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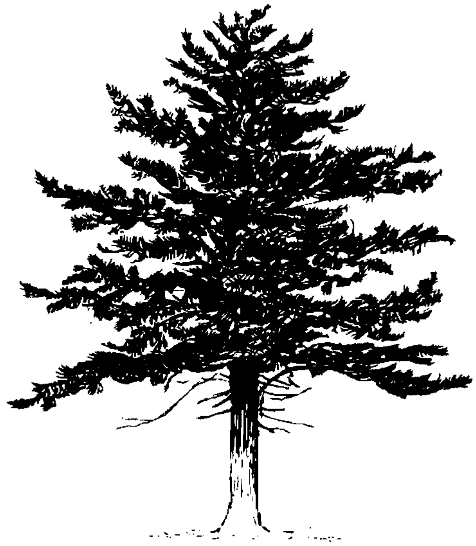

COMPETITIVE ELECTRICITY MARKETS IN NEW YORK STATE: EMPIRICAL IMPACTS OF INDUSTRY RESTRUCTURING

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ABSTRACT

The analysis finds that if high industrial prices for electricity induce industrial customers to leave the regulated grid for self-generation or contracts with IPPs, this raises rates for those remaining on the system and reduces quantities purchased. It is assumed that lower industrial sector rates, such as those associated with a competitive electricity industry, will effectively eliminate defections.

A switch to a more efficient two-part tariff, which can be expected to occur in a competitive electricity market, has the effect of increasing sales of electricity in all sectors while still raising needed revenues. Such a price structure is also found to lower the average price of electricity in each sector. An efficient two-part tariff is also likely to shift revenue responsibilities to immobile residential and commercial customers. This would occur because industrial customers shift demand by defection in response to average price changes, but residential and commercial demand is inelastic to customer charges.

If prices are efficient, strandable cost allocations only have a minor effect on electricity demand because strandable cost payments are raised via a customer charge. If strandable costs are recovered by a wires charge (e.g. higher prices),however, there will be negative demand effects. Strandable costs significantly affect the average price of electricity and the average monthly bill in either case. Their allocation is important for equity reasons, as is the method of collection in determining the levels of sales.

Removing strandable costs lowers the average price of electricity in each sector and increases demand. Lowering strandable costs is the only option which clearly benefits all sectors.

Competitive Electricity Markets in New York State:
Empirical Impacts of Industry Restructuring

R. Ethier and T. D. Mount

1. INTRODUCTION

Much qualitative work has been done on evaluating the impacts of competition on the electric industry of New York State, with most observers asserting that it will benefit consumers by lowering prices (The New York Times, March 30,1995; Staff Position Paper 1995; Recommended Decision 1995). As yet, there are few empirical estimates of these effects, even though quantitative estimates are necessary for informed public policy decision making.

Likewise, industrial defections, where industrial customers, in response to high prices, leave the regulated utility system for self-generation or Independent Power Producer (IPP) contracts are similarly in need of empirical attention. Industrial sector defections are important because they are one of the justifications for moving to a competitive system.

Two features of competition are considered which differ from the current world of regulated electricity generation and delivery: efficient price structures and strategies for paying for stranded assets. The current electric industry price structures and the mechanisms for recovering the costs of capital investments have developed under government-sanctioned monopoly and regulation. A competitive market requires a rethinking of both issues. How should electricity be priced in a competitive world? And what is to be done with the regulated utilities and their (possibly uneconomic) assets? These questions can be illuminated by economic theory and empirical evidence.

Of course there are a large number of other important issues which will determine the success of a move to competition. For example, system reliability, monopoly power, and social programs all need to be considered. Nevertheless, the implications of revised pricing schemes and strategies for re-allocating existing costs of stranded assets are still unexplored and they promise to be far-reaching.

The analysis finds that if high industrial prices for electricity induce industrial customers to leave the regulated grid for self-generation or contracts with IPPs, this raises rates for those remaining on the system and reduces quantities purchased. It is assumed that lower industrial sector rates, such as those associated with a competitive electricity industry, will effectively eliminate defections.

A switch to a more efficient two-part tariff, which can be expected to occur in a competitive electricity market, has the effect of increasing sales of electricity in all sectors while still raising needed revenues. Such a price structure is also found to lower the average price of electricity in each sector. An efficient two-part tariff is also likely to shift revenue responsibilities to immobile residential and commercial customers. This would occur because industrial customers shift demand by defection in response to average price changes, but residential and commercial demand is inelastic to customer charges.

If prices are efficient, strandable cost allocations only have a minor effect on electricity demand because strandable cost payments are raised via a customer charge. If strandable costs are recovered by a wires charge (e.g. higher prices),however, there will be negative demand effects. Strandable costs significantly affect the average price of electricity and the average monthly bill in either case. Their allocation is important for equity reasons, as is the method of collection in determining the levels of sales.

Removing strandable costs lowers the average price of electricity in each sector and increases demand. Lowering strandable costs is the only option which clearly benefits all sectors.

2. OUTLINE

The next section discusses efficient electricity rates. Generally, current rates structures are inefficient, with a mix of Ramsey pricing and multi-part tariffs. With a competitive industry, it is likely that there will be increased reliance on an efficient two-part tariff. A simple two-sector demand model is developed to illustrate the potential impacts of both rate restructuring and a reduction in utility ratebases due to disallowance of strandable costs. A two-part tariff will both increase demand and shift revenue collection to sectors with inelastic demand. A reduced ratebase results in lower average prices, but sales are not affected very much if rate structures are efficient.

The current price structure and the two-part tariff are then evaluated in a dynamic model of New York State electricity supply and demand. The model uses a complete Generalized Logit demand system coupled with a New York State electric supply finance model. This model is used to provide forecasts of New York State assumed that lower industrial sector rates, such as those associated with a competitive electricity industry, will effectively eliminate defections.

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A Base Case scenario is developed to show model properties and create a baseline forecast. Then an Industrial Defection scenario is run, which assumes that high industrial electric rates cause industrial users to either self-generate or contract with Independent Power Producers. This is compared with the Base Case scenario to assess the impact of industrial defections on remaining utility customers. Industrial defections do raise rates for the remaining customers.

Then a Competitive scenario using a more efficient two-part tariff is developed, with strandable costs recovered through the customer charge. Compared with the Base Case, this results in greater demand and lower marginal costs. The Competitive scenario is then run with strandable costs recovered via a wires charge on transmission. This reduces demand in each sector and raises average costs for industrial customers while lowering them for residential customers.

A version of the Competitive model is then run with strandable costs removed and no wires charge to determine the impact on prices, demand, and average electricity prices. All customers become unambiguously better off with strandable costs removed, with the residential sector receiving the largest benefit in terms of lower average costs.

3. RATE RESTRUCTURING

The advent of competitive electricity generation will bring a new pricing system, one which is oriented primarily around the efficient delivery of electricity services. Economic theory shows that in equilibrium, long run marginal cost pricing is the most efficient way to allocate any commodity (Kahn, 1971, pp. 65-70). It maximizes consumer and producer surplus while ensuring that each user pays the cost which their extra unit of consumption imposes on the system. Any departure from marginal cost pricing will result in a less efficient provision of services.

Prices above marginal cost lead to too little consumption, in that there is consumer surplus to be gained by lowering the price. Any price below marginal cost would result in a greater than socially optimal level of consumption. A move toward an economically efficient pricing system would result in prices which are quite different from the ones in use today, and would also lead to very different equity characteristics.

In the case of electricity, however, this simple economic story is complicated by the fact that currently long run marginal costs are lower than average total costs. Long run marginal cost pricing raises some revenue, but not enough to cover all costs. If these additional costs are legitimate, they must be covered by some pricing mechanism. In regulated industries, regulatory economists have devised ways of raising additional revenue with minimum losses in efficiency. These mechanisms could also be used in a partially deregulated industry (e.g. competition among sources of generation with regulated distribution).

3.1 RAMSEY PRICING

One such method is Ramsey pricing, which determines optimum departures from marginal cost pricing, thus providing increased revenues in an economically efficient way. It is so named because it was first outlined by Frank Ramsey in a 1927 article on optimal taxation. It was further developed by Hicks (1947), Hotelling (1938), Pigou (1947), and Samuelson (1951). Baumol and Bradford (1970) provide a thorough description of its history.

The intuitive rationale for Ramsey pricing is that "the damage to welfare resulting from departures from marginal cost pricing will be minimized if the relative quantities of the various goods sold are kept unchanged from their marginal cost pricing proportions." (Baumol and Bradford, 1970, p. 271). That is, consumption of each good must decrease by the same percentage.

To achieve this, prices must rise most for those consumers with relatively inelastic demand and least for consumers with relatively elastic demand. In the extreme, those customers with perfectly inelastic demand provide all of the revenues required above marginal unit costs. Baumol and Bradford give a variety of equivalent mathematical formulations of the Ramsey price calculation.

The practical problem with this solution is the large difference between residential and industrial elasticities of demand. Generally, industrial users have a higher price elasticity, as they have greater opportunities to substitute other energy sources or to find more efficient supplies of electricity. This includes the option of self-generation. Residential customers have much less flexibility in substituting for electricity use, and thus are less able to respond to price changes.

The logic of Ramsey pricing is such that an industrial consumer with an elastic demand for electricity will pay a lower marginal price than a residential customer who has inelastic demand. This, when coupled with price differences due to different costs of service (e.g. local distribution costs are not incurred by industrial customers), portends large price differentials between sectors.

3.2. THE TWO-PART TARIFF

A powerful and potentially more efficient alternative to Ramsey pricing is the two-part tariff. In this case, each unit of the good is priced at marginal cost, but the buyer must first pay a fixed fee or customer charge to be allowed to purchase the good. The customer charge is set so that the sum is sufficient to cover the difference between average and long run marginal costs. Optimal two-part tariffs for a monopoly are described by Walter Oi (1971). Brown and Sibley (1986) provide a comprehensive treatment of both two-part tariffs and Ramsey pricing.

If it can be implemented, the two-part tariff provides a great deal of flexibility. But a two-part tariff can work only when resale of the commodity is effectively impractical. Electricity satisfies this condition. It is generally not feasible for an electricity customer to resell to another consumer. Under this condition, a two-part tariff is preferable to Ramsey pricing.

The two-part tariff provides a less distorting and more efficient method of revenue collection than Ramsey pricing. This is because customer charges can be adjusted across customer classes. While all customers would pay the efficient marginal cost for each unit of electricity, the customer charge could differ. The charge would depend on the consumer's elasticity of demand for access to electricity services, which is significantly less elastic than demand for the marginal unit of electricity. So a customer charge can raise equivalent revenues more efficiently (with less distortion in electricity demand) than increasing marginal prices under Ramsey pricing.

In theory, the customer charge can capture all of a buyer's consumer surplus, allowing the producer to be "a better monopolist". This is because the customer charge distorts purchasing decisions less than simply increasing the price of the commodity. Alternatively, in the context of regulating a public utility, a two-part tariff can be set to maximize social welfare (or aggregate consumer surplus). This could mean maximizing efficiency and minimizing distortions, adjusting tariffs across income classes to make them more equitable, or some combination of the two.

In important ways, the customer charge can be viewed as a lump sum tax. And while a lump sum tax is efficient in that it does not tend to distort consumer behavior, it has the potential to create inequities. One of the biggest challenges will be to design an efficient pricing system which retains an equity component.

3.3. SECTORAL INEQUITIES

It is likely that residential electricity customers, who have no alternative options for buying electricity, have a relatively inelastic demand for electricity services. They are willing to pay a lot for access to the grid. Industrial customers are likely to have a much more elastic demand for access to the grid. They have the option of self-generation or, as seems increasingly plausible, of contracting directly with a non-utility generator.

A high customer charge to industrial customers will raise their average costs and tend to drive them off the system. The average cost of electricity matters when there are options to choose among. While residential and commercial customers are likely to be sensitive to the average cost of electricity, they are not able to shift demand with current technology in the same way as industrial customers. Thus industrial demand is likely to be much more price elastic than residential or commercial demand.

Combining these observations with the logic of Ramsey pricing and the feasibility of a two-part tariff for electricity services portends high customer charges for residential users and relatively low customer charges for industrial users. With efficient pricing, residential and commercial customers will bear the brunt of the costs above long run marginal cost, and thus pay a higher proportion of their bill in the form of customer charges. Combined with the inherently higher cost of service for residential and commercial customers, primarily billing overhead and local distribution network costs, average residential and commercial electricity prices will be even higher relative to industrial prices than those witnessed today.

The reality that residential and commercial customers will bear the brunt of the customer charges will also create inequities within these sectors as well. When looked at in terms of average cost per unit of electricity, a customer charge will hit those who use relatively small amounts of electricity harder than those who use large amounts of electricity. The average price of electricity declines toward the marginal price as the quantity consumed increases.

In theory, if each customer's utility function were known, a customer specific charge could be set so that dis-utility resulting from the charge was equated across all customers, subject to revenue constraints. Since this is unrealistic, a uniform rate design will likely be used for each class of customers. When comparing a home with a myriad of appliances, electronics, and electric baseboard heating to that of a typical senior citizen, these potential inequities become apparent. While it seems unlikely that many residential customers will be pushed off the system by a customer charge, even with full strandable cost recovery, it may still be a significant amount of money to some customers.

A multi-part tariff for electricity in the residential sector might be appropriate for a regulatory commission concerned with equity. Under a multi-part tariff, the customer charge is paid in steps. The largest portion is paid over the first X units of electricity, a smaller portion over the next Y units, until ultimately each unit is priced at long run marginal cost. Even a rising block rate might be appropriate for some customers in order to supply "lifeline" service (below or near marginal cost service to special, generally low-income, customer categories). In this case, a class of customers is allowed to pay less than long run marginal cost for the first units of electricity, but as consumption rises, incremental rates rise above long run marginal cost. Clearly, rate structures can become quite complicated for an equity minded regulatory commission, but an important lesson of competition is that it will be much harder to use utility rates to implement welfare programs than it was in a fully regulated environment.

4. EFFECTS OF RATE RE-STRUCTURING: AN EXAMPLE

The following simple numerical examples compare Ramsey pricing and a two-part tariff, showing that a two-part tariff results in increased demand. The example constructs an electric utility with one generating unit, transmission costs, and two classes of customers.

A 1000Mw nuclear plant with a $5 billion capital cost (which results in fixed yearly capital expenditures of $459 million), $20/MWh production costs and a 0.95 capacity factor is owned by a utility. At full capacity, the average cost (capital plus production costs) is $75/MWh. All other power is assumed to be purchased at $30/MWh. This simple model divides consumption between residential and industrial sectors. There is a distribution cost of $40/MWh for the residential sector and $20/MWh for the industrial sector. The residential sector is characterized by a constant price elasticity of -0.5. The industrial sector price elasticity of demand is -1. The number of customers in the residential sector is 1,239,240, while the industrial sector has 2,974 plants. The utility's net revenues are approximately zero under each scenario. The results are summarized in Tables 1 and 2.

The entire output of the nuclear plant, minus line losses, plus 7,694,102 MWh of replacement power, is consumed by the two sectors at initial marginal prices of \$105/MWh and \$67/MWh for the residential and industrial sectors, respectively. In addition, there is a small customer charge. This is a two-part tariff, but with inefficiently high marginal rates. The competitive rates are \$70/MWh and \$50/MWh respectively. While these marginal prices do not precisely match current rates, they are meant to be representative and will be called Status Quo prices.

Table 1 shows that initial household demand is 6.38 MWh per customer per year, while industrial customer demand is 2,429 MWh/Yr. Average prices, including customer charges, are \$112/MWh and \$67.4/MWh, respectively. Note that the customer charge has no effect on electricity consumption (the income effect of the customer charge is zero).

The next scenario uses Ramsey pricing with a zero customer charge. Residential marginal prices rise to \$118/MWh, while industrial prices fall to \$63/MWh, reflecting the Ramsey pricing adjustment for different elasticities. Residential demand falls to 6.02 MWh, while industrial demand rises to 2,570 MWh.

Demand is then calculated for a two-part tariff with marginal prices at the marginal cost of replacement power plus the variable distribution cost. This is combined with a yearly customer charge of \$370 for the residential sector and zero for the industrial sector to balance the utility's books. (The zero customer charge for the industrial sector reflects that sector's higher price elasticity of participation in the electricity market.) As expected, Table 1 shows that demand rises sharply with the fall in the marginal price of electricity associated with the two-part tariff. Residential sector demand rises to 7.81 MWh per household per year, while industrial demand rises to 3255 MWh per year per industrial customer. Average cost for the residential sector is \$5/MWh greater than the Status Quo price, while it is \$17.4/MWh less for the industrial sector.

The right hand side of Table 1 shows the effects of pricing on sector demand and revenues. Status Quo and Ramsey revenues are similar, but two-part tariff revenues from the residential sector rise by over \$100 million. This shows the effectiveness of the customer charge in raising revenue without reducing demand, as the two-part tariff both raises the most revenue and has the highest demand for the residential sector.

Table 1. A Simple Demand Example with High Capital Costs (Dollars in Millions)

		Residential Sector	Industrial Sector		Residential Sector	Industrial Sector	Total
Status Quo Pricing							
	Marginal Price	$105/Mwh	$67/Mwh	Sales	7,905 Gwh	7,224 Gwh	15,129Gwh
	Cust. Charge	$46/Yr	$1000/Yr	Revenues	$887.0	$487.0	$1,374.1
	Quantity	6.38 Mwh/Yr	2,429 Mwh/Yr	Payments*	$333.7	$125.8	$459.5
	Ave Price Paid	$112/Mwh	$67.4/Mwh				
Ramsey Pricing							
	Marginal Price	$118/Mwh	$63/Mwh	Sales	7,459 Gwh	7,644 Gwh	15,103 Gwh
	Cust. Charge	$0/Yr	$0/Yr	Revenues	$879.6	$484.0	$1,363.6
	Quantity	6.02 Mwh/Yr	2,570 Mwh/Yr	Payments*	$357.5	$101.8	$459.3
	Ave Price Paid	$118/Mwh	$63/Mwh				
Two-Part Tariff							
	Marginal Price	$70/Mwh	$50/Mwh	Sales	9,682 Gwh	9,681 Gwh	19,363 Gwh
	Cust. Charge	$370/Yr	$0/Yr	Revenues	$1,136.2	$484.0	$1,620.3
	Quantity	7.81 Mwh/Yr	3,255 Mwh/Yr	Payments*	$458.5	$0	$458.5
	Ave Price Paid	$117/Mwh	$50/Mwh				

* Payments equal Revenues minus the cost of Sales if the electricity were purchased in the spot market at $30/Mwh, and minus distribution costs. Payments can be interpreted as each sector's contribution to cover strandable costs.

Table 2. A Simple Demand Example with Low Capital Costs (Dollars in Millions)

		Residential Sector	Industrial Sector		Residential Sector	Industrial Sector	Total
Status Quo Pricing							
	Marginal Price	$95/Mwh	$61/Mwh	Sales	8,310 Gwh	7,2935Gwh	16,246 Gwh
	Cust. Charge	$46/Yr	$1000/Yr	Revenues	$846.5	$487.0	$1,333.5
	Quantity	6.71 Mwh/Yr	2,668 Mwh/Yr	Payments*	$264.8	$90.3	$355.0
	Ave Price Paid	$102/Mwh	$61.4/Mwh				
Ramsey Pricing							
	Marginal Price	$103/Mwh	$60/Mwh	Sales	7,950 Gwh	7,959 Gwh	15,909 Gwh
	Cust. Charge	$0/Yr	$0/Yr	Revenues	$825.4	$484.0	$1,309.4
	Quantity	6.41 Mwh/Yr	2,676 Mwh/Yr	Payments*	$268.9	$86.1	$355.0
	Ave Price Paid	$103/Mwh	$60/Mwh				
Two-Part Tariff							
	Marginal Price	$70/Mwh	$50/Mwh	Sales	9,682 Gwh	9,681 Gwh	19,363 Gwh
	Cust. Charge	$287/Yr	$0/Yr	Revenues	$1,033.4	$484.0	$1,517.4
	Quantity	7.81 Mwh/Yr	3,255 Mwh/Yr	Payments*	$355.6	$0	$355.6
	Ave Price Paid	$107/Mwh	$50/Mwh				

* Payments equal Revenues minus the cost of Sales if the electricity were purchased in the spot market at $30/Mwh, and minus distribution costs. Payments can be interpreted as each sector's contribution to cover strandable costs.

4.1. EFFECTS OF STRANDABLE COSTS

The above example can also show the effects of removing strandable costs from utility ratebases. Table 2 shows the effect on electricity prices of lowering the ratebase. Again, using the previous nuclear plant example, the prices required to cover utility costs are calculated under the Status Quo scenario, and then compared with the appropriate Ramsey prices and two-part tariff. But now the capital cost of the nuclear plant is reduced by $1 billion to simulate the effect of removing strandable costs from the utility's ratebase. Under Status Quo and Ramsey pricing the customer charges are the same in both scenarios, with only the marginal prices varying. With the two-part tariff, the efficient marginal prices are the same in both scenarios but the customer charges vary.

Within the Low Capital Cost scenario, the revenue relationships are similar to those in the High Capital Cost scenario (Table 1). The interesting comparison now is between the High and Low Capital Cost scenarios for each pricing option. Unsurprisingly, lowering capital costs lowers the needed marginal prices and thus increases demand in the Status Quo and Ramsey examples. In the Ramsey pricing example, marginal prices in the residential sector fall from $118/MWh to $103/MWh. The quantity demanded rises to 6.41 MWh/year from 6.02 MWh/year. Industrial prices also fall, from $63 to $60/MWh, and demand rises to 2676 MWh per year from 2570 MWh. Residential prices fall more than industrial prices, as we would expect from the Ramsey rule.

With the two-part tariff, marginal prices are unchanged across the High and Low Capital Cost scenarios, as are the quantities demanded. But the residential customer charge falls from $370/Yr to $287/Yr. The industrial customer charge remains zero. Importantly, the average price of electricity falls for each scenario as the ratebase is lowered.

Table 2 also shows utility revenues and electricity demand by sector. The results are similar to Table 1: the two-part tariff results in both the highest revenue and the highest demand in each sector. Since utility revenues are set to approximately equal costs, revenues under each pricing option are less than those in the High Capital Cost scenario.

In each case, strandable cost payments are about $100 million lower for the Low Capital Cost scenario. Reducing the utility's capital costs has direct effects on the cost of electricity to consumers. The amount of electricity demanded rises when the marginal cost falls, but is unaffected by capital cost changes when a two-part tariff is used. Table 3 shows how electricity sales vary with the pricing mechanism used.

Table 3. Total Electricity Sales Summary (GWh)

Price Mechanism	High Capital Costs	Low Capital Costs	Difference (Low - High)
Status Quo	15,129	16,246	-1,117
Ramsey Pricing	15,103	15,909	-806
Two-Part Tariff	19,363	19,363	0

These simple examples are used to illustrate the effects of two fundamental changes which are likely to occur in the electricity market as the industry moves toward competition. Both the structure of rates and the treatment of stranded costs affect the pattern of electricity demand and the revenue collected. More importantly, the effects of these two features of demand interact with each other in predictable ways.

5. AN ANALYSIS OF NEW YORK STATE

Changing the structure of electricity prices increases the uncertainty of consumer response to changes in average prices. Economic theory suggests that, as the marginal price drops, more is consumed, but theory can not accurately forecast how much more. To estimate the combined effects of a smaller ratebase and new price structures, a dynamic model is used to predict New York State electricity demand by sector. Demand is modeled as a function of lagged prices and quantities, as well as current period prices for electricity, substitutes, and other expenditures. The electricity supply component calculates electricity prices from statewide financial data, updating each year based on demand, fuel prices, and capital costs.

5.1. THE DEMAND MODULE

The Demand Module is a Generalized Logit Model estimated using pooled cross-section and time-series data with fixed state effects (see Dumagan and Mount 1991, Rothman, Hong and Mount 1993, and Weng and Mount 1996). Data from 48 states for the years 1977-1990 were used for estimation. A system of demand equations was estimated for each of three demand sectors: residential, commercial, and industrial.

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Demand relationships were estimated for electricity, natural gas, oil and other expenditures in the residential model. In the commercial sector, other was divided into labor and capital expenditures. In the industrial model, coal was also added. Expenditure shares for each category are estimated as a function of lagged expenditure shares and current period prices, as well as data for heating and cooling degrees days. A standard geometric lag structure for quantities demanded was also included in the demand equations. The demand equations appear in the Appendix.

Data on energy quantity by source and consumption sector is from the US Department of Energy (DOE) State Energy Data System (SEDS), Consumption Estimates for States, 1970-1991. Energy prices and expenditures are from US DOE State Energy Price and Expenditure Data System (SEPEDS), 1970-1991. Capital quantity information was taken from US Bureau of Economic Analysis (BEA), Gross State Product Files for 1977-1990. Employment information is from Full and Part-Time Employees by Industry for States, BEA, 1967-1994. Income and industry earnings are from Personal Income by Major Source and Earnings by Industry for States, 1969-1995, also collected by the US BEA.

Numerous desirable theoretic constraints were included in the estimation of the model, primarily that the underlying cost function and demand equations are linear homogeneous in prices and income, with a symmetric Hicksian matrix of partial derivatives at every data point. This symmetry implies that an underlying expenditure or utility function could in principle generate the Generalized Logit Model (Dumagan and Mount 1991, p. 9). The model was estimated using the Iterative Seemingly Unrelated Regression (ITSUR) estimator which is part of the econometrics component of SAS.

The model's demand parameters are difficult to interpret because of the dynamic theta weights which change with expenditure shares. More relevant measures of the model's characteristics are the empirical elasticities, provided in the Appendix. The short-run own price elasticities of electricity are small for each sector: -0.042 for the residential sector, -0.151 for the commercial sector, and -0.261 for the industrial sector. But the long-run elasticities are significantly higher, with a rise to -0.332 in the residential sector, -0.582 in the commercial sector, and -0.653 in the industrial sector. These numbers are in accord with historical estimates of electricity elasticity. The remaining own price elasticities each have the expected negative sign, while the cross-price elasticities are generally small.

5.2. ELECTRIC UTILITY COST MODULE

To create a dynamic electricity model, an electric utility Cost Module was constructed to compute statewide electricity prices endogenously. Utility costs, like electricity demand, are aggregated to the state level. Dynamics within the model are generated by energy input price and demand changes. The prices of all goods other than electricity are provided exogenously.

The basic model inputs come from state level aggregate financial data for the New York State electric utilities, contained in *Financial Statistics of the Major Investor-Owned Utilities in New York State* (1994). These include existing generation, transmission, and distribution plant capital costs, yearly Operations and Maintenance (O&M) expenditures, generating capacity, and NUG purchases. Financial information such as debt/equity split, tax payments, and allowed return on capital is also used. Much of the background for the Cost Module is derived from US EPA CCMU Documentation (1984), Cole (1986), Reeser (1984), and Chapman (1982).

Endogenous electricity prices and quantities are computed by using current year demand by sector as calculated in the Demand Module to calculate allowed and needed revenues in the Cost Module. Next year's prices are then calculated so as to satisfy revenue requirements at current demand. These prices are then input into the Demand module to calculate next period quantities. For further explanation of the Demand and Cost Modules, input values, as well as more detailed model dynamics, see Ethier (1996).

5.3. CUSTOMER DEFECTIONS

The residential sector is assumed to have an exogenously determined number of customers. They neither leave the grid in response to price rises nor join in response to price decreases. The same is assumed true of commercial sector customers. They may substitute oil heat for electric heat in response to a rise in the price of electricity, but they will not leave the electric grid for an alternative electricity provider.

Such an assumption is more difficult to make for the industrial sector. While there is little evidence that electricity prices are a significant factor in industry relocation (Bartik 1985), certainly it is a factor in industry decisions to seek alternative electricity sources. These alternative sources include self-generation and direct contracting with independent electricity generators.

Defection is addressed in the model via an endogenously computed industrial sector defection factor. This causes a decrease in industrial sector demand as a function of rising industrial electricity prices. The rationale is that as electricity prices rise above true marginal costs, industrial sector customers are increasingly likely to leave the system. Importantly, there are no second-order effects. That is, industrial users may leave the grid, but they do not leave the state and thus they do not affect employment or income in the state. They also continue to be included in the industrial demand for natural gas, oil, coal, capital and labor.

The equation used for defection is:

$$\text{self\_gen}(t) = \alpha*\lambda*(\beta*\ln(\text{Marg\_Cost}(t))-\ln(\text{Price}(t))) + (1-\lambda)*\text{self\_gen}(t-1) + c\ ;$$

where industrial sector demand and customer charges are lowered each period by the factor "exp(self_gen(t))." In year zero, self-gen (0) = 0. α, λ, and β are user supplied inputs which could, in theory, be estimated. In practice, accurate estimation is difficult with the available data. λ is the proportion of defection occurring in the first time period. α is the long-run elasticity of defection, and β and c are parameters used to normalize the initial year to zero.

Industrial defections are important for two reasons: 1) to the extent that they have occurred they may have already adversely affected residential and commercial rates, and 2) the specter of industrial defections has already resulted in lower average industrial rates and has provided the main rationalization for moving to competitive electricity provision. Empirical examination can inform these issues.

6. THE BASE CASE

An initial run called the Base Case is used as both a means to evaluate model performance and as a baseline against which to compare other model results. The Base Case uses 1994 statewide average prices for each sector and aggregate state quantities by sector as a calibration year. The model then iterates forward, adjusting prices in each sector by an equal percentage as necessary to satisfy revenue requirements. The customer charge remains constant. This case assumes a continuation of the current regulated utility paradigm in that high marginal rates are charged, there are no industrial defections, and all costs are recovered.

Energy price forecasts are from the *Annual Energy Outlook* 1995 compiled by the Energy Information Administration (EIA). The EIA projects the real price of oil to increase by 2.4% per year and the real price of natural gas to increase by 3.1% per year until 2010. It expects the real price of coal to increase 8% by 2010. It is assumed that these rates of increase occur across all sectors and are constant across scenarios. Incidentally, the Energy Information Administration forecasts that nationwide, real electricity prices will stay constant or fall slightly over the next twenty years (EIA, 1995), which is consistent with the model results.

The marginal electricity prices generated by the model are plausible (Figure 1), with a slight price rise in the short run, followed by a larger decline after year five. Quantities demanded rise slightly over time (Figure 2). Note that the price adjustment mechanism used by the model in this case keeps customer charges constant in real dollars, and also adjusts the price of electricity in each sector by the same proportion to generate needed revenues.

So simply iterating the model forward without adjusting price ratios, customer charges, or utility parameters provides unobjectionable results. Additional testing has shown that the Demand Module is robust to a large range of price variations, and that the Cost Module adds new generation appropriately, adjusting prices as needed.

7. DEFECTION SCENARIO

An interesting empirical question is the effect of industrial sector defections on customers remaining on the system. The fear of industrial defection has already led to lower industrial rates in an effort to preempt defections, and has also provided an argument for the move to competition. It has become increasingly clear that even with falling industrial rates, the regulated utility model is untenable in an era of falling marginal costs of electricity (Bayless, 1994).

The dynamic model makes it possible to determine how the effects of industrial defections evolve by comparing results with the Base Case with no defections. (Table 4 summarizes the assumptions of each of the scenarios.) The expectation is that the more industrial customers leave the system, the higher rates become for the remaining customers. This in turn has two second order impacts: increased rates induce further shifts of industrial customers and higher rates lead to reduced demand in other sectors, so that fixed costs must be spread among fewer units of electricity, further raising rates.

Figure 1. Base Case Electricity Prices by Sector

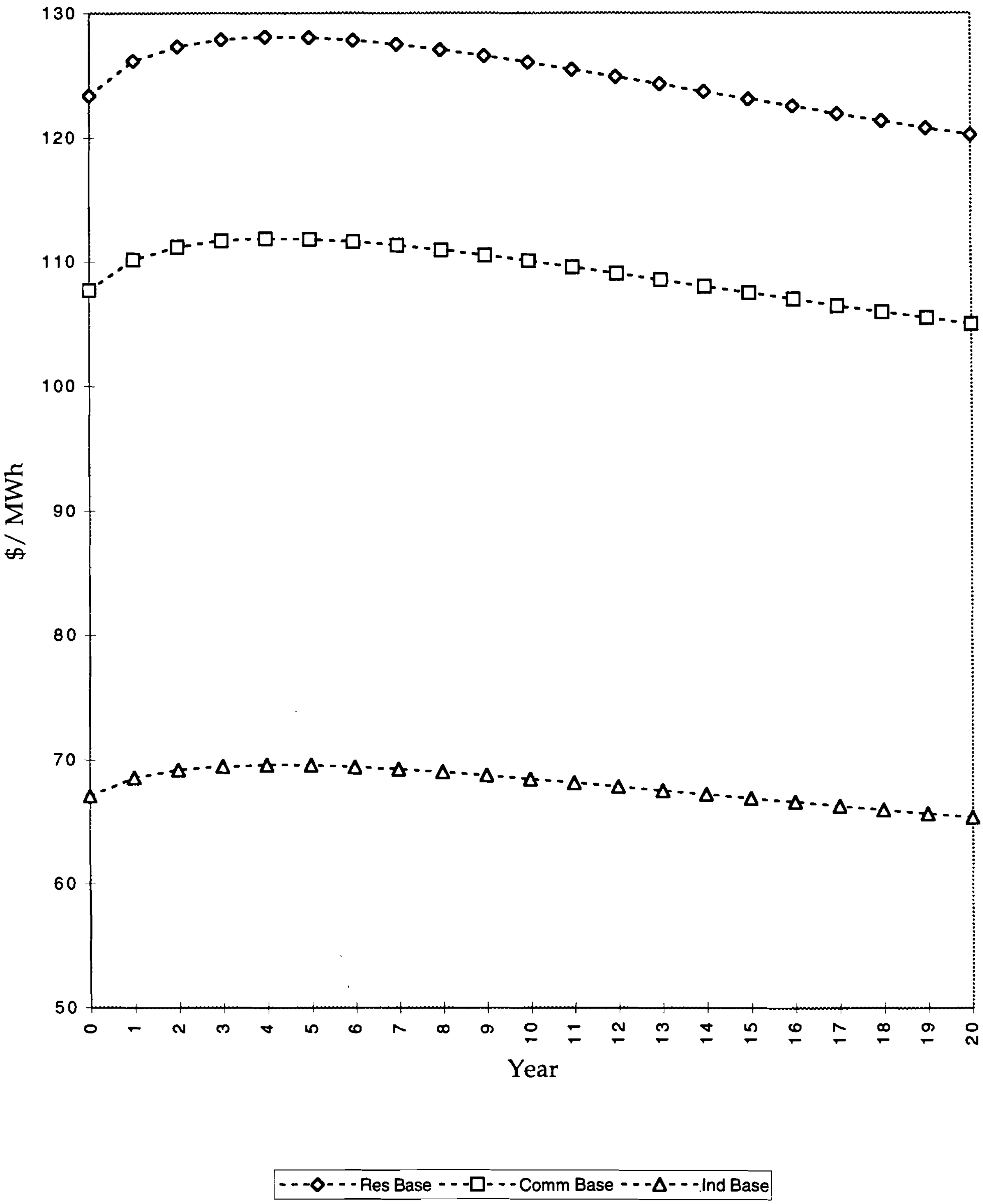


Figure 2. Base Case Electricity Demand by Sector

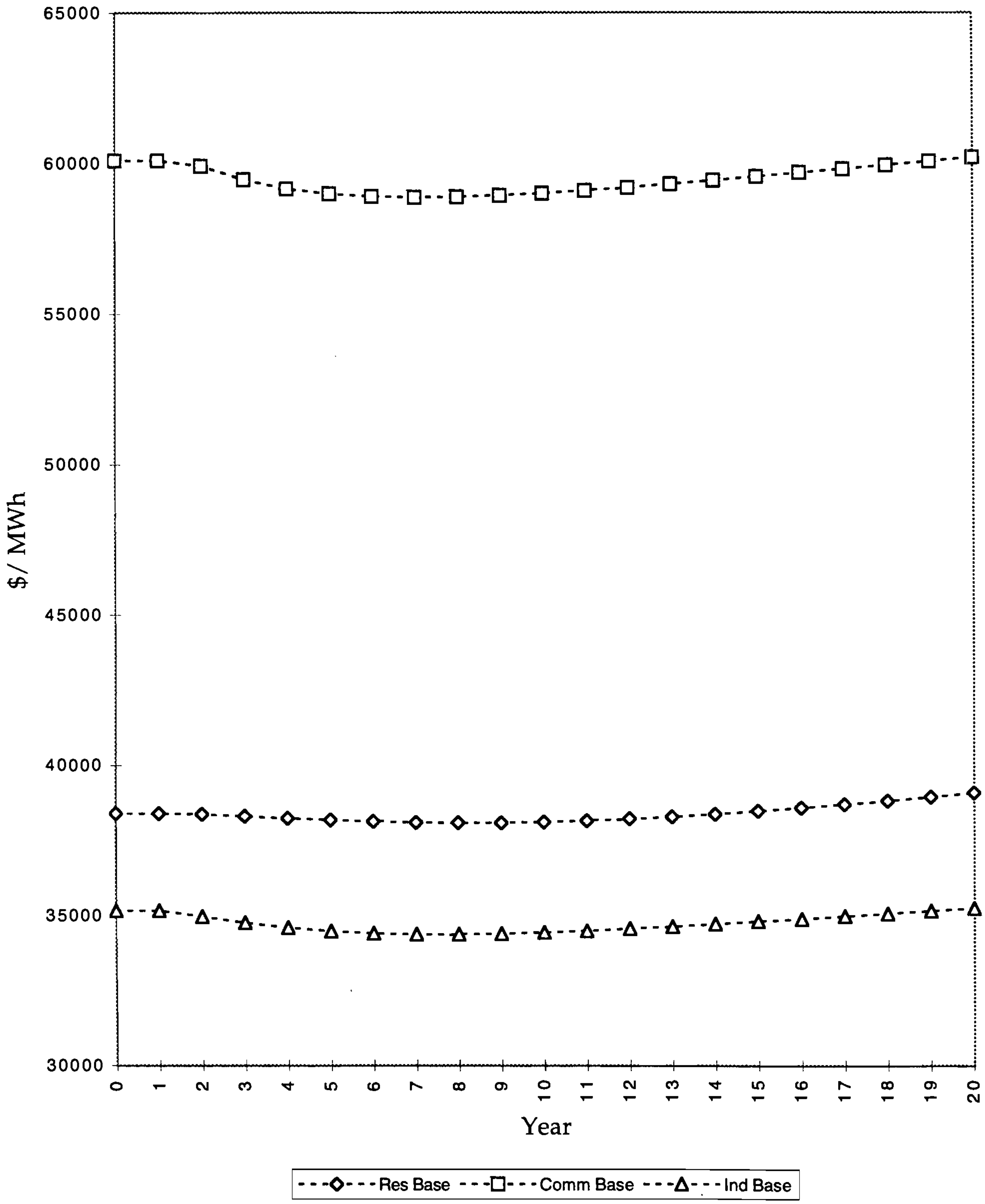


Table 4. Scenario Outlines

Scenario	Initial Year Values	Industrial Defection Rate	Ratebase Used	Price Adjustment Mechanism**
Base Case	1994 Base Year*	0	High	Adjust Marginal Price; Fixed Cust. Charge
Industrial Defection	1994 Base Year	Endogenous	High	Adjust Marginal Price; Fixed Cust. Charge
Competitive	1994 Base Year	0	High	Marginal Price = Marginal Cost; Adjustable Cust. Chg.
Wires Charge	1994 Base Year	0	High	Marginal Price = Marg. Cost + Wires Charge; Adjustable Cust. Chg.
Low Strandable Costs	1994 Base Year	0	Low	Marginal Price = Marginal Cost; Adjustable Cust. Chg.

* Base Year values are provided in Ethier (1996).

** In each scenario, Adjusted values are changed so as to generate Allowed Revenues at current demand.
For Competitive, Wires Charge, and Low Strandable Cost scenarios, marginal prices are a function of marginal cost.

A comparison of the Base Case scenario with a scenario involving defections (Figure 3) supports the expectation of higher rates for remaining customers. The final year residential price under the Defection scenario is $132.51/MWh, $12.24/MWh higher than the Base Case final year. (Table 5 summarizes the start year and final years of each scenario, as well as providing the average cost of electricity.) The average residential price is $12.49/MWh higher. Commercial sector prices are also higher under the Defection scenario.

Demand also falls in each sector, as shown in Figure 4. Note that industrial sector demand falls dramatically. This shows industrial customers leaving the grid for self-generation or NUG contracts. The model levels off with just under 40% of the initial industrial customers defecting. This may be a large amount of defections, but the reality is that there is no way to know how many industrial customers would have opted out of the traditional utility system. It seems likely that the number would be significant. The effect on remaining customers is likely to be proportional to the number of defections.

8. COMPETITIVE PRICING

Another scenario of interest is the effect of moving to a more efficient two-part tariff. As discussed above, there is likely to be increased use of the two-part tariff under a system of competitive electricity provision. The Competitive scenario uses a nearly efficient two-part tariff where the marginal prices are close to the long run marginal costs of production and distribution, while the customer charge varies to generate revenues which cover the remaining fixed costs. This scenario could be thought of as a competitive generation system coupled with a regulated transmission system, where marginal prices are driven to the efficient level. Retail service might or might not be competitive. The variable customer charge reflects a transmission access fee charged to each customer to cover fixed distribution and transmission expenses as well as strandable costs.

Figure 5 shows the price of electricity for the residential and industrial sectors under a Competitive scenario and under the Base Case scenario. As Figure 5 shows, the marginal price of electricity is lower for each sector under Competitive pricing. Figure 6 shows that the resultant quantities demanded rise with lower marginal prices. So the dynamic model indeed shows that using a more efficient two-part tariff increases demand over a revenue-equivalent set of pseudo-Ramsey prices.

Figure 3. Defection versus Base Case Electricity Prices

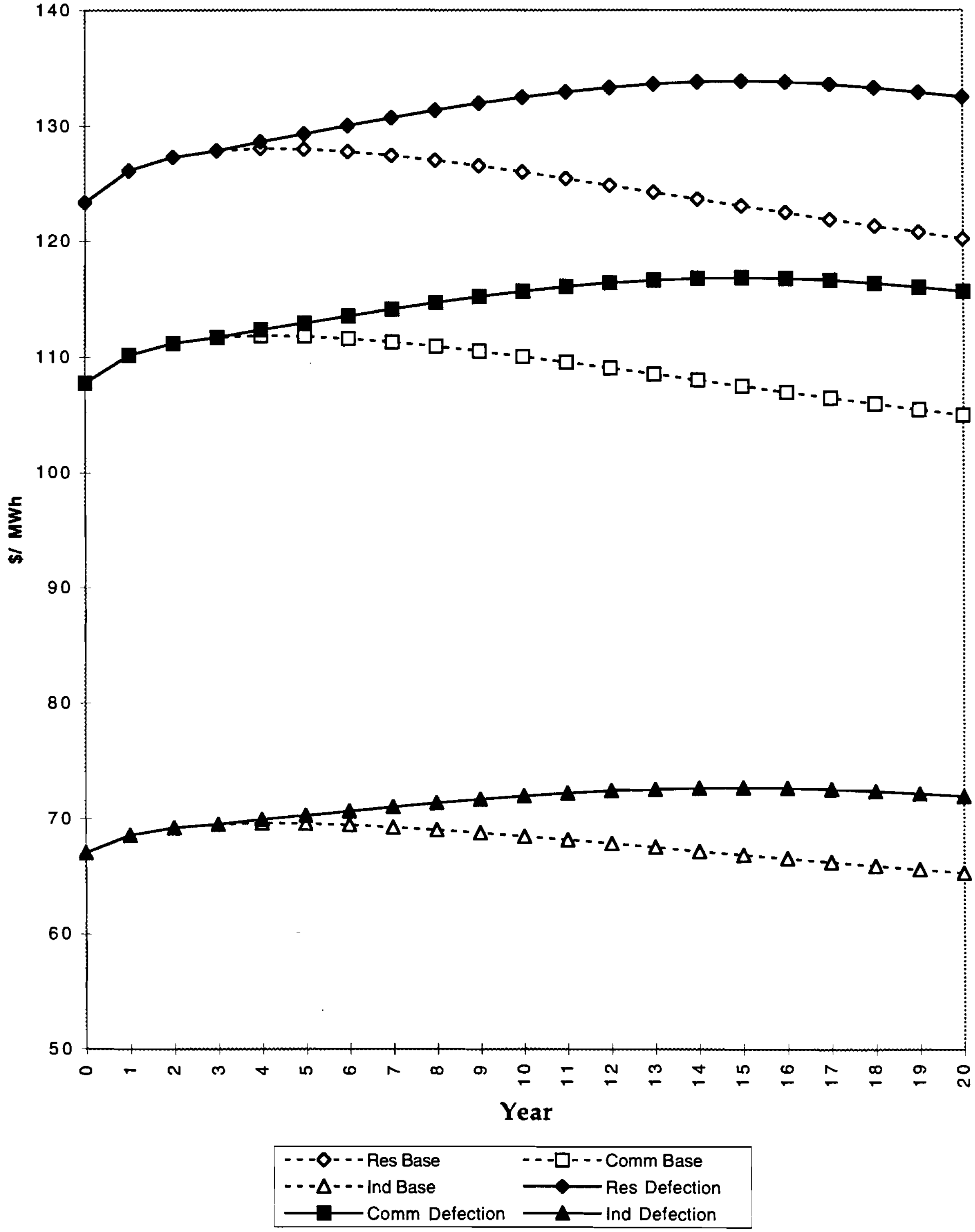


Table 5. Scenario Summaries by Sector: Electricity Prices, Quantities, and Customer Charges

Marginal Prices ($/MWh)	Start Year	Base Case Final Year	Defection Final Year	Competitive Final Year	Wires Charge Final Year	Low Strandable Costs Final Year
Residential	$123.37	$120.27	$132.51	$95.12	$98.53	$95.09
Commercial	$107.74	$105.05	$115.73	$91.85	$95.12	$91.81
Industrial	$67.04	$65.34	$71.99	$60.49	$65.44	$60.49
Quantities (GWh)						
Residential	38,396	39,246	38,103	43,086	42,587	43,115
Commercial	60,086	60,320	57,301	64,922	63,808	64,922
Industrial	35,172	35,348	19,960	37,517	35,641	37,517
Totals	133,654	134,914	115,364	145,524	142,036	145,553
Customer Charge ($/Yr)						
Residential	$50.00	$50.00	$50.00	$213.92	$136.76	$99.44
Commercial	$250.00	$250.00	$250.00	$1,069.58	$683.82	$497.22
Industrial	$1,200.00	$1,200.00	$1,200.00	$5,133.97	$3,282.35	$2,386.64
Average Price ($/MWh)						
Residential	$131.55	$128.27	$140.76	$126.30	$118.70	$109.57
Commercial	$111.18	$108.47	$119.33	$105.46	$103.97	$98.14
Industrial	$67.54	$65.83	$72.86	$62.47	$66.77	$61.41

Figure 4. Defection vs. Base Case Quantities of Electricity

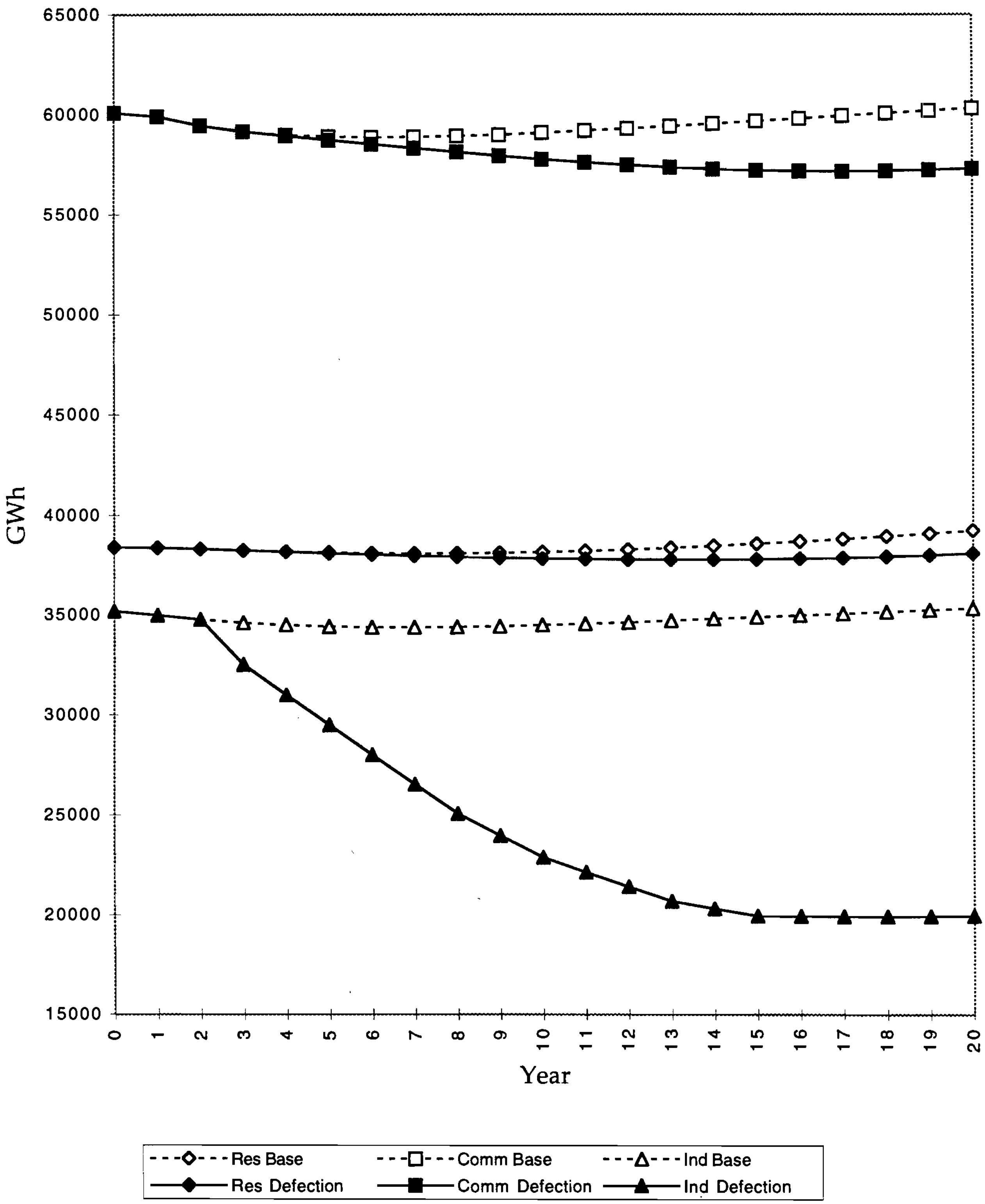


Figure 5. Marginal Electricity Prices by Sector: Base Case vs. Competition

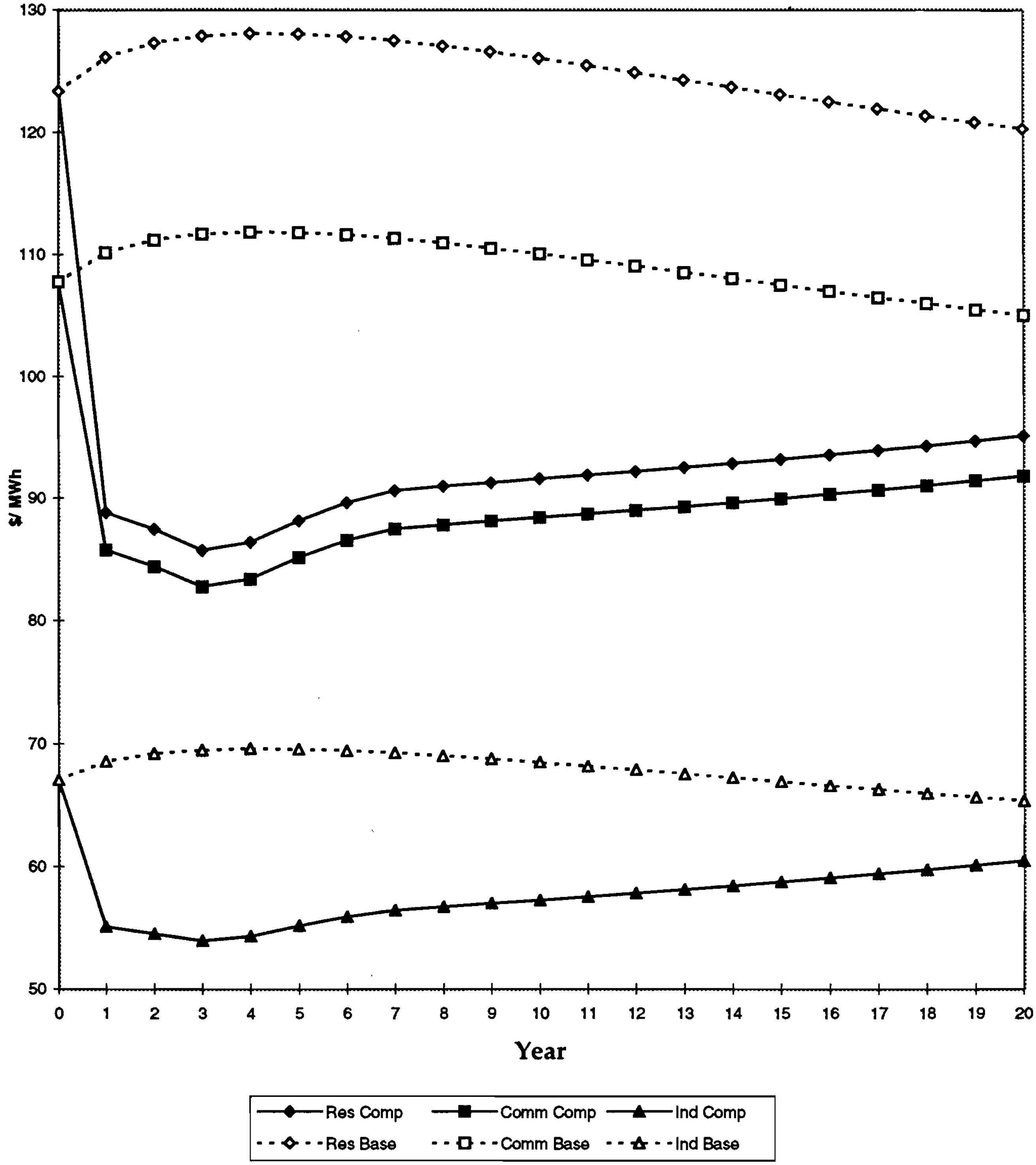
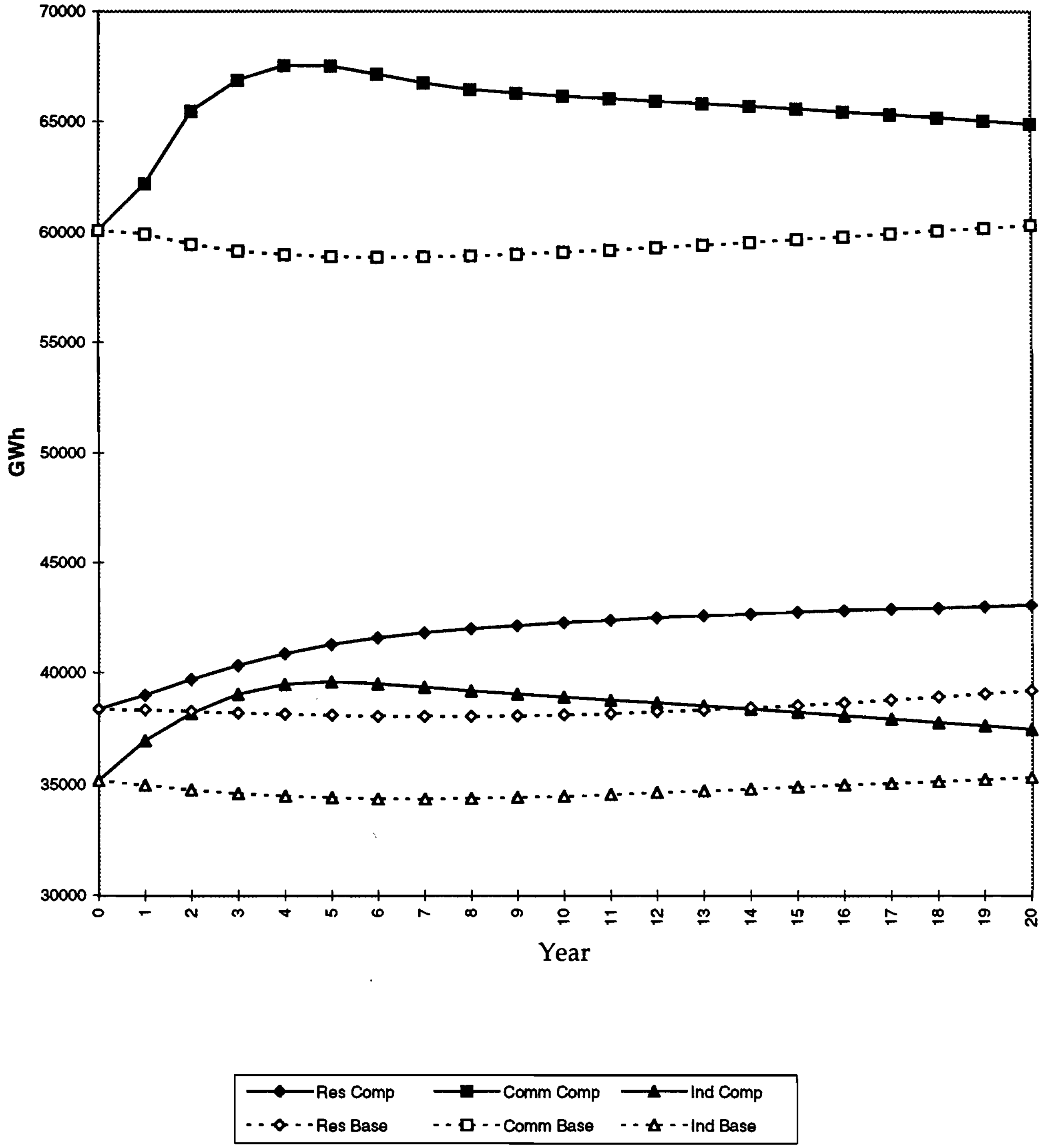


Figure 6. Electricity Quantity by Sector: Base Case vs. Competition



In the first year, residential prices are $127.29/ MWh for the Base Case, while the are $88.81/MWh for the Competitive case. Industrial sector prices fall less, from $68.54/ MWh to $55.10/ MWh, because they start closer to marginal cost. In the final year, residential prices are $95.12 vs. $120.27/ MWh, while industrial prices are $60.49 vs. $65.34/ MWh for Competitive and Base Case scenarios, respectively. Residential quantities rise from 38,396 GWh in the calibration year to 43,086 GWh under Competition and 39,246 GWh under the Base Case. Industrial quantities rise under Competitive pricing, from 35,348 GWh under the Base Case and to 37,517 GWh.

One important source of revenue not captured in Figure 5 is the customer charge. The Base Case residential customer charge is a constant $50/year per household, while the Competitive customer charge varies over the 20 year forecast period, and is much larger than the Base Case customer charge. In the first year under Competitive pricing, the residential customer charge rises to $364/year per household. It decreases to $214 in the final year of the forecast period.

One way to combine the effects of marginal prices and customer charges is by calculating the average price per unit of electricity for a household under each case. Table 5 shows that Competitive Pricing does indeed result in lower average costs of electricity and higher demand. In the residential sector the average price drops from $128.27/ MWh in the final year of the Base Case to $126.30/ MWh in the final year of the Competitive Pricing scenario. Note that this occurs while demand increases by over 3,810 GWh's from the Base Case final year.

9. STRANDABLE COST COLLECTION

Currently, there is no clear consensus about the resolution of the strandable cost issue. Customers could be responsible for anything between all or none of calculated strandable costs. The Competitive forecast was calculated assuming that customers would assume responsibility for all strandable costs through the customer charge, which would reflect a transmission access fee. It is interesting to model both the impact of removing strandable cost responsibility from ratepayers and the effect of a wires charge instead of a fixed access fee.

The PSC has calculated that strandable costs for nuclear plants and NUG contracts could surpass $10 billion statewide (PSC opinion 1995). Using this number as an upper bound of strandable cost reductions, the Competitive scenario is re-evaluated with $10 billion in strandable cost recovery via a per MWh wires charge on transmission. This mechanism has been proposed as an appropriate means for recovering strandable costs in a competitive market. This model run is called the Wires Charge scenario, and its results ought to be compared primarily with the Competitive scenario.

A transmission wires charge of $6.80/MWh generates over $550 million/year under the initial year demand, and during the 20 year forecast period will approximately cover a $10 billion strandable cost. Since the marginal price in each sector is $6.80/MWh higher with the Wires Charge scenario than under the Competitive scenario, there are demand effects in each sector.

As expected, the higher marginal prices which result from the imposition of the wires charge reduce demand and raise the average price of electricity, although the customer charge does fall. The Final year residential price for the Wires Charge scenario is $98.53/ MWh, versus $95.12 for the Competitive scenario. Final year demand falls from 43,086 GWh to 42,587. The average residential price actually falls, from $126.30 to $118.70 because the wires charge causes the industrial sector's average price to rise from $62.47 to $66.77. So in this case, the wires charge shifts some revenue responsibility from residential to industrial customers. Note that industrial defections do not occur with a wires charge.

See Figures 7 and 8 for marginal prices and quantities under each scenario. Figure 9 shows that the needed customer charge falls with the imposition of the wires charge. The strandable cost payment mechanism clearly affects marginal price, demand, and average price in each sector. If strandable cost payments are lumped into customer charges, demand will be higher. Using a wires charge will lower demand and may also shift revenue collection across sectors. In this example, residential customers achieve lower average prices at the expense of industrial customers, who are faced with higher average prices. Commercial customers face slightly lower average prices with a customer charge. Of course, if industrial customers were able to leave the system at these higher prices, average prices would change.

10. REDUCING STRANDABLE COSTS

The last scenario examines the effects of removing strandable cost responsibility from ratepayers. It will be assumed that strandable costs are absorbed by either the government, utilities, IPPs, or some combination of the above. And while it seems likely that some portion of strandable costs will be removed from

Figure 7. Marginal Price with and without Wires Charge

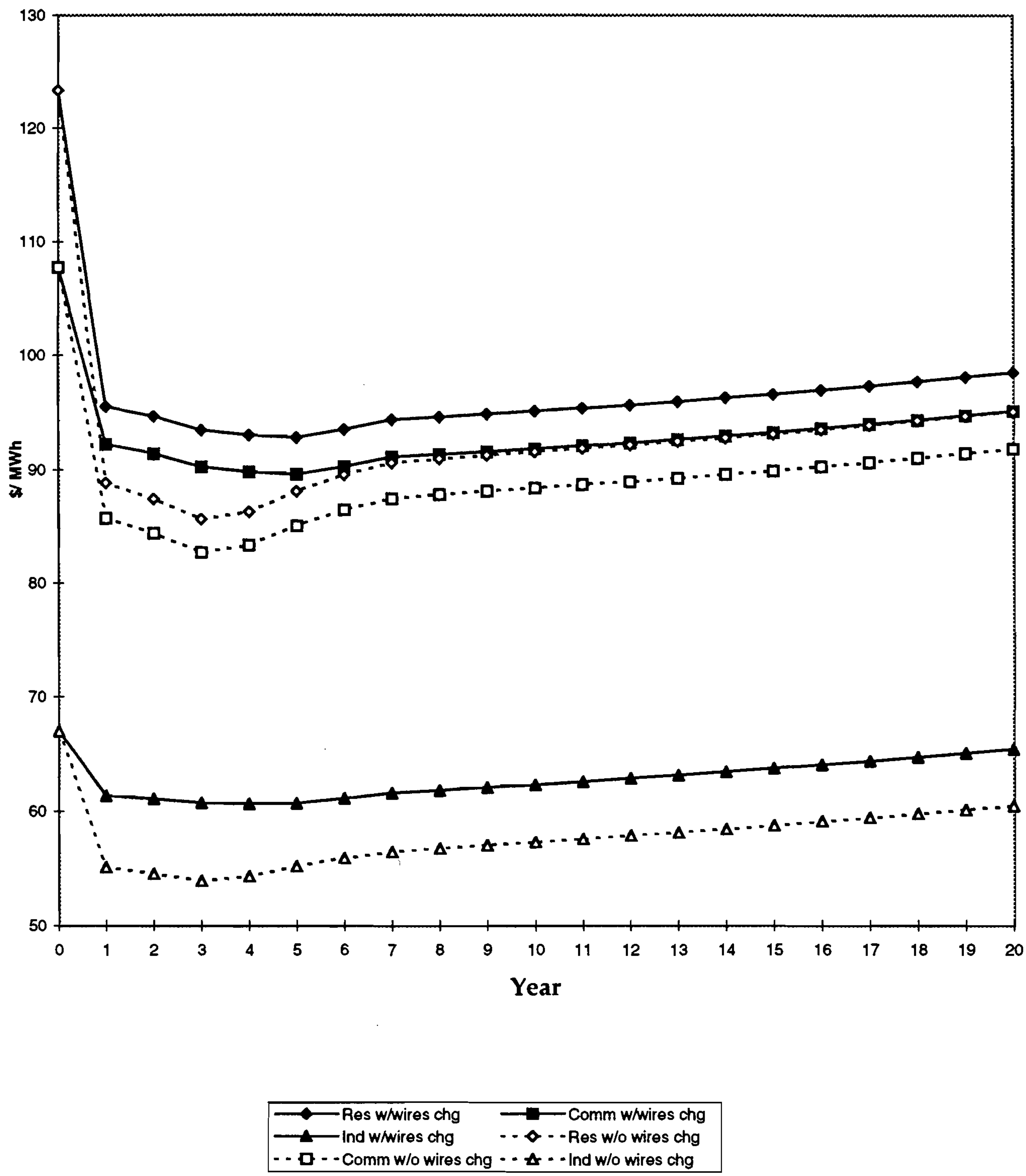


Figure 8. Electricity Demand With and Without Wires Charge

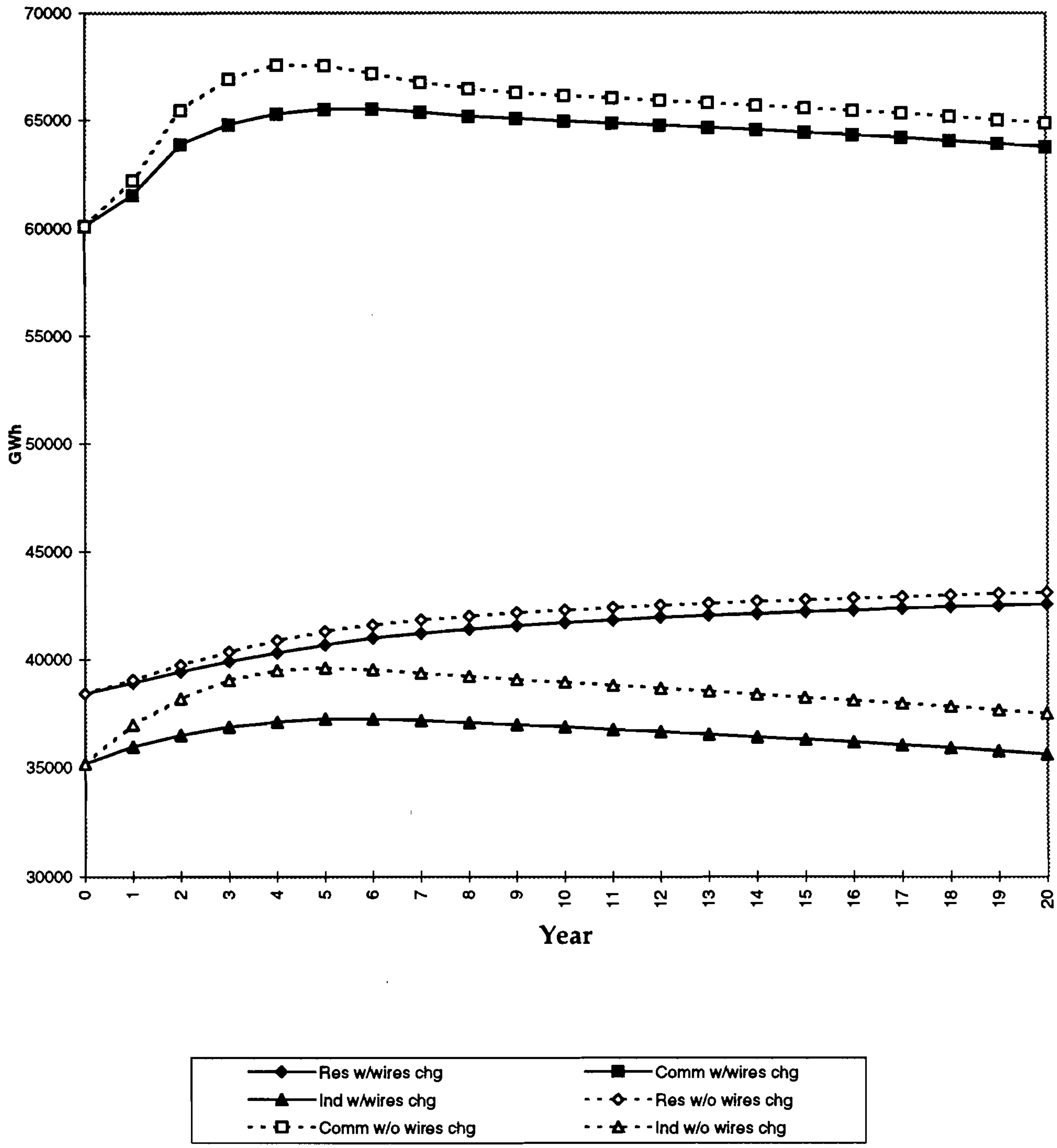


Figure 9. Residential Customer Charge: High and Low Strandable Costs, with and without Wires Charge

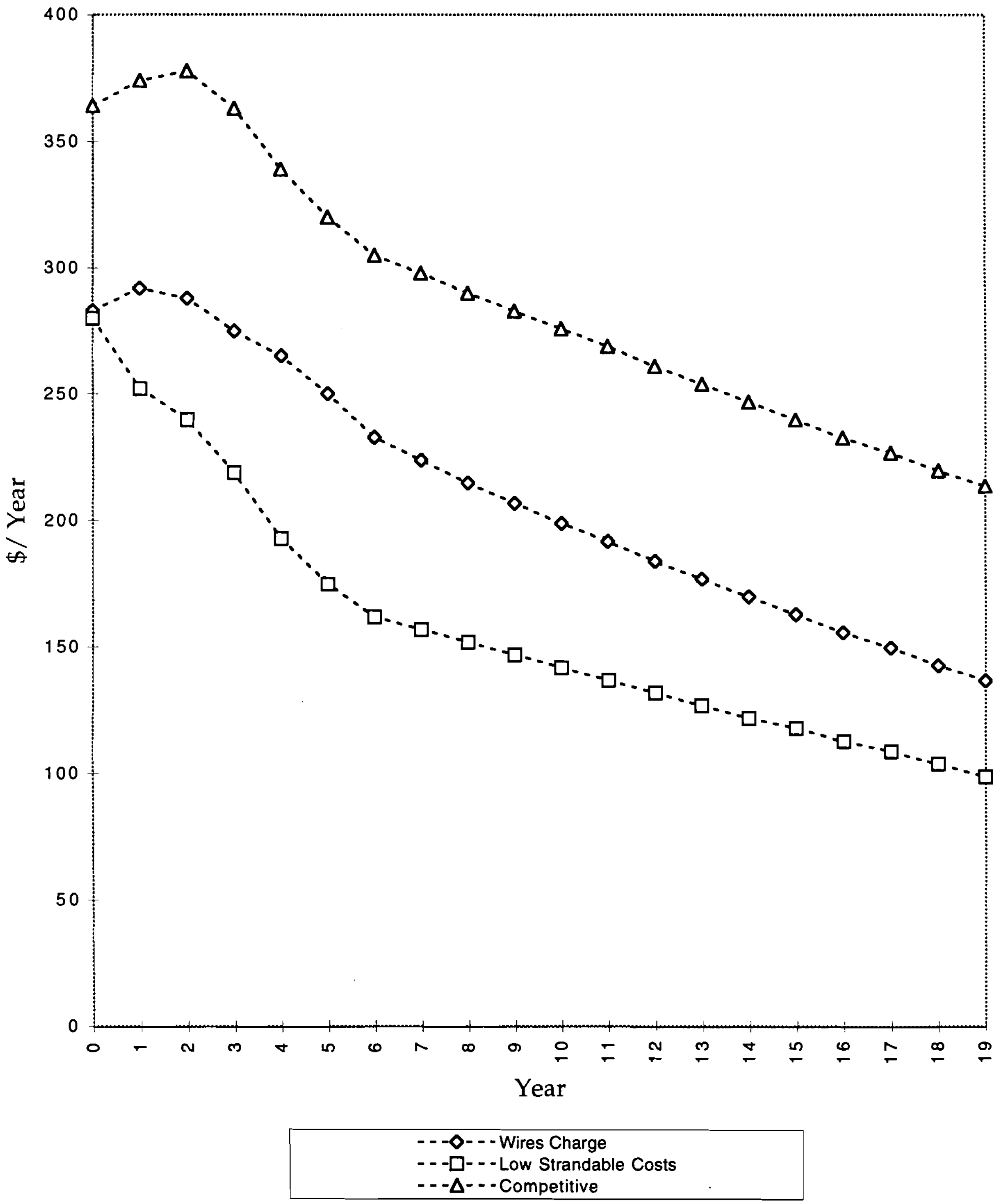


Figure 7 utility ratebases, the exact amount has yet to be determined. As an upper bound, the Low Strandable Cost scenario will look at the impact of removing all $10 billion in PSC estimates from utilities ratebases and IPP contracts.

The pricing mechanism used is the same as under the Competitive scenario. That is, marginal price is close to marginal cost of production with no wires charge, and the remainder of needed revenues are derived from adjustable customer charges. Unsurprisingly, with the small income effect from the customer charge, this results in marginal prices and demand which are virtually identical to those realized under the Competitive scenario. All of the cost reductions appear in the customer charge and in the calculated average price of electricity.

Marginal prices and sector demands, since they are essentially the same as the Competitive scenario, are not graphed. The customer charges for the Low Strandable Cost scenario appears in Figure 9, where they are clearly less than the customer charges for either the Competitive or the Wires Charge scenarios.

Final year average prices are calculated for the Competitive and Low Strandable Cost forecasts and shown in Table 5. Unsurprisingly, average costs are lower with Low Strandable Costs. The average cost for the residential sector in the final year of the Competitive run is $126.30/ MWh, while it is $109.57/ MWh with Low Strandable Costs. Industrial sector average costs also fall as strandable costs are removed: from $62.47/ MWh to $61.41/MWh. Note that lowering strandable costs benefits residential customers more because they pay the bulk of the bill under the Competitive scenario.

Clearly strandable cost reductions can dramatically affect customer welfare. Not only is an average customer's bill lowered as strandable costs are removed from the calculation, but when costs are recovered via a transmission tax, there are demand effects as well. A wires charge also has distributional effects.

11. COMPARING AVERAGE PRICES

One useful way of comparing scenarios is by using the average electricity price. The advantage of computing average prices is that they incorporate marginal prices, customer charges, and demand responses into one number which can be easily compared across sectors and scenarios. Demand effects are summarized in Figure 10.

Figure 11 shows the average price of residential electricity for each of the five scenarios. Unsurprisingly, of the two scenarios that assume a regulated

Figure 10. Total Quantity of Electricity Sales by Scenario

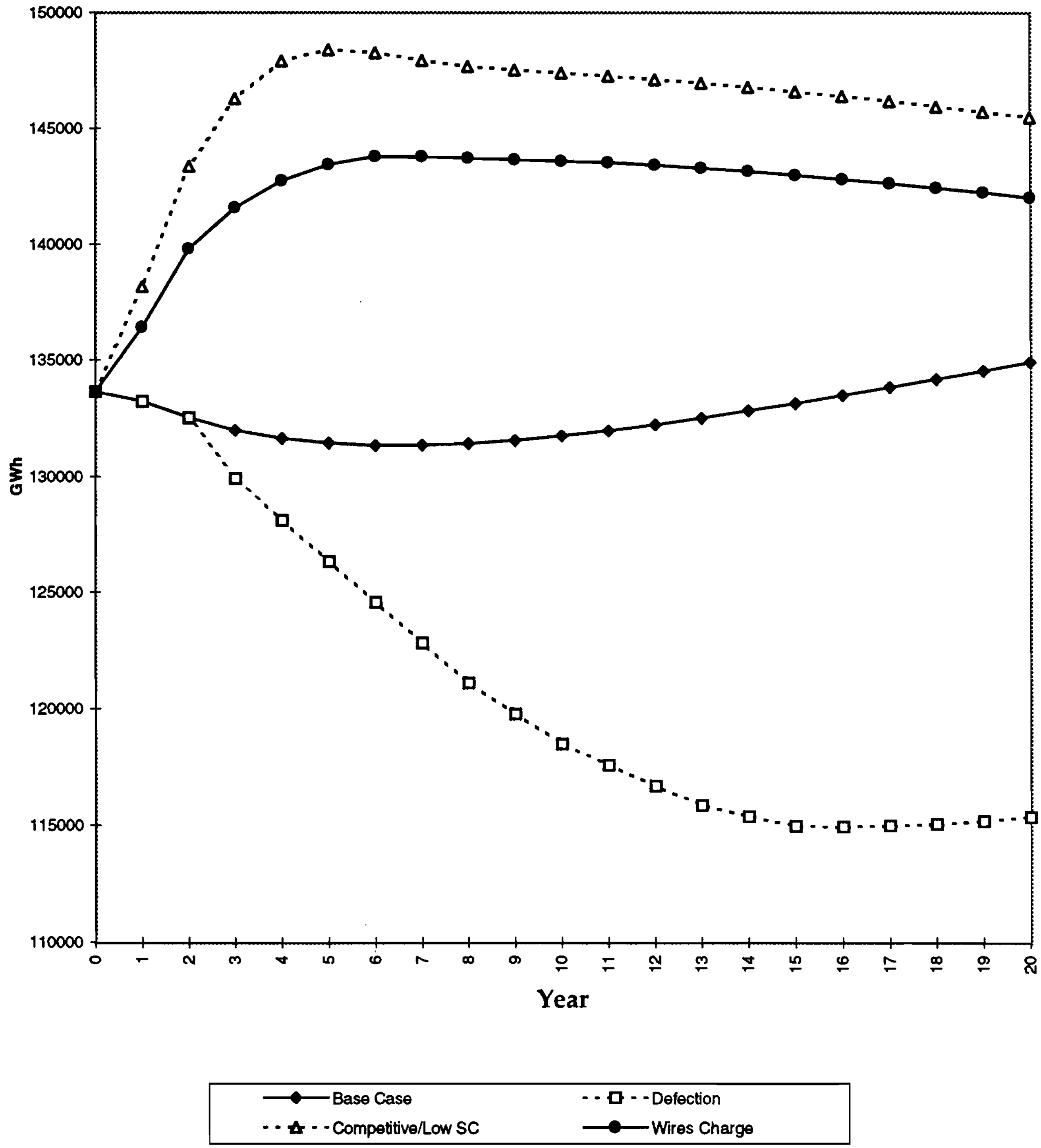
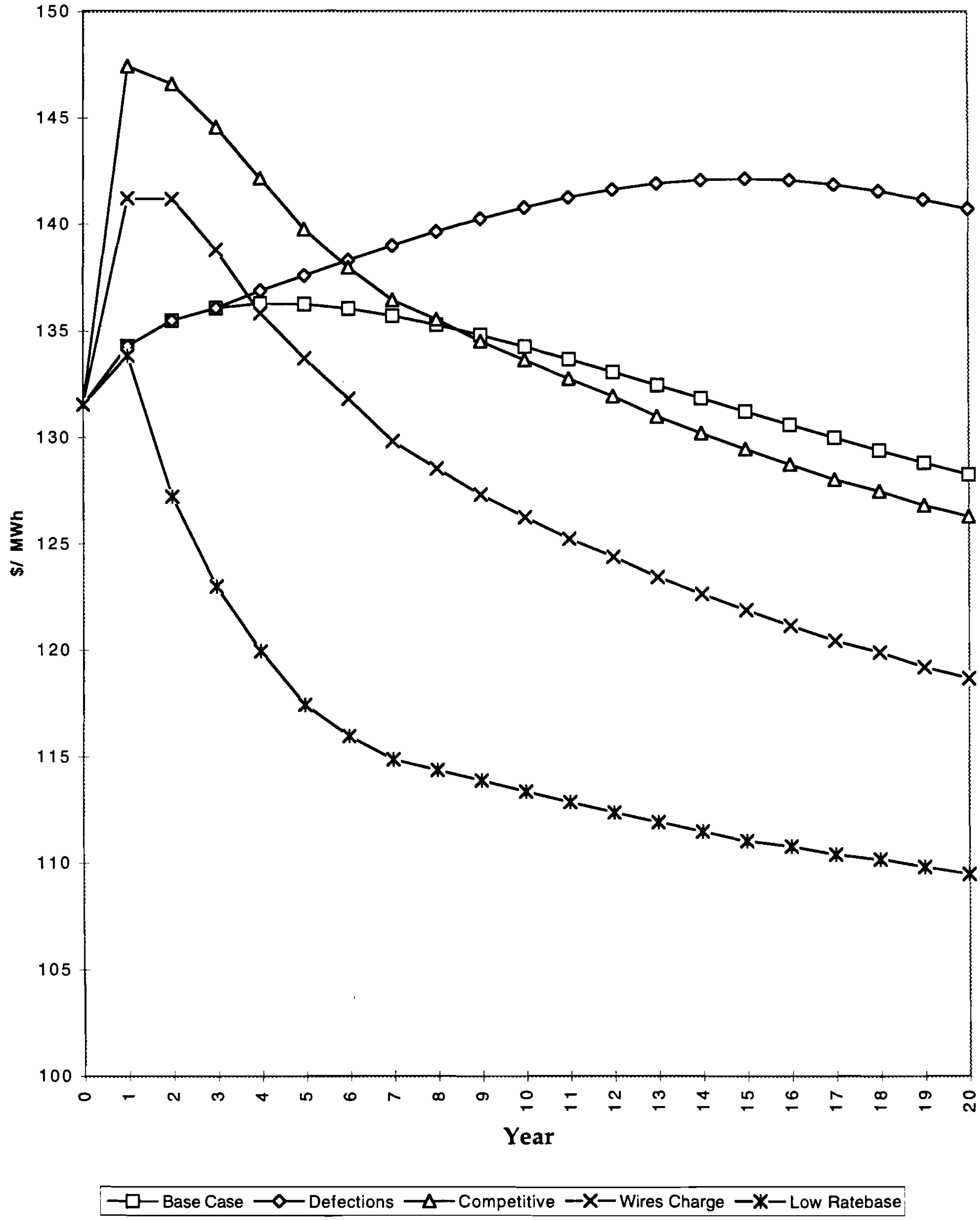


Figure 11. Average Residential Price of Electricity



environment, the Defection scenario results in higher average prices than does the Base Case. Under a competitive system, the Wires Charge scenario results in uniformly lower average residential prices than does the Competitive scenario because the wires charge shifts revenue responsibilities to the industrial sector. The Low Strandable Cost scenario produces the lowest average costs of any scenario.

When using average cost as the yardstick, it is not clear that residential customers are better off under the Competitive scenario than under the Base Case because Competitive average prices are higher for the first eight years. But if the Defection scenario, not the Base Case, were the appropriate baseline, then the Competitive scenario might be preferred. However, if strandable cost recovery were via a wires charge, residential customers might prefer a competitive system because the Wires Charge scenario produces lower average costs than the Competitive scenario. The Wires Charge scenario might also be preferred to the Base Case scenario.

The Low Ratebase scenario is the only one which clearly dominates the other scenarios. In every year other than year zero, the average price for the Low Ratebase scenario is strictly less than the average price under each of the other scenarios.

Figure 12 shows the average industrial price of electricity for the same five scenarios. The scenarios three scenarios which assume a competitive pricing system produce lower industrial sector prices than the Base Case and Defection scenarios (which assume a regulated system.) Unlike the residential sector, the Low Ratebase scenario does not produce the lowest average costs in every year. In fact, the Low Ratebase scenario produces only slightly lower average prices than the other two Competitive scenarios. This is in contrast to the residential sector, where the Low Ratebase scenario produces much lower prices than the Competitive scenario. This reflects the fact that the residential sector, with its inelastic demand for electricity, pays for a large share of fixed costs, so any reduction in strandable costs benefits the residential sector more than the industrial sector.

When strandable costs are recovered via a wires charge, strandable cost charges are spread more evenly between sectors. This can be seen in a comparison of the Wires Charge and Competitive scenarios. In the industrial sector, the Wires Charge produces uniformly higher average prices than does the Competitive scenario, the opposite of the residential sector. This is because the wires charge shifts revenue collections from the residential sector to the industrial sector.

Another means of comparing the effects of scenarios is by the ratio of average residential price of electricity to the average industrial price. Figure 13 shows that

Figure 12. Average Industrial Price of Electricity

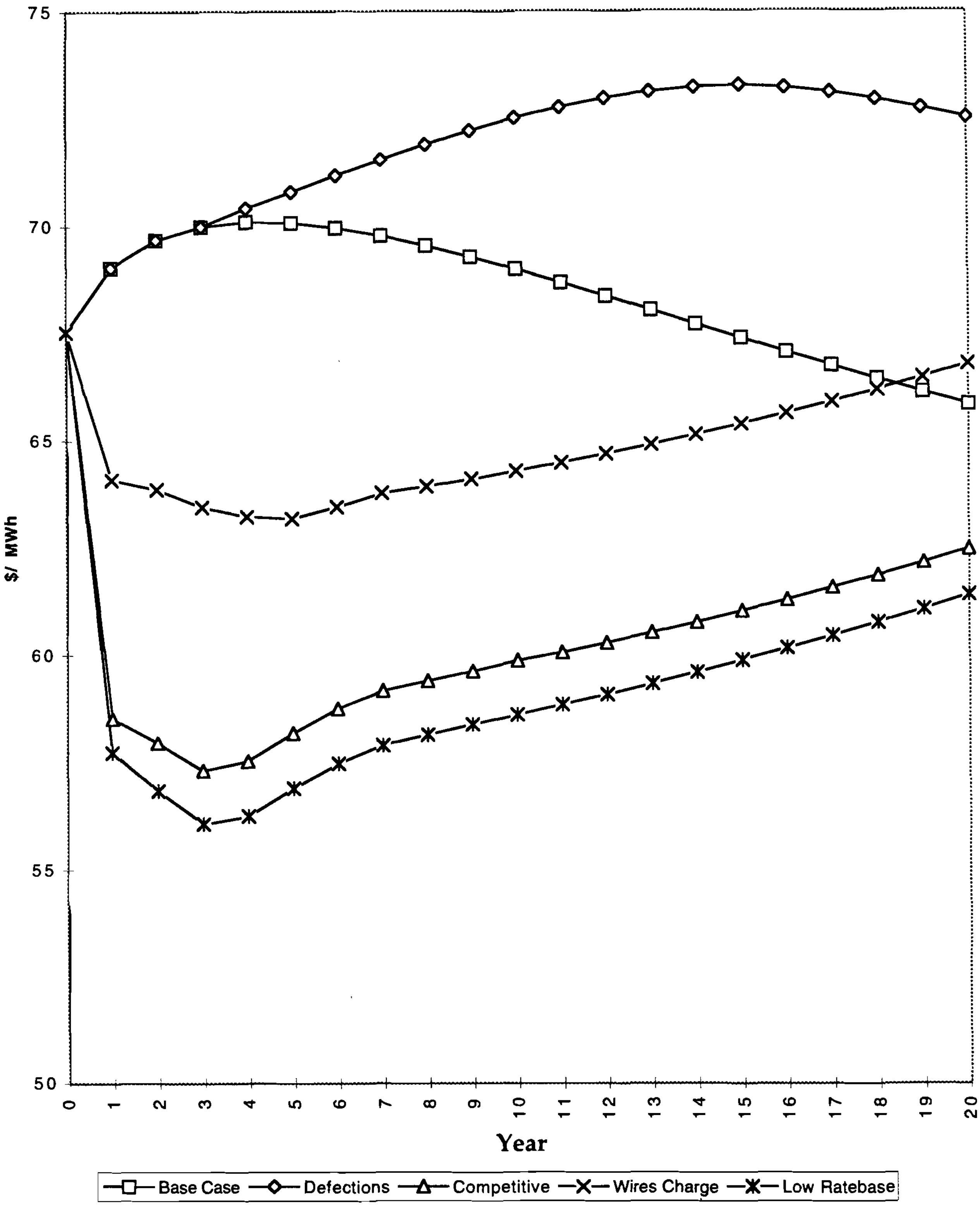
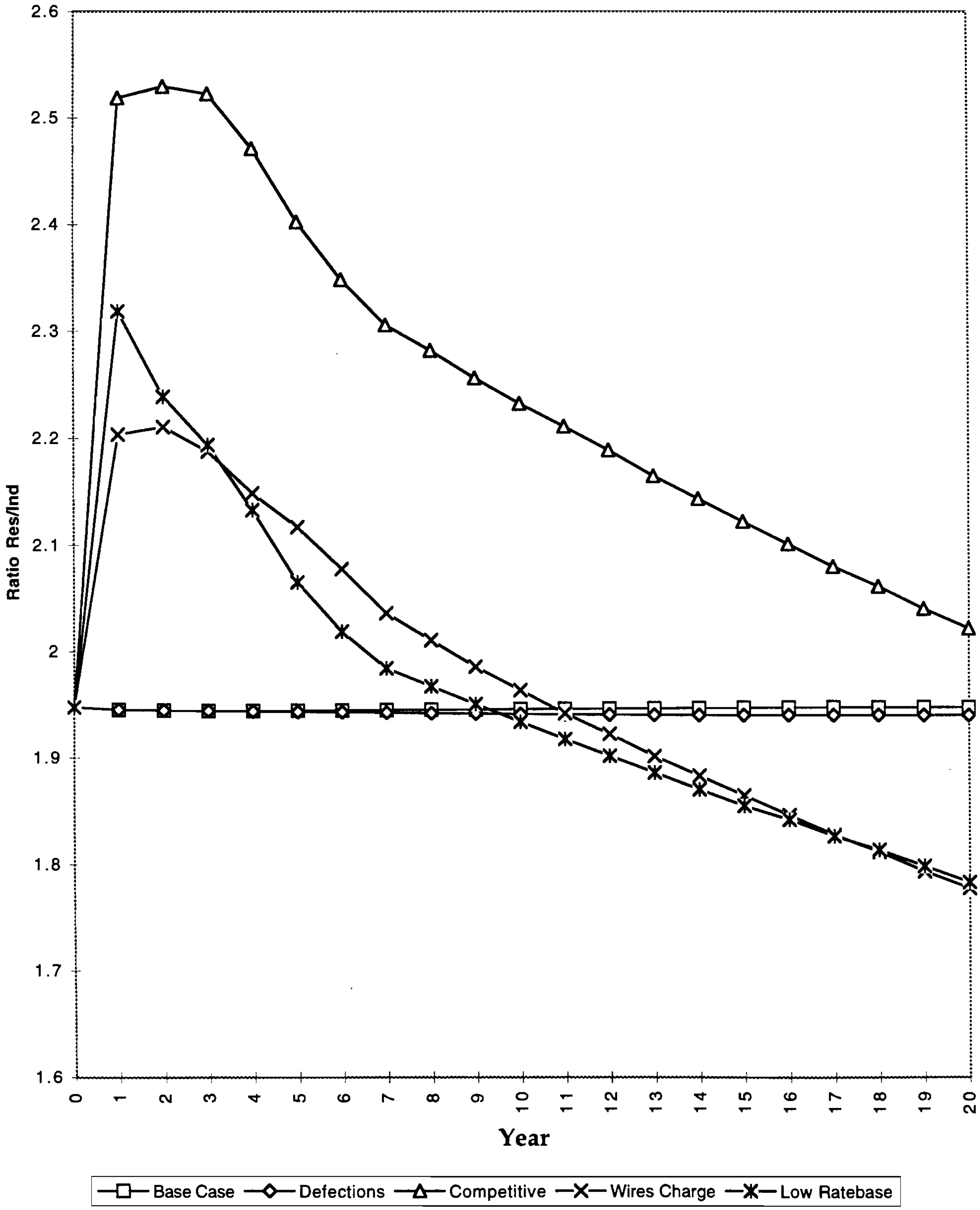


Figure 13. Ratio of Residential to Industrial Average Prices



this ratio varies greatly both across scenarios and over time within scenarios. For the first ten years of the forecast period, the Base Case and Defection scenarios produce relatively stable ratios. Each of the three scenarios under competition produces more unequal price ratios than the two scenarios which assume a regulated environment. This is not surprising, because equity concerns are a central part of the regulatory process but they are much less important in a competitive pricing environment.

But interestingly, after about the tenth year of the forecast period, the Wires Charge and Low Ratebase scenarios produce more equal average prices than the regulated scenarios as capital costs recovered through the customer charge begin to decline. The Competitive scenario always results in more unequal pricing.

Comparing average prices can quickly show the equity impacts of different pricing and strandable cost options. The Defection scenario is clearly worse than the Base Case projection in each sector. In contrast, the Competitive scenario and the Wires Charge scenario have different revenue implications for the residential and industrial sectors. The Low Ratebase scenario benefits each sector.

12. CONCLUSIONS

Competition is likely to show that the current rates charged for electricity, while satisfactory in a regulated environment, are untenable in a world with many new players unless there is a high level of direct state involvement. Consumers are still likely to be concerned about reducing average prices, with a two-part tariff being the most efficient way of generating revenue while keeping the average price low.

Existing electricity rates combine Ramsey-type marginal prices with moderate customer charges. In general, when a two-part tariff is feasible, Ramsey pricing is not desirable. It is less efficient than an efficient two-part tariff at generating needed revenues without distorting demand. As Table 1 shows, Ramsey pricing results in higher average costs as fixed costs are spread across fewer units of electricity. In a competitive setting, Ramsey pricing would surely give way to more efficient unit pricing as suppliers undercut one another's marginal prices. This would produce the lowest average costs as well. But in a regulated setting, equity concerns have helped to prevent the use of an efficient two-part tariff.

The potential of two-part tariffs to generate additional revenue is great. Since residential and commercial demand is essentially unchanged by the size of the customer charge, large fixed costs can be recovered without losing the efficiency characteristics of having marginal price equal marginal cost. With a two-part tariff, average residential sector rates can be raised even as electricity demand increases, which is not true under strict Ramsey pricing. Of course, customers who use little electricity may be faced with unacceptably high average costs of electricity.

Two-part tariffs are less effective for customers who are sensitive to average electricity costs because they have access to other sources of electricity. Industrial customers are likely to be able to either contract with NUGs or employ self-generation. This is made possible by modern, moderate sized gas turbine technology. The introduction of these technologically advanced low-cost sources of electricity has exacerbated the problem of strandable costs through the use of legislated contracts for NUG sources of power, and it has also provided industrial users with a technical means to escape paying for strandable assets.

High costs, from nuclear plants and 6¢ power contracts with NUGs, among other causes, have resulted in utilities charging high rates to all customers. Industrial customers, having other options, have recently been able to reduce this burden by plausibly threatening to switch to alternative sources of electricity. To accommodate these industrial customers, utilities have been forced to shift cost responsibility toward captive residential and commercial users. The two-part tariff allows this to be done without lowering electricity demand as much as it would be lowered if marginal prices increased.

So it is the sensitivity of industrial customers to average, not just marginal, electricity rates which limits the ability of the two-part tariff to collect revenues in this sector. This constraint is not present in the other two sectors because inexpensive alternative sources of electricity are not as readily available.

The empirical analysis shows that industrial defections clearly produce higher rates for all remaining customers as industrial customers leave the system. To the extent that this is a plausible scenario, it justifies moves to keep industrial customers on the system.

Competitive pricing will lower average industrial rates, reducing the likelihood of defections. It will also place the bulk of responsibility for strandable costs on residential and commercial customers, raising their average costs. The imposition of a wires charge would shift some responsibility for strandable costs back to industrial customers. It would also reduce demand in each sector. How strandable cost revenues are collected affects prices across sectors as well as sales within each sector.

Removing strandable costs ensures that each sector benefits from a competitive system. The Low Strandable Cost scenario provides the lowest marginal prices, customer charges, and average price in each sector, as well as the largest demand. The Low Strandable Cost scenario, when compared with the Competitive scenario, also shows that the demand and marginal price effects of strandable costs are negligible when a two-part tariff is used.

The scenarios which assume a regulatory environment produce the most equal average prices in the residential and industrial sector over the first half of the forecast period. The Competitive scenario produces highly unequal average prices. The Wires Charge scenario produces more equal average prices, while the Low Strandable Cost scenario produces the most equal average prices in the long term.

A competitive system of electricity provision will dramatically affect rate structure and demand as state control over prices is reduced. To the extent that industrial defections reduce industrial sector demand, competitive pricing may benefit all sectors even if some revenues are shifted to immobile customers. But two facets of a competitive system over which the state will have some control, the means and quantity of strandable cost recovery, will also play large roles in determining the impact of competition on each sector. A wires charge has the potential to produce more equal average prices, at the expense of reduced demand, while removing strandable costs can make competition attractive for all sectors.

APPENDIX

Demand Equations

The estimated Residential Model is given in (1), where i=1 is electricity, 2 is natural gas, and 3 is oil. N is other, non-energy goods, s is the state, and t is the year. HDD is heating degree days and CDD is cooling degree days. The distributed lag parameter on quantities is λ, while β_i is the coefficient of the Stone Price Index. The remaining parameters are defined as above.

$$\text{(1)} \qquad \ln\left(\frac{w_{its}}{w_{nts}}\right) = (\alpha_{i0s} - \alpha_{n0s}) + \sum_{j=1,\ j\neq i}^{n}\left(\alpha_{ij}\theta_{ij(t-1)s}\ln\frac{p_{jts}}{p_{its}}\right) - \sum_{j=1}^{n-1}\left(\alpha_{nj}\theta_{nj(t-1)s}\ln\frac{p_{jts}}{p_{nts}}\right) + (\beta_i - \beta_n)\ln\frac{I_{ts}}{PI^{*}_{ts}} + \lambda(\ln x_{i(t-1)s} - \ln x_{n(t-1)s})$$
$$+ \gamma_{i1}\,HDD_{ts} + \gamma_{i2}CDD_{ts} + (e_{its} - e_{nts}) \ ; \quad i = 1,2,3$$

The estimated Commercial and Industrial Models are:

$$\text{(2)} \quad \ln\left(\frac{w_{its}}{w_{nts}}\right) = (\alpha_{i0s} - \alpha_{n0s}) + \sum_{j=1}^{n}\left(\alpha_{ij}\theta_{ij(t-1)s}\ln\frac{p_{jts}}{p_{its}}\right) - \sum_{j=1}^{n-1}\left(\alpha_{nj}\theta_{nj(t-1)s}\ln\frac{p_{jts}}{p_{nts}}\right)$$
$$+ \lambda(\ln x_{i(t-1)s} - \ln x_{n(t-1)s}) + \gamma_{i1}\,HDD_{ts} + \gamma_{i2}\,CDD_{ts} + (e_{its} - e_{nts}) \ ;$$

$$i = 1,2,\ldots, n-1$$

$i = 1, 2, 3, 4, 5, 6$ (industrial only);

where i=1 is electricity, 2 is natural gas, 3 is oil, 4 is capital, 5 is labor in the commercial sector and coal in the industrial sector, while 6 is labor in the industrial sector only. θ is defined below:

$$\theta_{ik} = w_i^{\gamma-1} w_k^{\gamma}$$

Other parameters are defined as above. [1]

[1] For a more detailed explication of the model and derivation of elasticities, homogeneity properties, and Hicksian cross-price effects, see Dumagan and Mount (April 1991).

MODEL ELASTICITIES

Residential Sector

Short Run Hicksian Price Elasticities

	Electricity	N Gas	Oil	Other
Electricity	-0.042	0.017	0.003	0.022
N Gas	0.030	-0.118	0.000	0.088
Oil	0.010	0.000	-0.193	0.184
Other	0.000	0.001	0.001	-0.002

Long Run Hicksian Price Elasticities

	Electricity	N Gas	Oil	Other
Electricity	-0.332	0.037	0.018	0.277
N Gas	0.330	-0.631	0.005	0.296
Oil	0.233	0.041	-1.011	0.737
Other	0.001	0.003	0.004	-0.008

Short Run Marshallian Income & Price Elasticities

	Electricity	N Gas	Oil	Other	Income
Electricity	-0.052	0.011	0.000	-0.862	0.903
N Gas	0.020	-0.123	-0.004	-0.783	0.890
Oil	0.005	-0.003	-0.195	-0.238	0.431
Other	-0.011	-0.006	-0.003	-0.984	1.004

Long Run Marshallian Income & Price Elasticities

	Electricity	N Gas	Oil	Other	Income
Electricity	-0.343	0.030	0.014	-0.371	0.670
N Gas	0.319	-0.637	0.001	-0.036	0.354
Oil	0.222	0.035	-1.015	2.830	-2.072
Other	-0.010	-0.003	0.000	-1.007	1.020

Industrial Sector

Short Run Price Elasticities

	Electricity	N Gas	Oil	Coal	Capital	labor
Electricity	-0.261	-0.004	-0.004	0.000	0.215	0.054
N Gas	-0.014	-0.371	-0.004	0.001	0.448	-0.060
Oil	-0.009	-0.002	-0.187	0.000	0.255	-0.058
Coal	0.002	0.003	0.002	-0.004	0.411	-0.415
Capital	0.022	0.012	0.012	0.003	-0.552	0.503
labor	0.002	-0.001	-0.001	-0.001	0.216	-0.215

Long Run Price Elasticities

	Electricity	N Gas	Oil	Coal	Capital	Labor
Electricity	-0.653	-0.009	-0.003	-0.005	-0.239	0.909
N Gas	-0.065	-0.938	-0.013	-0.002	-0.938	1.955
Oil	-0.016	0.004	-0.451	-0.005	-0.256	0.724
Coal	0.075	0.043	0.044	0.012	-0.674	0.500
Capital	0.052	0.031	0.021	0.000	-0.121	0.017
Labor	0.006	-0.002	0.000	0.000	0.080	-0.085

Commercial Sector

Short Run Price Elasticities

	Electricity	N Gas	Coal & Oil	Capital	Labor
Electricity	-0.151	0.004	0.014	0.175	-0.042
N Gas	0.023	-0.213	0.079	0.167	-0.056
Coal & Oil	0.076	0.085	-0.177	0.280	-0.263
Capital	0.013	0.002	0.004	-0.426	0.407
Labor	-0.001	0.000	-0.001	0.123	-0.121

Long Run Price Elasticities

	Electricity	N Gas	Coal & Oil	Capital	Labor
Electricity	-0.582	-0.004	-0.024	-0.259	0.869
N Gas	0.022	-0.300	0.151	-0.780	0.907
Coal & Oil	0.198	0.246	-0.072	-1.713	1.341
Capital	0.123	-0.001	0.033	-0.769	0.614
Labor	-0.025	0.001	-0.010	0.248	-0.214

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