ELECTRIC INDUSTRY RESTRUCTURING IN OHIO:

RESIDENTIAL AND LOW INCOME CUSTOMER IMPACTS

Report to the Oak Ridge National Laboratory

ENERGY ASSOCIATES

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EXECUTIVE SUMMARY

This report analyzes the electric utilities in Ohio in order to determine how they are situated for the coming of competition. It begins with the status of the utilities as of 1995, the last year for which detailed data were available, and determines the detailed underlying cost structure behind the rates charged to customers. The study then develops a number of restructuring scenarios to be analyzed. These scenarios cover different approaches to dividing stranded asset costs between customers and stockholders, and between different groups of customers. They also cover wholesale versus retail competition, different regulatory structures for those services still under regulation, and new approaches to stranded asset costs such as securitization -- the use of special bonds to reduce costs. Throughout the report the special emphasis is on the impact of restructuring on low-income residential customers. Low-income customers are the most vulnerable to changes in the regulatory structure with the fewest alternative options.

The report finds that there are a great deal of above-market cost, potentially stranded assets in Ohio -- approximately $8.75 billion in 1995. The annual above-market costs total over $3 billion, of which about 2/3 is recovery of capital related costs and 1/3 is recovery of energy related costs. The distribution of stranded assets in Ohio is very uneven. Some utilities such as Cleveland Electric and Ohio Edison have very high levels of above-market costs. In contrast, Ohio Power has, under some estimates, costs which are actually below market costs.

The study looks separately at the near-term or *transition* period (approximately the next seven to ten years) and the longer term competitive market period. During the transition period the costs of stranded assets are being collected from customers while competitive markets are being developed. In the longer term market period it is assumed that all of the stranded asset costs have been collected and that the competitive market for generation is fully functioning.

In the transition period there are no overall savings to be had from restructuring as long as the utilities are allowed to recover *all* of their above-market costs. There cannot be. It is the stranded assets that are driving utility costs up, and allowing for the full recovery of those costs means that there are no savings. Overall savings can occur in the near-term under two conditions. One is that utilities do not recover all of their stranded asset costs. The other is that the cost of paying for stranded assets is reduced.

Securitization is an approach which can reduce the cost of paying for stranded assets. By replacing the conventional utility mix of debt and equity with special lower cost debt (theoretically obtainable as a result of special guarantees on the collection of moneys needed to pay off the bonds), the overall cost of paying for stranded assets can be reduced. This, however, is a financial transaction and not an element of restructuring/competition.

Allocation of the responsibility for paying for stranded asset costs during the transition period can create winners and losers. If industrial customers can use their market and political clout to get out from paying their fair share of stranded asset costs, they can significantly reduce their costs, even if full recovery of stranded asset costs is allowed. The converse side of this is that residential and commercial customers would see large rate increases to pick up the industrial share of stranded costs. Under the best transition period case for residential customers, where none of the stranded asset costs are allocated to customers, residential savings range from 7% to 37%, commercial savings range from 8% to 43%, and industrial savings range from 10% to 52% for different utilities. Under the worst case for residential customers, where residential and commercial customers bear full responsibility for stranded asset costs (and industrial customers pay none), residential rates go up from 1% to 22%, commercial rates go up from 1% to 23%, and industrial rates go down from 2% to 34%. Under a sharing case, where stranded asset costs are split evenly between customers and stockholders, with each customer class paying its fair share of these costs, the savings range from 3% to 19% for residential customers, from 3% to 22% for commercial customers, and from 4% to 27% for industrial customers.

Over the longer term, after the cost of stranded assets has been fully recovered, there are significant savings in overall costs to be gained from competition (compared to current costs). Market prices of power are expected to remain lower than the current power costs of most of the Ohio utilities. There remains, however, the question of cost allocation. If the savings are unfairly divided among customers, there may well be losers, even in the long term when market prices are down and stranded asset costs are paid off. Customers of Ohio Power, currently the lowest cost utility in Ohio, may well see their rates increase as they begin to pay market prices for power.

Many of the proposals that have been set forth for restructuring call for more of the costs of distribution to be collected as fixed customer charges rather than as variable kWh charges. Since, on average, low-income customers use less power than typical residential customers, this approach will end up allocating a greater portion of distribution costs to low-income customers.

Currently, Ohio utilities are spending approximately $31 million per year on low-income assistance programs. This works out to approximately $0.00024 per kWh, or 0.36% of revenues. We fully expect that low-income programs will continue under restructuring. The need will remain, and very likely increase. The cost of low-income programs will most likely be collected through the use of systems benefit charges collected at the distribution level from all customers. If current programs to support demand-side management, renewable resource development, and research and development are to continue, the systems benefit charges will need to reflect those costs as well.

INTRODUCTION

Throughout the country the long standing administratively based regulatory structure for determining the cost and service parameters for electric utilities is changing. More and more market elements are coming into the structure. There is a push by many players to eliminate much of the current regulation. For the production side of electricity at least, these players argue that a market approach will do a better job of pricing power and making it available to customers.

However, the electricity industry currently has a large base of investment in power production equipment, some of which may have difficulty competing in a market-based system.[1] What to do about this potentially uneconomic existing investment is an important question receiving a great deal of attention at the policy discussion level. Some argue that if the investment in existing facilities is uneconomic in a new market based system, that is too bad for the owners of the above-market cost facilities, and customers should bear no responsibility to help make those owners whole. Others argue that the owners of above-market cost facilities invested in those facilities in good faith and should not be made to bear the cost of a changing underlying industry structure. The arguments on both sides are long and involved, and this paper is not the place to explore them.[2] However, it is clear that the result of the debate is uncertain, and both approaches must be explored.

The purpose of this report is to analyze the current electric utility cost structure in Ohio, estimate the expected changes in that structure and cost levels under various restructuring proposals, and determine the likely impact on low income and other residential customers. The report analyzes the likely cost impacts of a variety of approaches to the above-market cost facility problem. The range of potential outcomes is very wide.

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1 The investment in plant which is unlikely to be able to compete in the electricity market place is what is generally considered to make up stranded generating assets. The assets are stranded because they are not worth their remaining book value.

2 Much of the discussion of the pros and cons of stranded asset cost recovery has taken place in testimony, public speeches, and presentations at conferences, and is thus not readily available for review. However, a good collection of articles addressing this issue can be found in two issues of the Electricity Journal -- October 1994, and November 1995.

We have analyzed the seven major investor-owned electric utilities serving retail customers in Ohio; Columbus and Southern, Cleveland Electric, Cincinnati Gas and Electric, Dayton Power and Light, Ohio Edison, Ohio Power, and Toledo Edison. These seven major electric utilities are entering the new world of restructuring in very different positions. Some are well placed for competition, while others will face serious difficulties.

We have broken the analysis into two time periods -- a near-term to mid-term period (lasting approximately seven to ten years) and a long-term period (more than ten years out). We have done this because we believe that many of the transition issues such as cost recovery will be settled in the next seven to ten years. After that the workings of the market for power generation will be less entangled with transition issues than in the near and mid-term. The approach we have used is set forth in some detail in the discussion of the first time period -- the near and mid-term. The same overall approach is used for the long-term time period; however, the input assumptions are somewhat changed, and the number of variations is much less.

All costs in this study are in constant, 1995 dollars to reflect the use of 1995 FERC Form 1 data. It is assumed that general inflation will continue to operate on electric utility costs and prices will move to reflect that general inflation.

This report includes both tabular and graphical representations of the conclusions we are presenting. Complete tabular representations are found in the body of the report. Graphs are found in Appendix B.

OHIO STATEWIDE SUMMARY

Most of this report focuses on the impact of restructuring in Ohio on a utility-by-utility basis. This is necessary given that the utilities are positioned very differently for meeting competitive challenges. Some are well positioned, while others are likely to find themselves in very difficult positions. A combined statewide analysis could be misleading. Nevertheless, an estimate of the impact of restructuring on Ohio *as a whole* can be useful to get a sense of the overall effect on Ohio. The following eight graphs show the statewide picture. The base of information for these graphs is the 1995 data filed by the Ohio utilities with the Federal Energy Regulatory Commission (FERC) in the *FERC Form No. 1: Annual Report of Major Electric Utilities, Licensees and Others*. Each major investor-owned utility is required to file a FERC Form 1 each year providing data about the costs and operations of the utility for that year.

- Total Energy Production by Plant Type

This graph shows how many gigawatt hours (GWH) of electricity is produced by each of the main sources of power in Ohio. A gigawatt hour is one million kilowatt hours (kWH). It also shows the percentage for each type. This graph provides a useful overview of the electric energy picture in Ohio.

- Total Production Cost by Plant Type

This graph shows the capital and operating cost per megawatt hour (MWH) for each of the five main sources of power in Ohio. A megawatt hour is one thousand kWh. A cost of $10.00 per MWH is equal to a cost of $0.01 per kWh. The cost for "Other Production," while high, is neither unexpected nor problematical, since it represents a very small amount of power, generally used only at time of peak, from plants expected to run very little. On the other hand, the cost for nuclear -- $0.0865 per kWh -- is quite disturbing, since nuclear plants provide a large amount of base-load power in Ohio. The cost of nuclear power is a key reason for the overall high costs shown in the next graphs.

- Comparison of Market and Actual Cost of Production (dollars per MWH and dollars per year)

These two graphs compare the production cost of power in Ohio (capital plus operating) to an estimated market price of power. On a statewide basis, the cost of power is estimated to be $0.017 per kWh higher than the market price. This totals to an annual above-market cost of power of approximately $3 billion.

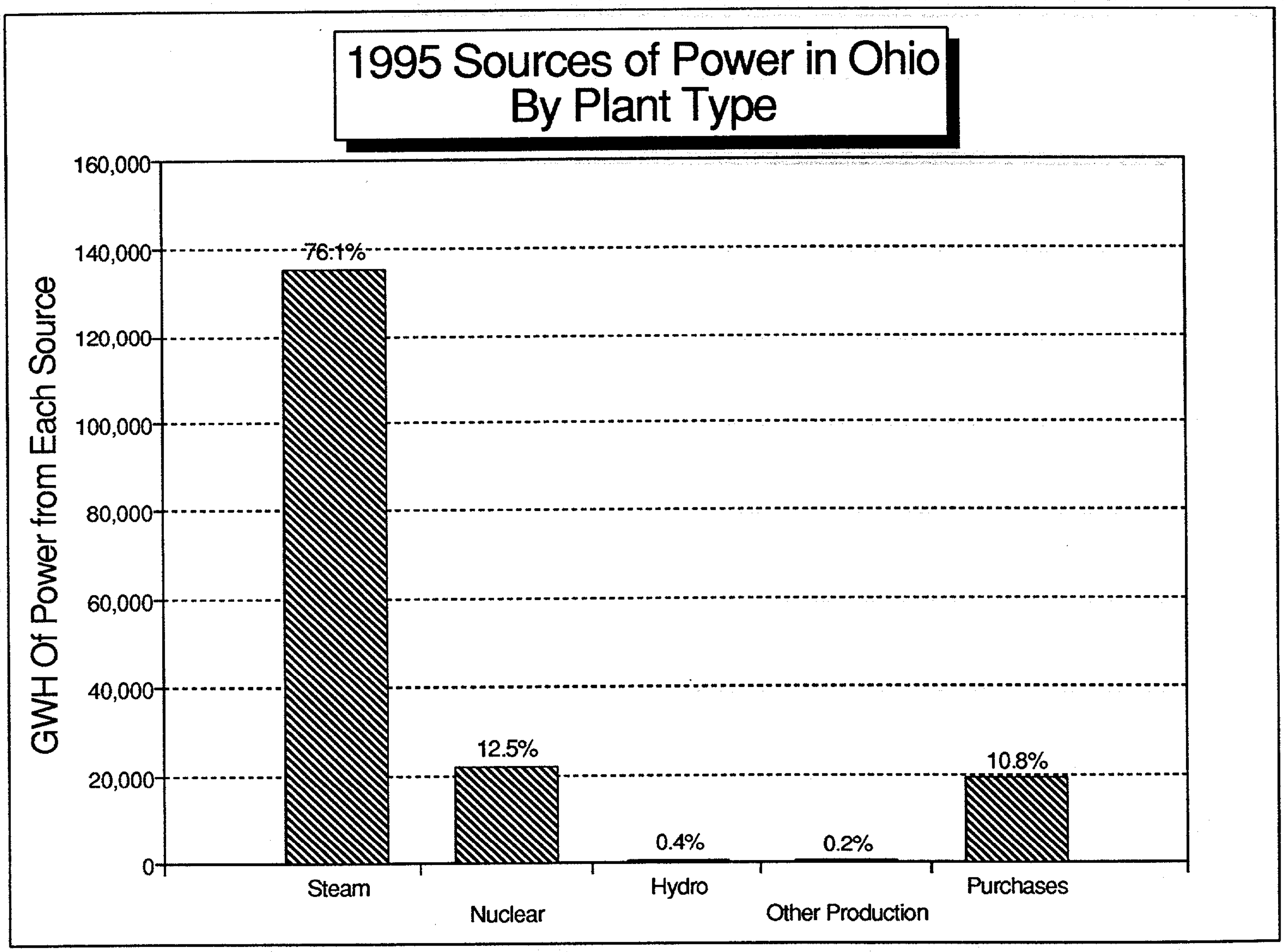
- Production Rate Base

This graph compares the market value of the production plant to the actual amount of production plant rate base. The final bar, "Above-Market Cost of Production Capital," is the single best measure of the amount of potentially stranded investment in Ohio. The amount, $8.7 billion, is extremely large.

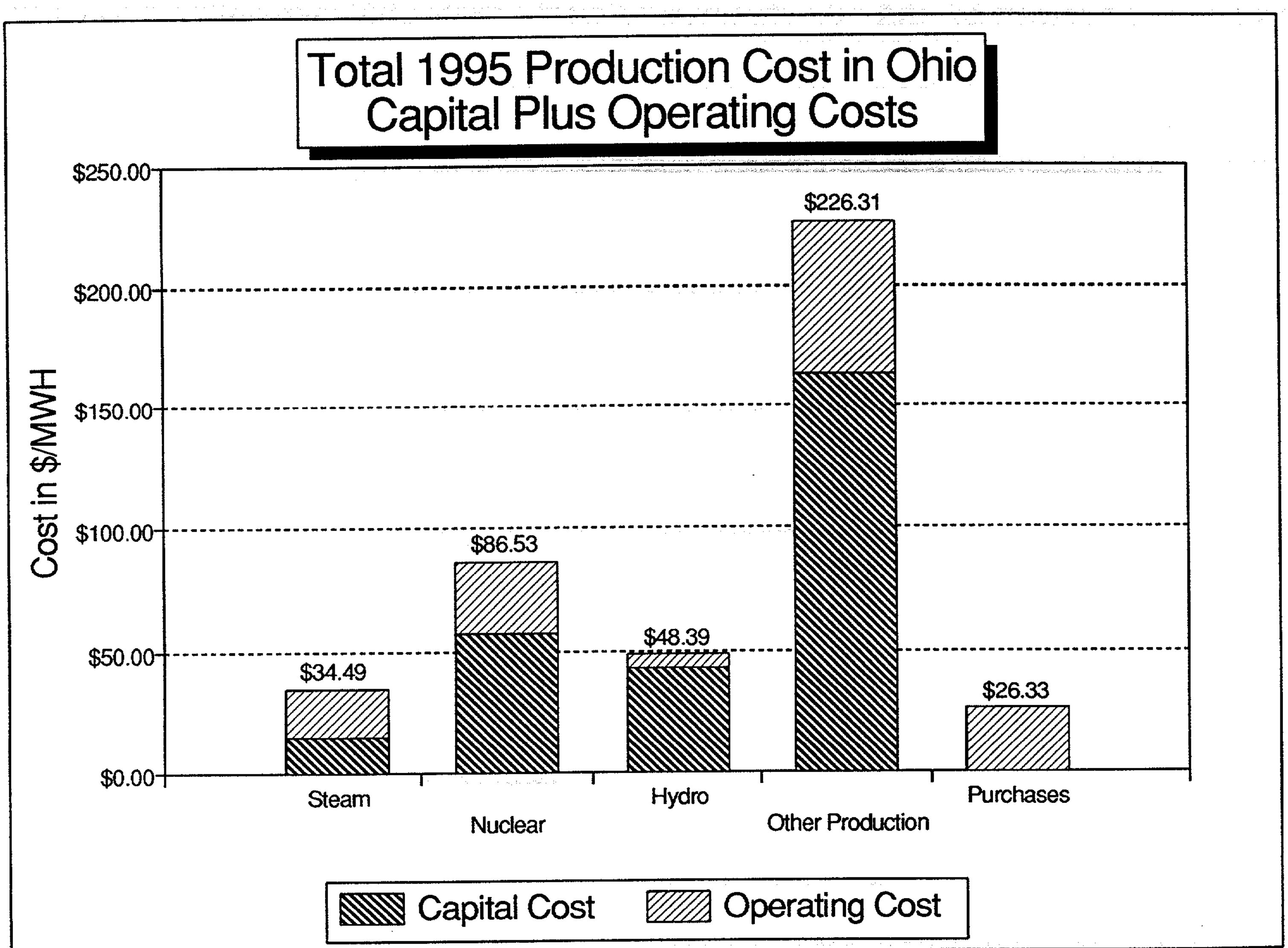
- Rate Impacts of Restructuring

The final three graphs show the estimated statewide impact of restructuring (over the next seven to ten years) for three different approaches to dealing with the stranded investment problem. The first graph assumes that stockholders bear all the cost of stranded investment. This approach provides large savings for all customers. The second graph assumes that all of the cost of stranded investment is borne by the customers, but that none of that cost is allocated to industrial customers. This approach provides large savings for industrial customers, but large increases for residential and commercial customers. The third graph assumes that the cost of stranded investment is shared equally between stockholders and customers, with all customer classes paying their share of the customer share. This approach provides savings for all customer classes.

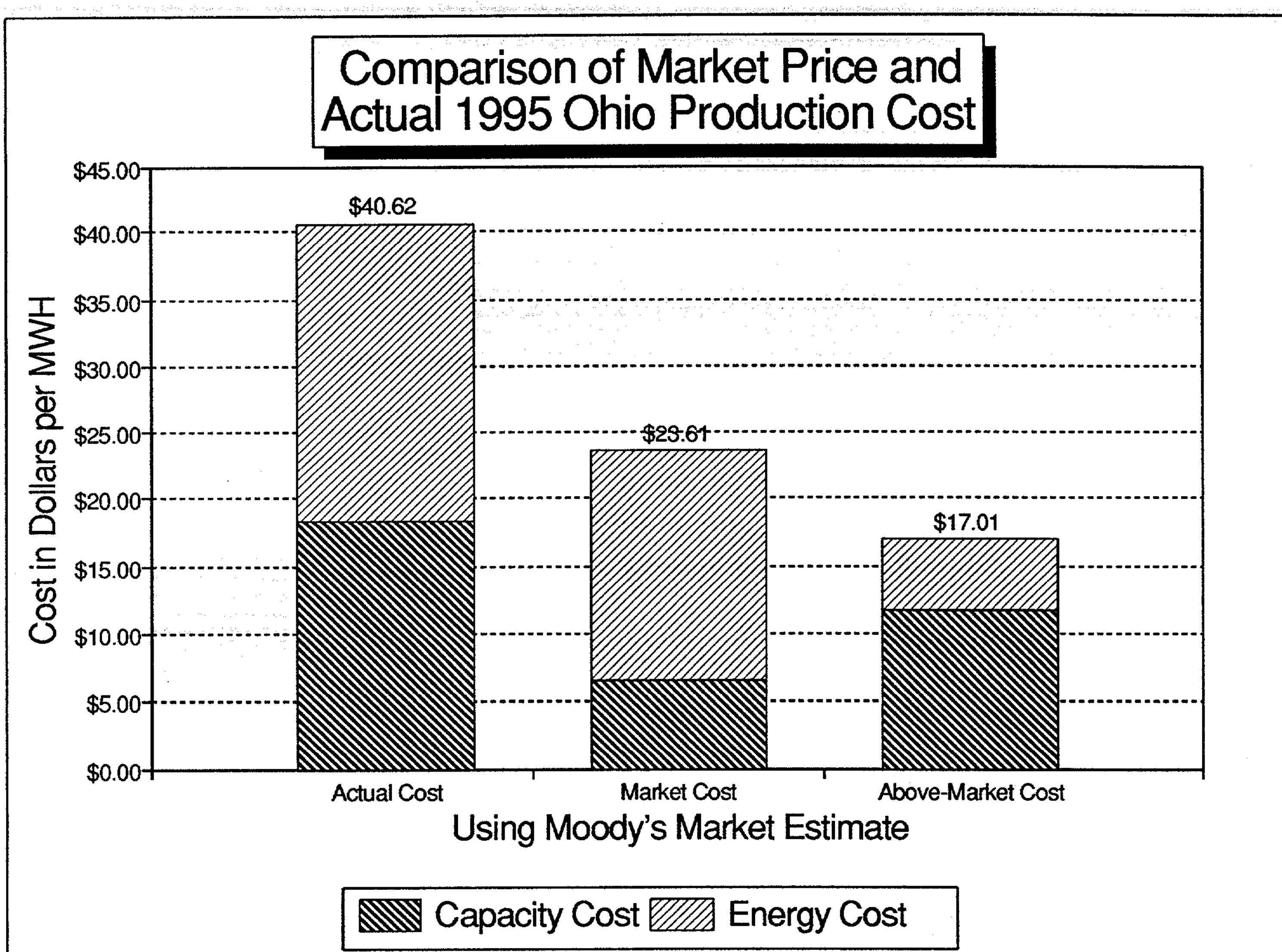
Again, we remind the reader that the results will be quite different for different utilities. Some of the Ohio utilities are reasonably low cost providers, while others have costs significantly higher than estimated market-based costs. It is important to look at the utility-by-utility results shown in the body of the report. The details of calculations used to produce the rate impacts are done are also found in the body of the report.



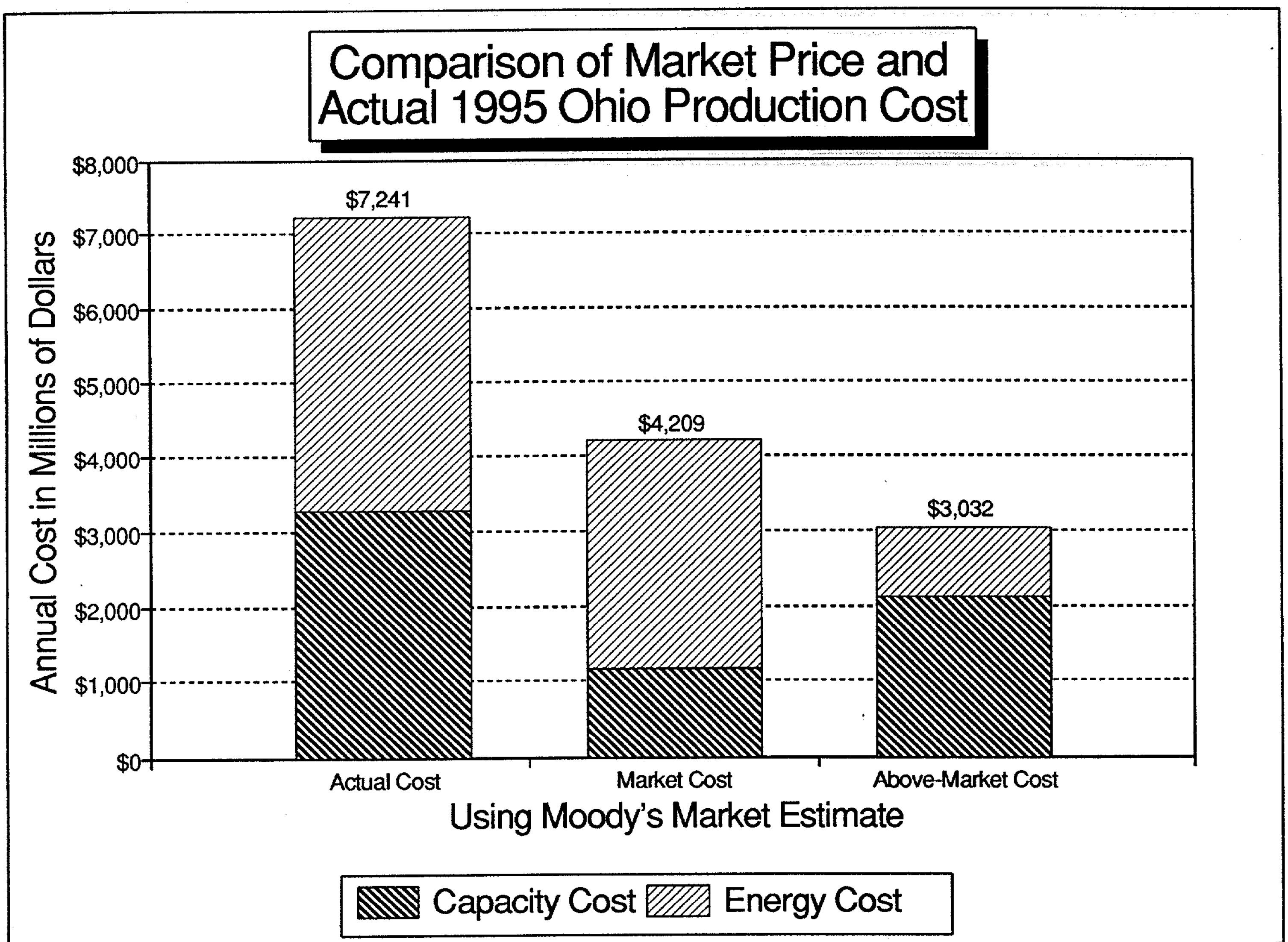
Source: *FERC Form No. 1: Annual Report of Major Electric Utilities, Licensees and Others, 1995.* These are actual reported 1995 generation values, summed for the seven companies.



Source: *FERC Form No. 1: Annual Report of Major Electric Utilities, Licensees and Others, 1995.* These are calculated values based on actual reported 1995 costs, summed for the seven companies.



Sources: *FERC Form No. 1: Annual Report of Major Electric Utilities, Licensees and Others, 1995* and Moody's Investors Service report, *Stranded Costs Will Threaten Credit Quality of U. S. Electrics, August 1995*. The actual cost is calculated from the data in the FERC Form No. 1.



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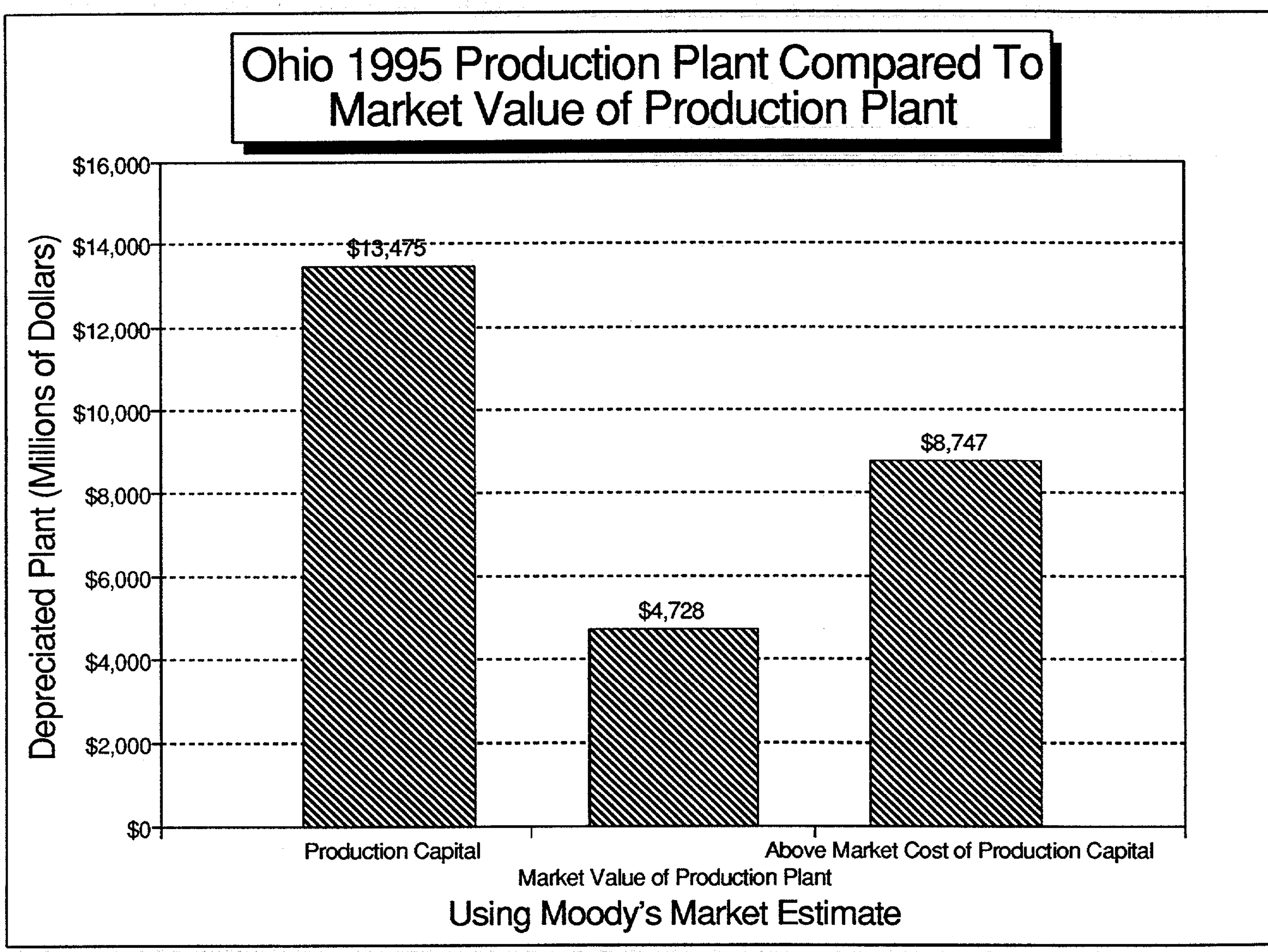
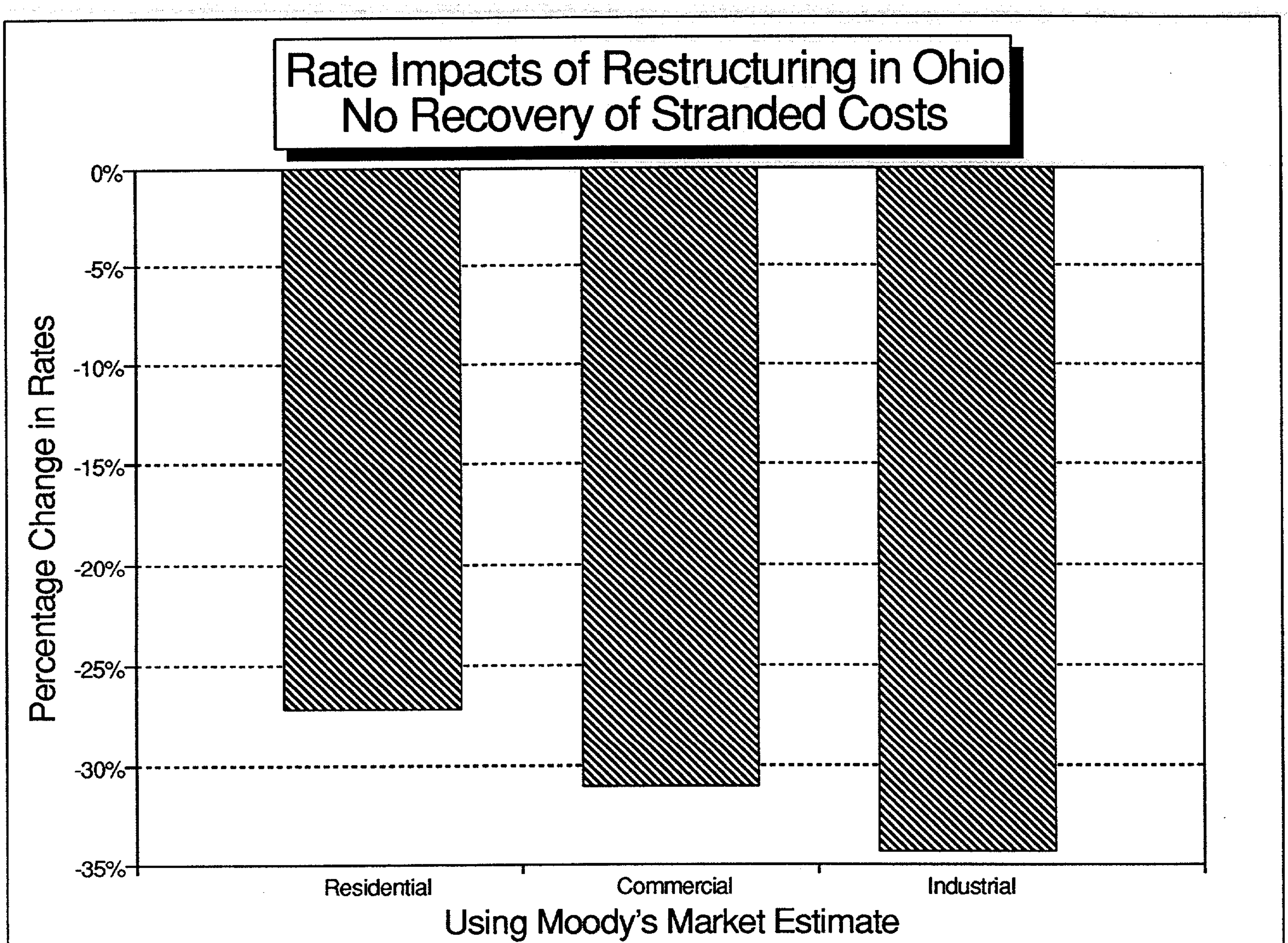


Source: *Electric Industry Restructuring in Ohio: Residential and Low Income Customer Impacts*, 1997.



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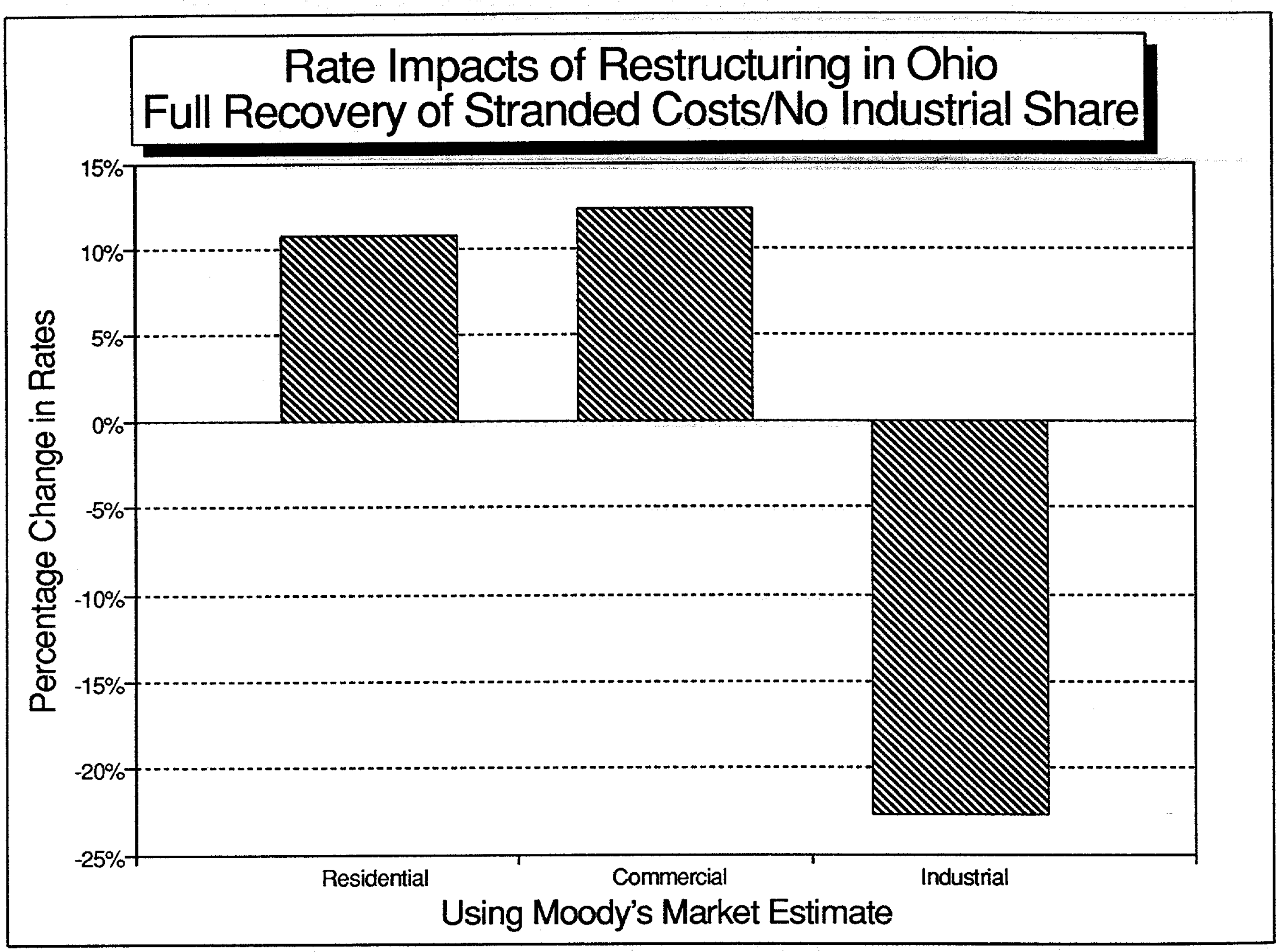

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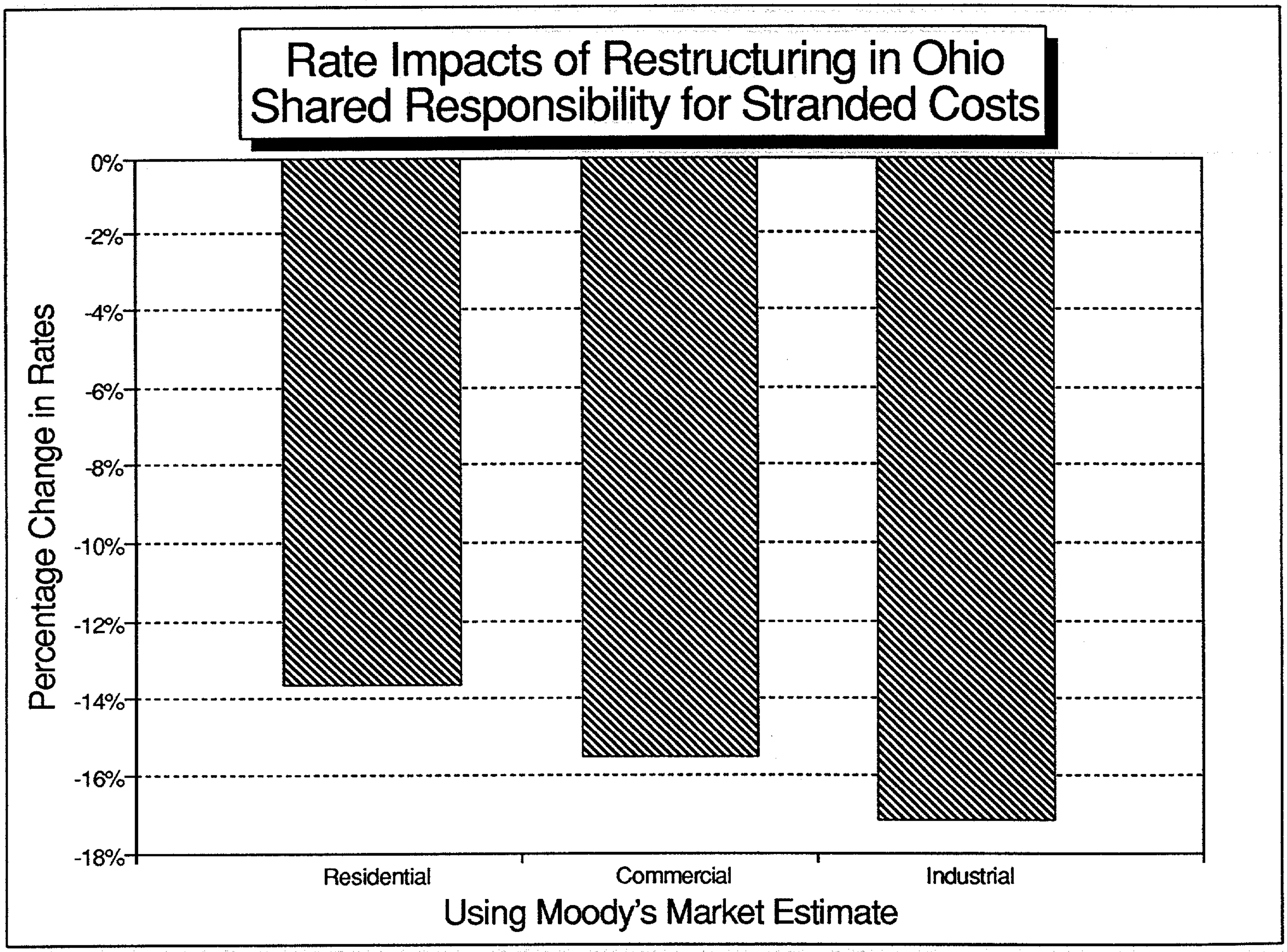

Source: *Electric Industry Restructuring in Ohio: Residential and Low Income Customer Impacts*, 1997.

RESTRUCTURING IN OHIO

There is no specific restructuring implementation process underway in Ohio at this time. House Bill 220 has recently been introduced in the legislature by Representative Amstutz to initiate discussion and consideration of competition and restructuring. This bill sets up a framework for proceeding, but does not include specific and detailed proposals. The Ohio Commission, like most commissions, is looking into the restructuring and competition situation and considering its options. It has convened a series of roundtable discussions of interested parties to discuss various approaches to restructuring.[3] It will also consider such issues as universal service for low-income customers. The current plan is to have recommendations developed by October 1, 1997.[4] Since there are no specific legislative or Commission derived restructuring scenarios at this time, we are not able to evaluate a specific Ohio restructuring plan.

Nevertheless, we fully expect that the scenarios we have addressed in this report will cover the range of approaches which Ohio might consider. We have included a range of stranded cost recovery from full to zero, we have included a range of industrial customer responsibility for stranded cost recovery from full to zero, and we have addressed both wholesale and retail competition. Furthermore, we have addressed the impacts of securitization as a cost-reduction adjunct to restructuring. We are confident that whatever proposals are set forward in Ohio can be given a preliminary evaluation using the range of scenarios we have set forward. More definitive answers, of course, will require a detailed review of the specific proposals at the time they are put forward.

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[3] Roundtable discussions are related to Ohio Energy Strategy Issue #37 and are related to Public Utility Commission of Ohio Docket No. 96-406-EL-COI.

[4] Personal communication with Dave Rinebolt of the Ohio Partners for Affordable Energy and Omar Farooq of the Ohio Department of Development.

INITIAL RATES BY CLASS

We first calculated the current average rates by customer class for the seven major Ohio utilities. These are shown in Table 1. All the comparisons in this report are based on these initial rates. The rates shown are for 1995, based on the utilities FERC Form 1 filings[5] which provide both sales and revenues by customer class. These average rates have rolled into them all the components of electricity rates including customer charges, demand charges for those customers so billed, on and off peak energy costs for time-of-use customers, etc. Thus, they are not the same as the tariffs filed with the Ohio Commission. The filed tariffs include, typically, customer charges, demand charges, energy charges, different rates for different blocks, etc. The average rates shown here are the total of all the revenues for each class (which are made up of all the elements listed above) divided by all the kWh sold to that class.

Table 1. Average 1995 Rates by Customer Class ($/kWh)

	Residential	Commercial	Industrial
Columbus & Southern	$0.0788	$0.0641	$0.0479
Cleveland Electric	$0.1104	$0.0947	$0.0654
Cincinnati G&E	$0.0773	$0.0683	$0.0462
Dayton P&L	$0.0867	$0.0694	$0.0509
Ohio Edison	$0.1057	$0.0947	$0.0622
Ohio Power	$0.0648	$0.0546	$0.0320
Toledo Edison	$0.1099	$0.1051	$0.0609

5 FERC Form 1: Annual Report of Major Electric Utilities, Licensees and Others, for the year ending 1995. Each of the seven utilities studied filed a FERC Form 1 in 1995.

ALLOCATION OF COSTS BY FUNCTION AND CLASS

In order to analyze the impact of restructuring of the electricity industry on customer costs we first had to develop estimates of how much of each customer class' rates were attributable to production, transmission, and distribution. This was necessary because each of those functions is likely to have its costs affected differently by restructuring.

- Production costs will move towards a market basis (with or without consideration of stranded costs);

- Overall transmission costs are unlikely to change significantly. This assumption is explained more fully in the later section on transmission costs;

- Overall distribution costs, while unlikely to change significantly, may be collected in different ways. Because different ways of collecting distribution costs will affect different customers unevenly, individual customers may see significant changes in their share of the distribution costs. Low-income customers may be especially hurt by these changes. These assumptions are explained more fully in the later section on distribution costs.

Using a cost allocation model developed by MSB (MSB Electric Restructuring Model, or MSB-ERM), we developed cost allocations based on categories and data from the utilities' 1995 FERC Form 1 filings. The FERC Form 1 provides cost data broken into many functional categories. It also provides sales and revenues by customer class. The MSB model provides estimates of the cost per kWh by class for production (both capital and operating costs), transmission, and distribution. Distribution costs are also developed on a per customer basis. The details of how the MSB model allocates costs are given in Appendix A. The results of the allocation, first by function alone, and then by function and class, are shown here. Differences in class load factors and in responsibility for distribution are reflected in the allocations.

We have developed a separate category for production administrative and general expenses (A&G) because we believe that, even if all power is purchased on the open market at market prices, there will still be a need for an administrative structure to coordinate and organize the purchase of power. The current utility production A&G expenses are a good proxy for the cost of that service. The market price of power should be compared to the cost of power from the utility *without* that A&G component, since it will presumably be paid by the customers over and above any market purchases of power.

The allocated costs shown here are at the customer level, not at the generator. Because of losses, the utility must produce more than the customer buys. Later, when we compare the cost of power produced by the utilities to the market cost of power, we will be comparing costs at the generator level rather than at the customer level. Costs at the customer level (on a per kWh basis) are higher than at the generator level because of the losses. The appropriate adjustments are made in the next section.

Table 2. Allocation of Costs by Function ($/kWh, at the customer level)

	Production			Transmission		Distribution	
	Capital	Operating	A&G	Capital	Operating	Capital	Operating
Columbus & Southern	$0.0149	$0.0219	$0.0027	$0.0032	$0.0026	$0.0102	$0.0066
Cleveland Electric	$0.0318	$0.0286	$0.0037	$0.0043	$0.0010	$0.0075	$0.0056
Cincinnati G&E	$0.0193	$0.0185	$0.0027	$0.0026	$0.0004	$0.0091	$0.0058
Dayton P&L	$0.0236	$0.0183	$0.0042	$0.0038	$0.0006	$0.0068	$0.0054
Ohio Edison	$0.0251	$0.0257	$0.0042	$0.0046	$0.0007	$0.0090	$0.0074
Ohio Power	$0.0085	$0.0197	$0.0020	$0.0027	$0.0009	$0.0041	$0.0035
Toledo Edison	$0.0276	$0.0312	$0.0043	$0.0023	$0.0008	$0.0081	$0.0053

Table 3a. Allocation of Costs by Function and Class ($/kWh, at the customer level) Residential Class

Residential	Production		Transmission	Distribution
	Capital	Operating		
Columbus & Southern	$0.0191	$0.0244	$0.0074	$0.0280
Cleveland Electric	$0.0386	$0.0319	$0.0064	$0.0334
Cincinnati G&E	$0.0265	$0.0211	$0.0040	$0.0257
Dayton P&L	$0.0317	$0.0221	$0.0058	$0.0271
Ohio Edison	$0.0384	$0.0295	$0.0079	$0.0299
Ohio Power	$0.0126	$0.0216	$0.0053	$0.0253
Toledo Edison	$0.0399	$0.0352	$0.0044	$0.0304

Table 3b. Allocation of Costs by Function and Class ($/kWh, at the customer level) Commercial Class

Commercial	Production		Transmission	Distribution
	Capital	Operating		
Columbus & Southern	$0.0191	$0.0244	$0.0074	$0.0133
Cleveland Electric	$0.0386	$0.0319	$0.0064	$0.0177
Cincinnati G&E	$0.0265	$0.0211	$0.0040	$0.0167
Dayton P&L	$0.0317	$0.0221	$0.0058	$0.0099
Ohio Edison	$0.0384	$0.0295	$0.0079	$0.0189
Ohio Power	$0.0126	$0.0216	$0.0053	$0.0151
Toledo Edison	$0.0399	$0.0352	$0.0044	$0.0256

Table 3c. Allocation of Costs by Function and Class ($/kWh, at the customer level) Industrial Class

Industrial	Production		Transmission	Distribution
	Capital	Operating		
Columbus & Southern	$0.0124	$0.0244	$0.0048	$0.0063
Cleveland Electric	$0.0287	$0.0319	$0.0048	$0.0000
Cincinnati G&E	$0.0187	$0.0211	$0.0028	$0.0036
Dayton P&L	$0.0219	$0.0221	$0.0040	$0.0029
Ohio Edison	$0.0237	$0.0295	$0.0049	$0.0041
Ohio Power	$0.0073	$0.0216	$0.0031	$0.0000
Toledo Edison	$0.0232	$0.0352	$0.0026	$0.0000

ABOVE-MARKET COSTS

Our next step was to estimate whether and how much the Ohio utilities' costs were above the expected market cost of power. We estimated above-market costs for production only. Production costs include both the capital cost and the operating cost related to the production of power. They do not include transmission and distribution costs. We have seen no references in the restructuring literature to any utility claims of above-market costs for either transmission or distribution. We are unaware of any utilities trying to claim recovery of stranded transmission or distribution costs.

We have used two estimates of the market price of power in the ECAR region. One is a study by Moody's Investors Service[6]. In this study, Moody's estimated the ten year average market price of power from 1995 to 2004, both for capacity and energy, in each of the North American Electric Reliability Council (NERC) reliability regions. Since Ohio is in the ECAR region, we have used the Moody's estimate of the market cost of capacity and energy for that region. The Moody's study estimated a market cost of capacity of $40 per kW-year and a market cost of energy of $0.017 per kWh. Moody's has recently issued a new report on stranded costs.[7] The new study looks more deeply into the stranded investment question and reaches slightly different conclusions. However, the new Moody's study continues to use the same market cost estimates as used in the 1995 study, suggesting that Moody's has seen no reason to change its estimate of market costs.

For a second estimate we used the cost of power from a combined cycle power plant. Most analysts studying the future wholesale markets for power have concluded that the highest cost which can be supported in the market place is the cost of building and operating the least expensive new power source. At this time the least expensive new power source is a gas-fired combined cycle plant. The estimated price of power from this type of unit is approximately $0.03 per kWh on a life cycle basis. While the Moody's estimate reflects the current make up of generating resources and thus represents a short-term to mid-term estimate of the market price, the combined cycle based cost represents a long-term maximum market price.

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6 "Stranded Costs Will Threaten Credit Quality of U.S. Electrics," Moody's Investors Service, August 1995. This is a report issued by Moody's to the general public.

7 "Moody's Calculates Little Change in Potential Stranded Investments," Moody's Investors Service, December 1996. This, too, is a report issued by Moody's to the general public.

Estimates of the market price of power have a major impact on the estimate of stranded cost, the cost of the transition to market pricing of electricity, and the long range cost of power. Unfortunately, market price estimates will remain just that -- estimates -- until a transformation to a deregulated market actually takes place. Given that uncertainty, we are fairly confident of our estimate of the long-range market price based on the cost of a combined cycle plant. Over the long run the market price must be related to the cost of providing power, and the combined cycle plant represents the best current estimate of the technology which will define the market. The short-term market price is more difficult to estimate. It is a function of how much excess capacity will be available to place in the market, how much power producers are willing to cut their margins in order to make deals, and how much recovery of investment will be allowed by Commissions (the more investment recovered through transition charges, the less that needs to be recovered in the market). There are other estimates besides the Moody's estimates. Eric Hirst and Les Baxter of Oak Ridge National Laboratory have studied market prices and stranded investment[8], but according to Baxter, the data used is dated and the methods are not as sophisticated as those used by Moody's and others.[9] Resource Data International (RDI) has recently released a study which includes detailed estimates of market prices. Unfortunately, that study is not available for detailed review. However, the total reported estimate of stranded investment in the RDI study is $143 billion for IOUs which is quite close to the $136 billion estimated by Moody's. This similarity suggests that the market price estimates are not very different.[10] It suggests that RDI's market price estimates are slightly lower than Moody's. Finally, we have been involved in analyzing restructuring proposals in Pennsylvania which include utility estimates of market prices for power (because estimates of market prices are necessary for calculating stranded costs which are a major issue in Pennsylvania). While not directly related to market prices in Ohio, the Pennsylvania market price estimates filed by the utilities do allow us to compare them to Moody's estimates for the PJM region (to which most of the Pennsylvania utilities belong). This comparison does not allow us to directly judge the Moody's ECAR market price estimate, but does allow us to judge the Moody's methodology. The Pennsylvania utilities market price estimates are very similar to those given by Moody's for PJM. For the period of overlap, 1999-2004, the Moody's estimate is $31.34 per MWH on a

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[8] L. Baxter and E. Hirst, *Estimating Potential Stranded Commitments for U.S. Investor-Owned Electric Utilities*, ORNL/CON-406, Oak Ridge National Laboratory, Oak Ridge, TN, January 1995.

[9] Personal communication from Les Baxter to Geoffrey Crandall, February 21, 1997.

[10] Reported in Electric Utility Week, March 10, 1997, page 15.

real levelized basis, while the PECO estimates average $30.86 per MWH, a difference of about 1.5%.

We also know that, under special circumstances, utilities are making deals to sell power at costs which are very low. For example, Wisconsin Electric Power Company recently agreed to sell power to non-jurisdictional retail customers in Illinois for a price including capacity cost of less than two cents per kWh. We do not believe that prices this low are indicative of a true market price, but instead are examples of prices being set for small amounts of excess power without the existence of a real market.

Based on these various considerations, we believe that use of the Moody's market price estimate of the near-term market price is reasonable. We do not believe that it will represent the longer term market price once the excess capacity in the system is more fully utilized, and we have used the combined cycle based market price for that purpose.

We expect, however, that when the utilities come to the Commission to make claims for recovery of stranded investment, they will make claims for market prices which are lower than those we have used. Lower market prices increase the amount of stranded investment that the utilities can attempt to recover through extra-market mechanisms. Thus, lower market price estimates are in the utilities interests. When the Commission evaluates utility stranded investment claims it will be important to scrutinize very carefully the assumed market prices.

Table 4 presents both sets of estimated market prices for each utility on a cost per kWh basis.

Table 4. Estimated Market Price of Power ($/kWh, at the generator level)

	Market Price of Capacity		Market Price of Energy	
	Based on Moody's	Based on Combined Cycle	Based on Moody's	Based on Combined Cycle
Columbus & Southern	$0.0073	$0.0090	$0.0170	$0.0210
Cleveland Electric	$0.0068	$0.0085	$0.0170	$0.0215
Cincinnati G&E	$0.0077	$0.0095	$0.0170	$0.0205
Dayton P&L	$0.0067	$0.0082	$0.0170	$0.0218
Ohio Edison	$0.0072	$0.0089	$0.0170	$0.0211
Ohio Power	$0.0064	$0.0079	$0.0170	$0.0221
Toledo Edison	$0.0068	$0.0084	$0.0170	$0.0216

The cost per kWh varies slightly between utilities because the utilities have different load factors which leads to the fixed capital cost being divided among a different number of kWh.

The market prices can now be compared to the utility costs. Tables 2 and 3a-c developed in the previous section show functionalized costs at the customer level. The market costs are at the generator level. These are on a different basis because of losses on the system between the generator and the customer. Therefore, an adjusted set of production costs must be developed which reflects the losses. This is shown in Table 5. For the reasons discussed in the previous section, these do not include administrative and general costs. The appropriate conversions will be made again (in reverse) when rates for different customer classes under different restructuring approaches are developed later in this report.

The costs shown in Table 5 are a snapshot look at the utility production costs as of 1995. Through the normal regulatory process of depreciation, the level of capital cost can be expected to decline over time. As a result, the above-market costs shown in Table 6 would also be expected to decline over time. Eventually, the above-market costs would go to zero. This would not, however, happen for a number of years. The question of changes in above-market costs over time are discussed further in a later section of this report, "The Long-Term Impacts of Restructuring." Additional discussion is provided in the section "Securitization -- a Long-Term Bond Approach to Stranded Costs."

Table 5. Allocation of Costs by Function ($/kWh, at the generator level) Utility Costs Without Administrative and General

	Production: Capital	Production: Operating
Columbus & Southern	$0.0140	$0.0217
Cleveland Electric	$0.0283	$0.0276
Cincinnati G&E	$0.0184	$0.0180
Dayton P&L	$0.0222	$0.0180
Ohio Edison	$0.0238	$0.0252
Ohio Power	$0.0082	$0.0196
Toledo Edison	$0.0261	$0.0314

The above market cost of power (for any of the estimated market prices) is the current cost of power minus the appropriate market price. Estimated above-market costs for the Ohio utilities are shown in Table 6.

Table 6. Above-Market Cost of Power ($ per kWh, at the generator level) Capital Plus Operating Costs Without Administrative and General

	Based on Moody's Market Price Estimate	Based on Combined Cycle Market Price
Columbus & Southern	$0.0114	$0.0056
Cleveland Electric	$0.0321	$0.0259
Cincinnati G&E	$0.0117	$0.0064
Dayton P&L	$0.0166	$0.0102
Ohio Edison	$0.0248	$0.0190
Ohio Power	$0.0043	($0.0023)
Toledo Edison	$0.0338	$0.0275

ALLOCATION OF ABOVE-MARKET COSTS

The key steps in estimating the impact of restructuring on various customers are determining how much of the above-market costs will be collected from customers, and how those costs will be allocated to each customer class. There is no single set way to do this. We have examined the impact resulting from various scenarios.

We looked at three separate scenarios for the collection of above-market costs from customers. From the perspective of the residential customers these can be considered a best case, a worst case, and a middle approach. All of these scenarios assume that the utility monopoly on the production of power no longer exists, and that all power is purchased in the competitive marketplace at the market price. These scenarios also assume that the utilities' above-market costs, to the extent that they are collected from the customers, are collected through the use of extra-market cost recovery mechanisms such as non-bypassable competitive transition charges.

- Best Case (Zero Recovery)

  In the best case for residential customers there is no collection of above-market costs. The full responsibility for above-market costs is borne by the stockholders. For utilities with above-market costs, this scenario produces the greatest savings for the customers.

- Worst Case (Full Recovery)

  In the worst case for residential customers there is full collection of above-market costs, but none of the capital related costs are allocated to the industrial class. They are entirely borne by the residential and commercial classes. Given the political clout which industrial customers have often wielded, it is possible that they will succeed in getting out from under their share of above-market costs, or at least the *capital* related portion of those costs. In fact, it is the desire of large industrial customers to avoid high utility costs caused by expensive plants which has, in many places, led to the initial demands for competition in the electric industry. We believe, however, that it is unlikely that industrial customers will be able to avoid paying their share of above-market *energy* related costs.[11]

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[11] Above market energy costs are those costs related to such things as fuel contracts, Independent Power Producer contracts, and the like which are more expensive than the cost of power in the market. Since these are directly related to the production of energy, and industrial customers are likely to

This worst case scenario for residential customers is essentially equivalent to the situation of allowing industrial customers to leave the system and purchase their power on the open market without charging them any type of exit or stranded cost fee. This has been a demand of many industrial customers for many years.

This scenario produces large savings for the industrial customers and leads to cost increases for the residential and commercial classes.

- Middle Approach (Half Recovery)

In the middle approach there is a sharing of the responsibility for above-market costs. Half of these costs are borne by the customers, while half are borne by the stockholders. Each customer class bears its fair responsibility for its share of the half of the costs borne by customers. This scenario produces savings for each customer class.

For each scenario there are two cases based on the assumption used for the market price of power. Thus, there are six separate scenarios. The production costs (sum of capacity and energy, including administrative and general) after allocation of above-market costs for these cases are shown in Tables 8a through 8f. Table 7 below summarizes the cases.

There is a new approach to recovery of above-market costs which has recently appeared and is being tested in California and Pennsylvania. This approach relies on the issuance of special bonds to reduce the cost to the customers of paying for stranded assets. These bonds, while not actually backed by government guarantees, are instead backed by a legal commitment to collecting the amortization payments from customers. As a result, backers claim that the bonds will be issuable at lower costs than regular utility debt. The utility uses the proceeds from the bonds to retire the stranded assets *from the rate base* (though not from actual service). The customers, rather than paying for the stranded assets as typical utility investment with a combination of debt and equity, pay instead a pure debt cost for the assets. In the California and Pennsylvania proposals the utilities are allowed full recovery of all above-market costs, and all customers are required to pay their share of that cost recovery through non-bypassable charges. This approach has the potential for reducing the customer cost of full stranded asset recovery, though there are potential drawbacks as well. We discuss this approach in some detail later in this report in a section titled "Securitization -- a Long-Term Bond Approach to Stranded Costs."

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continue taking energy after restructuring, it will be hard for these customers to avoid paying their share of these costs.

Table 7. Summary of Cases

Table	Market Price	Above-Market Cost Recovery	Industrial Share
Table 8a	Moody's	None	N/A
Table 8b	Moody's	Full	Zero
Table 8c	Moody's	Half	Full
Table 8d	Combined Cycle	None	N/A
Table 8e	Combined Cycle	Full	Zero
Table 8f	Combined Cycle	Half	Full

Table 8a. Production Cost After Restructuring
Market Price Based on Moody's Study
No Recovery of Above-Market Costs from Customers

	Residential	Commercial	Industrial
Columbus & Southern	$0.0295	$0.0295	$0.0260
Cleveland Electric	$0.0296	$0.0296	$0.0271
Cincinnati G&E	$0.0312	$0.0312	$0.0279
Dayton P&L	$0.0309	$0.0309	$0.0278
Ohio Edison	$0.0328	$0.0328	$0.0282
Ohio Power	$0.0288	$0.0288	$0.0247
Toledo Edison	$0.0307	$0.0307	$0.0262

Table 8b. Production Cost After Restructuring
Market Price Based on Moody's Study
Full Recovery of Above-Market Costs from Customers
Industrials Don't Pay Above-Market Capital Costs

	Residential	Commercial	Industrial
Columbus & Southern	$0.0451	$0.0451	$0.0309
Cleveland Electric	$0.0855	$0.0855	$0.0391
Cincinnati G&E	$0.0555	$0.0555	$0.0290
Dayton P&L	$0.0607	$0.0607	$0.0289
Ohio Edison	$0.0792	$0.0792	$0.0369
Ohio Power	$0.0389	$0.0389	$0.0273
Toledo Edison	$0.0976	$0.0976	$0.0414

Table 8c. Production Cost After Restructuring
Market Price Based on Moody's Study
Half Recovery of Above-Market Costs from Customers
Industrials Pay Fair Share of Above-Market Capital Costs

	Residential	Commercial	Industrial
Columbus & Southern	$0.0365	$0.0365	$0.0314
Cleveland Electric	$0.0501	$0.0501	$0.0439
Cincinnati G&E	$0.0394	$0.0394	$0.0339
Dayton P&L	$0.0423	$0.0423	$0.0359
Ohio Edison	$0.0503	$0.0503	$0.0407
Ohio Power	$0.0315	$0.0315	$0.0268
Toledo Edison	$0.0529	$0.0529	$0.0423

Table 8d. Production Cost After Restructuring
Market Price Based on Combined Cycle
No Recovery of Above-Market Costs from Customers

	Residential	Commercial	Industrial
Columbus & Southern	$0.0361	$0.0361	$0.0318
Cleveland Electric	$0.0369	$0.0369	$0.0339
Cincinnati G&E	$0.0375	$0.0375	$0.0335
Dayton P&L	$0.0381	$0.0381	$0.0344
Ohio Edison	$0.0398	$0.0398	$0.0342
Ohio Power	$0.0365	$0.0365	$0.0313
Toledo Edison	$0.0380	$0.0380	$0.0325

Table 8e. Production Cost After Restructuring
Market Price Based on Combined Cycle
Full Recovery of Above-Market Costs from Customers
Industrials Don't Pay Above-Market Capital Costs

	Residential	Commercial	Industrial
Columbus & Southern	$0.0447	$0.0447	$0.0325
Cleveland Electric	$0.0844	$0.0844	$0.0407
Cincinnati G&E	$0.0542	$0.0542	$0.0308
Dayton P&L	$0.0600	$0.0600	$0.0304
Ohio Edison	$0.0781	$0.0781	$0.0386
Ohio Power	$0.0348	$0.0348	$0.0287
Toledo Edison	$0.0957	$0.0957	$0.0428

Table 8f. Production Cost After Restructuring
Market Price Based on Combined Cycle
Half Recovery of Above-Market Costs from Customers
Industrial Customers pay Fair Share of Above-Market Costs

	Residential	Commercial	Industrial
Columbus & Southern	$0.0398	$0.0398	$0.0343
Cleveland Electric	$0.0537	$0.0537	$0.0472
Cincinnati G&E	$0.0426	$0.0426	$0.0366
Dayton P&L	$0.0460	$0.0460	$0.0392
Ohio Edison	$0.0538	$0.0538	$0.0437
Ohio Power	$0.0353	$0.0353	$0.0301
Toledo Edison	$0.0565	$0.0565	$0.0455

TRANSMISSION

We began our analysis of transmission by estimating the cost per kWh for transmission included in current rates by major customer class. We discussed previously (in the section "Allocation of Costs by Function and Class," and in more detail in Appendix A) how we allocated costs to various functions and rate classes. Using that approach we determined the following cost per kWh by rate class and by company.

Table 9. Transmission Costs by Customer Class ($/kWh, at the customer)

	Residential	Commercial	Industrial
Columbus & Southern	$0.0074	$0.0074	$0.0048
Cleveland Electric	$0.0064	$0.0064	$0.0048
Cincinnati G&E	$0.0040	$0.0040	$0.0028
Dayton P&L	$0.0058	$0.0058	$0.0040
Ohio Edison	$0.0079	$0.0079	$0.0049
Ohio Power	$0.0053	$0.0053	$0.0031
Toledo Edison	$0.0044	$0.0044	$0.0026

We have little reason to believe that a move towards restructured electricity markets will significantly affect the ongoing cost of transmission. Transmission is assumed in most restructuring models to remain as a natural monopoly. As a natural monopoly we assume that transmission will remain regulated. Transmission pricing will most likely be regulated primarily by the Federal Energy Regulatory Commission (FERC). While many state commissions are exploring alternatives to cost-of-service pricing such as performance-based regulation, FERC has given no indication that it intends to move away from cost-of-service pricing.

It is likely, however, that transmission companies will become operationally independent of production and distribution companies and will cover larger geographical areas. The melding of the transmission elements of the seven major Ohio utilities into a single entity is likely. This entity may be a single large company. A more likely change will be that transmission planning and operation will be coordinated over a wide range of companies covering a multi-state region. This is already beginning to happen with the recent proposals for the development of a Midwest Independent System Operator (ISO) which will stretch from West Virginia to

Missouri. Whether or not utilities will be able to continue to own and control their own transmission (subject to ISO operations) is unknown at this time.

Even given that the structure of the transmission companies and how they are regulated is subject to change, we still believe that significant changes in the cost of transmission are unlikely. Our reasons are the following:

- There is little or no stranded investment related to transmission.
- The overwhelming majority of transmission cost (77%) is for the recovery of capital related costs such as return on investment, taxes, and depreciation. No matter what the structure of the transmission companies becomes, these costs will still have to be recovered. Changes in the structure might affect the cost of capital slightly, but the impact on cost recovery is unlikely to be more than a few percent.
- Only about 3% of transmission costs in Ohio are for general administrative costs which are the usual targets of cost reductions under a performance-based system of regulation. Thus the likelihood of performance-based regulation significantly affecting the cost of transmission is small.

We have developed a proxy for the impact of a wide-area approach to transmission planning and operation by calculating a weighted average transmission cost for the seven major Ohio utilities (weighted by sales). We have calculated this average separately for each major rate class -- residential, commercial, and industrial. Tables 10 and 11 show the impact on each utility of a shift to statewide transmission pricing. As shown in Table 11, the impact of statewide averaging on the different Ohio utilities is not large. The largest impact for any utility and customer class is only about $0.002 per kWh.

Table 10. Statewide Blended Transmission Costs by Customer Class ($/kWh, at the customer)

Residential	$0.0062 per kWh
Commercial	$0.0062 per kWh
Industrial	$0.0040 per kWh

Table 11. Change in Transmission Costs by Customer Class from a Shift to Statewide Transmission Pricing ($/kWh, at the customer)

	Residential	Commercial	Industrial
Columbus & Southern	-$0.0012	-$0.0012	-$0.0008
Cleveland Electric	-$0.0002	-$0.0002	-$0.0008
Cincinnati G&E	+$0.0022	+$0.0022	+$0.0012
Dayton P&L	+$0.0004	+$0.0004	No Change
Ohio Edison	-$0.0017	-$0.0017	-$0.0009
Ohio Power	+$0.0009	+$0.0009	+$0.0009
Toledo Edison	+$0.0018	+$0.0018	+$0.0014

DISTRIBUTION

Under all of the restructuring proposals being discussed, distribution (the provision of customer connections to the electrical system) remains a regulated monopoly function. There is generally assumed to be little or no potential stranded investment in distribution, since there is little or no opportunity for a customer to move to a different supplier of distribution service. The only real potential is if the customer chooses to generate its own electricity and to disconnect from the grid. Otherwise, even a customer who provides much of its own power will most likely purchase the same connection service from the distribution utility. Over half (56%) of the cost of providing distribution services in Ohio is capital related -- cost of capital, depreciation, and taxes. One fifth (20%) is operations and maintenance of the distribution system, and the rest (24%) is general administrative costs related to distribution.

It is unlikely that the *overall cost* of distribution will change very much from restructuring. There are efforts to develop lower cost approaches to providing distribution service such as the use of various forms of distributed resources which inject power into the system close to the customer so as to minimize the need for new distribution facilities. However, this approach is expected to moderate the general increase in distribution costs rather than to change the overall cost of distribution in a major way.

While the overall cost of distribution is not expected to change very much from restructuring, the *allocation of those costs* to different customers and customer classes *is* likely to change significantly. Several different elements of restructuring are likely to lead to pressures to change distribution cost allocation.

A distribution-only utility collecting its revenues based almost entirely on a cost per kWh used by the customer faces the potential for an extremely variable revenue stream as customer usage varies. While this is currently true for a vertically integrated utility, current vertically integrated utilities generally have a fairly significant portion of their costs (for fuel) which also vary with customer usage. Thus, under the current structure, overall utility net revenues are somewhat buffered. A distribution-only utility will not have that buffer of fuel costs. Therefore, there has been some discussion in the restructuring debate on the wisdom of shifting all or some of the distribution utility's revenue away from a kWh usage based rate to a customer charge.[12] A shift to distribution pricing more heavily based on a customer charge

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[12] See, for example, the testimony of Dr. Miles O. Bidwell, Jr. on behalf of the Independent Power Producers of New York and ENRON Capital and Trade Resources in New York State Public Service Commission Case 96-E-0900, In

could have serious impacts on low usage customers, many of whom may be low income. A customer who uses half the average usage of the residential class could end up paying almost twice as much per kWh for distribution services as an average usage customer if the entire cost were in the customer charge.

Another regulatory change that may affect the allocation of distribution costs is a shift toward performance-based ratemaking and price cap regulation. Under many of these approaches the distribution utility will have a great deal of freedom to offer price discounts to customers who are considered to have a high likelihood of leaving the system and/or making other arrangements for power. If the price cap is applied as a broad average rather than on a customer specific basis, the utility may be able to shift costs from customers who have multiple power options and are highly sensitive to rates to customers who have fewer options and are less able to respond to higher rates. In general it is the larger customers and the industrial classes that have more options and the residentials (and especially low-income residentials) who have fewer options. Thus it is likely that a move to performance-based ratemaking and price caps will exacerbate the impact of a shift to greater fixed charges on low-income residential customers.

Modeling the impact of price caps on the allocation of distribution costs is extremely difficult. To do so would require good estimates of elasticity of demand by customer class, usage level, and income, and a clearly set forth price cap proposal. None of these is available for Ohio at this time. In a later section of this report we look at the impact of regulatory restructuring on low-income customers as compared to average residential customers. That analysis focuses on the shift in rate structure to collect more of the allocated costs from higher fixed monthly charges. A price cap approach to distribution regulation will exacerbate this problem by allocating more of the overall cost to low-income and other residential customers.

Table 12 shows the distribution costs for residential and commercial customers both on a per kWh basis and a per customer basis. Table 13 shows the average usage per customer.

Many of the approaches under consideration for collecting above-market power costs from customers rely on the use of stranded asset charges levied at the distribution level (in order to insure that all customers pay their share). These generation related charges are *not* included in the distribution costs discussed here. While they will probably be collected through the distribution utility, they are

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the Matter of Orange and Rockland Utilities, Inc, April 25, 1997. This is one of several restructuring cases in New York. Dr. Bidwell gave similar testimony several times.

generation related costs and are included in the generation costs previously discussed.

Table 12. Distribution Costs by Customer Class (at the customer)

	Residential		Commercial	
	per KWH	per Customer	per KWH	per Customer
Columbus & Southern	$0.0280	$295	$0.0133	$1,412
Cleveland Electric	$0.0334	$253	$0.0177	$1,462
Cincinnati G&E	$0.0257	$295	$0.0167	$1,376
Dayton P&L	$0.0271	$312	$0.0099	$808
Ohio Edison	$0.0299	$260	$0.0189	$1,237
Ohio Power	$0.0253	$286	$0.0151	$930
Toledo Edison	$0.0304	$255	$0.0256	$1,702

Table 13. Average Usage per Customer

	Residential	Commercial
Columbus & Southern	10,546	106,230
Cleveland Electric	7,569	82,626
Cincinnati G&E	11,457	82,634
Dayton P&L	11,518	82,003
Ohio Edison	8,680	65,434
Ohio Power	11,307	61,538
Toledo Edison	8,385	66,459

IMPACT ON THE AVERAGE CUSTOMER

We have constructed the production cost, transmission cost, and distribution cost for the residential, commercial, and industrial customer classes under the various restructuring scenarios. We can now combine the elements to determine the post-restructuring cost per kWh by class, and the percentage change in rates from the starting point. In this section we will assume the average residential, commercial, and industrial customer and use the average per customer costs.

As discussed in the previous section, performance-based regulation with price caps for distribution utilities will tend to cause a shift in the allocation of distribution costs from industrial customers to residential and commercial customers. However, the amount of distribution cost currently charged to industrial customers is small -- on the order of five percent of distribution cost, compared to approximately one third of the kWh sales being industrial. As a result, the impact of shifting a portion of that small share from the industrial class to the residential and commercial class would be small.

However, as we discussed in the previous section on distribution costs, one of the approaches being discussed for distribution costs is to charge a much larger portion of the cost as a customer charge, with a resultant major impact on the rates of low usage customers, many of whom may be low income. We will analyze this scenario in the next section of the report.

Tables 14a through 14f show the resultant class rates for the scenarios as discussed in the section on Allocation of Above-Market Costs (and set forth in Table 7). Tables 15a through 15f compare the restructured rates to the previous rates and show the percentage change for each class.

Table 14a. Total Cost After Restructuring
Market Price Based on Moody's Study
No Recovery of Above-Market Costs from Customers

	Residential	Commercial	Industrial
Columbus & Southern	$0.0636	$0.0489	$0.0363
Cleveland Electric	$0.0692	$0.0535	$0.0312
Cincinnati G&E	$0.0631	$0.0540	$0.0355
Dayton P&L	$0.0641	$0.0469	$0.0348
Ohio Edison	$0.0689	$0.0578	$0.0364
Ohio Power	$0.0603	$0.0501	$0.0287
Toledo Edison	$0.0673	$0.0625	$0.0303

Table 14b. Total Cost After Restructuring
Market Price Based on Moody's Study
Full Recovery of Above-Market Costs from Customers
Industrials Don't Pay Above-Market Capital Costs

	Residential	Commercial	Industrial
Columbus & Southern	$0.0793	$0.0646	$0.0412
Cleveland Electric	$0.1250	$0.1093	$0.0431
Cincinnati G&E	$0.0874	$0.0783	$0.0366
Dayton P&L	$0.0939	$0.0767	$0.0359
Ohio Edison	$0.1154	$0.1043	$0.0451
Ohio Power	$0.0704	$0.0602	$0.0314
Toledo Edison	$0.1341	$0.1293	$0.0454

Table 14c. Total Cost After Restructuring
Market Price Based on Moody's Study
Half Recovery of Above-Market Costs from Customers
Industrials Pay Fair Share of Above-Market Capital Costs

	Residential	Commercial	Industrial
Columbus & Southern	$0.0706	$0.0559	$0.0417
Cleveland Electric	$0.0897	$0.0740	$0.0479
Cincinnati G&E	$0.0713	$0.0622	$0.0414
Dayton P&L	$0.0756	$0.0584	$0.0429
Ohio Edison	$0.0864	$0.0754	$0.0489
Ohio Power	$0.0630	$0.0528	$0.0308
Toledo Edison	$0.0895	$0.0847	$0.0463

Table 14d. Total Cost After Restructuring
Market Price Based on Combined Cycle
No Recovery of Above-Market Costs from Customers

	Residential	Commercial	Industrial
Columbus & Southern	$0.0702	$0.0555	$0.0421
Cleveland Electric	$0.0765	$0.0608	$0.0379
Cincinnati G&E	$0.0694	$0.0603	$0.0411
Dayton P&L	$0.0714	$0.0542	$0.0414
Ohio Edison	$0.0759	$0.0649	$0.0424
Ohio Power	$0.0679	$0.0578	$0.0353
Toledo Edison	$0.0746	$0.0698	$0.0366

Table 14e. Total Cost After Restructuring
Market Price Based on Combined Cycle
Full Recovery of Above-Market Costs from Customers
Industrials Don't Pay Above-Market Capital Costs

	Residential	Commercial	Industrial
Columbus & Southern	$0.0789	$0.0642	$0.0427
Cleveland Electric	$0.1239	$0.1082	$0.0447
Cincinnati G&E	$0.0861	$0.0770	$0.0384
Dayton P&L	$0.0932	$0.0760	$0.0374
Ohio Edison	$0.1142	$0.1032	$0.0467
Ohio Power	$0.0662	$0.0561	$0.0327
Toledo Edison	$0.1323	$0.1275	$0.0468

Table 14f. Total Cost After Restructuring
Market Price Based on Combined Cycle
Half Recovery of Above-Market Costs from Customers
Industrial Customers pay Fair Share of Above-Market Costs

	Residential	Commercial	Industrial
Columbus & Southern	$0.0739	$0.0592	$0.0446
Cleveland Electric	$0.0933	$0.0776	$0.0513
Cincinnati G&E	$0.0745	$0.0654	$0.0442
Dayton P&L	$0.0792	$0.0620	$0.0462
Ohio Edison	$0.0899	$0.0789	$0.0519
Ohio Power	$0.0668	$0.0566	$0.0341
Toledo Edison	$0.0931	$0.0883	$0.0495

Table 15a. Change in Rates After Restructuring
Market Price Based on Moody's Study
No Recovery of Above-Market Costs from Customers

	Residential	Commercial	Industrial
Columbus & Southern	-19.3%	-23.7%	-24.3%
Cleveland Electric	-37.3%	-43.5%	-52.3%
Cincinnati G&E	-18.4%	-20.9%	-23.1%
Dayton P&L	-26.0%	-32.5%	-31.7%
Ohio Edison	-34.9%	-38.9%	-41.6%
Ohio Power	-6.9%	-8.2%	-10.2%
Toledo Edison	-38.8%	-38.8%	-50.3%

Table 15b. Change in Rates After Restructuring
Market Price Based on Moody's Study
Full Recovery of Above-Market Costs from Customers
Industrials Don't Pay Above-Market Capital Costs

	Residential	Commercial	Industrial
Columbus & Southern	0.6%	0.7%	-13.9%
Cleveland Electric	13.3%	15.5%	-34.1%
Cincinnati G&E	13.0%	14.7%	-20.8%
Dayton P&L	8.4%	10.4%	-29.6%
Ohio Edison	9.1%	10.2%	-27.6%
Ohio Power	8.6%	10.2%	-1.8%
Toledo Edison	22.1%	23.1%	-25.4%

Table 15c. Change in Rates After Restructuring
Market Price Based on Moody's Study
Half Recovery of Above-Market Costs from Customers
Industrials Pay Fair Share of Above-Market Capital Costs

	Residential	Commercial	Industrial
Columbus & Southern	-10.4%	-12.8%	-12.9%
Cleveland Electric	-18.8%	-21.9%	-26.7%
Cincinnati G&E	-7.8%	-8.9%	-10.2%
Dayton P&L	-12.8%	-16.0%	-15.8%
Ohio Edison	-18.3%	-20.4%	-21.5%
Ohio Power	-2.8%	-3.3%	-3.6%
Toledo Edison	-18.6%	-19.4%	-24.0%

Table 15d. Change in Rates After Restructuring
Market Price Based on Combined Cycle
No Recovery of Above-Market Costs from Customers

	Residential	Commercial	Industrial
Columbus & Southern	-10.9%	-13.4%	-12.2%
Cleveland Electric	-30.7%	-35.8%	-42.0%
Cincinnati G&E	-10.3%	-11.6%	-11.1%
Dayton P&L	-17.6%	-22.0%	-18.8%
Ohio Edison	-28.2%	-31.5%	-31.9%
Ohio Power	4.9%	5.8%	10.6%
Toledo Edison	-32.1%	-33.6%	-40.0%

Table 15e. Change in Rates After Restructuring
Market Price Based on Combined Cycle
Full Recovery of Above-Market Costs from Customers
Industrials Don't Pay Above-Market Capital Costs

	Residential	Commercial	Industrial
Columbus & Southern	0.0%	0.1%	-10.8%
Cleveland Electric	12.3%	14.3%	-31.6%
Cincinnati G&E	11.3%	12.8%	-16.9%
Dayton P&L	7.6%	9.4%	-26.6%
Ohio Edison	8.0%	8.9%	-24.9%
Ohio Power	2.3%	2.3%	2.4%
Toledo Edison	20.4%	20.4%	-23.1%

Table 15f. Change in Rates After Restructuring
Market Price Based on Combined Cycle
Half Recovery of Above-Market Costs from Customers
Industrial Customers pay Fair Share of Above-Market Costs

	Residential	Commercial	Industrial
Columbus & Southern	-6.2%	-7.6%	-6.9%
Cleveland Electric	-15.5%	-18.0%	-21.6%
Cincinnati G&E	-3.7%	-4.2%	-4.2%
Dayton P&L	-8.6%	-10.7%	-9.3%
Ohio Edison	-14.9%	-16.7%	-16.6%
Ohio Power	3.1%	3.7%	6.8%
Toledo Edison	-15.3%	-15.9%	-18.8%

IMPACT ON THE LOW INCOME RESIDENTIAL CUSTOMER

The previous section of this report is based on the average customer in each class. However, low income customers use less electricity than the typical residential customer. Under current rate structures, this does not significantly affect their electricity rate. The existence of a monthly customer charge causes the average per kWh cost for the low usage customer to be slightly higher than the average, but the effect is small since the monthly customer charge is comparatively small. As we discussed in the section on distribution, there are proposals to collect a much greater portion of distribution costs through increased customer charges. If this occurs, the bills paid by low usage customers for distribution services may go up dramatically.

In this section of the report we analyze a low usage residential customer using electricity at only 81.5 percent of the class average. This reduced level of usage is based on a report prepared by the Energy Information Administration of the Department of Energy.[13] We attempted to get Ohio specific data on electricity usage of low-income customers with little success. We were able to obtain estimates of the average usage for low-income customers participating in the weatherization assistance program (WAP) for two utilities -- Centerior Gas and Electric (CGE) and Dayton Power and Light (DPL).[14] For CGE, the estimate is that the WAP eligible customers use 74% of the average residential customer usage. For DPL, the figure is 84%. We also received information suggesting that Percentage of Income Plan (PIP) eligible customers use essentially the same amount of electricity as average customers. Given the paucity of data for Ohio as a whole and the uncertainty of those data which are available, we decided to use the national level data as the best indicator of low-income power usage.

We also assume that the monthly customer charge is set to recover 50 percent of the cost of distribution. While 50 percent is just an assumption, it is based in part on the fact that slightly more than half (56%) of the distribution costs for Ohio utilities are fixed costs related to the recovery of capital costs, depreciation, and taxes. The rest are split between operations and maintenance and general administrative costs.

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[13] Table 5.4, *Household Energy Consumption and Expenditures 1993*, Energy Information Administration DOE/EIA-0321(93), October 1995. We compared the average electricity usage for households eligible for federal assistance with the average usage for all households.

[14] Personal communication from Michael Blasnik, Proctor Engineering, Subcontractor to the Ohio Department of Development.

As we discussed earlier, a shift to performance-based ratemaking or price cap regulation will tend to cause a shifting of costs from the industrial and commercial classes and from larger customers to the residential class and smaller customers. This effect is not specifically analyzed in this section because the parameters leading to such a shift are dependent on the specific regulatory approach adopted. However, it is clear that this effect will exacerbate the impact on low-income customers.

Table 16 shows the current average cost of distribution for the residential class.

Table 16. Distribution Costs for the Average Residential Customer (per kWh, at the customer level)

Columbus & Southern	$0.0280
Cleveland Electric	$0.0334
Cincinnati G&E	$0.0257
Dayton P&L	$0.0271
Ohio Edison	$0.0299
Ohio Power	$0.0253
Toledo Edison	$0.0304

In contrast, Table 17 shows the cost per kWh for a low usage residential customer assuming that distribution rates are structured with a 50 percent customer charge component as we discussed above. Table 17 also shows the *incremental* cost per kWh for distribution and the percentage rate impact for low usage customers compared to the average customer.

Table 17. Distribution Costs for the Low Usage Residential Customer (per kWh, at the customer level)

	Cost per kWh	Increase in Cost	Percent Increase in Rates
Columbus & Southern	$0.0312	$0.0032	4.0%
Cleveland Electric	$0.0372	$0.0038	3.4%
Cincinnati G&E	$0.0286	$0.0029	3.8%
Dayton P&L	$0.0302	$0.0031	3.5%
Ohio Edison	$0.0333	$0.0034	3.2%
Ohio Power	$0.0282	$0.0029	4.4%
Toledo Edison	$0.0339	$0.0035	3.1%

In summary, the low-income, low-usage residential customers face the potential for a significant *additional* rate increase of three to four percent compared to the average residential customer if distribution rates are restructured to place a larger portion of the costs on a customer charge basis. The larger the share shifted to the customer charge, the greater the additional rate increase for low-income customers. Other regulatory changes which allow for more rate flexibility on the part of distribution utilities are likely to worsen the problem.

STRANDED BENEFITS

The main focus of this paper so far has been on stranded assets -- those generating assets where the cost of power is greater than the market value of that power. The major focus of restructuring discussions has been on how to deal with the collection and allocation of stranded asset costs. However, there is another category of costs which must also be dealt with in the face of restructuring. This is the category of *stranded benefits*. Stranded benefits is the term generally used to describe expenditures made by utilities for what is loosely viewed as the public good. These might include such things as payments for research and development not expected to bring immediate payback, set-asides for renewable energy development, environmental clean-up beyond standards, and low-income programs. There is a general belief that, under utility restructuring, these types of programs are unlikely to be funded unless there is a mandate requiring that they be funded. Many policy makers believe that an industry of such national size and importance as the electric utilities must continue to be involved in these non-profit-generating activities (either directly or as a funding source). The most common approach suggested for dealing with stranded benefits is the use of a *systems benefit charge* (SBC). This is a charge collected by the distribution company which must be paid by *all* electricity users and cannot be bypassed.[15]

In this paper we will focus on those stranded benefits directly related to low-income customers. Low-income customers face many problems related to their use of energy. The key problem is affordability; current programs are aimed at both reducing the level of energy usage of low-income customers (who often have very inefficient energy using stock) and helping them to pay for energy they use. Both parts of the programs are important for helping low-income customers.

Current estimates are that electric utility expenditures in Ohio on various low-income weatherization and assistance programs total approximately $50,500,000.[16] These expenditures include low-income discounts, fuel assistance funds, and demand-side management programs to assist the low-income customers, and include funds spent for electricity, natural gas, and other fuel assistance. To get a sense of what this figure represents vis a vis the current cost of electricity, we compare it to both the total retail expenditures on electricity in Ohio and to retail sales. In 1995

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[15] This was reviewed and discussed at the May 15, 1997 meeting of the Ohio Legislatures - Joint Committee on Electricity Restructuring.

[16] This figure is based on Public Utility Commission of Ohio Data as supplied by Omar Farooq of the Ohio Department of Development in an August 29, 1997 letter.

retail sales in Ohio by the seven major investor-owned utilities were approximately 129 billion kWh. Retail revenues for these companies were approximately $8.76 billion. The low-income expenditures account for approximately $0.00039 per kWh, and 0.57 percent of revenues.

We believe that whatever restructuring rules are adopted will include requirements for the continuation of low-income assistance programs. While we cannot tell the exact nature of the programs, we have assumed that the level of funding will remain similar to the existing levels. We have not made any adjustment to the near-term and mid-term calculations of rates to reflect the stranded benefits of low-income programs, because the size of the other transition costs far outweigh the size of the low-income program costs. However, for our analysis of the long-term in which we have assumed that transition costs are no longer present in the rates, we have added a cost element of $0.00039 per kWh to reflect the stranded benefit cost of low-income programs. The impact on typical customers is very small.

Given the potential impact of restructuring on low-income customers, it may be necessary to increase the level of funding for low-income weatherization and assistance programs. This is especially true since the overall level of funding for low-income weatherization and assistance programs has been dropping in recent years. While we will not in this report propose a more appropriate level of low-income weatherization and assistance funding at this time, the impact of a higher level is straightforward to calculate. Each additional $10 million of low-income weatherization and assistance funded through a systems benefit charge would cost $0.000078 per kWh, and would equal 0.11 percent of current revenues.

Finally, there are also proposals to use system benefit charges to fund other programs such as demand-side management, renewable resources, and long-term research and development. To the extent that the SBC is used to fund these programs, the cost impact would be the same $0.000078 per kWh for each $10 million of program as calculated above.

LONG-TERM IMPACTS OF RESTRUCTURING

Much of the analysis so far in this report focuses on the near-term to mid-term (through approximately the next seven to ten years). This is a period in which we expect to see utilities collecting whatever transition costs to the deregulated power market are allowed by regulators. The major transition costs are expected to be recovery of above-market or stranded costs.

In the longer term (after seven to ten years) we expect the following changes in cost recovery for the Ohio utilities. The basis for many of these expectations are discussed in previous sections of this report.

1. Above-market stranded investment costs will have been fully recovered;

2. Whatever excess capacity is currently in the generation mix will be either fully utilized or retired;

3. Transmission will have become a geographically broad-based system, most likely independent of the current utilities (at least functionally);

4. Approximately half of the costs of distribution will be collected on a customer charge basis;

5. Some sort of system benefit charge will be collected to pay for low-income programs. In these calculations we have assumed low-income programs at the current level of expenditure. Different levels of expenditures would lead to slight additions to, or subtractions from, the long-term costs we develop here.

These changes will lead to a different cost picture from that set forth earlier for the near-term and mid-term period.

The first change means that questions of how to allocate above-market cost recovery between stockholders and customers and between different customer classes will no longer matter. There will no longer be above-market costs to recover.

The second change means that the market price of power will no longer be driven by the existing mix of generating plants. Instead it will be driven by the cost of entry into the market. Current estimates of the nature of new generation suggest that the dominant technology will be natural gas-fired turbines, most likely combined cycle turbines. These combine low capital cost with high efficiency. The cost of power (capital plus operating) from these new combined cycle plants is expected to be approximately \$0.03 per kWh.[17] This cost is somewhat higher than the Moody's estimate used for the near-term to mid-term market cost of power.

The third change means that the cost of transmission should be reasonably uniform over a wide geographical area. This is not different from the approximation we used for our near-term to mid-term estimate in which we calculated a sales-weighted average cost of transmission for Ohio. While the averaging may actually take place over a wider geographical area in the long-term, we believe that the Ohio average is a reasonable one to use for this analysis.

The fourth change means that the cost of distribution for low-usage customers is likely to be higher than current levels. Since low-income customers are, on average, low-usage customers, they will be hurt by this change.

The fifth change adds a small systems benefit charge to pay for low-income programs. The impact of this charge on overall rates will be small.

However, this discussion of assumptions and changes does not address what is likely to be the biggest question in the post-transition period -- the allocation of generation costs between different customers and customer classes. We know that the average cost of power in the long-term power markets will be less than the average cost of generation at the current time for Ohio utilities (since all except Ohio Power have generation costs above the combined cycle market price -- see the earlier section "Above-Market Costs"). Thus, for all but Ohio Power there will be savings in generation costs. The question is, how will those savings be allocated? We have developed two scenarios to approach this problem. The two scenarios can be loosely correlated to a wholesale competition approach and a retail competition approach.

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[17] The cost is estimated as follows. The capital cost is approximately \$595 per kW, with an annual real levelized carrying charge rate of 10%, for an annual capacity cost of \$59.50 per kW-year. At an 80% capacity factor, the capital cost is \$0.008 per kWh. The heat rate is expected to be approximately 7000 BTU per kWh. The price of gas is expected to be approximately \$2.50 per MMBTU. This gives a fuel cost of approximately \$0.0175 per kWh. O&M costs add about another \$0.005 per kWh, for a total of approximately \$0.03 per kWh. See, for example, testimony of Scott T. Jones in the Pennsylvania Power and Light Company restructuring case in Pennsylvania, Docket R00973954. Other sources of interest are EPRI Technical Assessment Guides and the Wisconsin Advance Plan 7 filings.

In the wholesale competition approach we assumed that there would be full competition for the producers of power. The competitively produced and marketed power would be purchased by utilities who maintained a monopoly right to serve customers in their assigned service territory. Customers would not have the right to arrange their own power purchases independently of the utilities. At the retail level power would be priced based on cost of service principles. Under this approach all customers would share in the savings in generation costs.

In the retail competition approach we assumed that the utilities would no longer maintain a monopoly right to serve any retail customers. Retail customers would be free to make the best deals possible with any supplier. Under this approach whichever customers were the best bargainers with the most market clout would get the best deals and the lowest prices.

The resultant production costs by customer class from these two approaches are very different. In the next two sub-sections we examine the two approaches in more detail.

Wholesale Competition

The underlying assumption in our wholesale competition scenario is that the competitive market for generation provides power for the retail utilities who then sell that power to retail customers under a regulated monopoly structure. This scenario assumes that retail customers will not have a choice of suppliers and will not be able to make their own power arrangements. Under this approach the cost of power purchased by the regulated retail monopoly will be allocated to customers under general cost of service principles. Since the power will be priced with a capacity and an energy component, different customer classes will pay different prices based on differing usage patterns. Industrial customers who typically have high load factors will pay less per kWh than residential customers who have lower load factors. But each class will pay the same capacity cost per kW and energy cost per kWh.

The resultant production costs per kWh for the different customer classes under the wholesale competition scenario are shown in Table 18.

Table 18. Long-Term Production Costs After Restructuring Under Wholesale Competition
($/kWh, at the Customer, Including Administrative and General)

	Residential	Commercial	Industrial
Columbus & Southern	$0.0361	$0.0361	$0.0318
Cleveland Electric	$0.0369	$0.0369	$0.0339
Cincinnati G&E	$0.0375	$0.0375	$0.0335
Dayton P&L	$0.0381	$0.0381	$0.0344
Ohio Edison	$0.0398	$0.0398	$0.0342
Ohio Power	$0.0365	$0.0365	$0.0313
Toledo Edison	$0.0380	$0.0380	$0.0325

Retail Competition

As described above, the underlying assumption in the retail competition scenario is that customers are free to make whatever deals with suppliers they are able to negotiate. The best bargainers with the most market clout will get the best deals.

It is generally believed that the customers with the most market clout, best bargaining ability, and the size to strike the best deals will be the industrial customers. This is borne out by experience in both telephone and gas deregulation where the largest portion of the savings have gone to the largest customers. We have based our analysis of how costs are likely to be shared on recent analyses of the results of natural gas deregulation. A study by Geoffrey Crandall and Rajnish Barua[18] looked at changes in the prices of natural gas for various customer classes in the wake of deregulation in 1984. Crandall and Barua concluded that between 1984 and 1995 the price of gas for residential customers declined slightly (by 1%), while the price of gas for industrial customers declined by 37% over the same period. Commercial gas prices declined by an intermediate amount (10%).

[18] Geoffrey Crandall and Rajnish Barua, "Do We Really Want to Jump Into Restructuring of the Electric Industry Before Examining What Happened in the Natural Gas Industry?", Tenth NARUC Biennial Regulatory Information Conference, 1996.

Based on the results of natural gas deregulation we have taken as our starting point for retail competition the assumption that residential customers will see little or no savings in their power costs, that industrial customers will see the greatest savings, and commercial customers will be in the middle. However, it must be noted that the Crandall/Barua analysis is done in current, not real dollars. The costs in this study are shown in real dollars. Therefore, to be consistent, an assumption of no savings in current dollars (as the Crandall/Barua study found for residential customers) means a reduction in real dollar costs of 25.6% over a ten year period. That was our assumption for residential production costs. We assumed an additional 10% reduction for commercial customers. The rest of the savings were all allocated to the industrial customers. Since the retail competition scenario allows customers to purchase from any supplier they wish to use, we assumed that prices across the state would be uniform. After adjusting for losses, and adding back the administrative and general costs, we arrived at the costs shown in Table 19.

Table 19. Long-Term Production Costs After Restructuring Under Retail Competition
($/kWh, at the Customer, Including Administrative and General)

	Residential	Commercial	Industrial
All Ohio Utilities	$0.0413	$0.0374	$0.0271

Other Long-Term Costs

Having developed the cost of power for the two scenarios we analyzed, it is necessary to develop the rest of the costs which customers will see -- transmission, distribution, and systems benefit charges. These costs were developed following the principles discussed above.

Table 20. Long-Term Transmission Costs
($/kWh, at the Customer)

Residential	$0.0062 per kWh
Commercial	$0.0062 per kWh
Industrial	$0.0040 per kWh

Table 21. Long-Term Distribution Costs (at the customer)

	Residential		Commercial	
	per KWH	per Customer	per KWH	per Customer
Columbus & Southern	$0.0280	$295	$0.0133	$1,412
Cleveland Electric	$0.0334	$253	$0.0177	$1,462
Cincinnati G&E	$0.0257	$295	$0.0167	$1,376
Dayton P&L	$0.0271	$312	$0.0099	$808
Ohio Edison	$0.0299	$260	$0.0189	$1,237
Ohio Power	$0.0253	$286	$0.0151	$930
Toledo Edison	$0.0304	$255	$0.0256	$1,702

Table 22. Long-Term Systems Benefit Charges ($/kWh, at the Customer)

	Residential	Commercial	Industrial
Columbus & Southern	$0.0004	$0.0004	$0.0004
Cleveland Electric	$0.0004	$0.0004	$0.0004
Cincinnati G&E	$0.0004	$0.0004	$0.0004
Dayton P&L	$0.0004	$0.0004	$0.0004
Ohio Edison	$0.0004	$0.0004	$0.0004
Ohio Power	$0.0004	$0.0004	$0.0004
Toledo Edison	$0.0004	$0.0004	$0.0004

Overall Long-Term Cost Impact

We now combine the various cost elements to determine the long-term cost of power. We show two sets of tables -- one set assuming wholesale competition and one set assuming retail competition.

Table 23. Long-Term Total Cost After Restructuring for Average Customers Under Wholesale Competition
($/kWh, at the Customer)

	Residential	Commercial	Industrial
Columbus & Southern	$0.0705	$0.0558	$0.0424
Cleveland Electric	$0.0768	$0.0611	$0.0382
Cincinnati G&E	$0.0697	$0.0606	$0.0414
Dayton P&L	$0.0717	$0.0545	$0.0417
Ohio Edison	$0.0762	$0.0652	$0.0427
Ohio Power	$0.0682	$0.0581	$0.0356
Toledo Edison	$0.0749	$0.0701	$0.0369

Table 24. Long-Term Change in Rates After Restructuring for Average Customers Under Wholesale Competition
(Compared to current rates)

	Residential	Commercial	Industrial
Columbus & Southern	-10.6%	-13.0%	-11.7%
Cleveland Electric	-30.5%	-35.5%	-41.6%
Cincinnati G&E	-10.0%	-11.2%	-10.6%
Dayton P&L	-17.3%	-21.7%	-18.3%
Ohio Edison	-28.0%	-31.2%	-31.5%
Ohio Power	5.3%	6.2%	11.4%
Toledo Edison	-31.9%	-33.4%	-39.6%

Table 25. Long-Term Total Cost After Restructuring for Average Customers Under Retail Competition
($/kWh, at the Customer)

	Residential	Commercial	Industrial
Columbus & Southern	$0.0758	$0.0572	$0.0377
Cleveland Electric	$0.0812	$0.0616	$0.0314
Cincinnati G&E	$0.0735	$0.0605	$0.0350
Dayton P&L	$0.0749	$0.0537	$0.0344
Ohio Edison	$0.0777	$0.0628	$0.0356
Ohio Power	$0.0731	$0.0590	$0.0314
Toledo Edison	$0.0782	$0.0695	$0.0314

Table 26. Long-Term Change in Rates After Restructuring for Average Customers Under Retail Competition
(Compared to current rates)

	Residential	Commercial	Industrial
Columbus & Southern	-4.0%	-11.0%	-21.6%
Cleveland Electric	-26.5%	-35.1%	-52.1%
Cincinnati G&E	-5.1%	-11.5%	-24.5%
Dayton P&L	-13.7%	-22.7%	-32.7%
Ohio Edison	-26.6%	-33.8%	-43.0%
Ohio Power	+12.7%	7.9%	-2.0%
Toledo Edison	-28.9%	-33.9%	-48.6%

These tables shows an interesting result. First, it is important to remind the reader that the rates shown are in constant, 1995 dollars. Thus, a zero percent change in rates as shown in the tables would actually appear to the customer as an increase in current dollar rates. During the transition period between the 1995 starting point and the point in which the long-term rates are expected to be in effect, the impact of inflation is expected to be such that a rate unchanged in current dollar terms would be equivalent to a 25.6 percent decrease in constant dollar terms. Thus, the percentage impact tables above would need to show a decrease of at least 25.6 percent for any given utility and rate class to indicate an overall unchanged rate in current dollars.

The cost of electricity goes down (in constant dollars) for all utilities except Ohio Power. Ohio Power currently produces power at a cost less than the expected long-term market price of power. Under a market-based pricing approach, Ohio Power will be able to sell its power into the market at a price higher than its costs, creating a windfall. Under a deregulated, competitive market for power, this windfall would belong to the company and would not be returned to the customers. Thus, the rates go up, and the company earns more money. This situation is discussed further in a later section of the report titled "**Low Cost Producers**."

The conclusion with respect to the long-term impact of restructuring is that, adjusted for inflation, there are likely to be savings for most customers *compared to current rates*. The underlying reason why long-term rates under restructuring are lower than current rates is the assumption that the above-market costs will be wrung out of the system during the transition period. Since it is the above-market costs which are causing the current rates to be so high, it is obvious that eliminating them will reduce rates.

However, we note that the present mix of uneconomic generating assets is currently working its way out of the system even without restructuring. Eventually, even without restructuring, these assets would have passed out of the ratebase, and the cost of power would have dropped to reflect that these over-priced assets are gone. The question of whether restructuring will provide lower long-term rates than a non-restructured electric utility world depends on whether a market approach to generation is likely to keep generating costs lower than an approach based on regulation. The record suggests that while aggressive regulation has, in some jurisdictions, kept rates low (as low or lower than expected market costs), in general the regulation approach has not been very successful at keeping rates down.

The long-term impact for low-income customers appears less rosy. The following tables (Table 27 and Table 28) include the impact of higher distribution costs per kWh for low-usage customers. These are based on the same assumption for low-income usage of electricity discussed in the previous section on low-income customers, that low-income customers use approximately 81.5 percent of the usage of the average customer.

Table 27. Long-Term Total Cost After Restructuring for Low-Income Customers ($/kWh, at the Customer)

	Wholesale Competition	Retail Competition
Columbus & Southern	$0.0736	$0.0788
Cleveland Electric	$0.0805	$0.0849
Cincinnati G&E	$0.0725	$0.0763
Dayton P&L	$0.0747	$0.0779
Ohio Edison	$0.0795	$0.0810
Ohio Power	$0.0710	$0.0758
Toledo Edison	$0.0783	$0.0816

Table 28. Long-Term Change in Rates After Restructuring for Low-Income Customers Under Wholesale Competition (Compared to current rates)

	Wholesale Competition	Retail Competition
Columbus & Southern	-6.6%	No Change
Cleveland Electric	-27.1%	23.1%
Cincinnati G&E	-6.2%	1.2%
Dayton P&L	-13.8%	-10.1%
Ohio Edison	-24.8%	-23.3%
Ohio Power	+9.7%	+17.0%
Toledo Edison	-28.8%	-25.7%

These tables suggest that eventually, even for low income customers, there is a potential for savings from electric utility restructuring. As with the average customer, Ohio Power remains an exception. The savings will be significantly less than those achieved by other customers, and will be bought by significant increases in costs during the transition period if residential and low-income customers are treated unfairly during that time period.

SMALL CUSTOMER AGGREGATION

It is a commonly held view that, in a restructured utility world, small customers (both residential and commercial) will be less valued as customers than larger customers.[19] The transaction costs required to serve these small customers combined with load factors which are generally more sharply peaked than the overall system load factor make these expensive customers to serve. In addition, since small customers are generally viewed as less likely to bargain hard for low cost power than large users, most analysts expect to see small customers paying more for power than large customers. While some of the price differential may be cost-based (because of the transaction costs and the load factor difference), it is likely that the small residential or commercial customer will not get as good a deal out of restructuring as large customers. This tendency is borne out by the experience with natural gas in the wake of deregulation. Between 1984 and 1993, the price of natural gas to industrial customers went down, on average, approximately 33 percent, while the price to residential customer went up approximately 0.5 percent.[20] While the increase to small customers is not very large, the comparison with the reductions for industrial customers is striking.

One of the ways which has been discussed in consumer advocate circles for improving the chances of small customers getting a decent electricity price is the use of small customer aggregation. Under small customer aggregation, either cooperative buying groups or entrepreneurial companies will organize small customers into groups which will be much larger than individual customers. These groups, by virtue of their increased size, have the potential to negotiate better power supply deals than individual customers could on their own. The transaction cost of negotiation would be much less than for individual customers, both for the customers and for the power suppliers. In addition, a skillful aggregator will be able to put together customer groups which have better load factors than individual customers would have. A better

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[19] There is no specific source which gathers together the discussion relative to this point. The issues have most generally been raised in testimony before public utility commissions and legislative hearings, public speeches and presentations at conferences and meetings, etc. The reasoning for this view is as set forth in the text. Whether it will actually turn out to be the case is unknown at this time, since the market is not yet in place. We do know, however, that in the telephone and natural gas markets, large customers have gotten the best deals. See, for example, Crandall and Barua, op cit, or the Hamrin, et al reference cited in the next footnote.

[20] *Affected with the Public Interest*, Hamrin, Marcus, Morse, and Weinberg, National Association of Regulatory Utility Commissioners, 1994, page xiii.

load factor would enable the aggregated buying group to make a better deal with respect to capacity versus energy costs.

There are several ways in which a small customer buying group could improve its load factor. One is through the mixing of customers with different load shapes. This approach is likely to have limited success, since most residential customers have fairly similar load shapes. Addition of commercial loads into the mix would help, but commercial loads are also unlikely to be very large during the deep valley periods when residential customer loads are low. An approach which might be more successful is for the aggregator to include an interruptible option in its offering. By avoiding the highest peaks (on a typical utility system, the highest ten percent of load occurs less than one percent of the time), the amount of *capacity* (as opposed to energy) which must be purchased for the group is significantly reduced.

The use of small customer aggregation will not reduce the cost of providing distribution services to residential and small commercial customers. These customers will continue to need a much greater investment in distribution equipment to serve their needs than will the large customers. Therefore, even if power production costs were absolutely equal between all customer classes, the small customers would pay a higher overall rate (per Kwh) than large customers.

The end result of aggregating small customers in order to make less costly power purchases is likely to be residential and commercial rates with the following components:

- Production costs somewhere between those of the unaggregated small residential or commercial customer and those of the industrial class. Where on that continuum the production costs actually turn out will be a function of how well the aggregators do their work.
- Transmission costs somewhere between those of the unaggregated small residential or commercial customer and those of the industrial class. Again, where on that continuum the production costs actually turn out will be a function of how well the aggregators do their work.
- Distribution costs will most likely not be changed as a result of aggregation.

In total, the result of successful small customer aggregation is likely to be that rates will be lower than they would be without aggregation, but not as low as those of large industrial customers.

It is not possible to develop post-restructuring rates for aggregated residential and commercial loads with any more specificity. The success of the aggregators, and the ability to improve load factors is too uncertain to be able to reach specific conclusions in advance.

LOW COST PRODUCERS

Analysis of the data has shown that there is a great deal of difference in costs between different Ohio utilities. Some -- Ohio Power, Cincinnati Gas and Electric, and Columbus and Southern -- are low-cost providers, while others -- Ohio Edison, Toledo Edison, and Cleveland Electric -- are very high cost providers. In fact, Ohio Power costs are less than the long-term, combined cycle based estimate of market cost.

If low-cost producers are able to earn market-based prices for their power, the result will be a windfall for stockholders and a penalty for customers unless that windfall is returned to the customers. This is demonstrated in Tables 24 and 26 which show the long-term change in rates for the different utilities after restructuring. Residential and commercial rates go up for Ohio Power, while they go down for the other utilities.

If it is considered fair for customers to pay at least a portion of the above-market costs of high cost providers during the transition period, it must be considered equivalently fair for customers to receive at least some of the benefits of the below market costs of low cost providers. There is absolutely no justification for these benefits to be retained solely by the stockholders.

SECURITIZATION -- A LONG-TERM BOND APPROACH TO STRANDED COSTS

One of the newest approaches under consideration for dealing with stranded investment is the use of special bonds to pay off the above-market costs. This approach which is known as *securitization* has been included in both the California and Pennsylvania restructuring laws. The idea behind this approach is that the transition costs will be reduced because debt is cheaper than the current utility cost of capital. It is presumed that the utilities will be able to market these bonds at a good interest rate because the laws authorizing them state that the utility commissions will be *required* to allow the utilities to collect the bond amortization costs from ratepayers. While this falls somewhat short of government backing of the bonds, it provides a great deal more protection to bond buyers than would be typical for utility bonds. As a result, the cost of paying for stranded investment is expected to be less than the current cost of capital. It will certainly be less than the cost of equity.

In principle this method should work to reduce costs. However, there are some significant questions which must be considered about the approach.

- How will the shift in the capital structure caused by the conversion of equity to debt affect the overall cost of capital for the utilities?

  Financial theory suggests that a lowering of financing cost comes from reduced risk and not from changes in the capital structure. The costs of the underlying elements shift to counter the change in capital structure balance. For example, if a utility replaces a lot of its equity financing with debt, the overall level of risk on the debt will go up (due to reduced interest coverage ratios). As a result the cost of debt will presumably go up. Laws which mandate the recovery of stranded costs through transition charges may reduce the cost of capital by reducing investor risk. If special low cost bonds are issued to pay for transition costs, the cost of all the other capital used by the utility will probably go up.

- What will be the life of the stranded investment bonds, and will this lengthen the transition period?

  Most restructuring analysts and policy makers are presently expecting the transition period to last approximately five to ten years. At that time there is an expectation that transition costs will have been paid off, and the benefits from restructuring can flow to the customers. New bonds to pay for transition costs may extend the period during which customers get little or no benefit from competition.

- Will costs which are not truly stranded costs be rolled into stranded investment bonds?

  The restructuring law adopted in California includes in the transition charges such things as *future* environmental costs for existing plants, severance packages for employees who may lose their jobs as a result of restructuring, and many other things which are not sunk costs. We have estimated that the total amount of money included in the California restructuring law for stranded costs (approximately $28 billion) is two or more times the actual stranded costs.[21] The estimated transition cost per residential household in California is hundreds of dollars per year.[22] This cost is non-bypassable and is not included in the law's calculation of expected savings from restructuring. The expected savings are far less than the transition cost, and, while the expected savings are only projected to occur, the transition costs are fixed by law and are unavoidable. Furthermore, under both the California and Pennsylvania approaches, calculation of the amount of stranded asset cost to be securitized requires an estimate now of the market price of power for the full transition period. As we discussed in a previous section, the market price of power is very uncertain. The securitization approach runs the risk of locking the customers into an unreasonably high estimate of stranded costs by virtue of an underestimate of the market price.

- What will be the impact of the utility commissions losing one more piece of oversight?

  Currently commissions can review utility costs and determine whether they are prudent and collectible, or are imprudent and should be disallowed. To the extent that the laws authorizing special bonds for transition costs *require* the commissions to allow the collection of these costs, one more element of regulatory oversight is lost.

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[21] California AB 1890, enrolled 8-31-6, Article 6. Requirements for the Public Utilities Commission, section 367 (a)-(e). While the law does not spell out the $28 billion figure, numerous reports in the press at the time of the law's passage gave that figure.

[22] Estimates based on work done for CAL-NEVA by MSB Energy Associates and Michael Karp & Associates in September 1996. The results were presented informally and are not published.

- While securitization may save money in the initial years, what is the impact in the later years?

  Under current regulatory practices the existing rate base is depreciated each year so that the cost in rates of the *existing* rate base goes down. This means that, over time, the amount of stranded assets will go down as they are depreciated. Also, as we discussed in the section on long-term costs under restructuring, the market price is expected to rise over the next few years. A rise in market price means a reduction in stranded assets. Thus, there are two forces tending to drive down the level and cost of stranded assets over time. In contrast, a long-term bond to retire stranded assets locks in the annual cost of that bond. What this means is that under securitization the cost to customers at some future point will be *higher* than it would have been under current regulatory treatments. It is necessary to calculate when that crossover point is reached how savings in early years compare to costs in later years, and the net present value of the two approaches in order to determine true savings. We have made such a calculation for the Ohio utilities which appears below.

The transition bond approach remains an interesting one. It has potential for reducing somewhat the consumer burden of paying off transition costs, but there are also significant dangers. The effectiveness of the bond approach depends a great deal on the specific details of each proposal and the circumstances of each utility. Each proposal must be examined carefully and evaluated fully to insure that the benefits are not outweighed by the disadvantages.

We have calculated the trajectory of costs using both traditional regulatory ratemaking and a securitization approach to collecting stranded asset costs. The result is shown below. We have made a number of assumptions in order to prepare this trajectory analysis. Our assumptions are reasonable mid-range assumptions. Different assumptions would lead to somewhat different results, but the general pattern of results is not very sensitive to the assumptions. Our assumptions are as follows:

- We have treated Ohio as a single entity. While the impact on different utilities will vary depending on the amount of stranded assets they have, we have chosen not to complicate this section by presenting seven separate analyses. The pattern of savings (as a fraction of stranded assets) will be similar for each utility, and the pattern of state-wide results we derive here can be used with the individual utility stranded asset levels shown in Appendix B.

- The current level of stranded assets in Ohio is $8.75 billion.

- Under current regulation the combination of rise in market prices and depreciation of existing assets would reduce the stranded assets to zero in ten years.

- Under securitization, special stranded asset bonds would replace a combination of both equity and debt on the stranded assets. While replacing just the equity portion would be more cost-effective, that is not what has been proposed in those jurisdictions where securitization is being considered.

- Stranded asset bonds would be ten year bonds with an interest rate of 10 percent.

- Under current regulation the return on investment and tax level as a percentage of undepreciated assets would remain much the same as it is now.

- We used a discount rate of 10.9% to determine the net present value of savings from securitization. This was the after tax weighted cost of capital for Ohio utilities (taken together) in 1995.[23]

[23] The 10.9% after tax weighted cost of capital is a calculated number based on the FERC Form 1 filings of the seven Ohio major investor-owned utilities. Essentially, the 10.9% figure is calculated by subtracting the sum of all of the utilities' expenses, including taxes but not interest payments, from the sum of all of the revenues. What is left is the moneys available to pay interest and returns to the stockholders. This remainder, divided by the total amount of undepreciated plant (the net rate base) yields the weighted cost of capital.

Table 29. Securitization of Stranded Assets Compared to Current Regulatory Recovery.
All Costs in Billions of Dollars.

Year	Undepreciated Stranded Assets	Annual Cost Under Current Regulation	Annual Cost Under Securitization	Annual Savings from Securitization	NPV of Savings
1	$8.747	$2.099	$1.424	$0.676	$0.609
2	$7.872	$1.977	$1.424	$0.553	$1.059
3	$6.998	$1.854	$1.424	$0.431	$1.375
4	$6.123	$1.732	$1.424	$0.308	$1.578
5	$5.248	$1.609	$1.424	$0.186	$1.689
6	$4.373	$1.487	$1.424	$0.063	$1.723
7	$3.499	$1.364	$1.424	($0.059)	$1.694
8	$2.624	$1.242	$1.424	($0.182)	$1.615
9	$1.749	$1.120	$1.424	($0.304)	$1.495
10	$0.875	$0.997	$1.424	($0.426)	$1.344

As this table shows, there is a real potential to save money through the use of securitization to pay of the cost of stranded assets. There are savings in six of the ten years, and the net present value of savings is positive. This analysis is based on a series of assumptions which approximate, but do not necessarily match exactly the situation which will be faced in Ohio if and when securitization is proposed. It will be necessary to do detailed analysis at that time based on the specific parameters of the bonds being offered and the conditions under which they are being offered.

One additional point is important. The use of securitization to reduce costs is unrelated to restructuring. Securitization is a financial transaction used to reduce the cost of money. It can be applied to vertically integrated utilities just as readily as it can be applied to restructured utilities, with much the same result. The same benefits and risks apply in either case.

CONCLUSIONS

It is impossible to ascertain with certainty the impact of electric utility restructuring on the different customer classes until the legislature and the Public Utility Commission make final determinations and post-restructuring market prices are known. The impact will vary tremendously depending on the level of collection of above-market costs, the way those costs are allocated to the different customer classes, and the way in which distribution company rates are set. According to the best estimates of future market prices for power, there are significant opportunities for most Ohio customers to save money in their power purchases. Whether or not such savings actually occur will depend on how much of the utilities' above-market costs will be charged to the customers and how much to the shareholders. Who will actually benefit from any savings depends on how the legislature and the Utility Commission end up allocating the costs and the savings to the different customer classes.

If the shareholders are made whole for the above-market costs, there will be no overall savings for the customers, and the customer classes will end up fighting over who will bear the cost of reimbursing shareholders for the above-market costs. If all customers share in paying for the above-market costs, there will be no significant changes in rates. If a customer class succeeds in avoiding paying its fair share of above-market costs, other classes will see their rates increase to cover them. If, however, shareholders are made to share in paying for the above-market costs, then there can be rate decreases for all customer classes.

If, as some restructuring proponents are suggesting, many of the costs of distribution are shifted from kWh charges to fixed customer charges, the potential cost increases for low usage residential customers could be much greater than for other residential customers.

Restructuring offers a near-term opportunity to save customers in Ohio money, but only if the utility shareholders share in paying for the transition costs by picking up some portion of the above-market costs. **Otherwise during the transition period there will not be any overall competitive savings to the customers**. In this case policy decisions made by the legislature and the PUCO will determine which, if any, customers will save during the transition period and which will not.

After the transition period, when stranded asset costs have been retired, there will be savings available to most Ohio customers. The exception is likely to be customers of Ohio Power who currently less than the expected future market price for power. Unless these customers receive a fair share of the windfall profits which Ohio Power can make selling its low cost power at market prices, they are likely to see their rates go up.

Securitization -- the use of special bonds to pay off stranded asset costs at reduced rates -- has a potential for reducing customer costs during the transition to competition. However, securitization is a financial transaction which could be used as readily under traditional regulation as under restructuring. It is *not* a restructuring strategy.

APPENDIX A. ALLOCATION OF COSTS BY CLASS AND FUNCTION

MSB has developed a model (MSB Electric Restructuring Model, or MSB-ERM) for estimating the impacts of various restructuring proposals on different customer classes. Since restructuring is expected to affect different customer classes and different utility functions in different ways, it was necessary to include in the model a cost allocation module which allocates current costs by function and customer class. The basic data source for the model is the FERC Form 1. The model develops allocated costs for the residential, commercial, industrial, sales for resale, and several other small customer classes. It also develops costs broken out into production (both capital, operating, and administrative and general), transmission (capital and operating), and distribution (capital and operating). Finally, it develops costs for each combination of class and function -- for example, residential production operating costs.

The method for allocating operating costs to function is fairly straightforward. The cost categories provided in the FERC Form 1 are generally quite clear as to function. For example, distribution operation and maintenance costs clearly fall into the category of distribution -- operating. Similarly, fuel for steam power plants clearly falls into the category of production -- operating. A few costs such as administrative and general (the cost of personnel, the main offices, employee benefits, etc.) must be allocated into different functions. MSB-ERM allocates these costs based on the allocation fractions of the more clearly differentiated costs.

Allocation of capital costs is a little more complicated. Capital costs are made up of four parts -- return on capital investment (both equity and debt), taxes, amortization, and depreciation. Return on capital investment is determined as the total revenue minus the total operating costs including taxes, depreciation, and amortization (T/D/A). While T/D/A is identified in the FERC Form 1 as an operating cost, it is really a cost related to the utility's capital investment. Income taxes are a function of income which is a function of return on capital investment. Depreciation and amortization are a function of capital investment. Therefore MSB-ERM categorizes T/D/A as a capital related cost rather than an operating cost. Total capital related cost, then, is the return on investment plus the taxes, depreciation, and amortization.

Capital investment is shown in the FERC Form 1 by functional category -- production, transmission, and distribution. The model allocates T/D/A to function in the same fractions that make up the capital investment.

Allocation of functionalized costs to the customer classes is more complicated. The total of the production, transmission, and distribution cost per overall kWh is less than the average revenue per kWh for residential customers, and more than the average revenue per kWh for industrial customers. Clearly residential customers are paying more per kWh for each function than the industrial customers. Commercial customers typically fall between residential and industrial customers in revenue per kWh. We have made several key assumptions:

- All customers pay the same fuel and O&M cost per kWh. This is a reasonable assumption in Ohio since the overwhelmingly coal based system does not have a wide variation in costs at different times. Because industrial customers have a higher load factor than residential and commercial customers, they pay a lower capital cost of generation per kWh.

- Industrial customers pay little or no distribution costs, since industrial power is most often delivered at the transmission or sub-transmission level.

- Customer classes pay the same fraction of transmission costs as they do of production capital costs.

Using these assumptions, the model adjusts the allocation of production, transmission, and distribution costs to each customer class so as to make the total of allocated costs equal to the class revenue. The result is the cost allocation table shown in Tables 3a-3c in the body of the report.

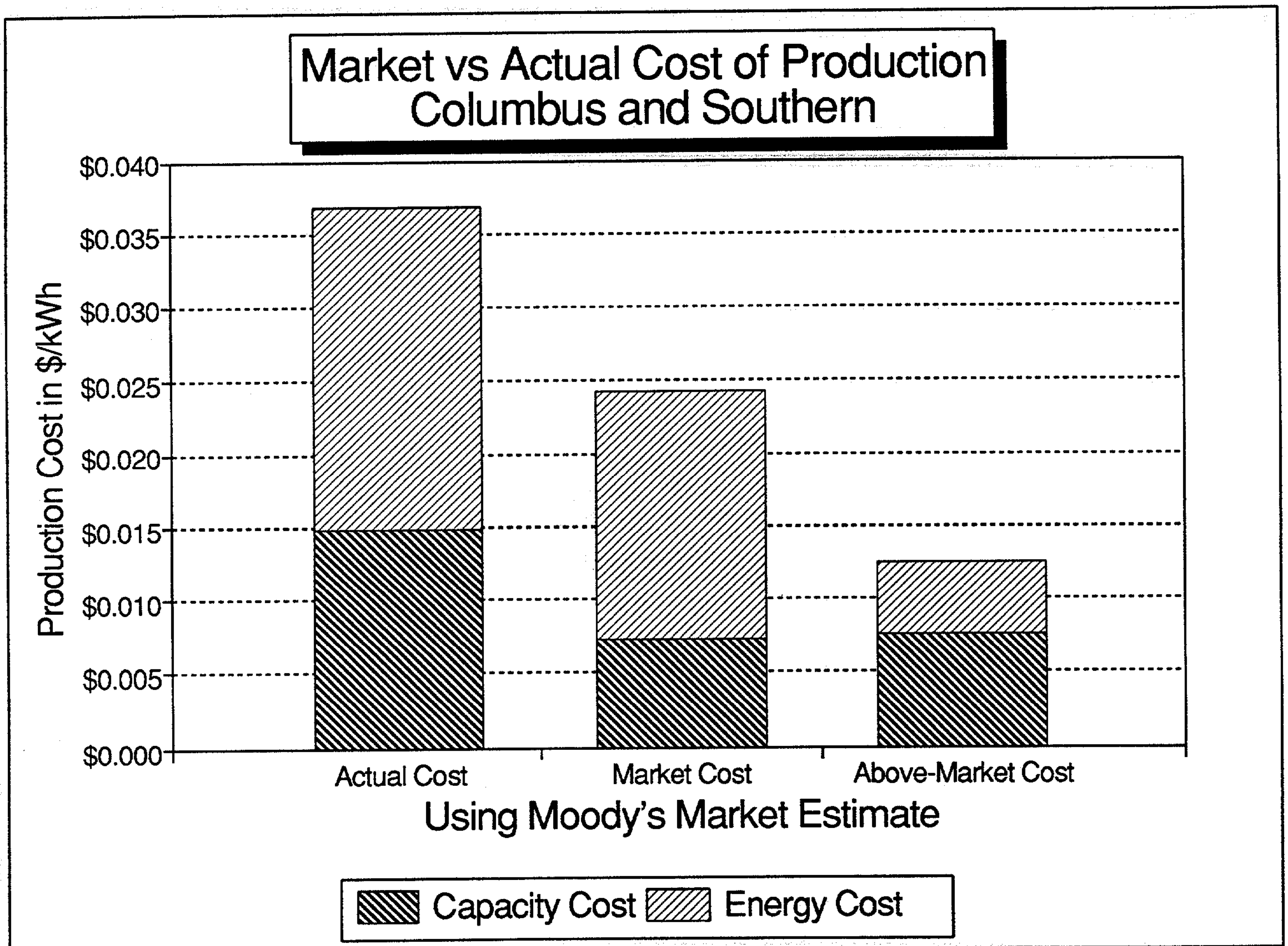
APPENDIX B. GRAPHICAL REPRESENTATION OF RESULTS

In addition to the tabular representations of the results shown in the body of the report we present in Appendix B graphs of the results. Five graphs are shown for each utility. The graphs are as follows:

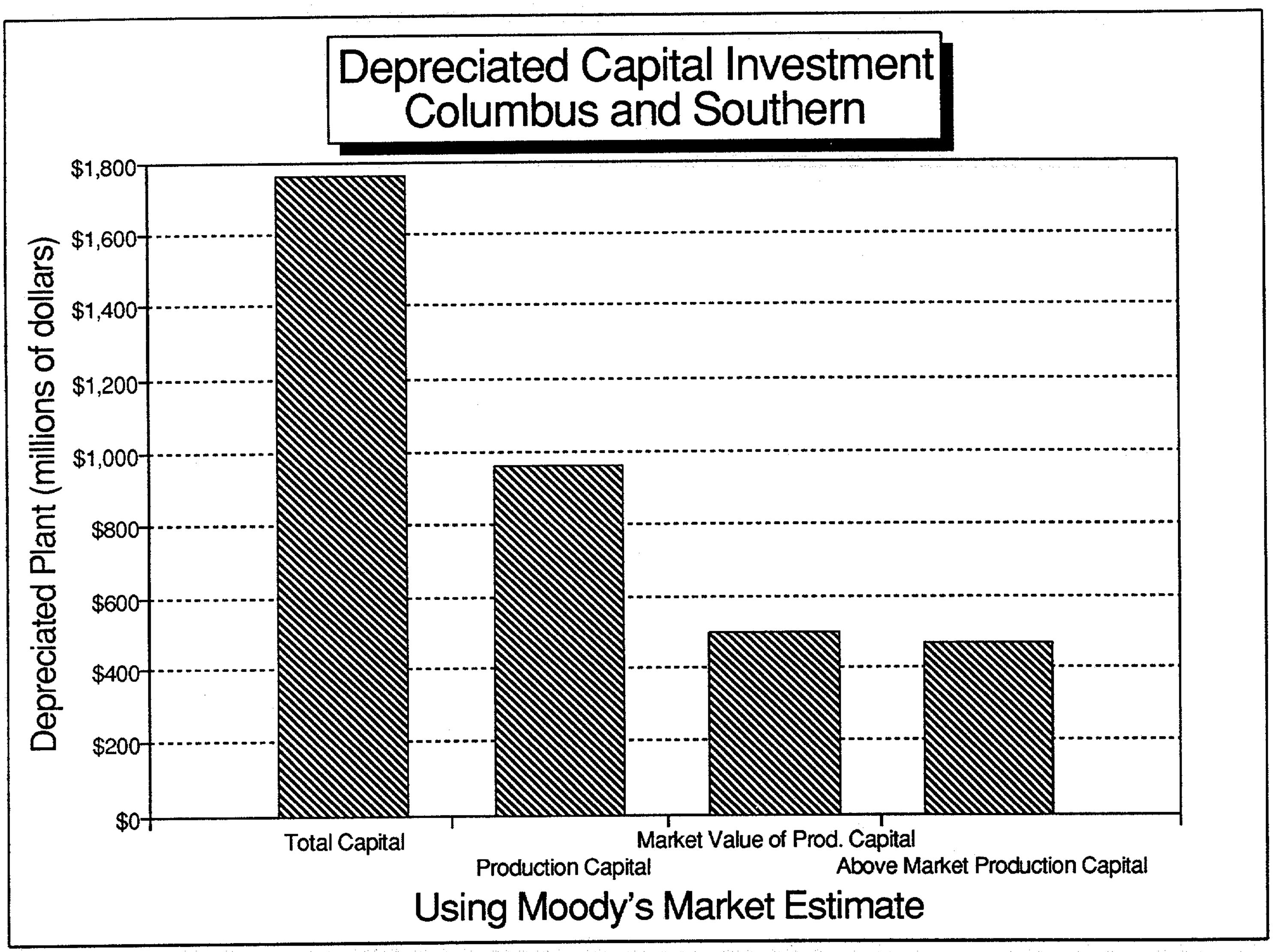
- Market cost of power versus actual cost of power;
- Depreciated capital investment -- total capital, production capital, market value of production capital, and above-market production capital;
- Rate impact of restructuring -- no recovery of stranded costs from customers;
- Rate impact of restructuring -- full recovery of stranded costs/no recovery of stranded capital costs from industrial customers;
- Rate impact of restructuring -- shared responsibility for stranded costs.

Graphs are shown only for estimates of the market price of power based on the Moody's study. Rate impacts are for the average customer.

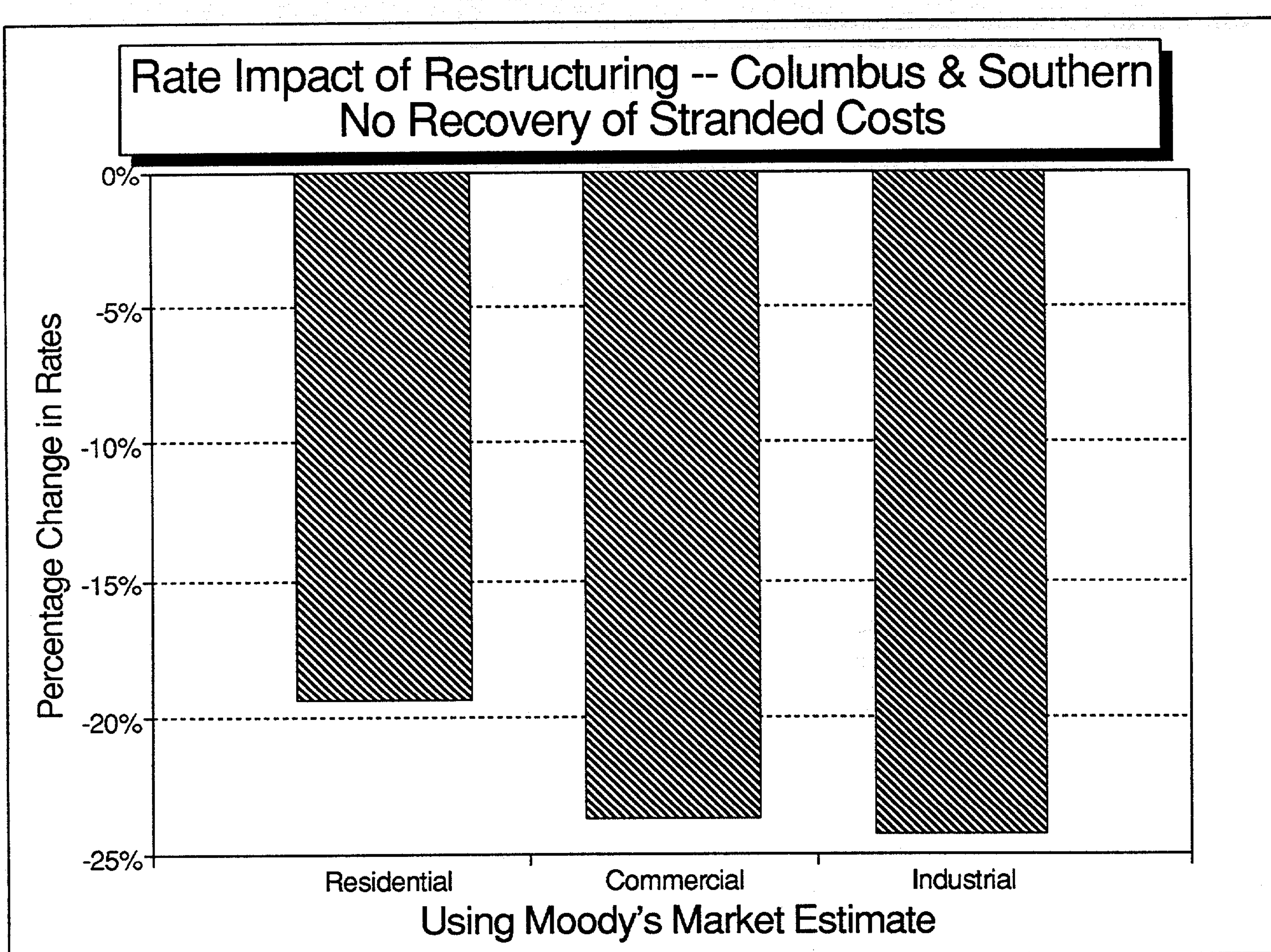
APPENDIX B1. COLUMBUS AND SOUTHERN



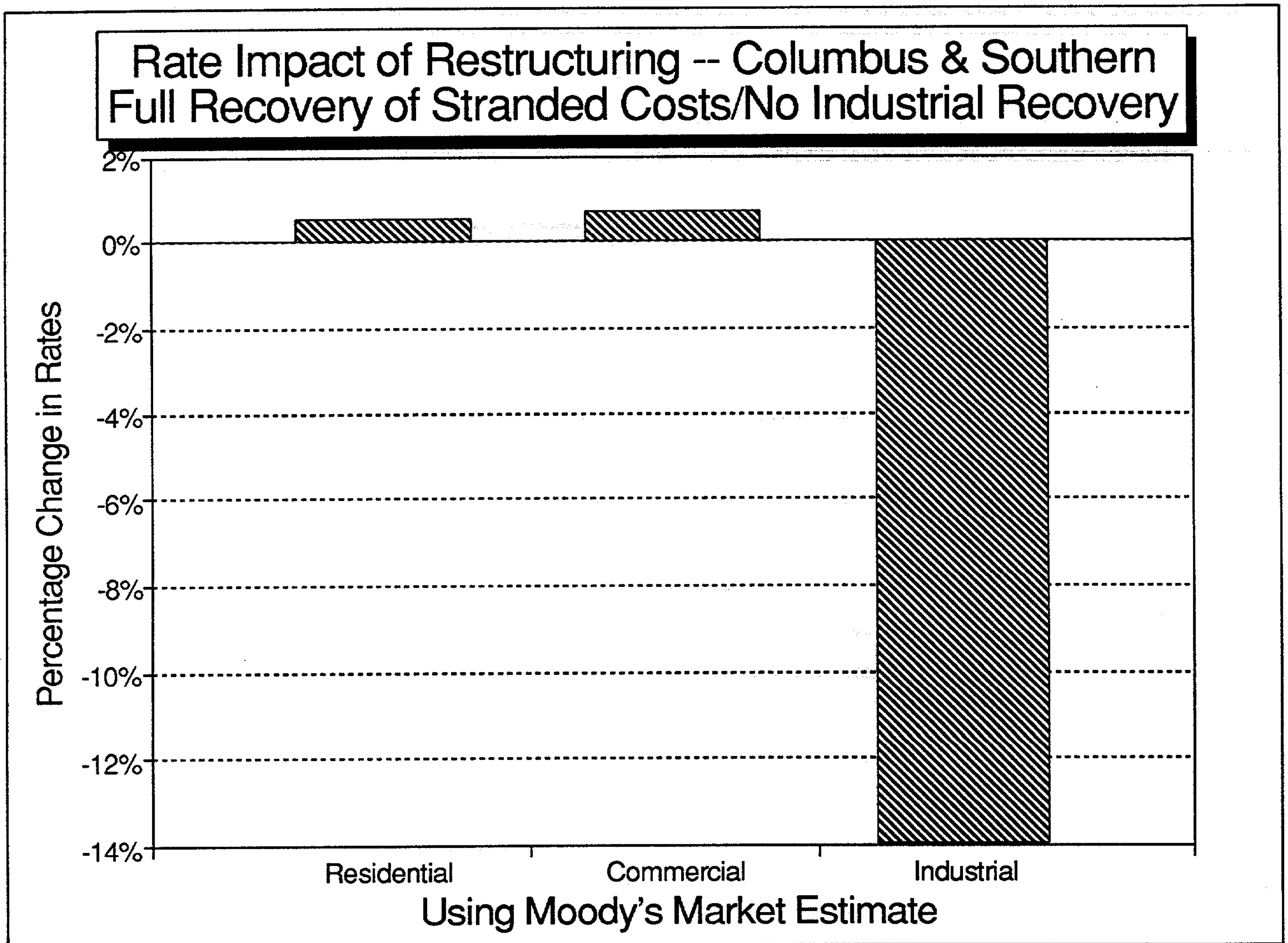
Market vs Actual Cost of Production
Columbus and Southern
$0.040
$0.035
$0.030
$0.025
$0.020
$0.015
$0.010
$0.005
$0.000
Production Cost in $/kWh
Actual Cost
Market Cost
Above-Market Cost
Using Moody's Market Estimate
Capacity Cost
Energy Cost

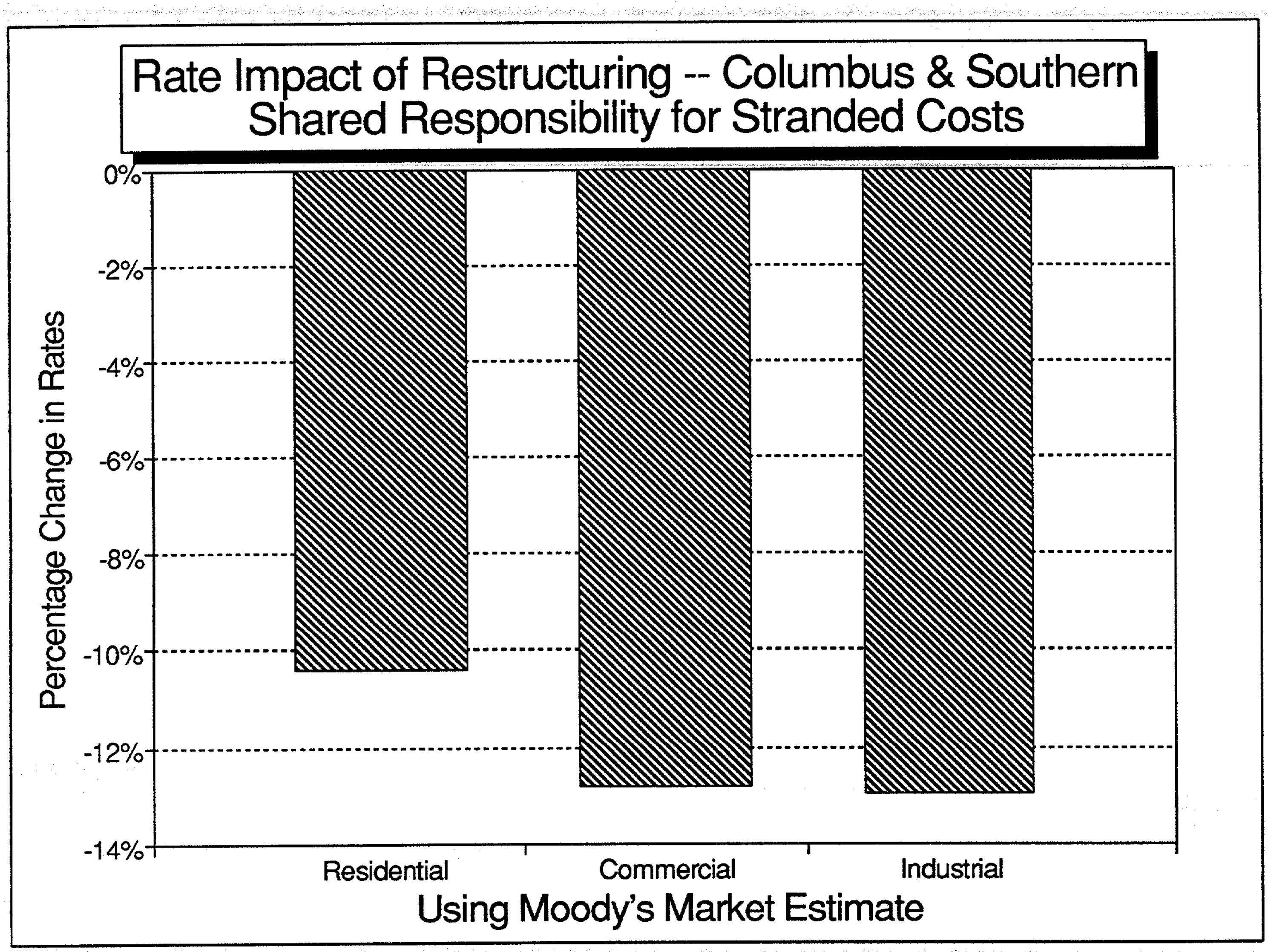


Depreciated Capital Investment
Columbus and Southern
Depreciated Plant (millions of dollars)
$1,800
$1,600
$1,400
$1,200
$1,000
$800
$600
$400
$200
$0
Total Capital
Production Capital
Market Value of Prod. Capital
Above Market Production Capital
Using Moody's Market Estimate



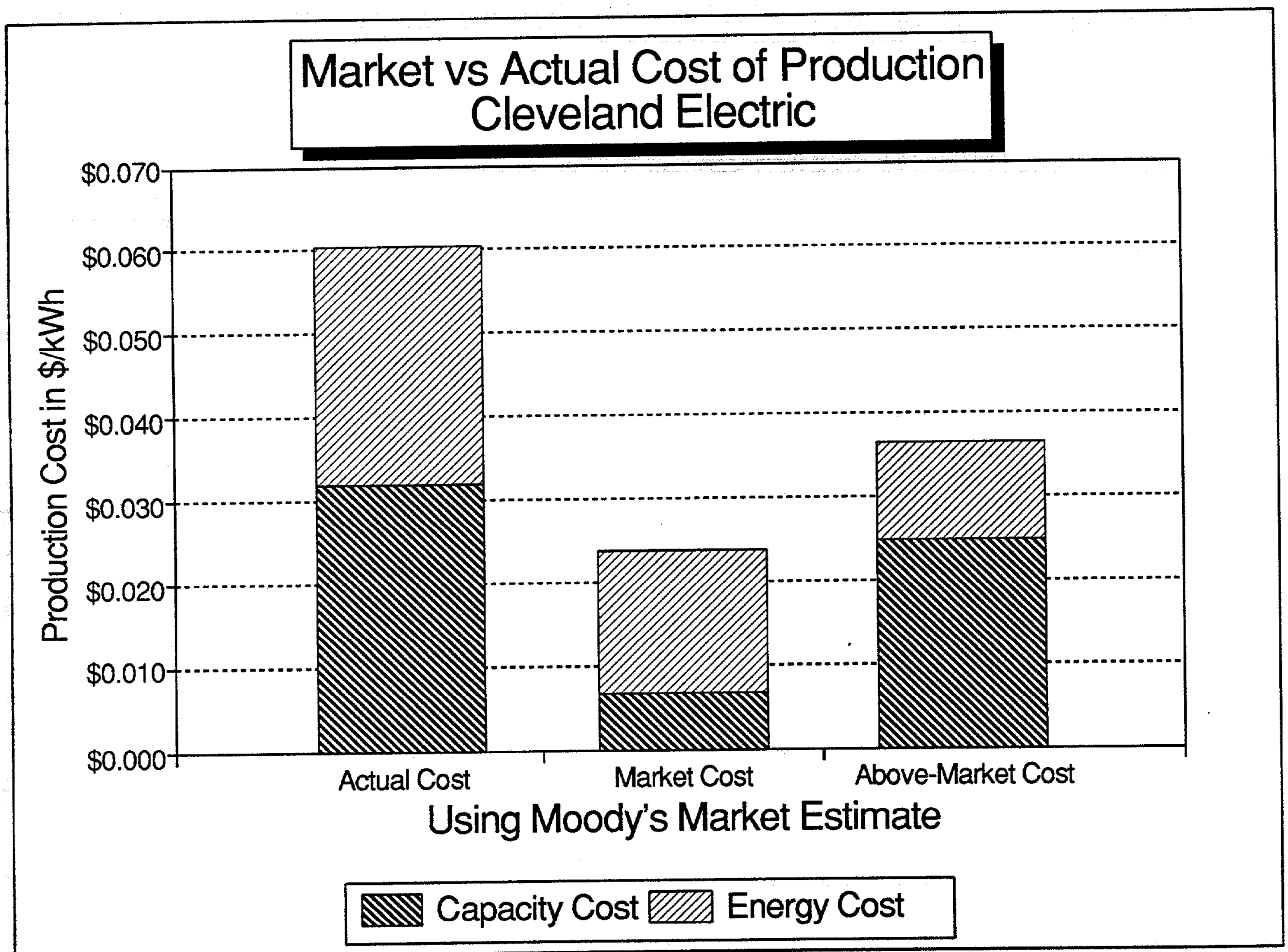
Rate Impact of Restructuring -- Columbus & Southern
No Recovery of Stranded Costs
0%
-5%
-10%
-15%
-20%
-25%
Percentage Change in Rates
Residential
Commercial
Industrial
Using Moody's Market Estimate

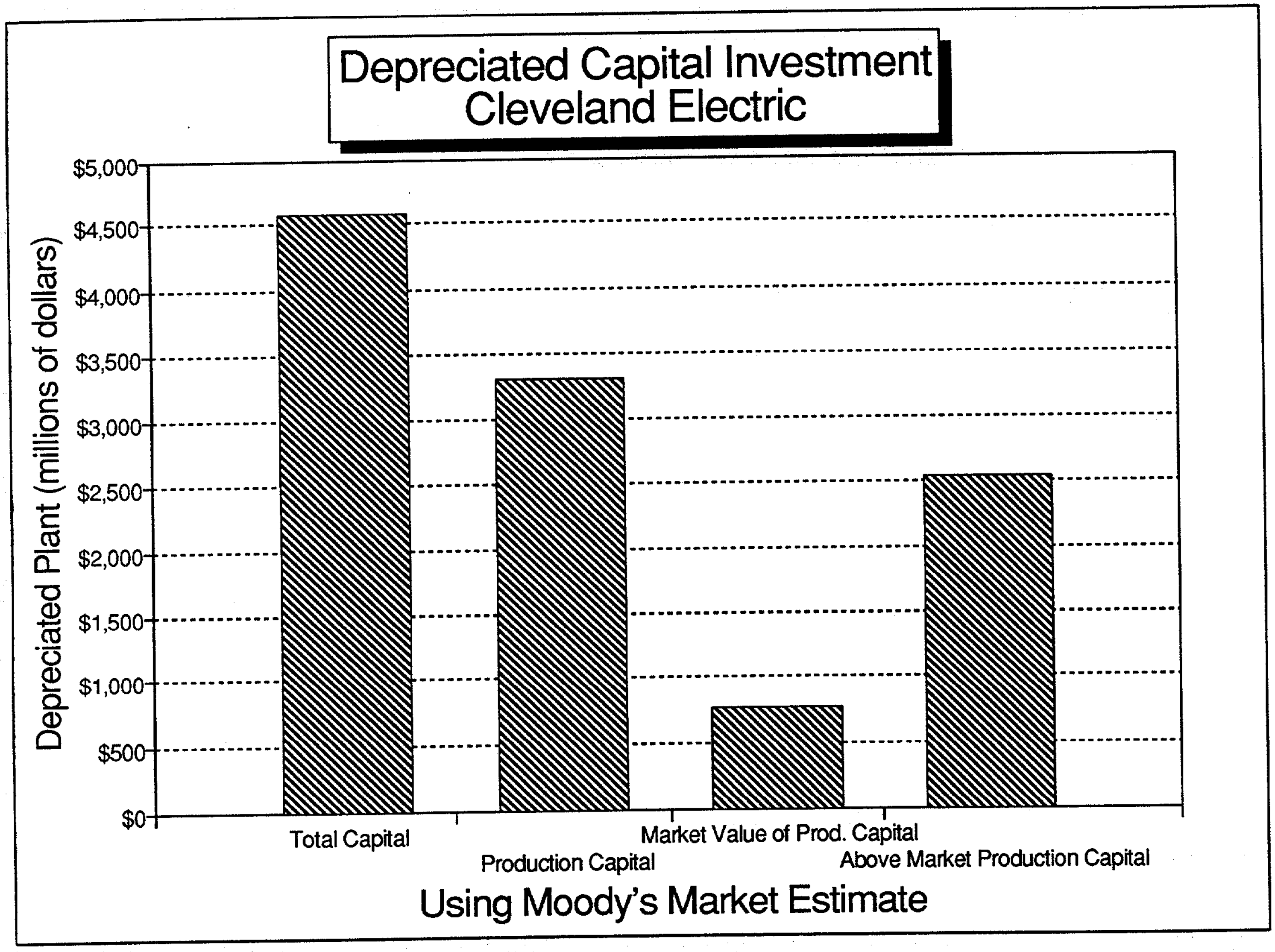

Rate Impact of Restructuring -- Columbus & Southern
Full Recovery of Stranded Costs/No Industrial Recovery
2%
0%
-2%
-4%
-6%
-8%
-10%
-12%
-14%
Percentage Change in Rates
Residential
Commercial
Industrial
Using Moody's Market Estimate



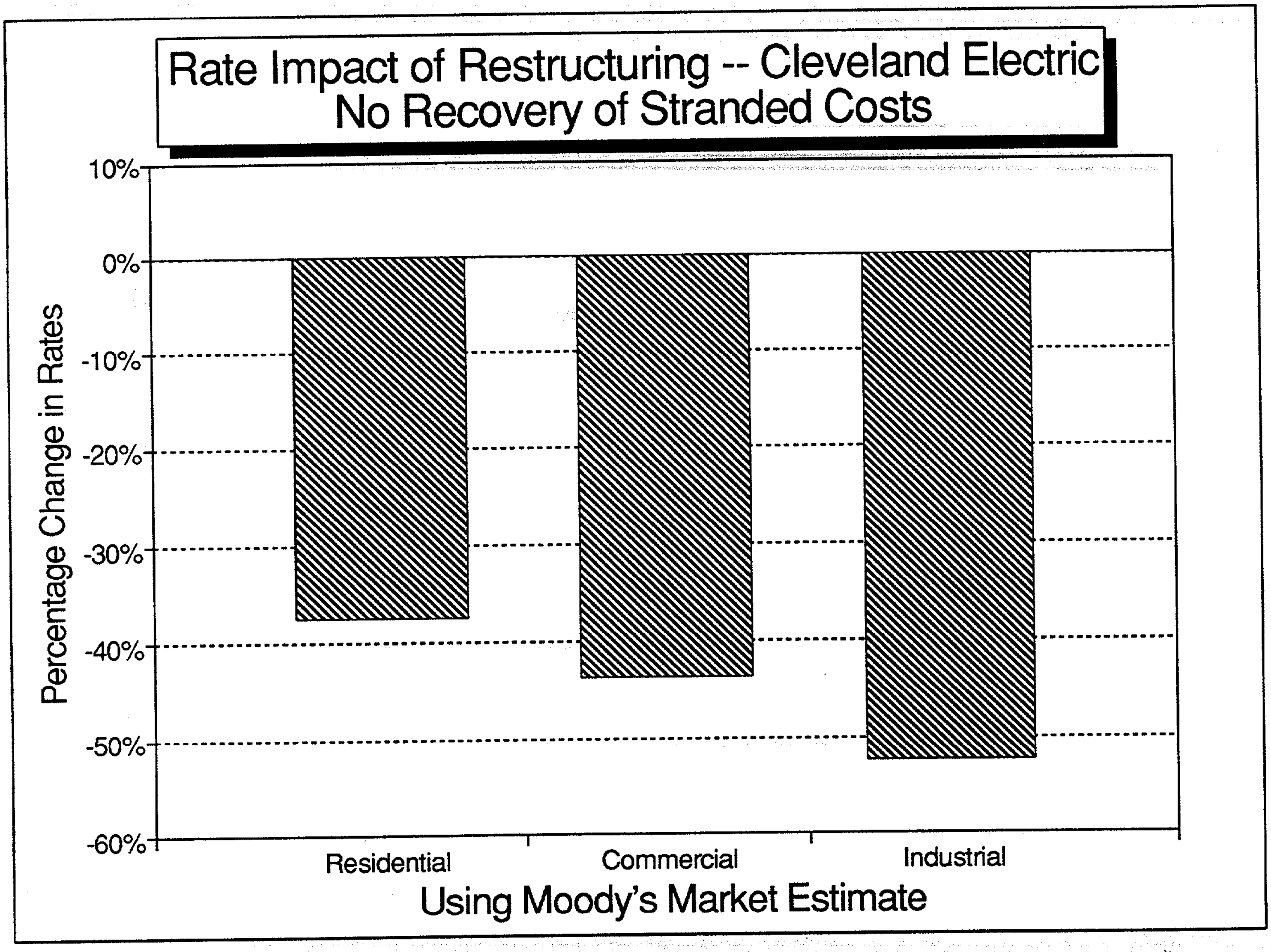
Rate Impact of Restructuring -- Columbus & Southern
Shared Responsibility for Stranded Costs
0%
-2%
-4%
-6%
-8%
-10%
-12%
-14%
Percentage Change in Rates
Residential
Commercial
Industrial
Using Moody's Market Estimate

APPENDIX B2. CLEVELAND ELECTRIC

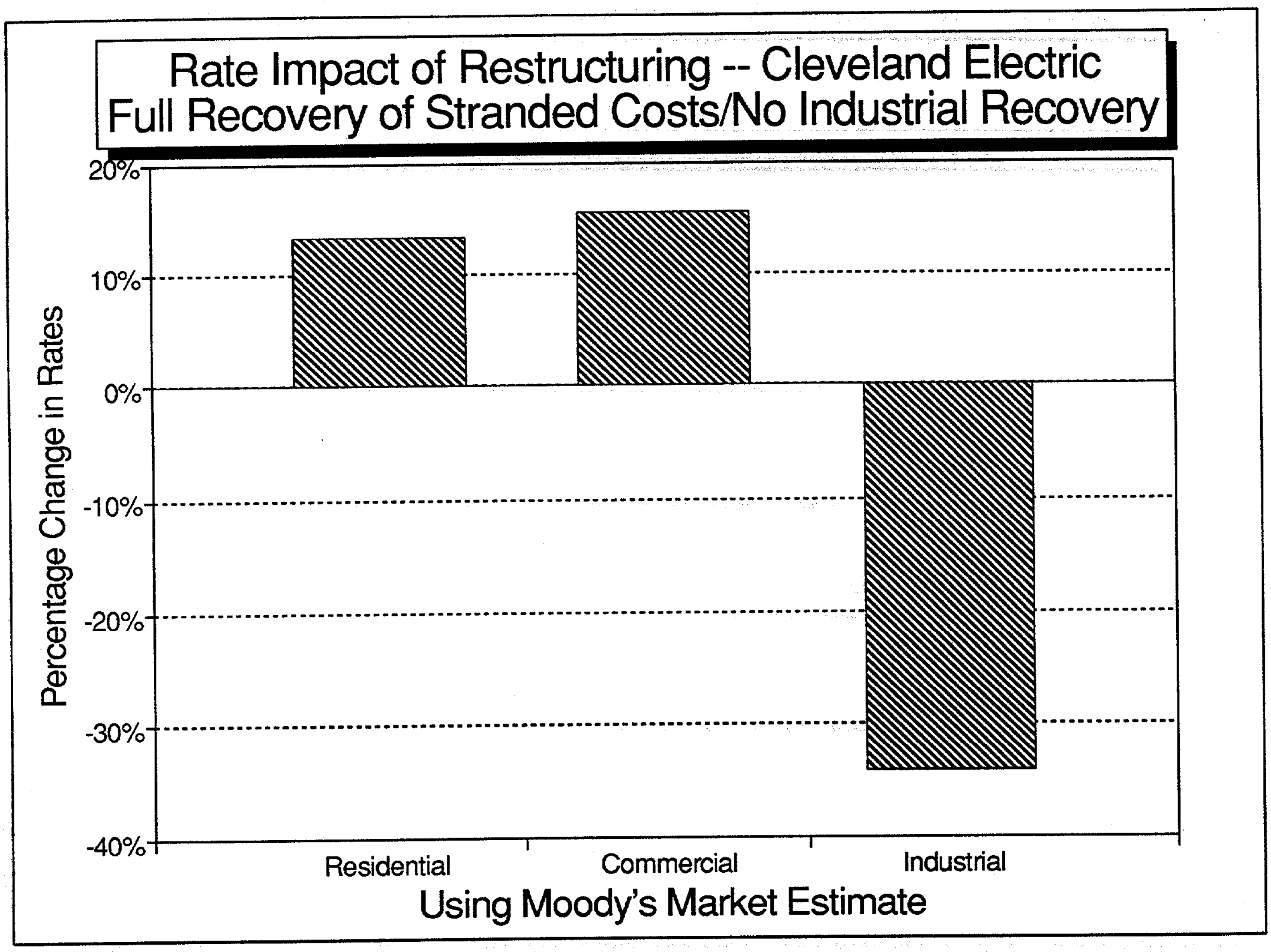

Market vs Actual Cost of Production
Cleveland Electric
Production Cost in $/kWh
$0.070
$0.060
$0.050
$0.040
$0.030
$0.020
$0.010
$0.000
Actual Cost
Market Cost
Above-Market Cost
Using Moody's Market Estimate
Capacity Cost
Energy Cost



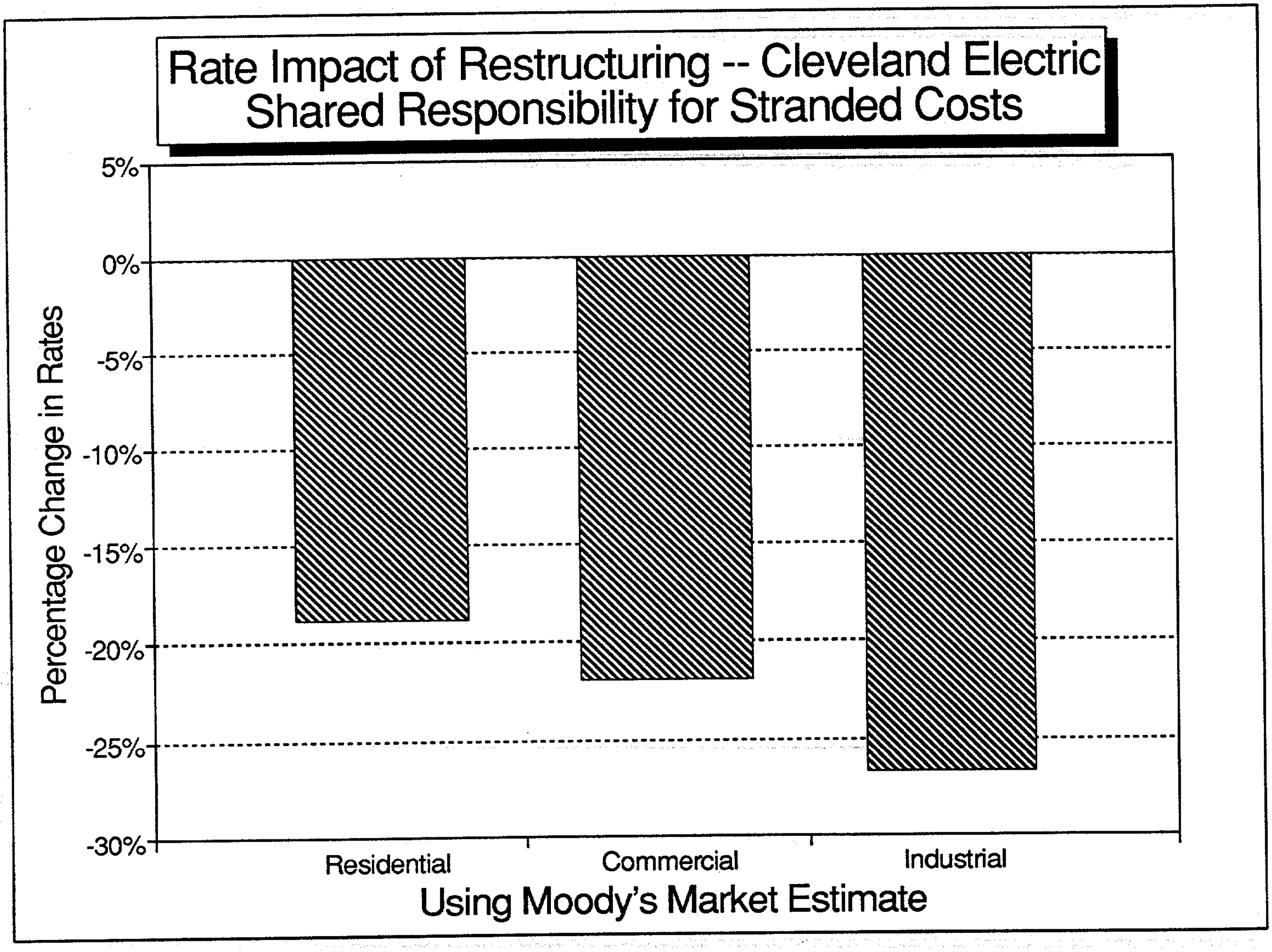
Depreciated Capital Investment
Cleveland Electric
Depreciated Plant (millions of dollars)
$5,000
$4,500
$4,000
$3,500
$3,000
$2,500
$2,000
$1,500
$1,000
$500
$0
Total Capital
Production Capital
Market Value of Prod. Capital
Above Market Production Capital
Using Moody's Market Estimate



Rate Impact of Restructuring -- Cleveland Electric
No Recovery of Stranded Costs
10%
0%
-10%
-20%
-30%
-40%
-50%
-60%
Percentage Change in Rates
Residential
Commercial
Industrial
Using Moody's Market Estimate

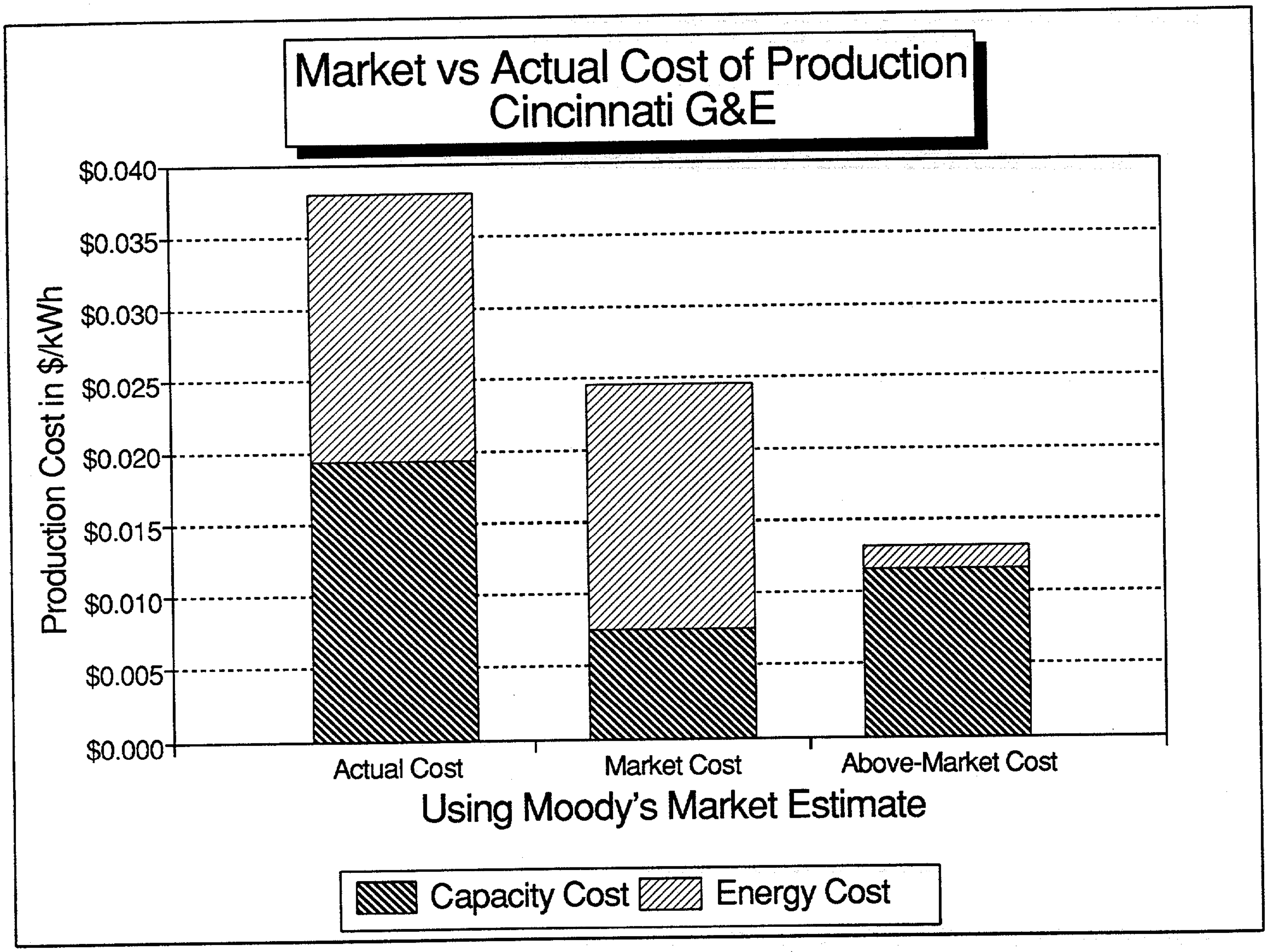


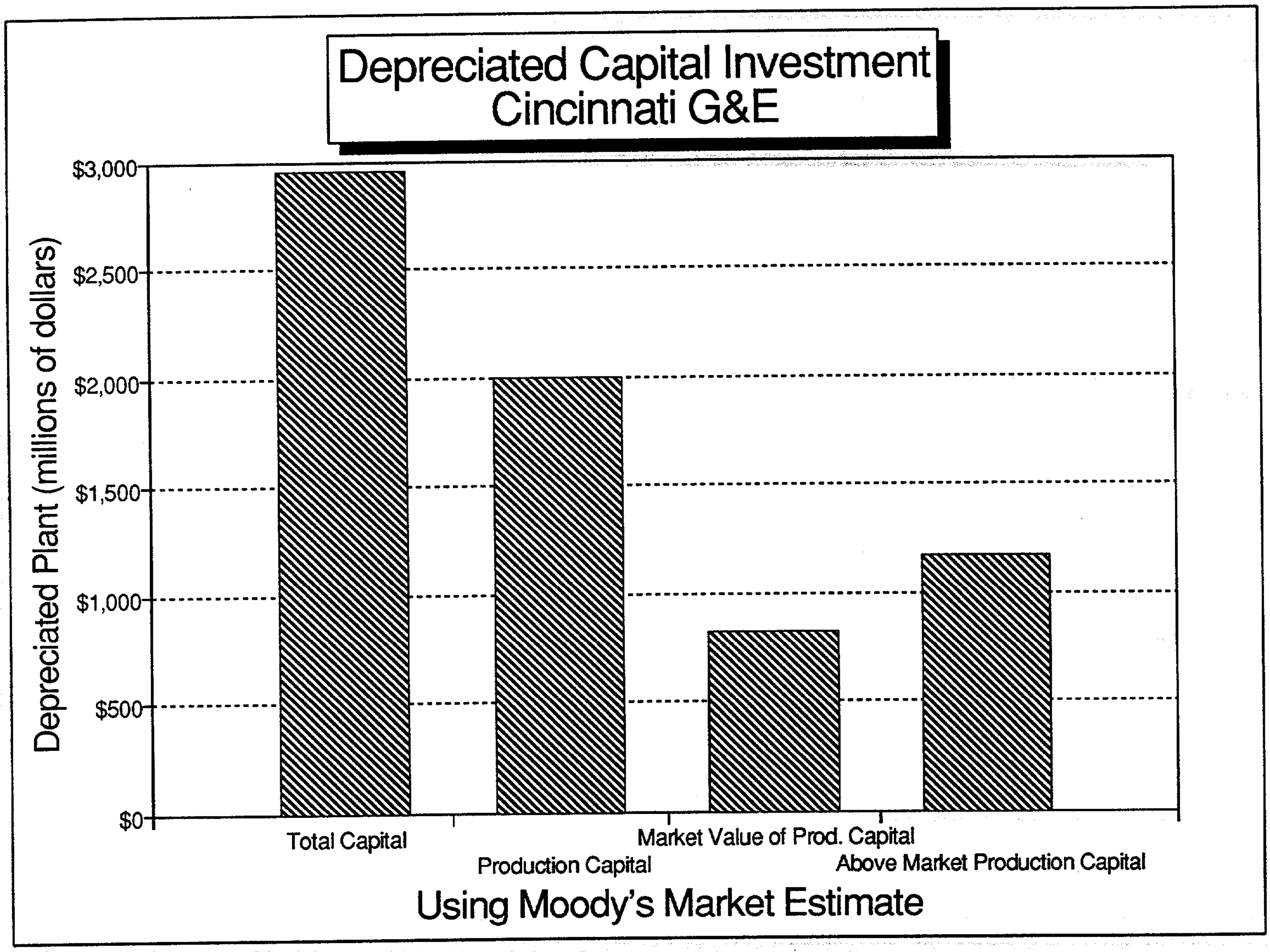
Rate Impact of Restructuring -- Cleveland Electric
Full Recovery of Stranded Costs/No Industrial Recovery
20%
10%
0%
-10%
-20%
-30%
-40%
Percentage Change in Rates
Residential
Commercial
Industrial
Using Moody's Market Estimate



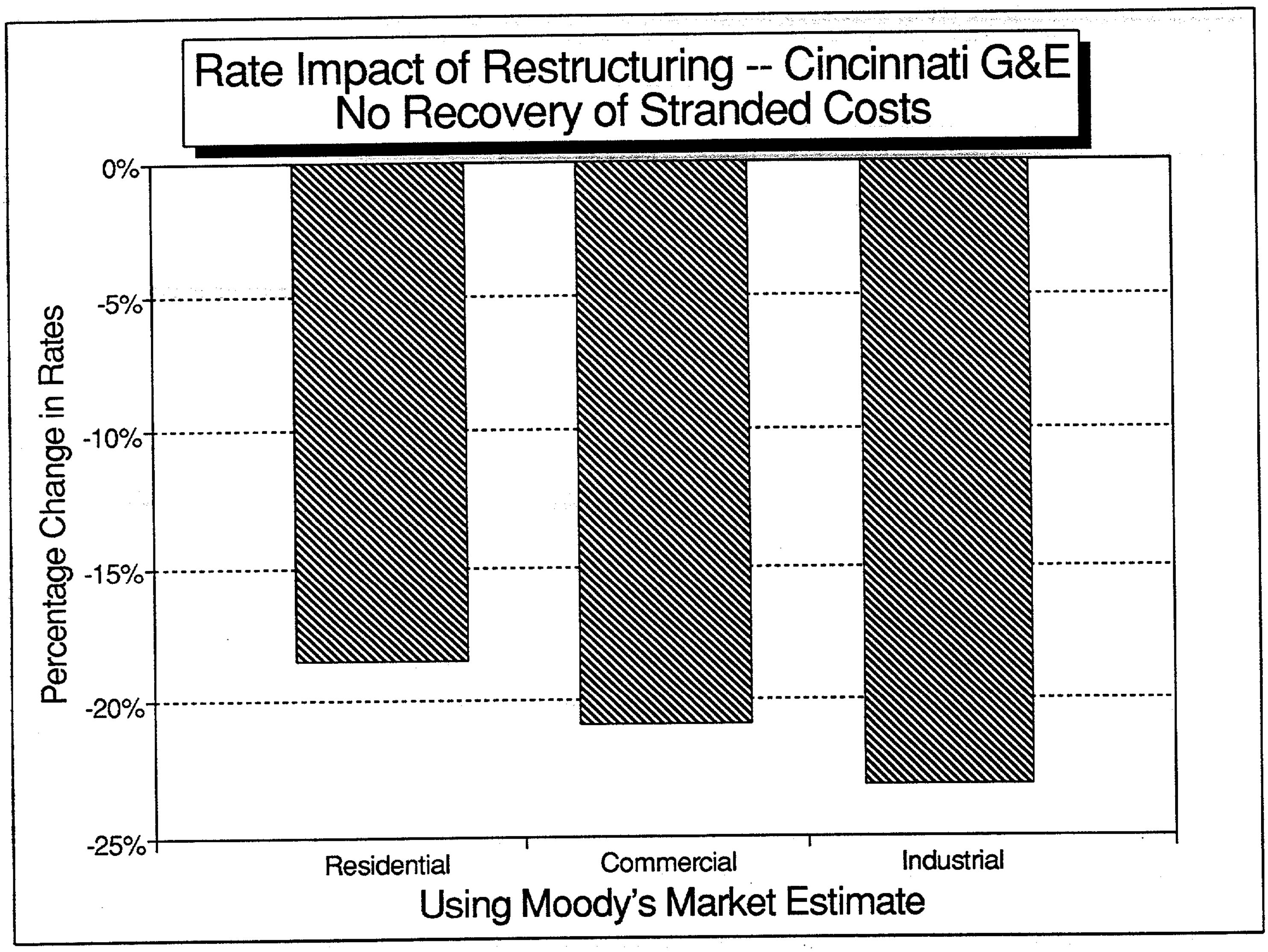
Rate Impact of Restructuring -- Cleveland Electric
Shared Responsibility for Stranded Costs
5%
0%
-5%
-10%
-15%
-20%
-25%
-30%
Percentage Change in Rates
Residential
Commercial
Industrial
Using Moody's Market Estimate

APPENDIX B3. CINCINNATI GAS AND ELECTRIC

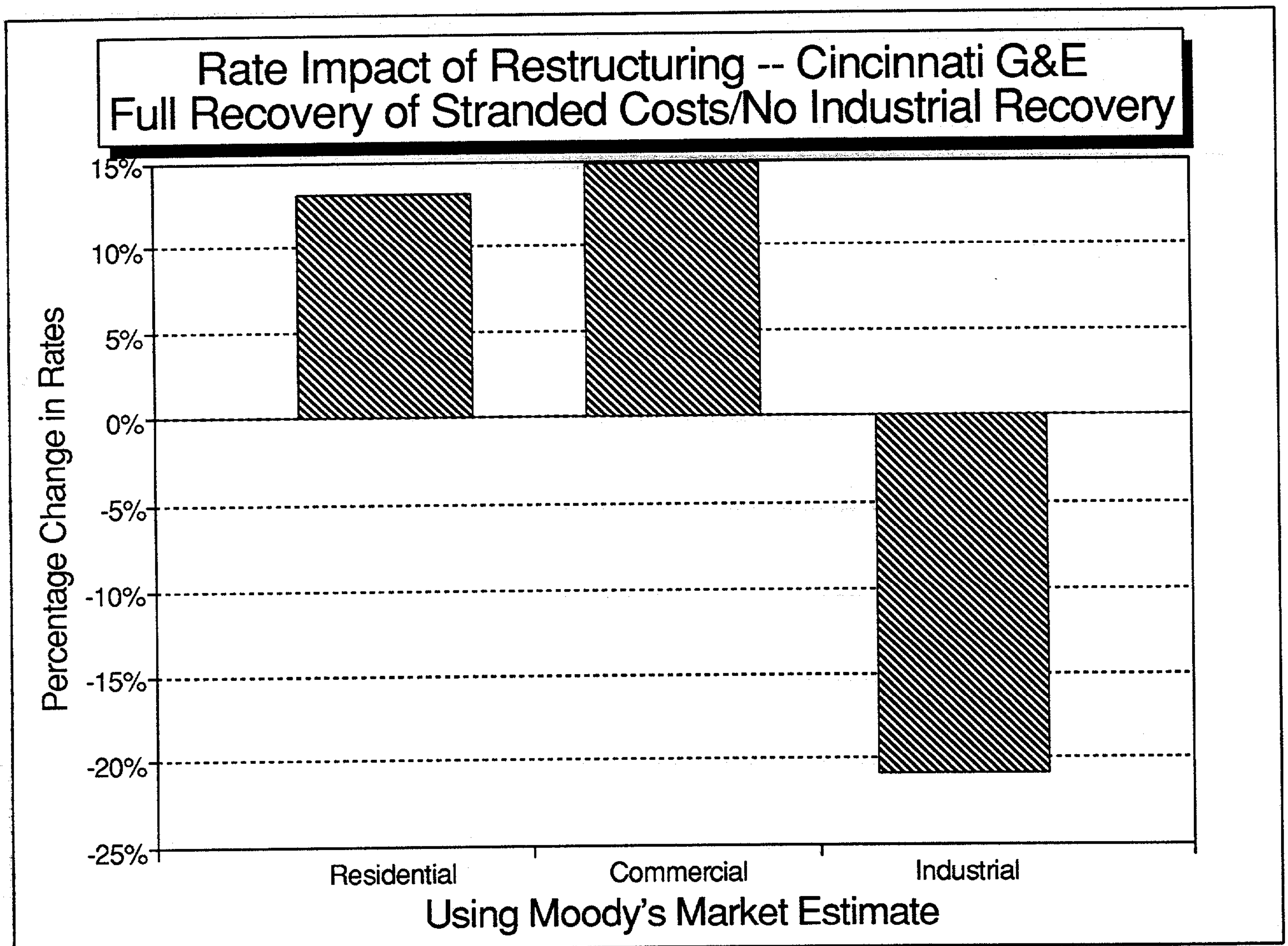

Market vs Actual Cost of Production
Cincinnati G&E
$0.040
$0.035
$0.030
$0.025
$0.020
$0.015
$0.010
$0.005
$0.000
Production Cost in $/kWh
Actual Cost
Market Cost
Above-Market Cost
Using Moody's Market Estimate
Capacity Cost
Energy Cost



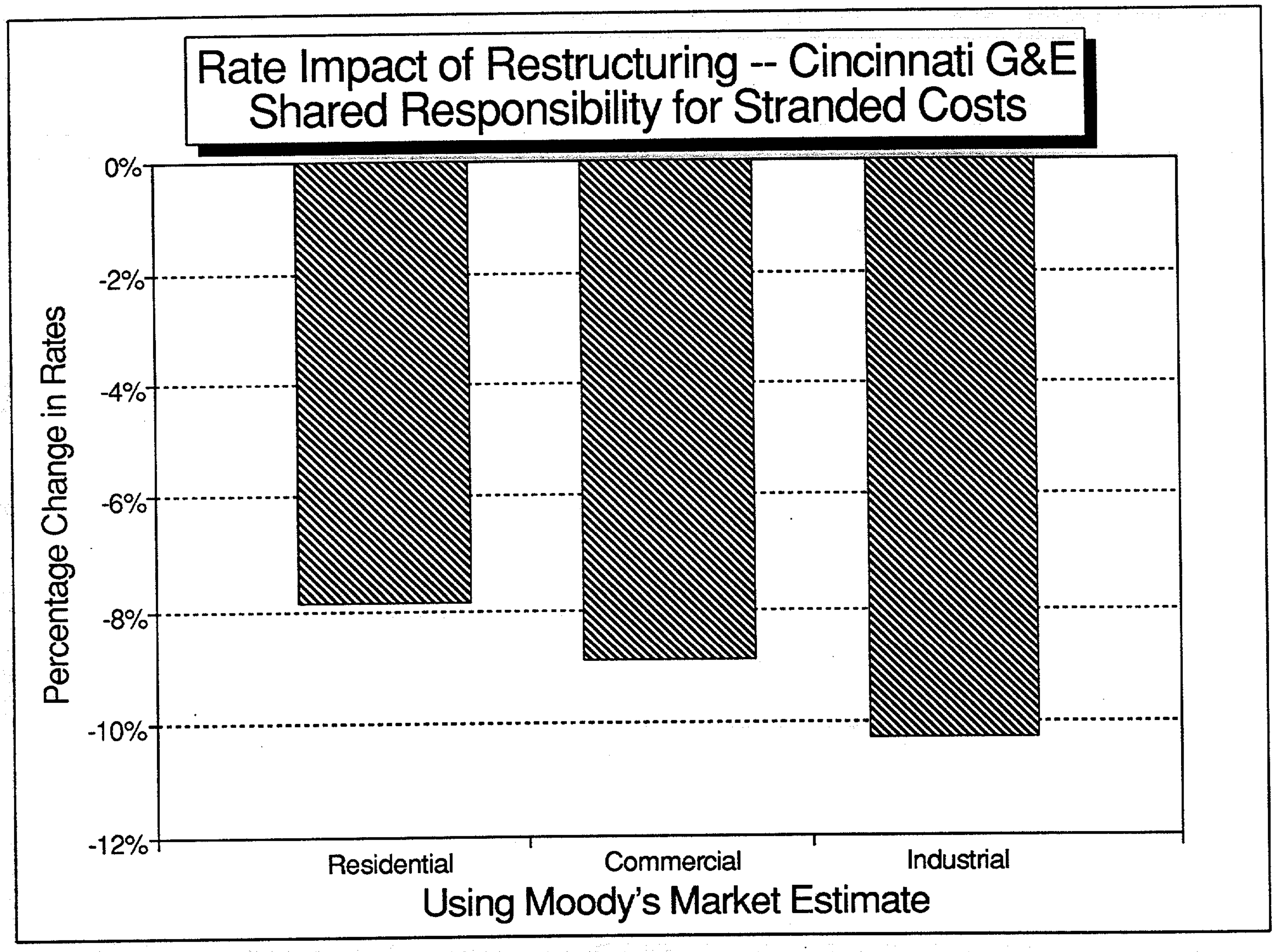
Depreciated Capital Investment
Cincinnati G&E
Depreciated Plant (millions of dollars)
$3,000
$2,500
$2,000
$1,500
$1,000
$500
$0
Total Capital
Production Capital
Market Value of Prod. Capital
Above Market Production Capital
Using Moody's Market Estimate



Rate Impact of Restructuring -- Cincinnati G&E
No Recovery of Stranded Costs
0%
-5%
-10%
-15%
-20%
-25%
Percentage Change in Rates
Residential
Commercial
Industrial
Using Moody's Market Estimate

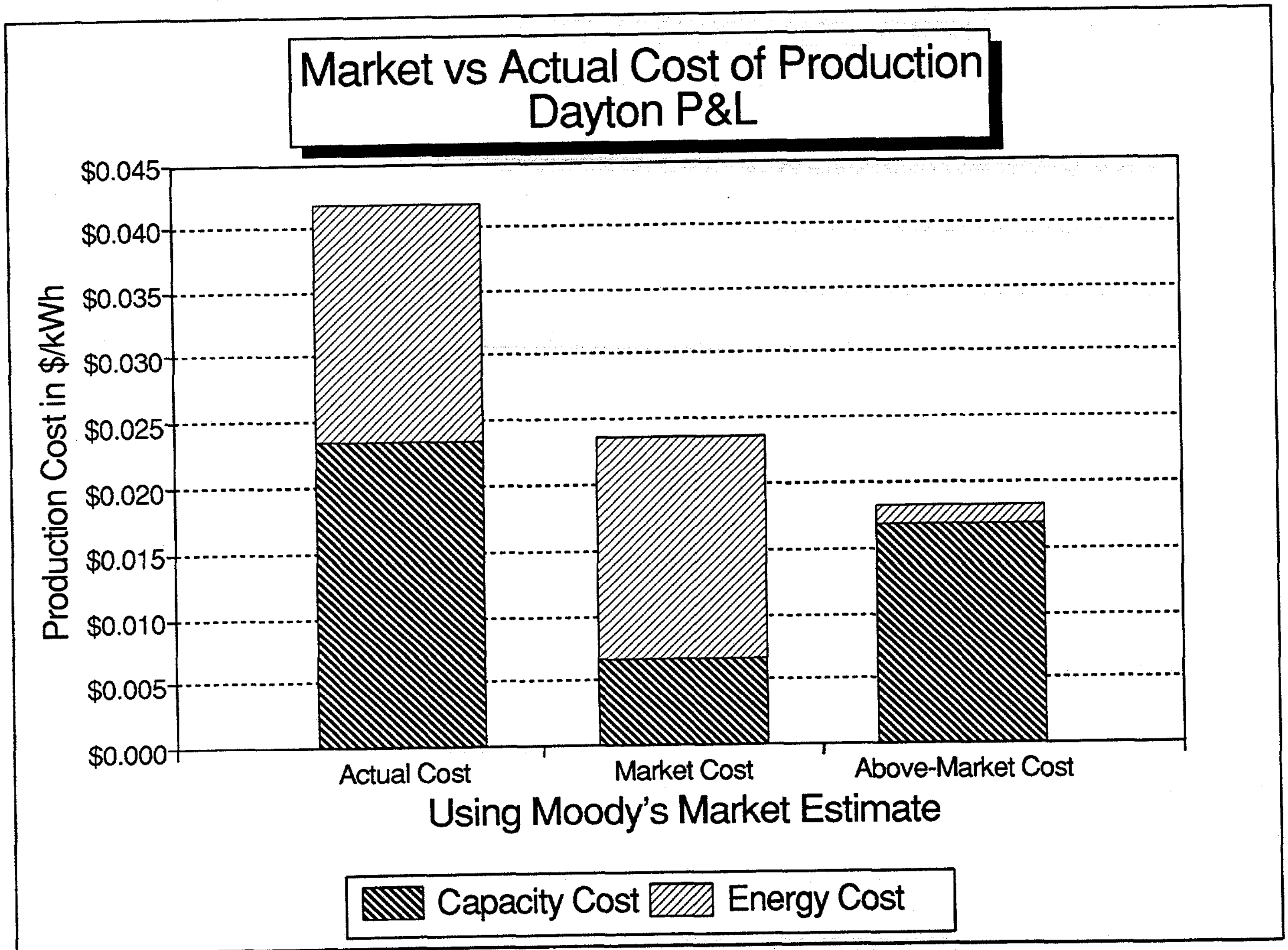


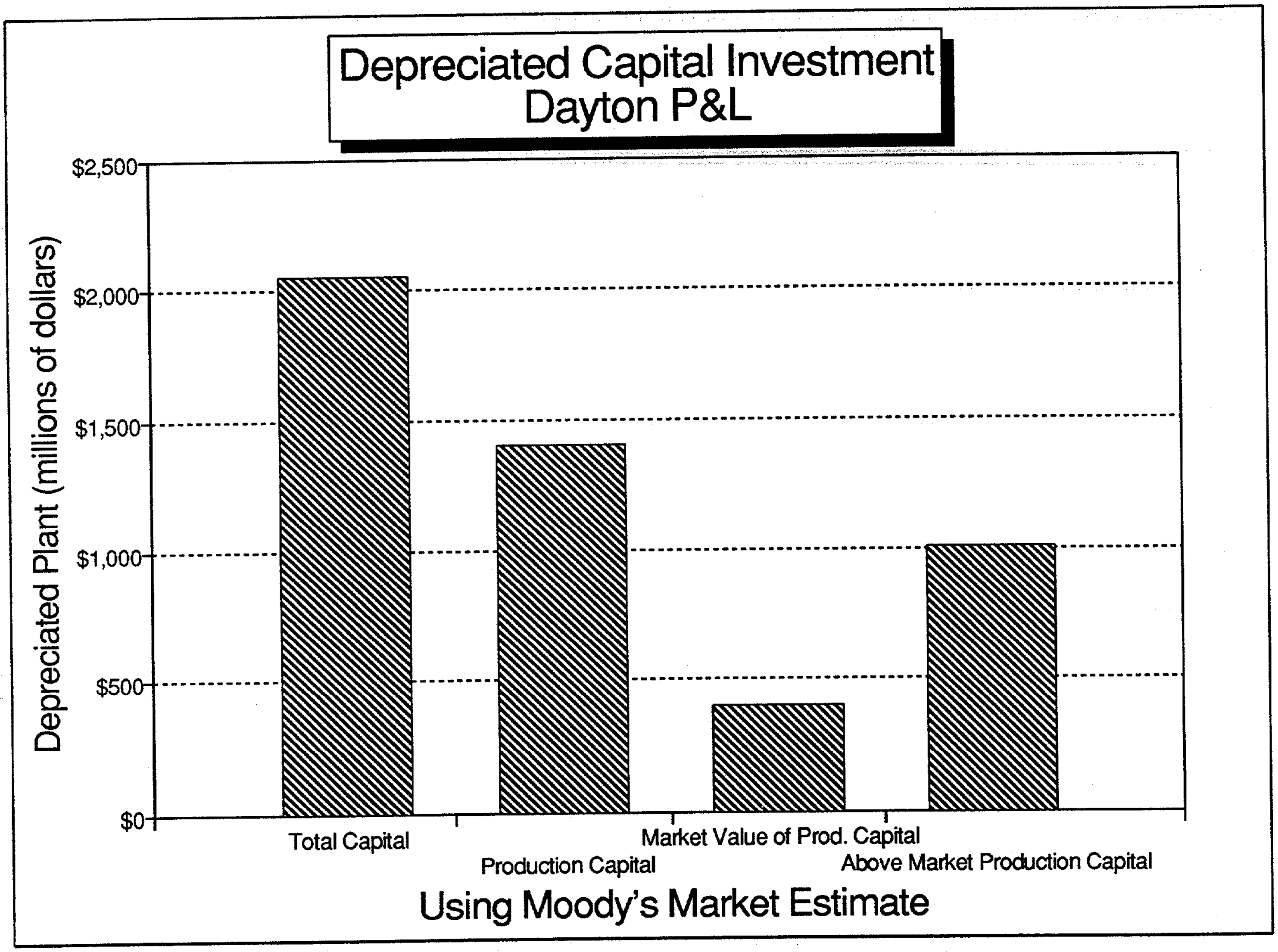
Rate Impact of Restructuring -- Cincinnati G&E
Full Recovery of Stranded Costs/No Industrial Recovery
15%
10%
5%
0%
-5%
-10%
-15%
-20%
-25%
Percentage Change in Rates
Residential
Commercial
Industrial
Using Moody's Market Estimate

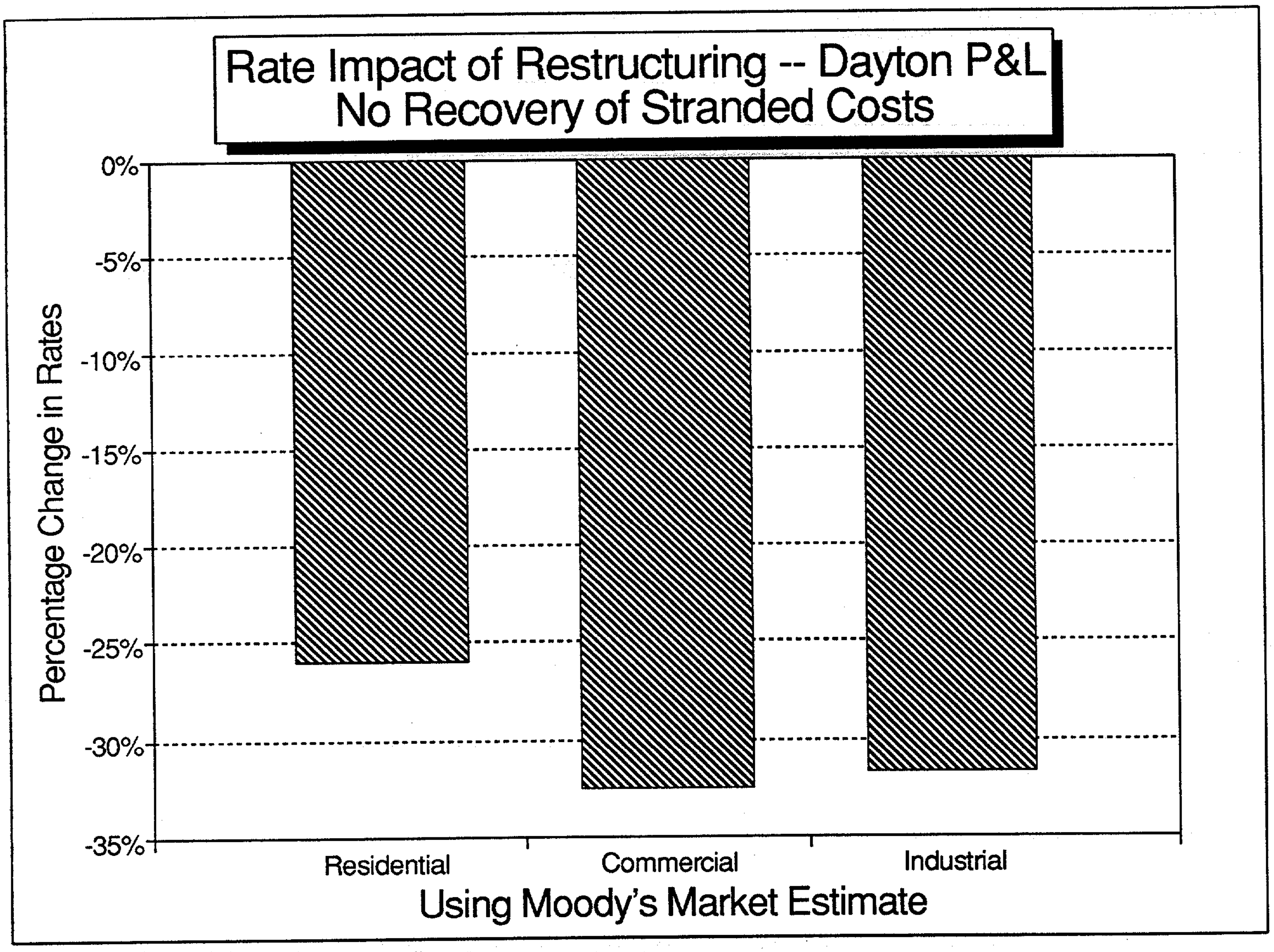


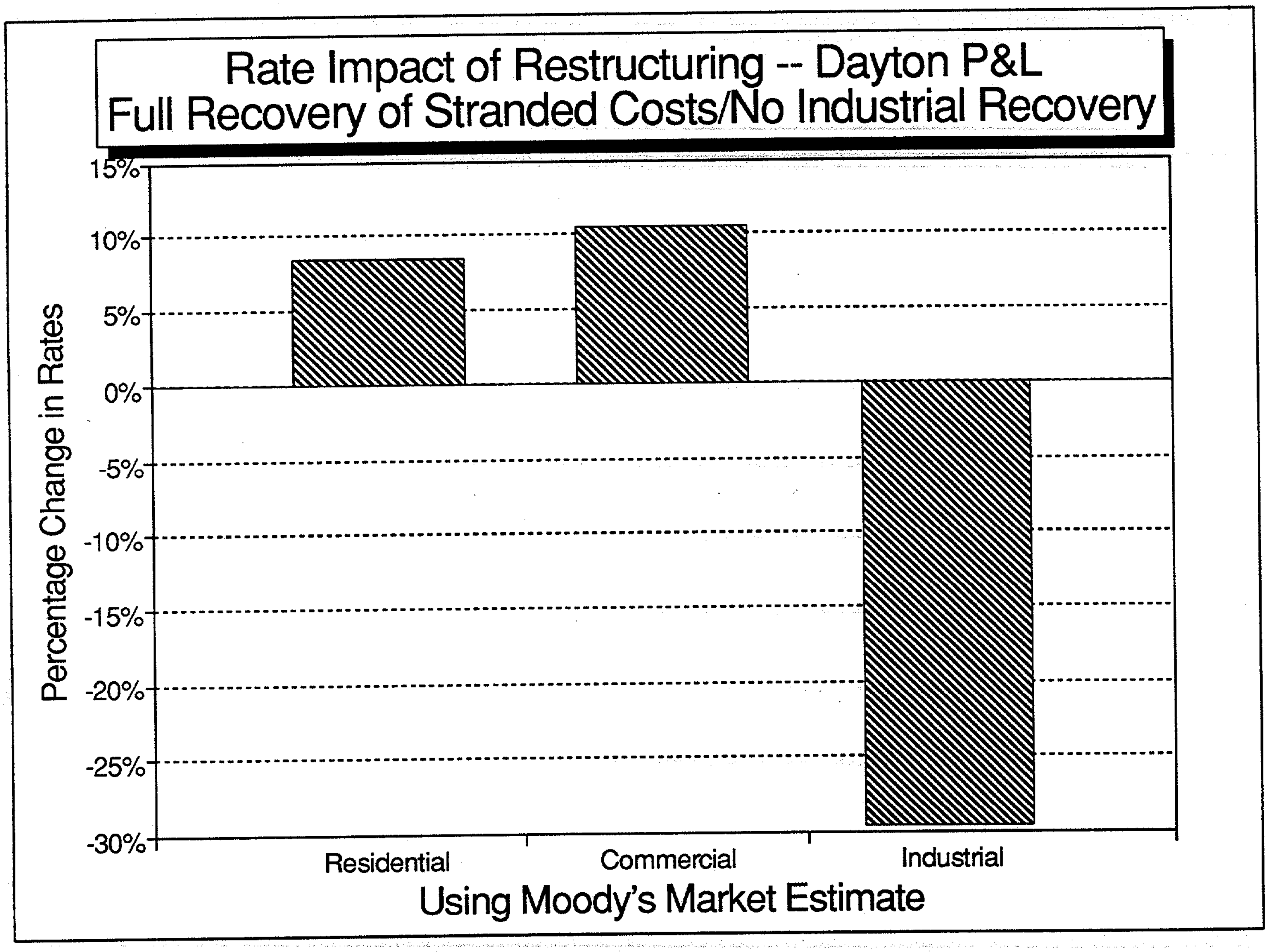
Rate Impact of Restructuring -- Cincinnati G&E
Shared Responsibility for Stranded Costs
Percentage Change in Rates
0%
-2%
-4%
-6%
-8%
-10%
-12%
Residential
Commercial
Industrial
Using Moody's Market Estimate

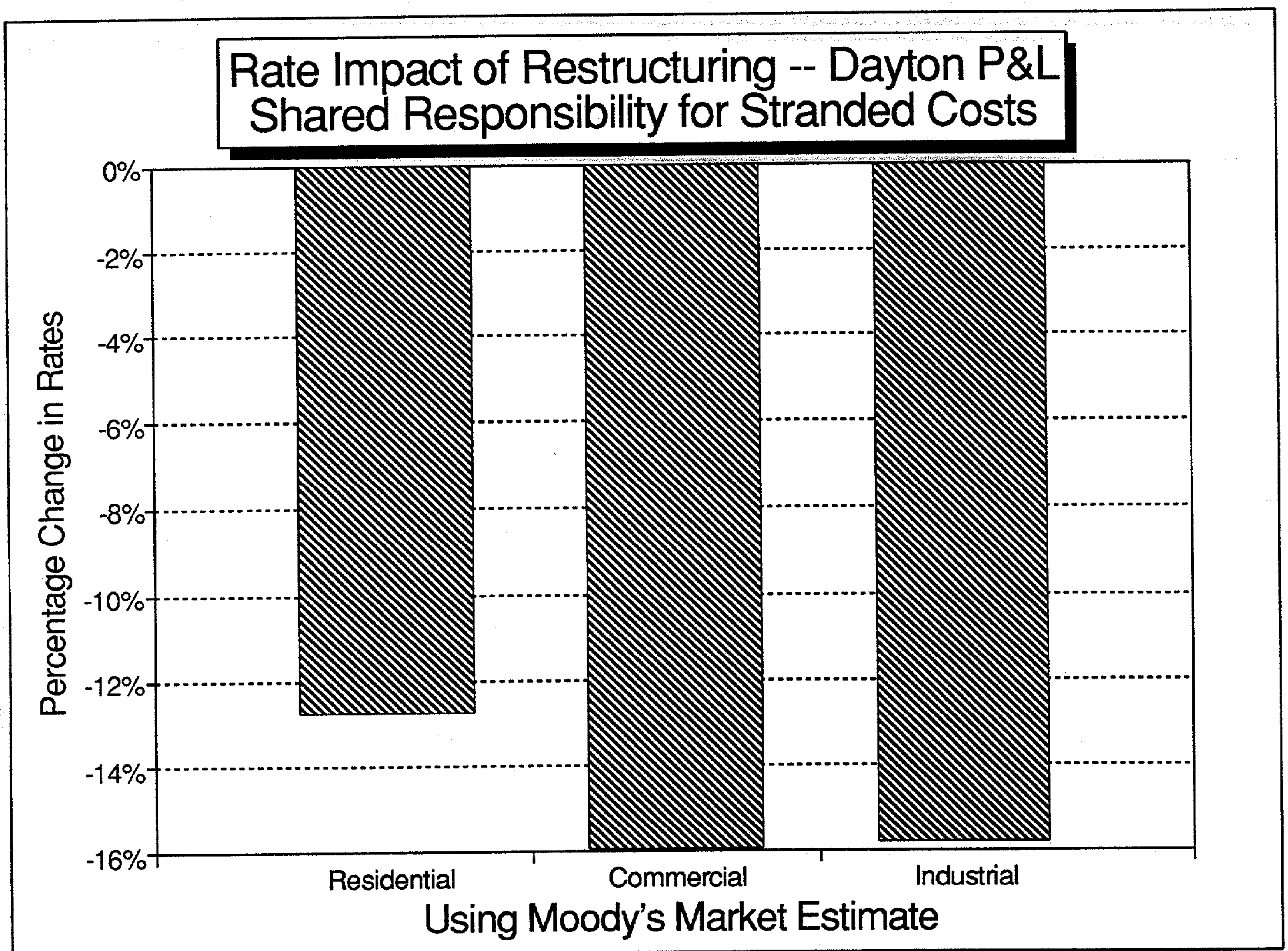
APPENDIX B4. DAYTON POWER AND LIGHT


Market vs Actual Cost of Production
Dayton P&L
Production Cost in $/kWh
$0.045
$0.040
$0.035
$0.030
$0.025
$0.020
$0.015
$0.010
$0.005
$0.000
Actual Cost
Market Cost
Above-Market Cost
Using Moody's Market Estimate
Capacity Cost
Energy Cost

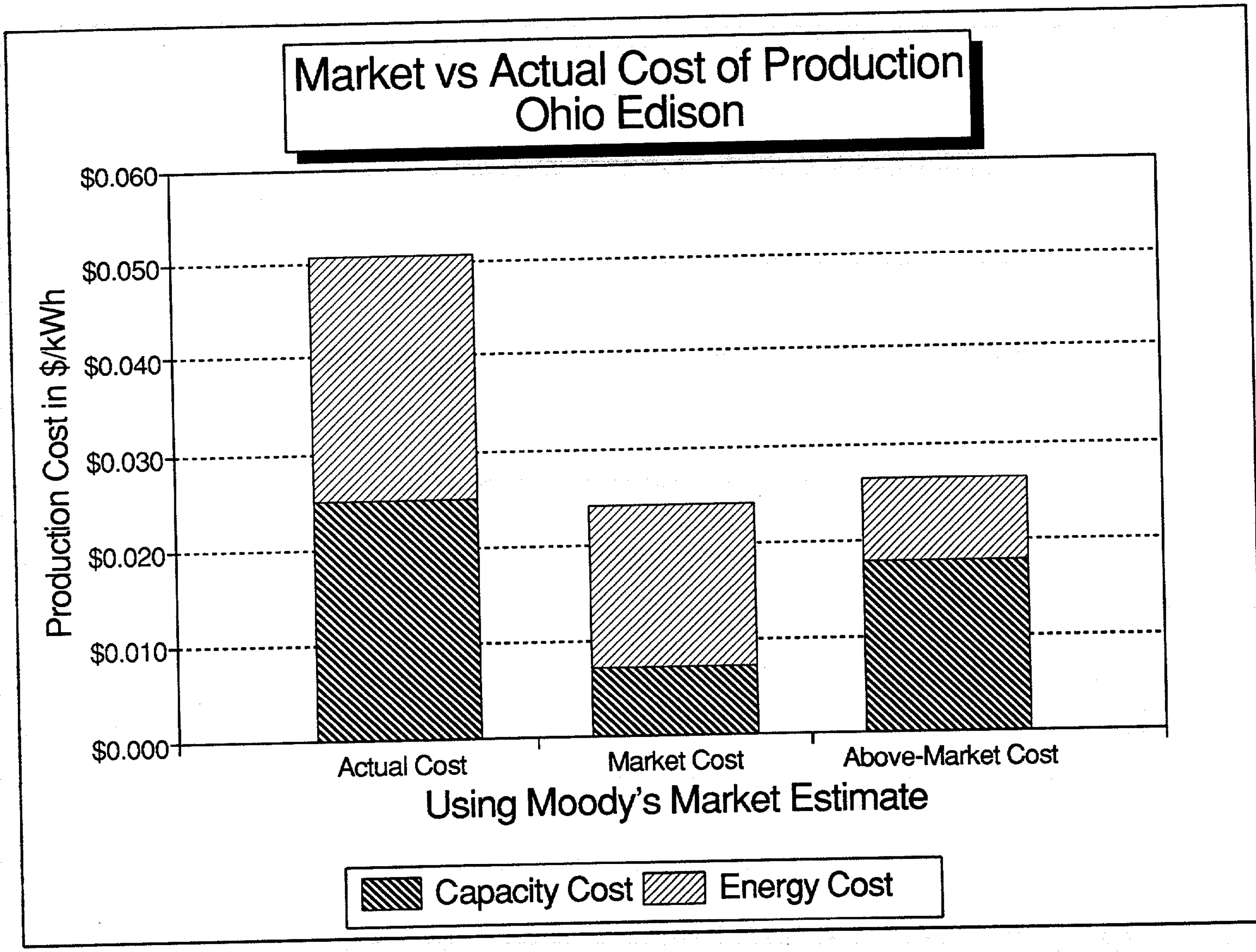

Depreciated Capital Investment
Dayton P&L
Depreciated Plant (millions of dollars)
$2,500
$2,000
$1,500
$1,000
$500
$0
Total Capital
Production Capital
Market Value of Prod. Capital
Above Market Production Capital
Using Moody's Market Estimate

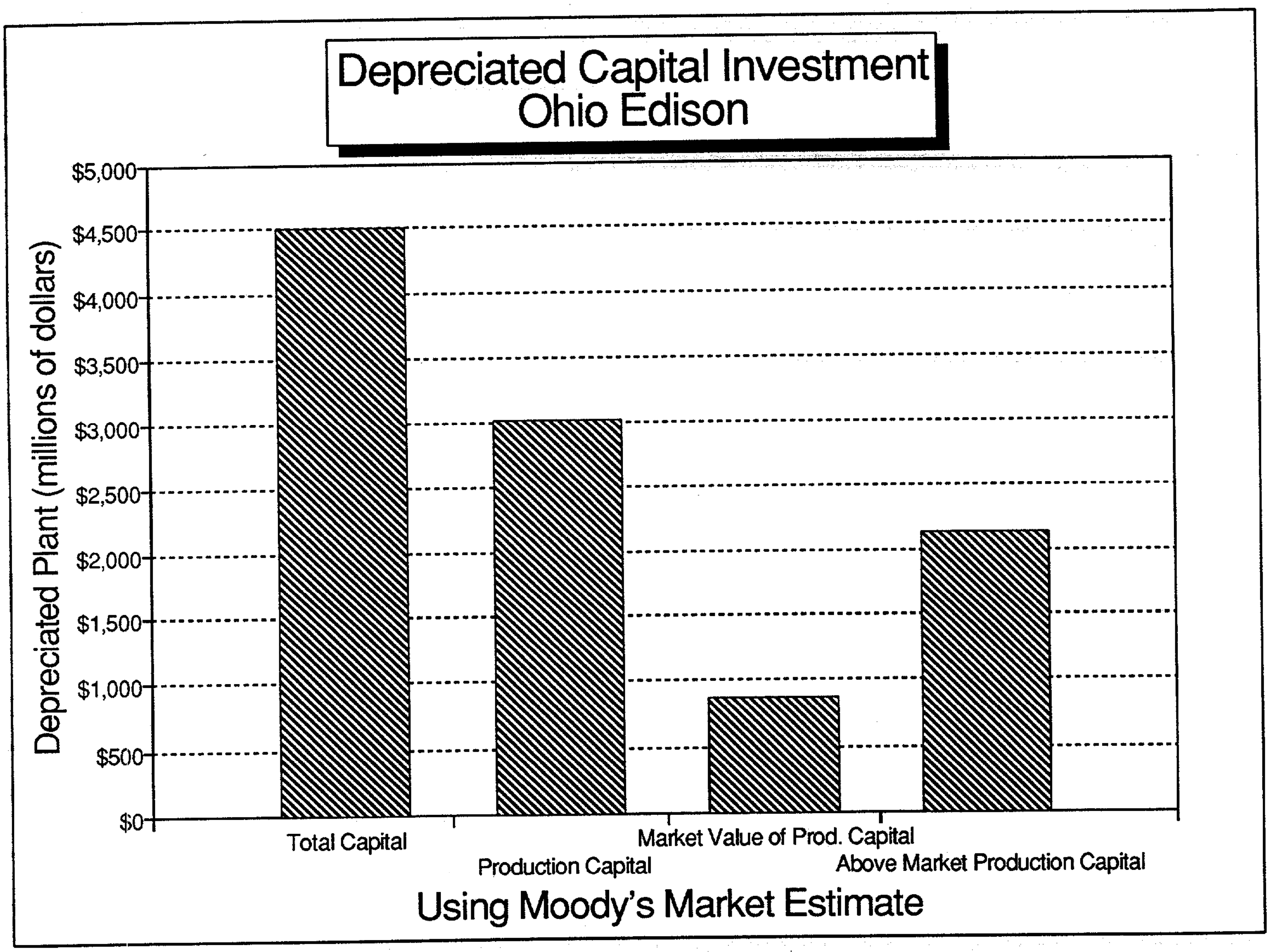

Rate Impact of Restructuring -- Dayton P&L
No Recovery of Stranded Costs
0%
-5%
-10%
-15%
-20%
-25%
-30%
-35%
Percentage Change in Rates
Residential
Commercial
Industrial
Using Moody's Market Estimate


Rate Impact of Restructuring -- Dayton P&L
Full Recovery of Stranded Costs/No Industrial Recovery
Percentage Change in Rates
15%
10%
5%
0%
-5%
-10%
-15%
-20%
-25%
-30%
Residential
Commercial
Industrial
Using Moody's Market Estimate

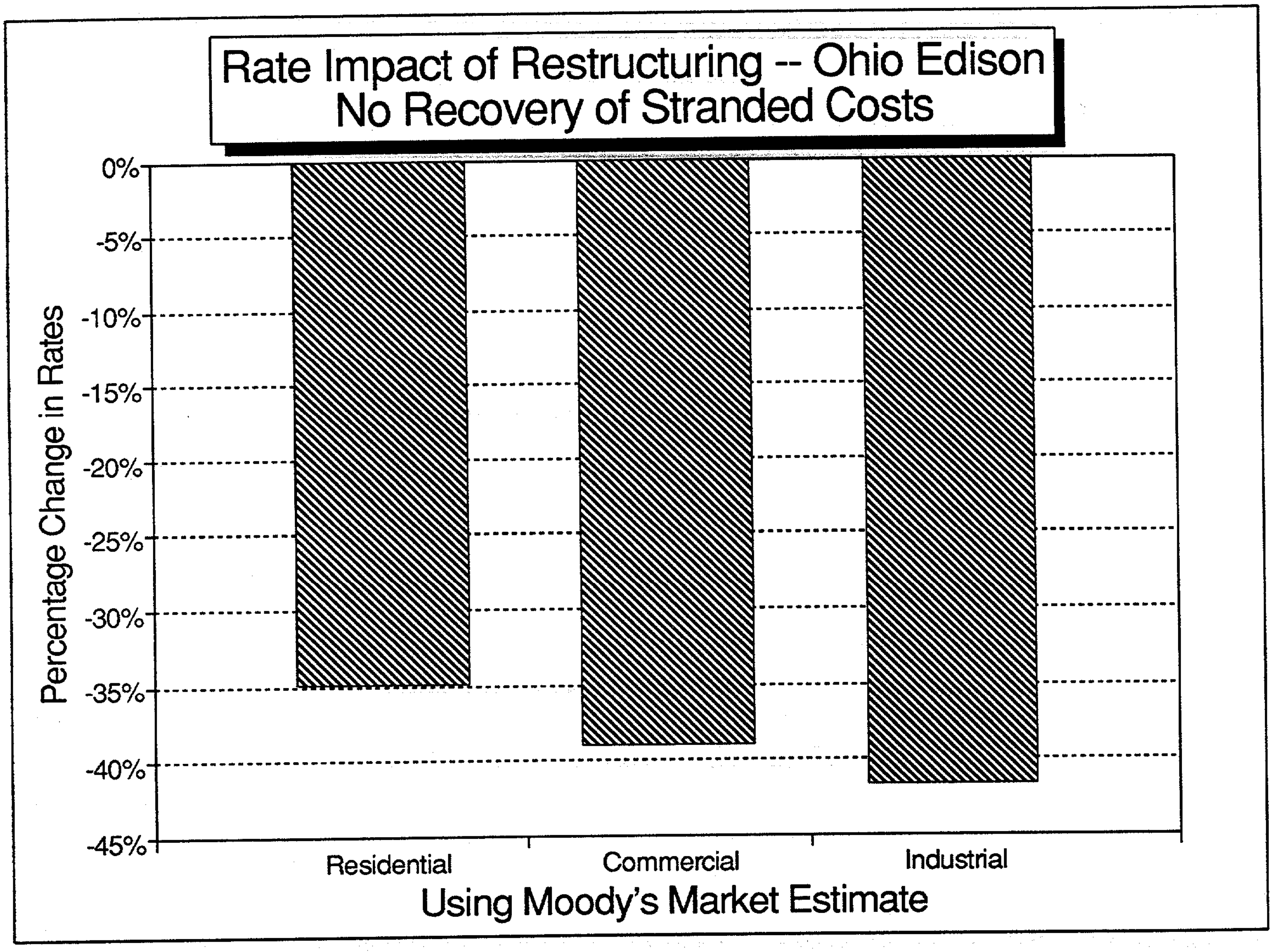

Rate Impact of Restructuring -- Dayton P&L
Shared Responsibility for Stranded Costs
0%
-2%
-4%
-6%
-8%
-10%
-12%
-14%
-16%
Percentage Change in Rates
Residential
Commercial
Industrial
Using Moody's Market Estimate

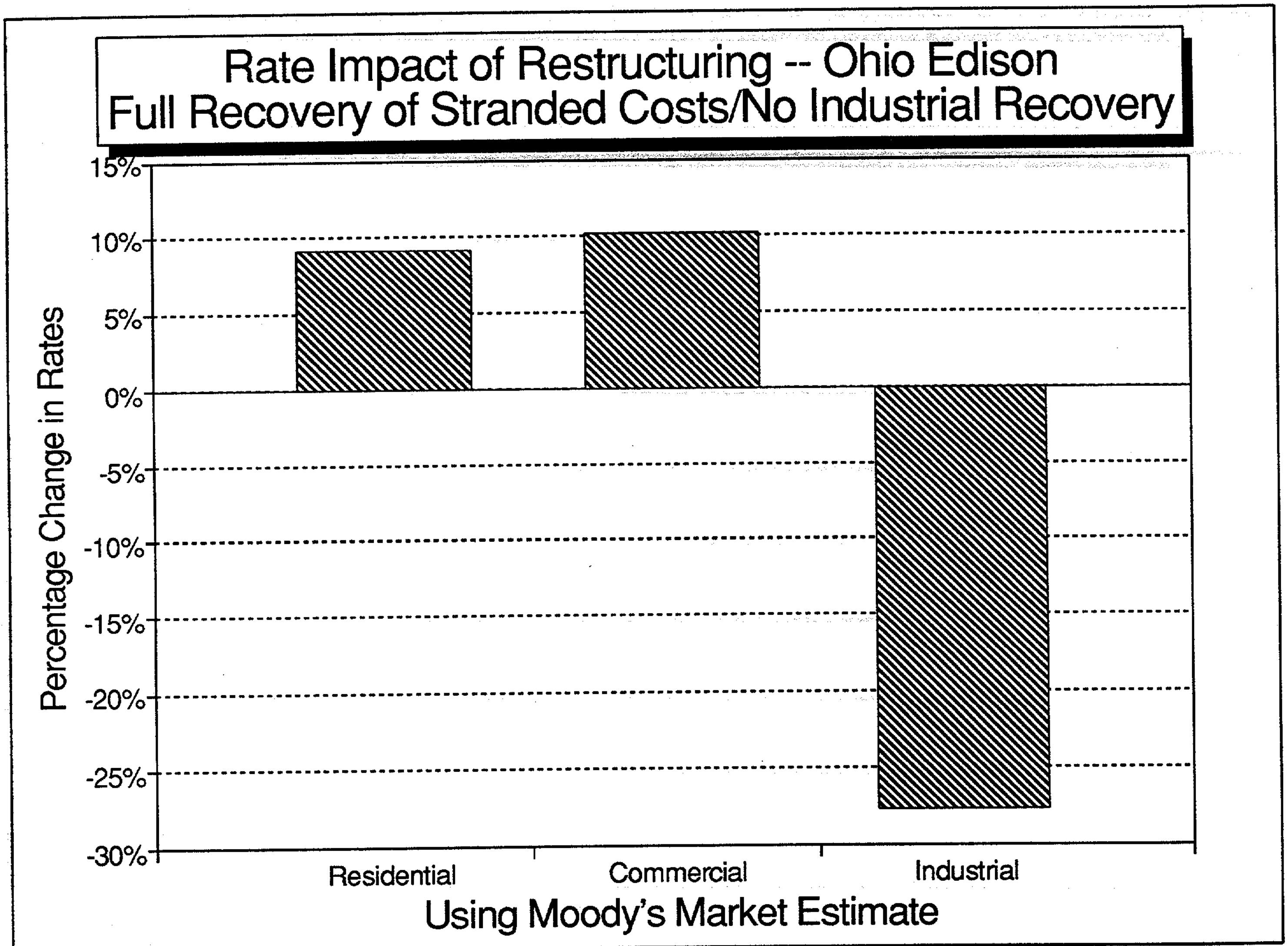
APPENDIX B5. OHIO EDISON

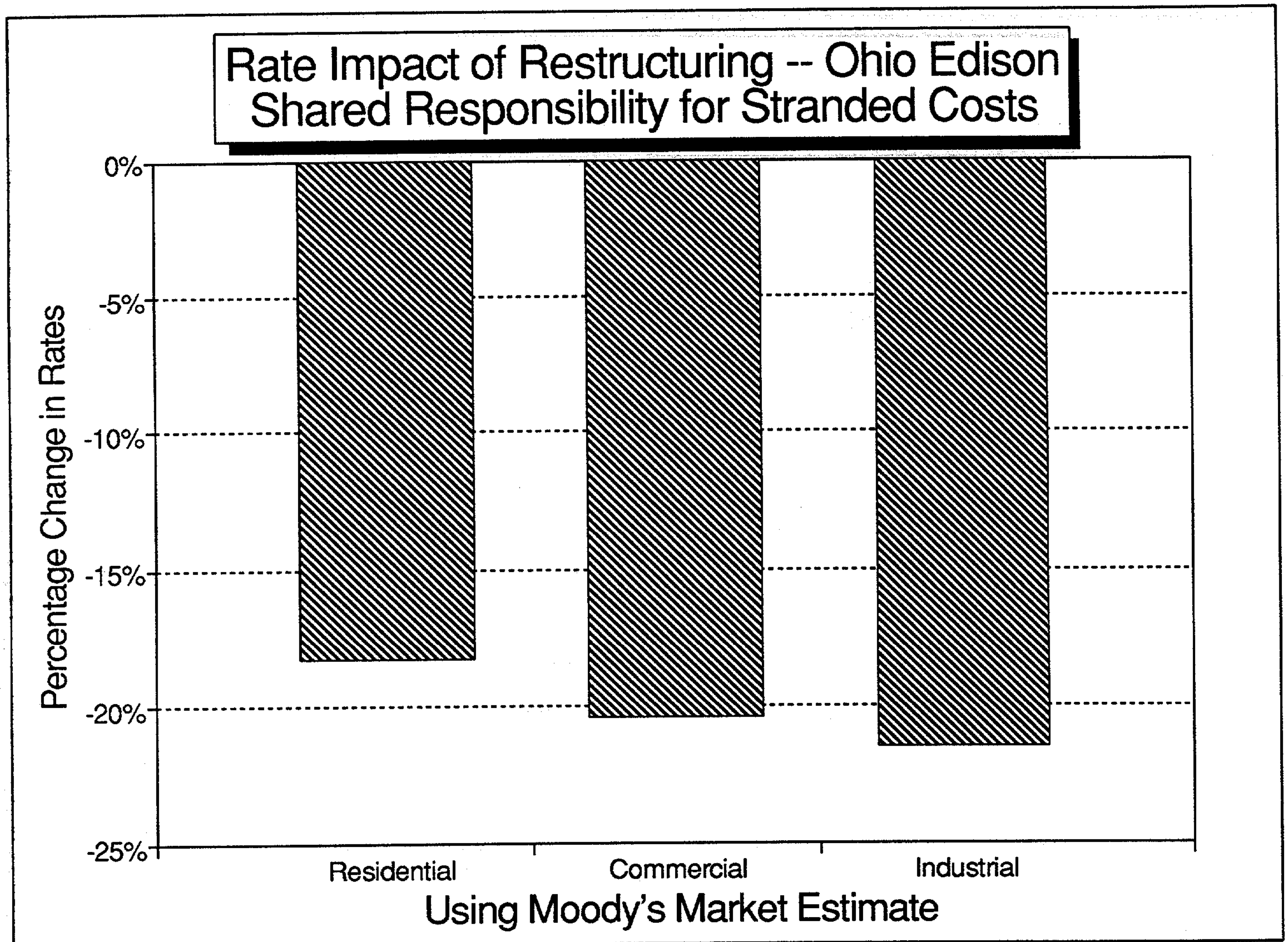

Market vs Actual Cost of Production
Ohio Edison
Production Cost in $/kWh
$0.060
$0.050
$0.040
$0.030
$0.020
$0.010
$0.000
Actual Cost
Market Cost
Above-Market Cost
Using Moody's Market Estimate
Capacity Cost
Energy Cost



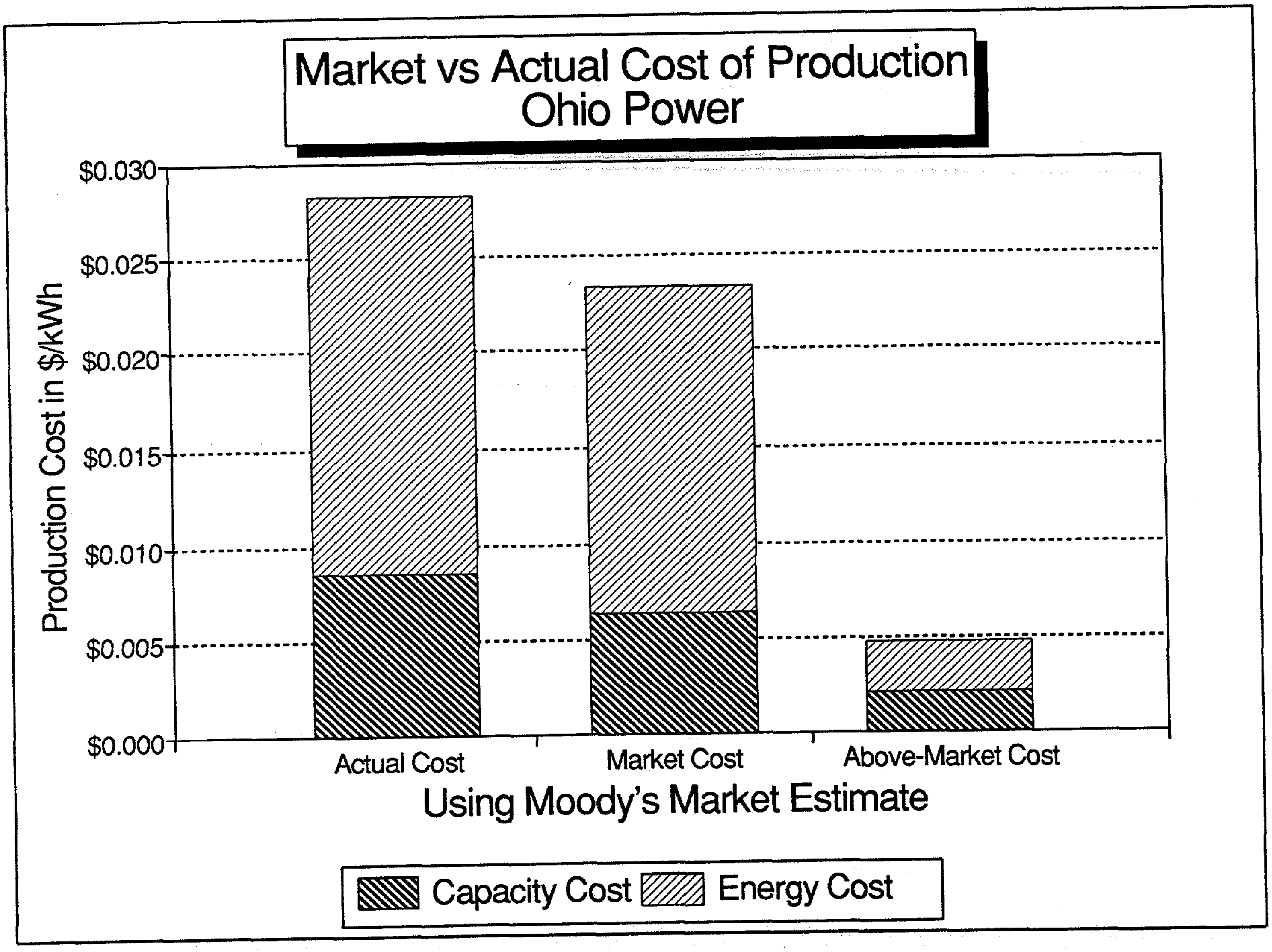
Depreciated Capital Investment
Ohio Edison
$5,000
$4,500
$4,000
$3,500
$3,000
$2,500
$2,000
$1,500
$1,000
$500
$0
Depreciated Plant (millions of dollars)
Total Capital
Production Capital
Market Value of Prod. Capital
Above Market Production Capital
Using Moody's Market Estimate

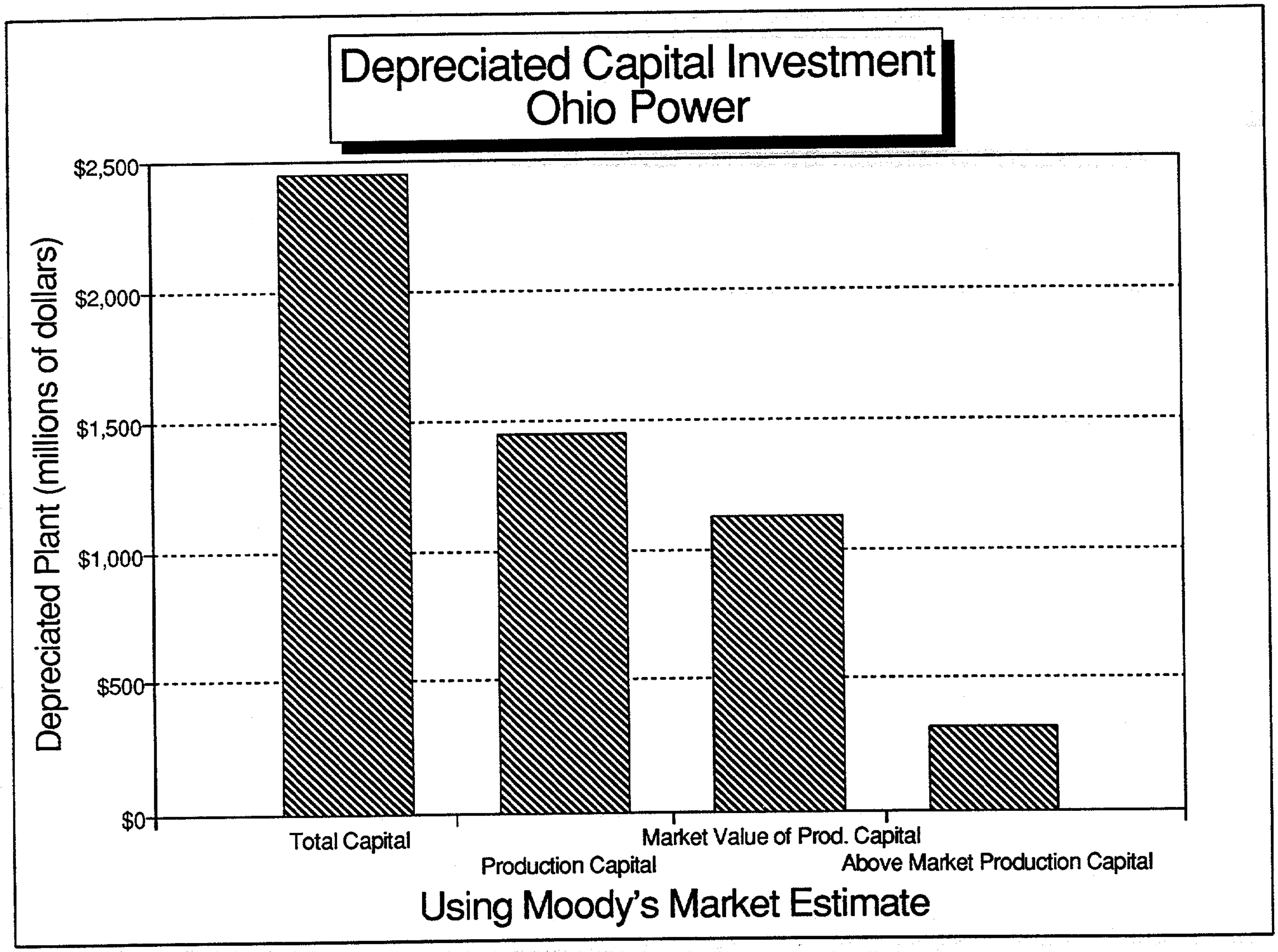

Rate Impact of Restructuring -- Ohio Edison
No Recovery of Stranded Costs
Percentage Change in Rates
0%
-5%
-10%
-15%
-20%
-25%
-30%
-35%
-40%
-45%
Residential
Commercial
Industrial
Using Moody's Market Estimate


Rate Impact of Restructuring -- Ohio Edison
Full Recovery of Stranded Costs/No Industrial Recovery
15%
10%
5%
0%
-5%
-10%
-15%
-20%
-25%
-30%
Percentage Change in Rates
Residential
Commercial
Industrial
Using Moody's Market Estimate

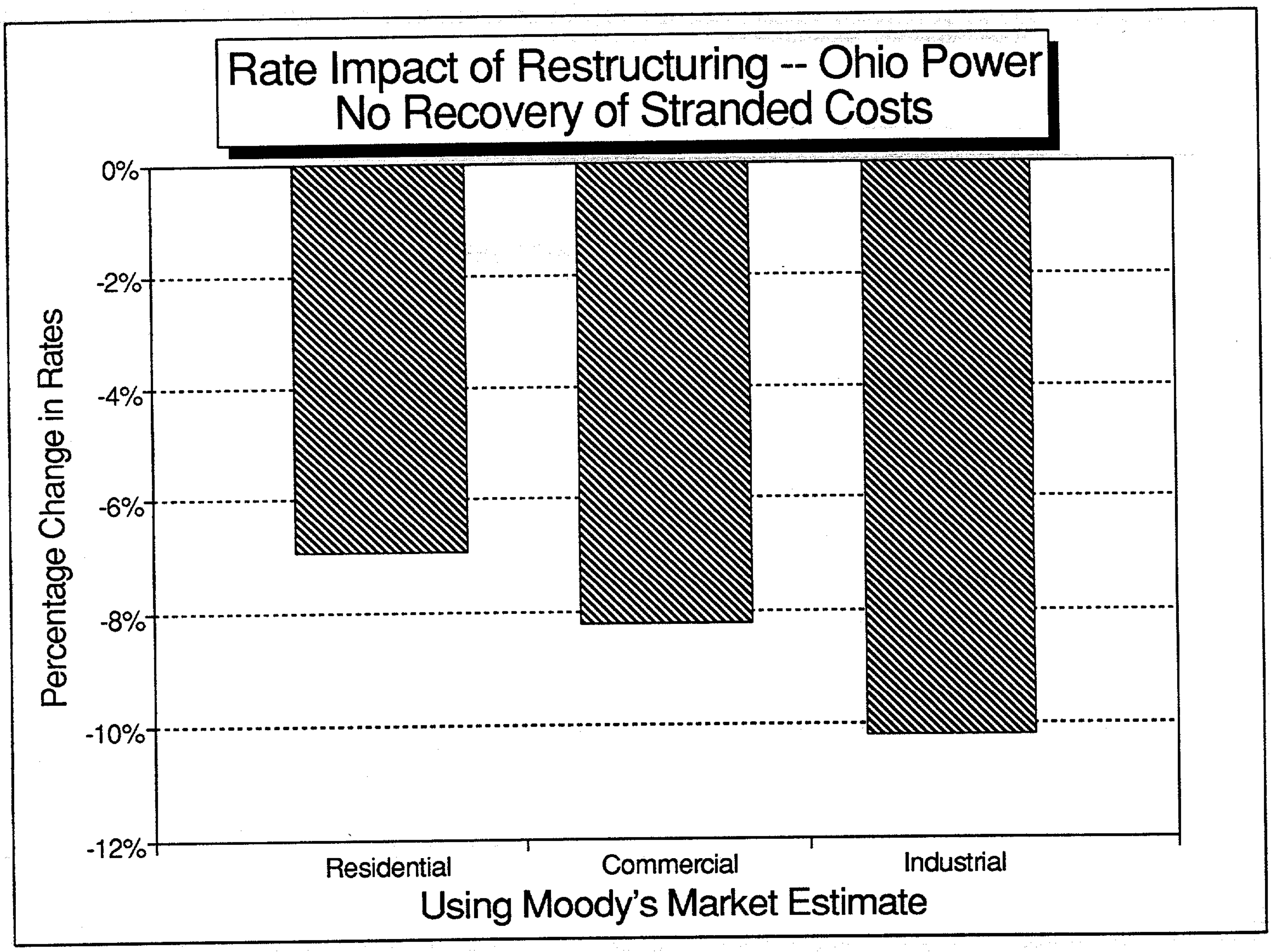

Rate Impact of Restructuring -- Ohio Edison
Shared Responsibility for Stranded Costs
0%
-5%
-10%
-15%
-20%
-25%
Percentage Change in Rates
Residential
Commercial
Industrial
Using Moody's Market Estimate

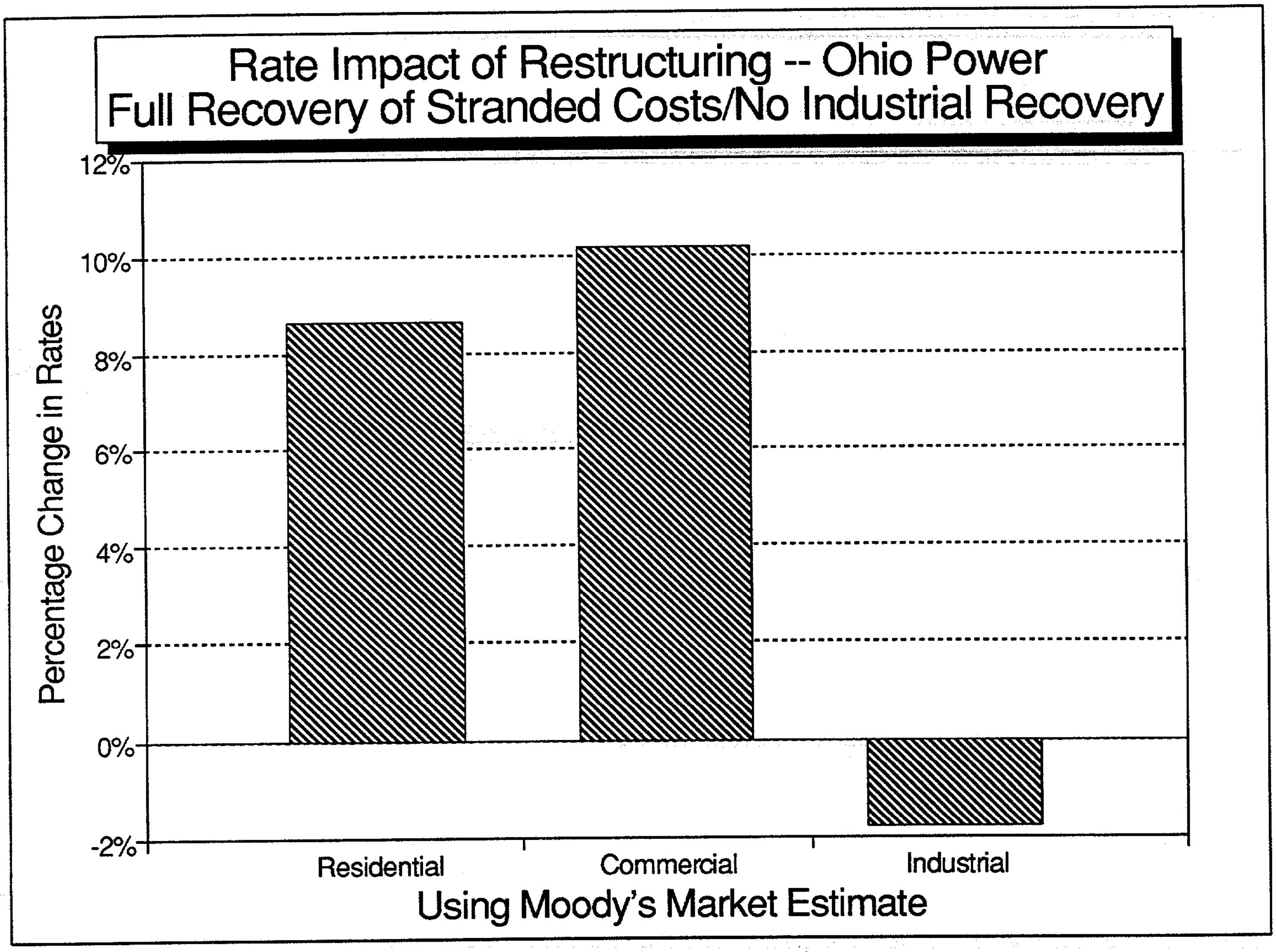
APPENDIX B6. OHIO POWER

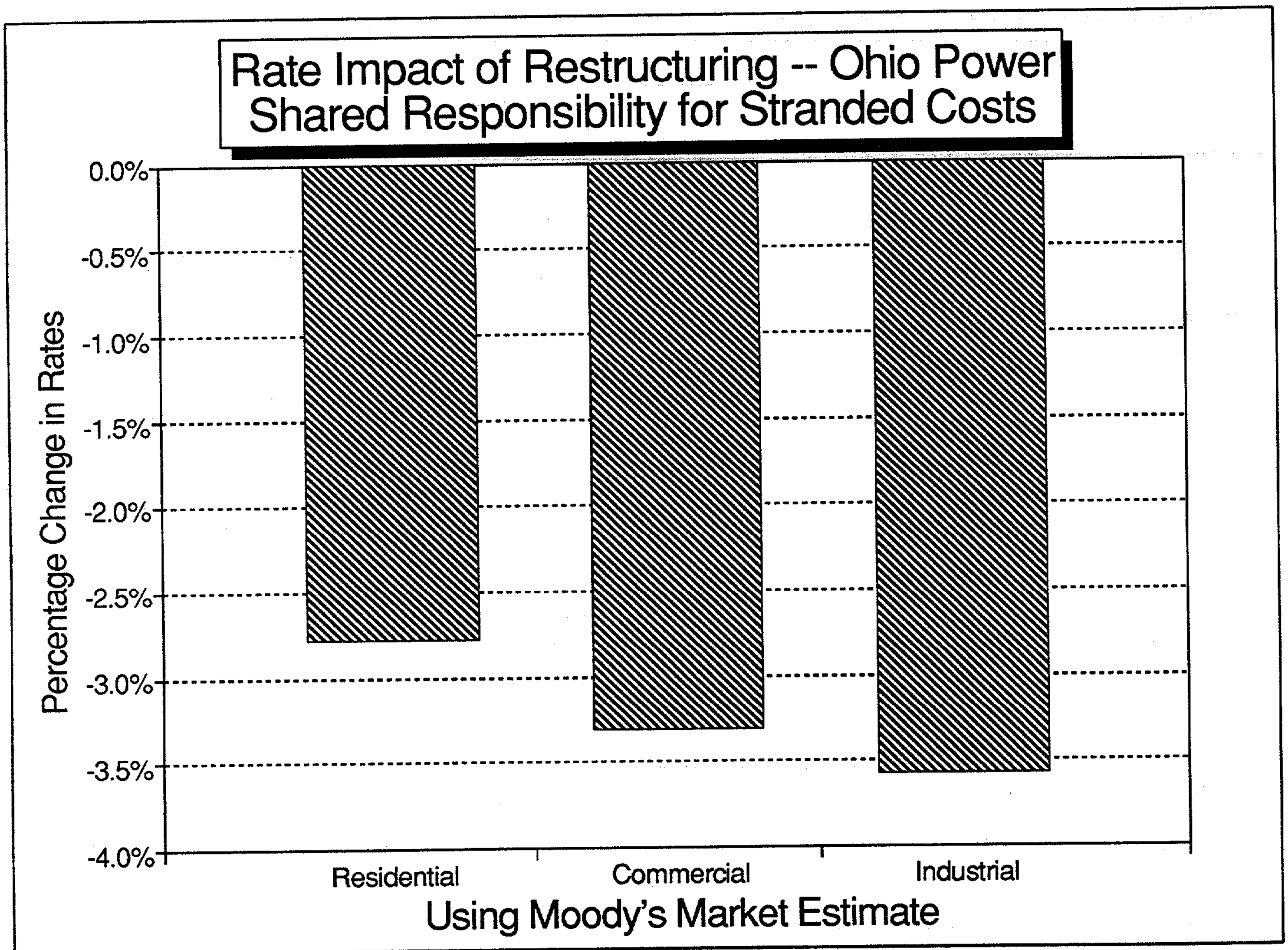

Market vs Actual Cost of Production
Ohio Power
$0.030
$0.025
$0.020
$0.015
$0.010
$0.005
$0.000
Production Cost in $/kWh
Actual Cost
Market Cost
Above-Market Cost
Using Moody's Market Estimate
Capacity Cost
Energy Cost



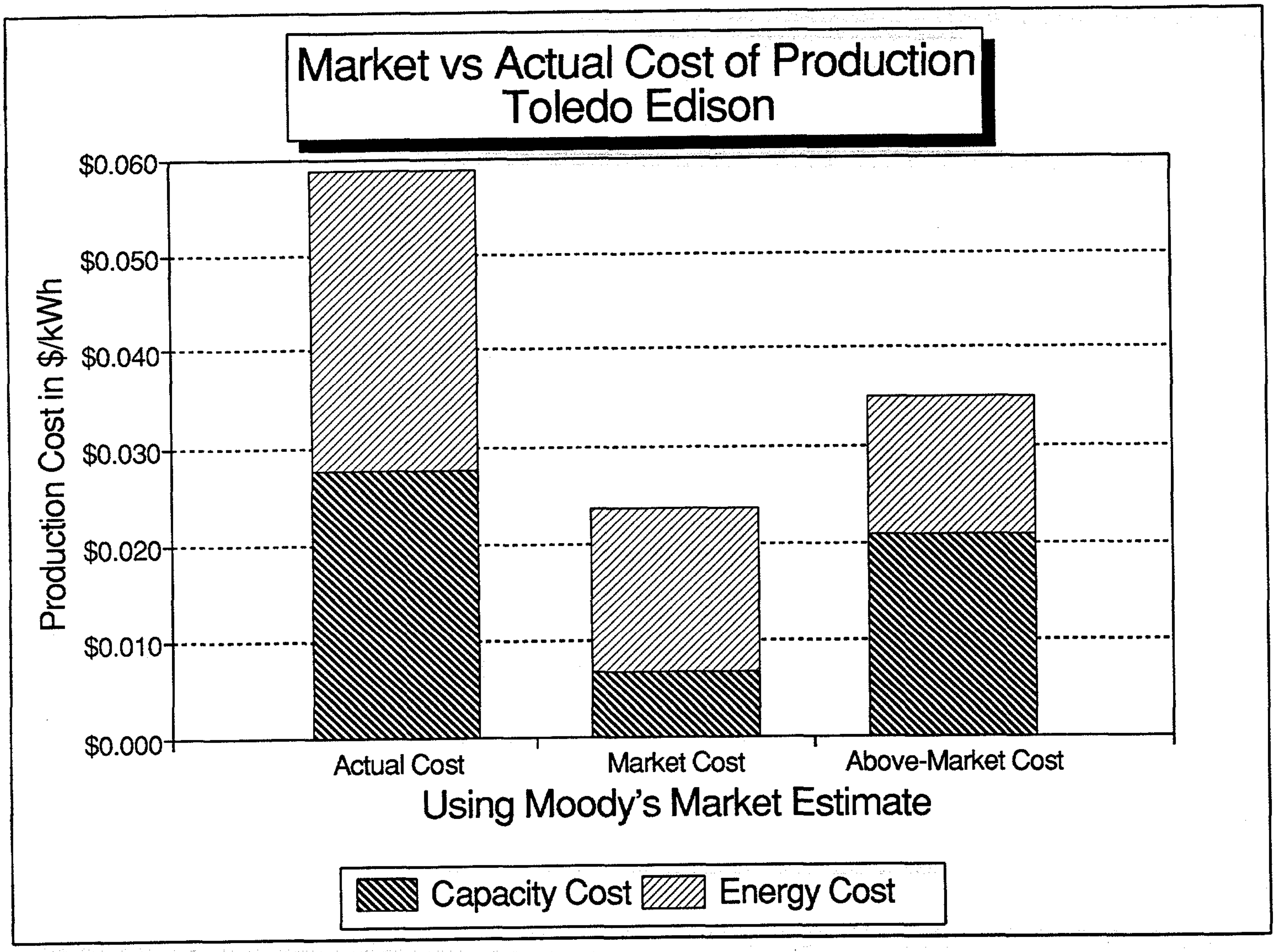
Depreciated Capital Investment
Ohio Power
Depreciated Plant (millions of dollars)
$2,500
$2,000
$1,500
$1,000
$500
$0
Total Capital
Production Capital
Market Value of Prod. Capital
Above Market Production Capital
Using Moody's Market Estimate


Rate Impact of Restructuring -- Ohio Power
No Recovery of Stranded Costs
0%
-2%
-4%
-6%
-8%
-10%
-12%
Percentage Change in Rates
Residential
Commercial
Industrial
Using Moody's Market Estimate

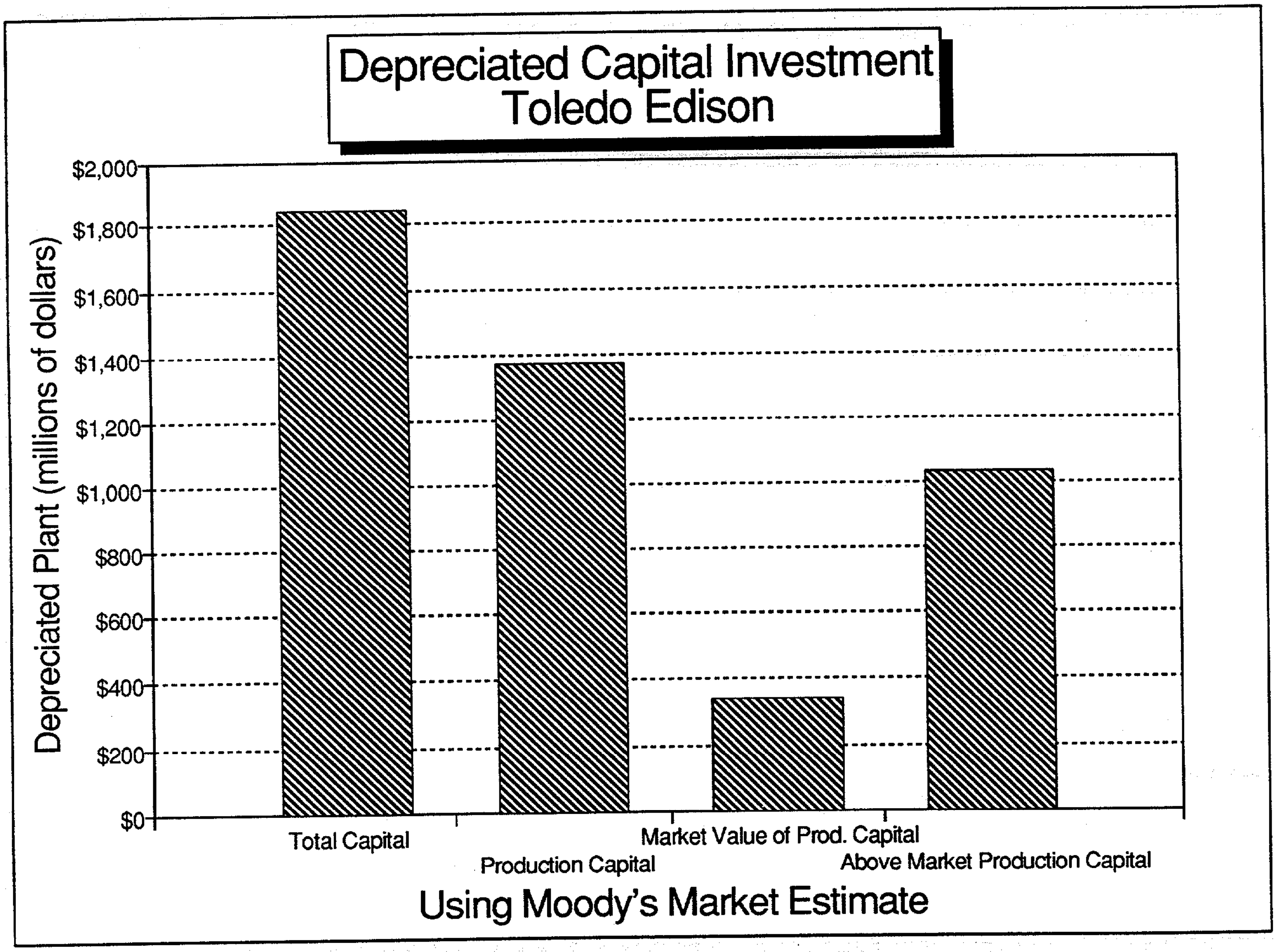

Rate Impact of Restructuring -- Ohio Power
Full Recovery of Stranded Costs/No Industrial Recovery
12%
10%
8%
6%
4%
2%
0%
-2%
Percentage Change in Rates
Residential
Commercial
Industrial
Using Moody's Market Estimate


Rate Impact of Restructuring -- Ohio Power
Shared Responsibility for Stranded Costs
0.0%
-0.5%
-1.0%
-1.5%
-2.0%
-2.5%
-3.0%
-3.5%
-4.0%
Percentage Change in Rates
Residential
Commercial
Industrial
Using Moody's Market Estimate

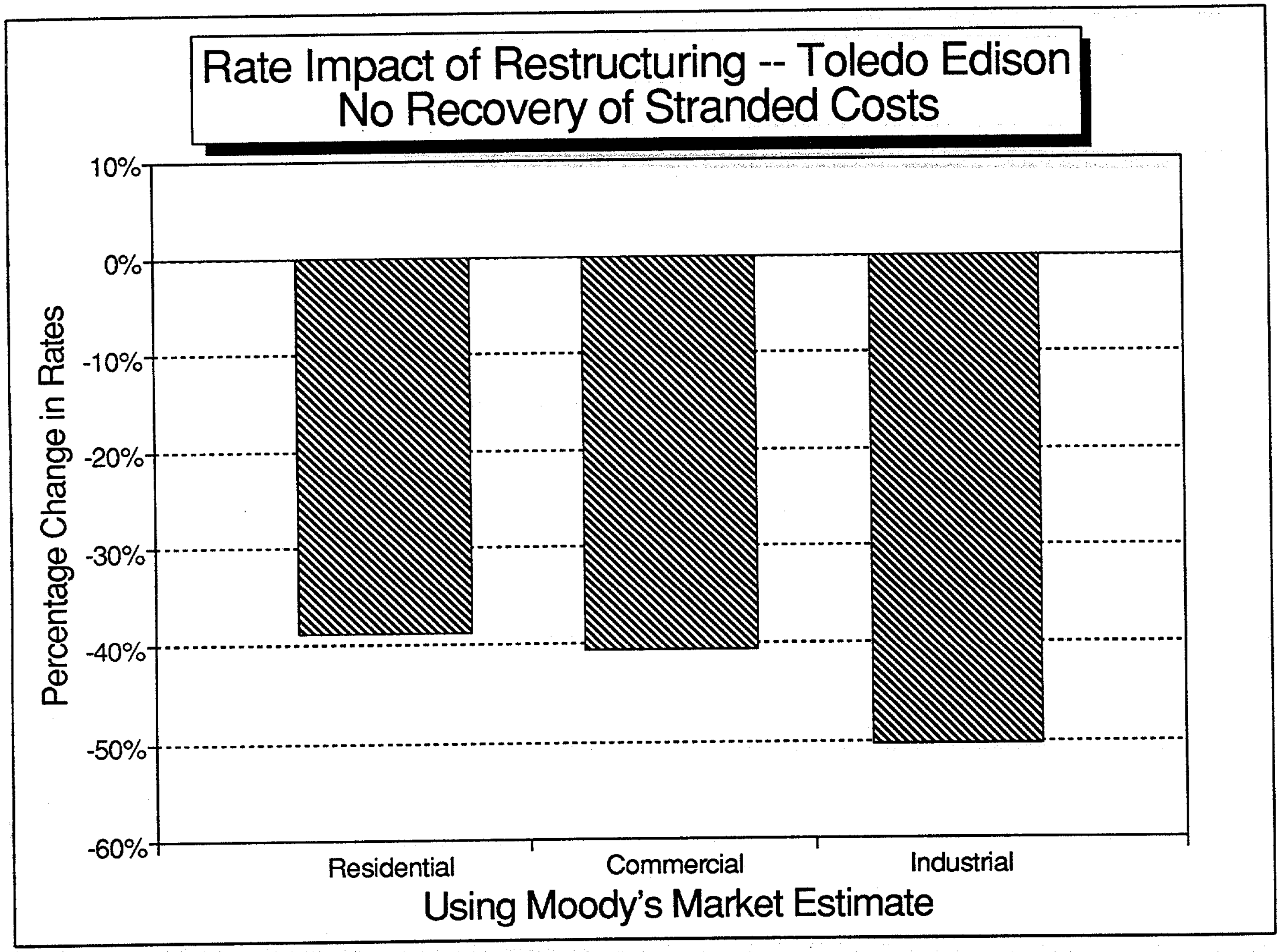
APPENDIX B7. TOLEDO EDISON

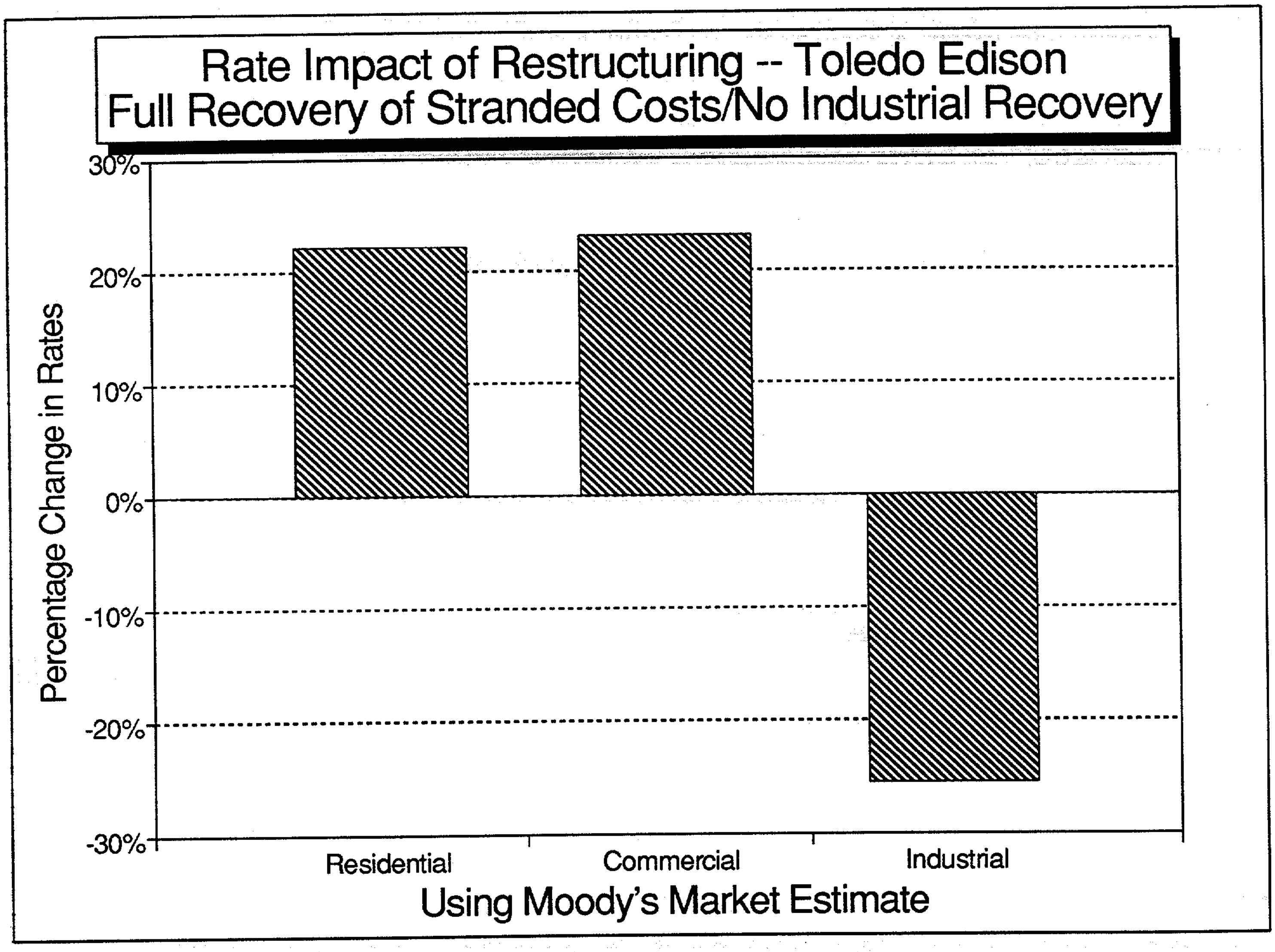


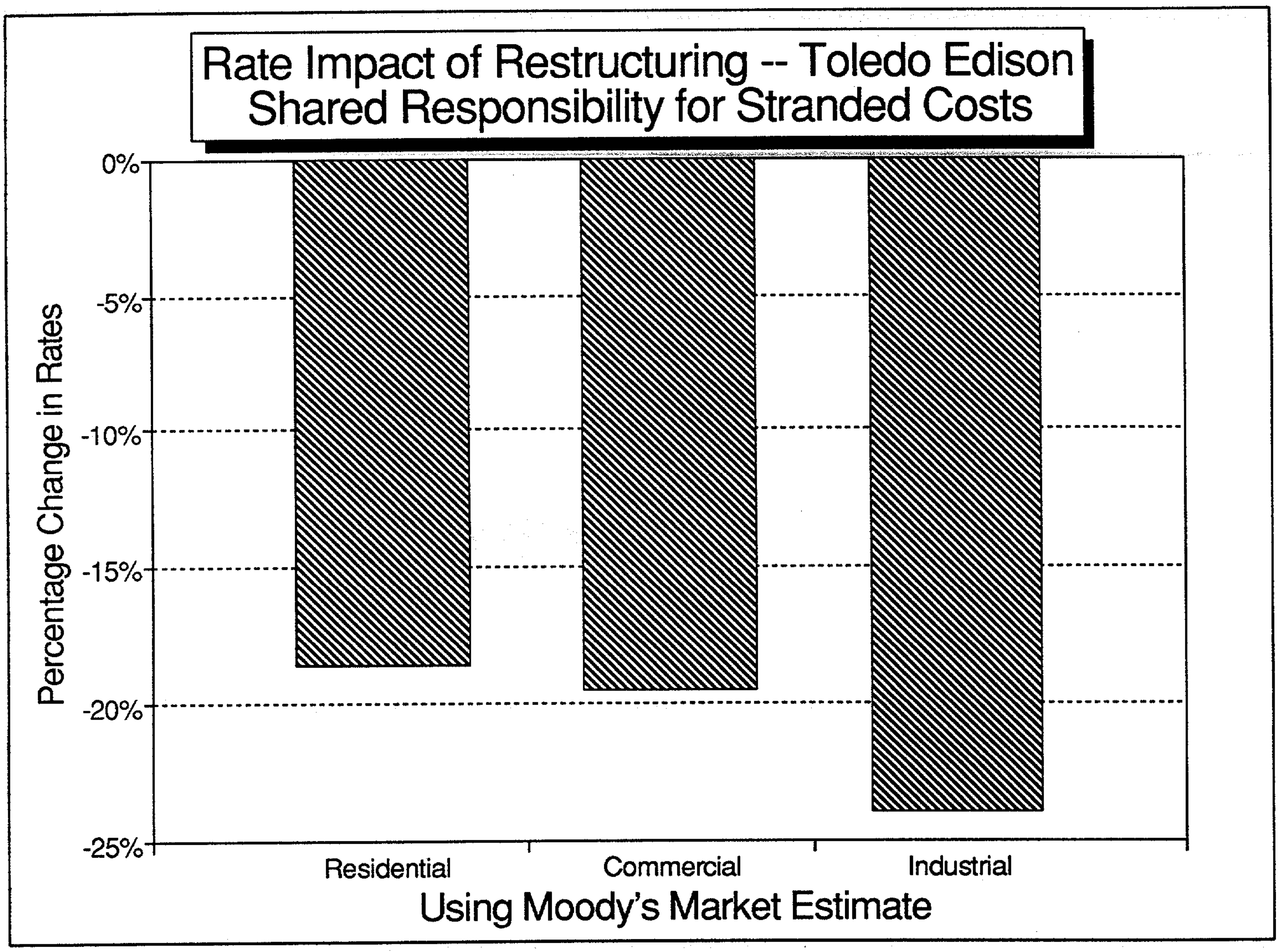
Market vs Actual Cost of Production
Toledo Edison
$0.060
$0.050
$0.040
$0.030
$0.020
$0.010
$0.000
Production Cost in $/kWh
Actual Cost
Market Cost
Above-Market Cost
Using Moody's Market Estimate
Capacity Cost
Energy Cost



Depreciated Capital Investment
Toledo Edison
Depreciated Plant (millions of dollars)
$2,000
$1,800
$1,600
$1,400
$1,200
$1,000
$800
$600
$400
$200
$0
Total Capital
Production Capital
Market Value of Prod. Capital
Above Market Production Capital
Using Moody's Market Estimate


Rate Impact of Restructuring -- Toledo Edison
No Recovery of Stranded Costs
10%
0%
-10%
-20%
-30%
-40%
-50%
-60%
Percentage Change in Rates
Residential
Commercial
Industrial
Using Moody's Market Estimate


Rate Impact of Restructuring -- Toledo Edison
Full Recovery of Stranded Costs/No Industrial Recovery
30%
20%
10%
0%
-10%
-20%
-30%
Percentage Change in Rates
Residential
Commercial
Industrial
Using Moody's Market Estimate


Rate Impact of Restructuring -- Toledo Edison
Shared Responsibility for Stranded Costs
0%
-5%
-10%
-15%
-20%
-25%
Percentage Change in Rates
Residential
Commercial
Industrial
Using Moody's Market Estimate