the potential to import power from cheaper suppliers to the south and west, suggesting these entrants would face limited competition from cheaper imports in the absence of growth in transmission capacity.

Despite these announcements, whether gas plants penetrate U.S. electricity markets faster than they would have in the absence of competition remains an open question. First, competitive markets are riskier for investors than regulated markets with more assured returns, and the cost of capital in a competitive market therefore will be higher than it would be with the continuation of the regulatory status quo. All else equal, a higher cost of capital will tend to yield lower levels of investment in new generating plants. Second, the siting of new power plants will continue to be a regulatory hurdle, even in a deregulated environment. Concerns over the effect of power plants on environmental quality will have to be addressed before regulators will permit these plants to operate. In addition, new generating plants will need to locate in areas that have access to gas pipelines and to high voltage transmission lines. The number of sites ideally situated for new gas plant development may be largely in the hands of existing generators, leaving a potentially limited number of sites for new entry by independent producers (at least in the short run). Lastly, the rate at which the industry can bring new gas-fired combined-cycle turbines on line may be limited by the capacity of the existing equipment manufacturers to deliver the equipment. If demand exceeds their capacity to produce, this will bid up the cost of this equipment and could have a dampening effect on the rate of new entry. Increases in the price of natural gas relative to competitive fuels like coal could also slow the rate of entry of new gas combined cycle units.

V. An Overview of the Numbers

Several studies have attempted to quantify the likely effects of electricity restructuring on carbon emissions. Some of these studies focus on the effect of one of the factors identified in the prior section, while others focus more broadly on the emissions impacts of restructuring generally and do not attempt to sort out the contributions of the different supply and demand-side factors identified above. Only one study, the DOE Policy Office Supporting Analysis of the Clinton Administration's Comprehensive Electricity Competition Act (CECA) based on the 1998 legislative proposal, separates out the effects of several of these factors on carbon emissions from the electricity sector (see Further Readings).[*]

The DOE study finds that, on net, restructuring as envisioned in the CECA will lead to 39 million metric tons (MMT) fewer carbon emissions in 2010 than would occur in the absence of an explicit policy to reduce carbon emissions from the electricity sector. (The fact sheets on the 1999 version of the CECA just released on April 15, 1999 indicate that the most recent version of the bill will reduce greenhouse gas emissions by 40 to 60

[*] After this Issues Brief was completed, DOE released further analysis on the 1999 version of CECA. This analysis seems to avoid some of the pitfalls identified in this brief. In addition, in the new analysis, both the increases and the decreases in carbon emissions associated with different policies or features of restructuring are generally smaller (with some exceptions) than they were in the 1998 analysis.

million metric tons in 2010. This higher anticipated level of reductions is attributable in part to a higher renewable portfolio standard, 7.5% versus 5.5%, in the new version of the bill.) These numbers are small fraction of the several hundred million ton reduction relative to business-as-usual that the United States likely would face to meet its Kyoto target. The DOE result comes from adding together the increases in carbon emissions associated with (1) increased demand for electricity as a result of lower prices, (2) incremental nuclear retirements and (3) increased availability of generating capacity, and the emission-reducing effects associated with (1) improvements in heat rates at existing fossil-fueled generators, (2) increased energy efficiency and (3) increased reliance on renewable energy.

The contributions to carbon reduction of the last two items – increased energy efficiency and increased reliance on renewables – are particularly worthy of discussion. The DOE study includes the presumed effects of an increasingly stringent RPS and continued DSM financed through a system benefits charge. It also includes a presumption that even without these policy measures, energy service companies will find substantial opportunities for energy efficiency in a restructured market and green power markets will grow. The DOE analysis indicates that restructuring would lead to roughly an increase of 4-12 million metric tons in annual carbon emissions in the next decade relative to the regulated reference case if DSM and renewables initiatives are factored out. Ongoing analysis at Resources for the Future suggests that, leaving aside efficiency and renewables initiatives, carbon emissions could increase by between 8 and 16 MMT by 2003 from national retail restructuring. Earlier studies (including one by Palmer and Burtraw - see Further Readings) found even greater increases.

There are reasons to question the magnitudes of the DOE figures for carbon savings from energy efficiency and renewables. The DOE analysis uses a base case in which utility expenditures on demand side management were still assumed to be increasing. Given that much of the revenues from the system benefits charge is likely to be replacing utility-sponsored programs instead of adding to them, the emission reductions resulting from energy efficiency programs under restructuring are potentially overstated.

The carbon savings from a renewable portfolio standard are uncertain; a recent study by the Union of Concerned Scientists (UCS) forecasts greater penetration of renewables without an RPS and, therefore, obtains a lower figure than that of the DOE report (see Further Readings). Moreover, the DOE study also assumes that 2.5% of residential demand will be met with green power over and above that attributable to the effect of the renewable portfolio standard. If in practice the green power market overlaps with the RPS, then the emission savings from increased renewables penetration will also be lower.

The DOE study also is more optimistic than many other studies about other effects of restructuring on carbon emissions, beyond energy efficiency and renewables impacts. Different assumptions could further raise carbon emissions by as much as 22 MMT. The differences are attributable largely to different assumptions regarding price responsiveness of demand, growth in transmission capability and extent of incremental nuclear retirements.

The DOE analysis assumes a lower price responsiveness of demand for electricity than EIA now uses, suggesting that demand increases in light of lower prices under restructuring may be larger. In addition, DOE uses a significantly lower figure for the reduction in nuclear generation than in a recent study by Geoff Rothwell (see Further Readings). Finally, the DOE study assumes that inter-regional transmission capability will not increase as a result of restructuring. Given that the FERC open transmission access rule requires firms to expand transmission capacity as necessary to satisfy demand for transmission service from a paying customer, the assumption of no growth in the presence of large disparities in regional electricity prices seems overly conservative. Expanding capacity through the construction of new lines can be very difficult and subject to long delays due to siting issues, but capacity could also be increased through efficiency improvements in the existing system. Allowing for transmission expansion increases generation from existing coal-fired facilities that might displace generation from cleaner facilities or delay investment in new facilities.

VI. Lessons for Policy Makers

Whether electricity restructuring is indeed a short cut or a detour on the road to achieving the Kyoto targets will depend on how policy makers design a restructuring policy. This review of the current state of knowledge concerning the effects of electricity restructuring on carbon emissions from the electricity sector offers three important lessons for policy makers as they embark on this important task:

1. *Restructuring will be climate-friendly only by design*. All of the analysis to date suggests that electricity restructuring is likely to lead to reductions in carbon emissions from the electricity sector only when the policy is designed to promote greater use of renewables and greater electricity conservation. While it might be possible for other measures (such as an explicit effort to retire old coal plants or to keep nuclear units on line) to augment or substitute for these policies, the analysis to date suggests that without some provision to promote conservation or greater use of renewables, restructuring will not yield lower carbon emissions, at least in the short run.

2. *The economic benefits of restructuring are an important consideration in formulating a climate-friendly restructuring policy.* If policy makers are going to incorporate carbon emission reduction measures into a restructuring policy, it is important for them to be cognizant of the potential costs of these measures. These costs come in the form of reduced economic benefits of restructuring. Policies that are highly prescriptive, such as a non-tradable renewable generation requirement or a provision that mandates retirement of older coal facilities, could severely limit the flexibility of the competitive market and the size of the efficiency gains from competition. More flexible policies, such as a tradable RPS or a small tax on carbon emissions from electricity generators, will place less of a burden on electricity suppliers and be more consistent with the goal of promoting efficiency in the electricity sector.

3. *Policy makers should develop a policy regarding early retirement of nuclear power plants before it's too late.* Nuclear power plants are already beginning to retire early because plant operators fear they will be unable to cover their costs at competitive electricity prices. More early retirements are expected. Replacing the generation from these plants with fossil-fueled generation will result in increases in carbon emissions from this sector, moving the U.S. further away from instead of closer to achieving the Kyoto emission reduction targets. U.S. policy makers need to evaluate the potential impacts of these nuclear retirements on the costs of achieving the Kyoto targets and of achieving other environmental goals. A complete evaluation of the role of nuclear plants in a carbon reduction strategy must consider both the environmental benefits of early retirement, in the form of lower waste disposal burdens, and the environmental costs. Active consideration of this issue by U.S. energy policy makers should begin now before many more nuclear power plants shut their doors forever and this important option for delaying increases in carbon emissions from the electricity sector is eliminated.

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