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# ELECTRIC RESTRUCTURING ISSUES FOR RESIDENTIAL AND SMALL BUSINESS CUSTOMERS

by

Kenneth Rose, Ph.D.
Senior Institute Economist

**The National Regulatory Research Institute**
The Ohio State University
1080 Carmack Road
Columbus, Ohio 43210
Phone: 614-292-9404
Fax: 614-292-7196
www.nrri.ohio-state.edu

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## Executive Summary

When a state considers electric restructuring, a commonly expressed concern is that the introduction of retail choice should not leave residential and small business customers behind. In other words, while "big dogs" may "eat first" (and perhaps the most), these smaller customers should also benefit from retail choice. Some states have adopted policies that specifically target residential and small business customers, such as customer education programs and measures to prevent unscrupulous marketing tactics (for example, "slamming" and "cramming"). However, some policies, such as setting low generation standard offer prices and rate discounts, may appear to be beneficial, but can actually reduce the competitive options available to these customers.

What has greatly complicated implementation of retail choice is the attempt to reconcile the consequential, but contradictory goals of: (1) making sure residential and small business customers benefit or are at least not harmed by competition, (2) encouraging the development of an efficient and competitive retail market (for example, policies aimed at limiting market power), (3) having broad customer participation, (4) protecting incumbent utilities from potential market losses (so-called "stranded costs"), and (5) maintaining "system benefits" that include system reliability, low-income assistance, and conservation and renewable programs. While every state has addressed, to varying degrees, each of these five overall goals, none has, or is likely to meet, all of them simultaneously.

These goals come into direct conflict when existing customer rates are unbundled into various price components. These include the following components: (1) a generation price, which has been given various labels such as standard offer, shopping credit, price to compare, backout rate, and other labels; (2) customer charges, which include charges for "stranded costs," low-income customer assistance, conservation and renewable programs, and other items; (3) transmission and distribution charges, for the "wires" that remain regulated; and (4) in many states, an automatic discount off the previously regulated rates.

Since states often also establish price ceilings during a transition period, all these price components must fit under the ceiling, which is the beginning of the practical difficulty. If the last three price components are established separately, this may mean that the generation component is set below what a competitive retail market would establish as its price. The result is insufficient "headroom" for competition to occur. As a result, few customers select an alternative supplier, as has occurred in several states, because few competitive options are being made available to them. The experience in the first states to adopt retail access indicates that, not surprisingly, there is a strong positive correlation between the economic incentive to select a supplier (the generation “price to compare” or standard offer relative to the retail market price) and the percentage of customers that have selected a supplier.

To avoid this problem, some states have established a generation price (or “shopping credit”) that is set sufficiently high so that alternative suppliers are encouraged to enter the market. While this avoids the problem of insufficient “headroom,” at least initially, the method is not without its problems. First, even with a generation price well above the retail market price, inducing many alternative suppliers to offer customers lower prices, and vigorous customer education to inform customers of their options, many or most customers remain at the established generation price. Preliminary evidence suggests that these customers may be disproportionately the elderly and low-income households. A second limitation, which is a limitation of any method that sets the generation price in advance without cyclic market adjustments, is that while there may be sufficient headroom initially, over time it may be eroded as market conditions change. Suppliers may abandon the area and try to “dump” customers back to the incumbent supplier at the established generation price.

There are two general categories of methods used by states to determine the generation price. The first is market-based methods, which include direct wholesale passthrough and standard offer auctions. The second is composed of administratively determined methods that include basing the price on the incumbent utility’s generation costs or a market estimate. While there are advantages and disadvantages to the various methods, market-based methods are better able to reflect market conditions and, if periodic adjustments are made, can change as market prices change over time. Because of the numerous factors that determine a retail price, it is difficult for administrative methods to simulate a dynamic market price, particularly in advance of actual market experience. At best, administrative methods are only rough approximations of the actual market price. Another advantage to market-based approaches is that they spread the benefits of a competitive market to all customers, not just those savvy enough to select a supplier.

Because of the design of most transitional unbundling schemes, if upward pressure continues on wholesale prices, residential and small business customers may find themselves in an increasingly disadvantageous bind of higher prices, few or no competitive options, or both. For customers served by an incumbent supplier, the generation “price to compare” may either continue to be below a competitive retail price, so that few competitive options are made available to them, or, when the generation price is sufficiently high to allow competitive suppliers to enter the market initially, the situation does not remain that way as wholesale prices move above the set retail price. In addition to the low (or negative) retail margin, uncertain and unstable prices increase the risk for alternative suppliers and force them to charge higher prices, abandon retail markets, or never enter in the first place. There will be little complaint from the incumbent supplier about the generation price, at least during the transition period, since its *total* generation compensation also includes the payment for "stranded costs." Also, the incumbent supplier (or its affiliate) is able to maintain a dominate market share. When the incumbent utility has exited the generation business either mostly or entirely, upward pressure is placed on the generation price since it is now supplied by the new owner or owners of the existing generation resources or is purchased in the wholesale market. However, since the amount of the "stranded cost" payment was determined when lower prices were expected (either estimated or determined by generation asset sales), customers continue to pay for "stranded costs" that never materialize. The combined result is a higher price of generation and continued payment for "stranded costs" to the former owner of the generation assets.

Perhaps one of the most significant issues facing small customers is the possible impact of market power and price discrimination. Due to consumer demand characteristics, relatively concentrated retail markets, and generation and transmission constraints that limit retail customer access to alternative suppliers, there may be significant opportunity for suppliers to exploit market power and raise their price above what a competitive market outcome would be. Also, since suppliers will be able to segment groups of customers, the opportunity (and incentive) exists to charge a higher price to smaller customers and sustain the higher price for an appreciable period of time.

It is hoped over time, as transition periods end, more new generation enters the market, and transmission constraints ease, that prices should moderate and all customers should benefit. However, some transition periods run until the end of this decade and, at this time, it remains to be seen to what extent supplier market power (both wholesale and retail) will develop to obstruct or prevent the full development of a competitive generation market. At this critical stage of restructuring, states need to seriously consider policies that encourage the development of a competitive generation market and ensure the spread of the benefits to as many residential and small business customers as possible. If this does not occur, political support for electric industry restructuring may be undermined by a perception that the only beneficiaries are large customers and electric power suppliers.

## TABLE OF CONTENTS

## LIST OF FIGURES

Page

**FIGURES**

# LIST OF TABLES

Page

TABLES

## ACKNOWLEDGMENTS

The author thanks the reviewers of an earlier draft of this report, Ken Costello, Deborah Flannagan, Grace Hu, Lisa Stump, and Vivian Witkind Davis. Thanks are also extended to those who, over the last couple of years, have helped hone the discussion of restructuring issues contained in this report, including Representative Priscilla Mead, Senator Bruce Johnson, Commissioner Craig Glazer, Mary Connor, and Alan Martin of Ohio, and numerous others at workshops, conferences, and hearings around the country that have tried to help “elevate the debate.” Also, this report may not have been written without the urging of Commissioner Ed Meyers of the District of Columbia and the Consumer Affairs Committee of NARUC. Any “rough spots” are, of course, the sole responsibility of the author.

## Section 1: Rate Unbundling and Establishing a Standard Offer Rate

### Introduction

At the signing of electric restructuring legislation, state governors often point out the potential benefits of the legislation for consumers of electricity. In particular, the benefit to residential consumers is often emphasized. While larger customers are often a primary political constituency that presses for retail choice, most states have sought a means to spread the potential benefits of competition to a wider range of customers, or, at the very least, make sure smaller customers are not made worse off by restructuring. Clearly, this goal is an important element in the design of the transition to a restructured industry. Other goals that are usually balanced with small customer impact, and are often at odds with each other, include encouraging robust competition by encouraging alternative supplier entry, encouraging customer participation, protecting the incumbent utilities from some or all market risks and revenue losses during a transition period, and maintaining "system benefits" that include distribution reliability, low-income assistance, and conservation and renewable programs. Balancing these and other policy goals greatly complicates the design of the transition.

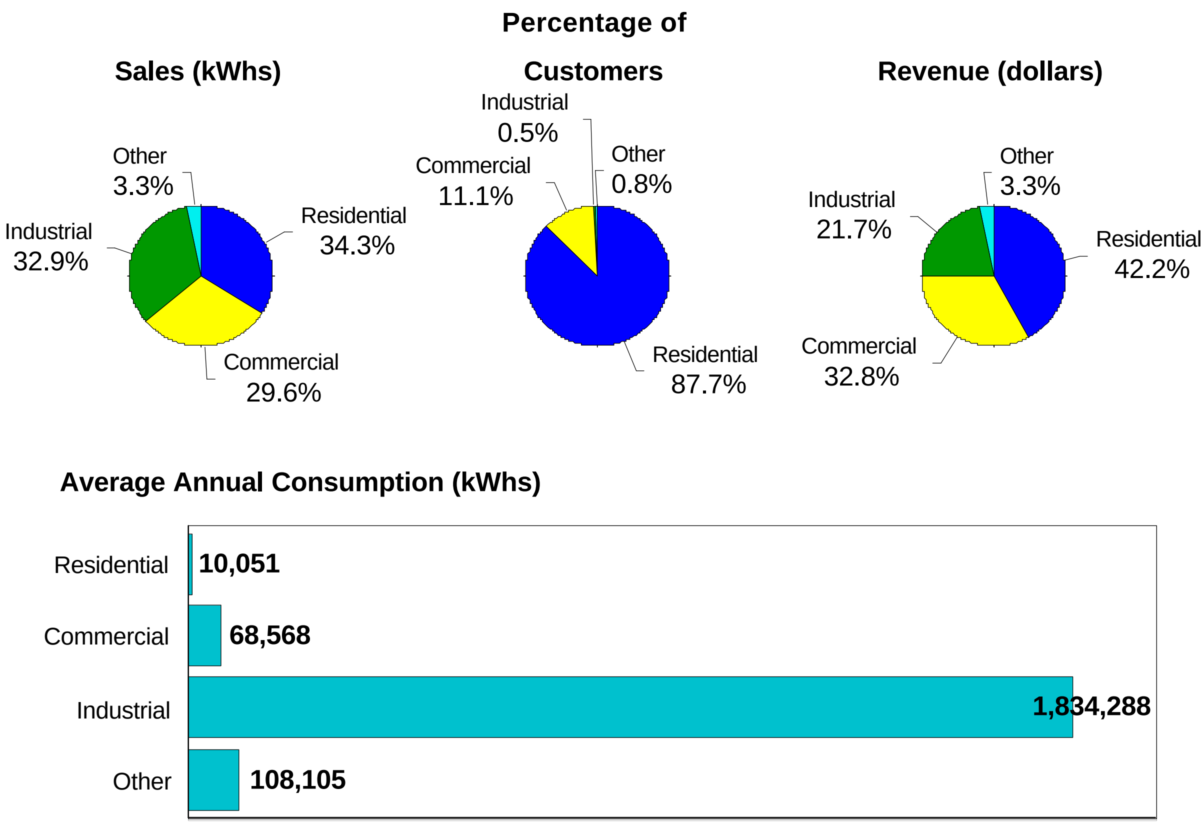
Now that nearly four years have passed since the first states passed their legislation, an analysis can be conducted to determine how small customers have fared under the different types of restructuring options. There are several issues that are particularly relevant to small customers. These issues include the design of the transition pricing components or how "unbundling" is accomplished and the method of determining the unbundled generation price.

Currently, twelve states allow choice for at least some segment of retail customers,[1] and several other states are expecting to begin their programs soon. In all, twenty-four states and the District of Columbia have either passed restructuring legislation or the state's commission has passed restructuring orders or reached settlements with utility companies. Three states in particular have had the longest running customer choice programs and, therefore, the most experience to date– California, Massachusetts, and Pennsylvania.[2] These states also differ from one another in how they designed their transition to a competitive retail market, which has

[1]As of April 2000 the following states currently allow retail access for at least some segment of customers: California, Connecticut, Delaware, Illinois, Maine, Massachusetts, Montana, New Hampshire, New Jersey, New York, Pennsylvania, and Rhode Island.

[2]Rhode Island has the longest running retail choice program in the country (not counting pilot programs) where phase in began in July of 1997. However, it is similar in design and outcome to Massachusetts which began in March of 1998.

**Figure 1.1**. In terms of total consumption, number of customers and revenue, residential customers have the largest shares, but they also have the lowest average usage.




Source: Electric Sales and Revenue 1997, DOE/EIA-0540(97), Washington, D.C., October 1998.

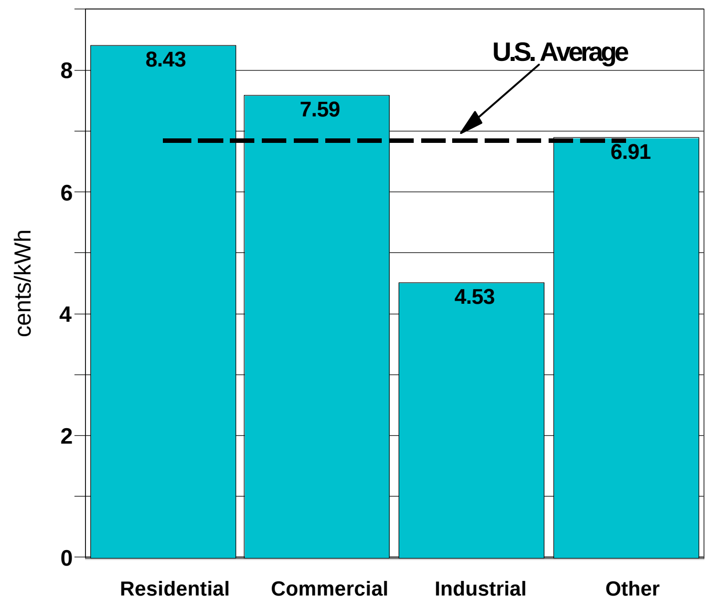
affected participation by small customers and how they have benefitted so far from restructuring. For this reason, these three states are examined in detail in this paper.

### What is a "Small Customer"?

Generally, for purposes of the paper, the term "small customer"refers to nearly all residential customers and smaller commercial and industrial customers. "Small" may be somewhat misleading since, as a group, residential customers alone accounted for almost $91 billion in revenue from U.S. sales of electricity in 1997. This was 42 percent of total industry revenue and was the largest share of any customer classification. Residential customers comprised 88 percent of all electric customers in 1997 and they also had the highest share of sales in terms of kilowatthours sold in the industry, at 34 percent. The breakdown by customer classification for sales, number of customers, and revenues is shown in Figure 1.1. As the chart at the bottom of Figure 1.1 indicates, in terms of per customer average annual usage, residential customers use much less electricity on average than any of the other three classifications. The average industrial customer's usage was over 182 times greater than the average residential customers' usage. "Small customer," therefore, refers to the typical usage pattern or load of individual customers, not the aggregate customer classification which is obviously very significant and nontrivial.

Nationwide in 1997, residential customers paid the highest average revenue per kilowatthour of any major customer classification. Industrial customers paid the lowest average revenue. Average revenue for the four major customer classifications is graphed in Figure 1.2. This average revenue per kilowatthour is defined as the weighted average of consumer revenue and sales within the customer classification. This is calculated by dividing retail electric revenue collected by the corresponding sales (kWhs) of electricity.

**Figure 1.2**. Residential customers pay the highest average revenue by major customer classification.




Source: Electric Sales and Revenue 1997, DOE/EIA-0540(97), Washington, D.C., October 1998.

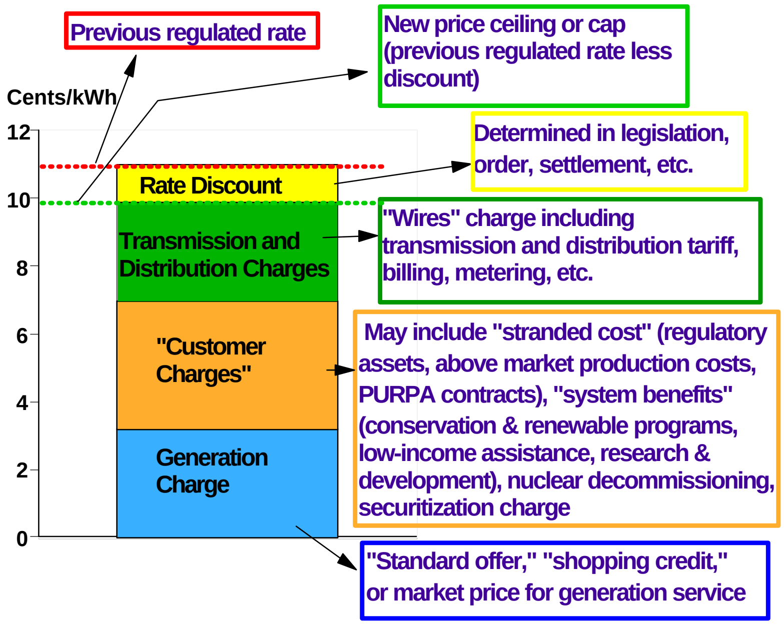
## Retail Rate Unbundling Issues for Small Customers

### Unbundled Rate Components

Under regulation, vertically integrated utilities had their rates determined in a rate case based on the total cost of generating and delivering the power to their customers. These rate cases tended to be long formal proceedings that lasted many months or even years. Frequency of rate cases depended on economic conditions and may occur every few years to over a decade. Adjustments to rates made between rate cases, for example, through a fuel adjustment mechanism, were made to the aggregate rates for the various rate classifications. Restructuring requires, in most cases for the first time, that the various service components be separated from one another. This is because not all services provided by the vertically integrated utility are being opened to competition. The regulated rates must be "unbundled," or the various service components separated into a competitive generation component and several noncompetitive parts.

While how this is done in each state that has or is in the process of restructuring has varied somewhat, the general elements are similar. Figure 1.3 breaks down an existing rate structure into four main components. Beginning at the bottom of the figure, the generation charge, is referred to as the "standard offer," "shopping credit,"

**Figure 1.3**. Four major rate components after unbundling.




or, if the customer chooses to purchase generation from a supplier they chose, it is simply the market price for generation (see text box on terminology below). From the retail customer's perspective, this is the only component that is subject to their individual choice under current industry restructuring. There may be competition introduced for other services, such as metering or billing, but, at least so far, the individual retail customer does not select the firm to buy these services from. How this generation component is determined, an important consideration for small retail customers, is the subject of a more detailed discussion below.

The next component is the customer charges. This may include the competition or competitive transition charge (CTC), which includes three basic types of uneconomic or "stranded costs": potentially "stranded" production or generation costs, net regulatory assets, and state and federal mandated program costs. The above-market production costs are past sunk or capital costs and current operating expenses that may not be recoverable in a competitive market. No new rate case or rate re-balancing is usually done to calculate these charges. These generation-related costs have usually been recovered in rates from customers, but may no longer be recoverable with market-based prices that may result in a lower revenue stream for the utility. The customer charge for recovery of these costs is derived from current costs as compared to actual market prices or forecasts of future market prices. This production cost category is usually the largest single category of the uneconomic costs. Regulatory assets include deferred expenses such as for taxes and deferred plant expenses and are directly from current regulatory books and should be offset by any regulatory liabilities. State or federal mandated expenses may include above-market Public Utilities Regulatory Policy Act (PURPA) contracts, demand-side management (DSM) expenses, renewable programs, and other costs incurred by the utility to comply with state and federal requirements and regulations.

The next price component are the "wires" charges that remain regulated. This may be determined by unbundling current rates (where transmission and distribution

[T&D] is often a "residual" calculation) or a cost-of-service or performance-based procedures (PBRs) are used to set initial rates. In the future, states may use PBR mechanisms for noncompetitive T&D services while metering, billing, and collections, subsets of T&D costs, may be subject to a competitive process. Generally, states determine the distribution charge through a regulatory mechanism or “residual” (discussed below) and the transmission charge is determined by FERC.

The final component is the rate discount, which is usually determined by legislation, commission order, or settlement agreement. Rate discounts are discussed in detail below.

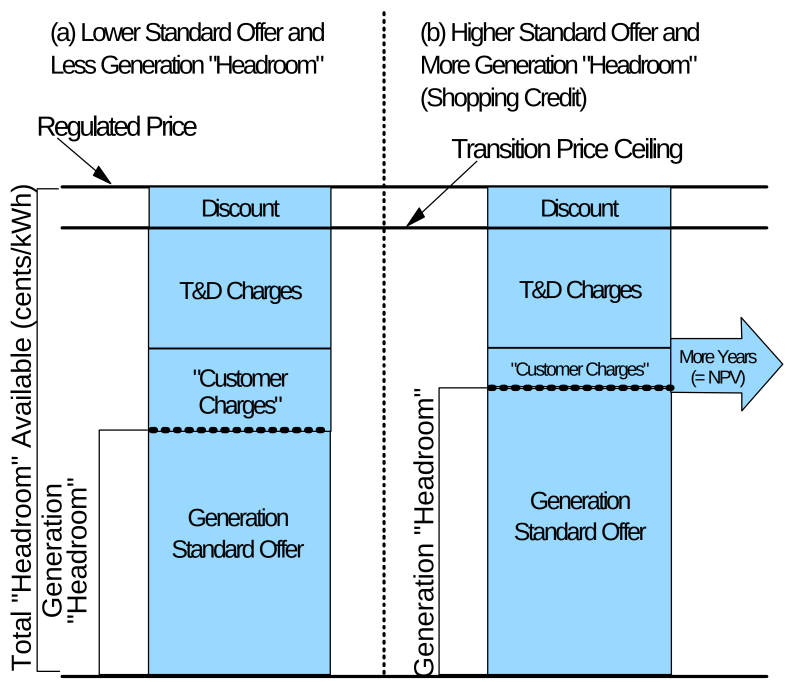
**Transitional Rate Issues and Their Importance to Small Customers**

From the consumer’s perspective, the most important overall consideration of the price components is what they add up to, or the total price paid for power. Of these price components, however, the most important to consumers after restructuring is clearly generation. As noted, this is the only component that the consumer, where there is retail access, has direct control and choice of supplier. While there may be competitive elements in T&D and customer charges, the individual consumer has no direct control or choice. Before attention is turned to this critical component for the small customers, the other three price components and how they are linked together are analyzed.

**Working Under A Price Ceiling**

Figure 1.4 illustrates the transitional pricing problem faced by those who are charged with carrying out the task of implementing restructuring in a state. Each pricing block, the discount, T&D, customer charges, and generation component (that is, the standard offer or price charged by the supplier chosen by the customer) must not exceed the existing rates determined by regulation. This rate is usually used as a starting point since most states have a rate freeze or ceiling at existing rate levels as part of their restructuring legislation, commission order, or settlement. All of the

**Figure 1.4**. The amounts of the transition pricing components determine the amount of generation “headroom” suppliers compete under.



pricing components must fit under this rate ceiling that acts as an overall constraint on the total price during the transition period. As will be discussed in more detail below, discounts are also common. The consequence of the discount, which typically lasts through a transition period,[3] is to lower the overall price ceiling to a transitional price ceiling as noted in Figure 1.4. This lower discounted price, when present, is typically the actual price ceiling under which the public utility commission or parties to a settlement must fit all the remaining price components.

**What's "Standard" About the "Standard Offer"? A Note On Terminology**

Unfortunately, there is no widely recognized standard terminology to describe the generation component, at least not yet. If the customer chooses a supplier of an electric rate, then the generation price is simply the agreed on price for power; that is fairly obvious. Consumers that are paying the generation price established by the state, however, may fall into one of three general categories:

1) customers that are no longer being supplied by their chosen supplier–for example, due to supplier default;
2) customers that cannot obtain power from an alternative supplier–for example, those that cannot meet financial requirements; and
3) customers that do not make a specific choice of supplier–that is, non-choosing customers.

This last group of customers, non-choosing customers, is usually the largest group of the three. These non-choosing customers or the established price they pay are referred to by different terms in different states. These terms include standard offer, default rate, last resort, or shopping credit. Confusingly, the same term is sometimes used in different ways. For example, one state may refer to "default customers" as customers that have not chosen a supplier, that is, the rate they default to, while another state uses the same term to refer to customers whose supplier defaulted and the customer returns to a standard offer. In some states, "standard offer" may refer to the total bundled price for delivered power.

For purposes of this paper, standard offer customer and standard offer rate refer to those customers that did not make a specific choice and the price non-choosing customers pay for generation only, respectively for generation. It will also be assumed that all three customer categories pay the same state-established price, recognizing that this may also vary by state practice since states may set different rates for each of the three categories.

## Rate Discounts

Discounts off the previously existing regulated price used to establish a transition price ceiling have been common among restructuring states, particularly among states with utilities that have relatively high rates (that is, above the national average). Typically, automatic rate discounts have been targeted only to small customers and are usually in the range of five to fifteen percent. The logic is that relatively larger customers would be both the primary beneficiaries of competition and be able to secure competitive power in the market on their own. The special consideration for small customers was intended to guarantee that small customers would also share in the benefits of a restructured market, prevent small customers from paying higher prices because of possible cost-shifting or because of price discrimination. The

[3]Often, but not always, this transition period corresponds with the period the incumbent utility is able to recover uneconomic or "stranded" costs.

amount of the discounts and how they have been determined has varied from state to state. Some mandated the discount amount in the original restructuring legislation. Other states determined it through a commission order, settlement with the parties, or a combined order and settlement procedure.

These automatic discounts have been the primary and the most widely distributed means by which small customers have received a lower price for their power during the transition to competition. However, it is not at all clear that discounts have always provided a long-run net benefit to small customers. There are at least three concerns that call for further explanation regarding discounts. First, as noted above, the discount reduces the amount of "headroom" available for the generation component or standard offer (since all the price components must fit under the price ceiling). This clearly has the effect of discouraging supplier entry into the market. If the discount is relatively small, then obviously its impact on generation headroom is more limited and may not be as significant as the other components, such as the customer charges. But even a relatively small discount makes it that much more difficult to provide reasonable generation headroom when designing the transition components. Second, a discount usually results from a process of political compromise, not a competitive process. Any benefit that is derived by customers is the direct result of the clash of the various interest groups, not because a thriving competitive market was given a chance to evolve. Indeed, because of the decreased generation headroom noted above, it may actually hinder the competitive process which, long term, may hurt smaller customers more if a competitive market fails to develop adequately or costly remedial actions are needed to resuscitate it.

The third concern depends on the transition design and how any potential uneconomic costs are determined. In many cases, the discount may not be a real permanent savings for eligible customers at all but only a temporary rate reduction that is financed by the customers themselves. Typically, as discussed, the discount is deducted from the existing regulated rate and the remaining price components are calculated to fit under the transition price ceiling that remains in effect throughout the transition period. If the T&D component is determined separately, this leaves the customer charges and the generation standard offer as the variable components. As noted, the customer charges are composed of several items, including support for programs such as low-income customer assistance or conservation and renewable programs. However, when there is uneconomic or "stranded" cost recovery, it is typically the largest single part of the customer charges. While there are many techniques for estimating uneconomic cost, when the recovery formula used allows recovery based on the shortfall of market revenue to the utility relative to all its generation costs (whether estimated or through asset sales), then the discount may not be factored in as a savings to customers. With no adjustment to the uneconomic cost recovered, the result is that the discount is primarily deducted from the generation cost component, making it lower than it would be without the discount. Aside from the headroom problems this may cause, it means that the generation price is not based on realistic market prices or generation cost of the incumbent, but on an artificial construct. As also discussed elsewhere, headroom can be increased by lengthening the recovery period. However, the net present value and, as a result, the total amount paid by customers is the same.

In short, the impact of the discount is either reduced headroom or a longer uneconomic cost recovery period. The main beneficiaries of the discount, therefore, are not small retail customers, but incumbent suppliers that are guaranteed to recover all their generation costs not recovered in the market and have a reduced threat that alternative suppliers will be competitive.

**In What Order Should the Unbundled Components Be Calculated?**

The order in which the main three price components illustrated in Figure 1.4– T&D, customer charges, and generation–are calculated (taking the amount of the discount as a given) can impact the amount of generation headroom. Because of the price ceiling, the last component becomes the remainder or residual after the other components are subtracted. Even if each is determined separately, it is highly unlikely that the components will sum to exactly the price ceiling. For example, beginning with the last regulation-determined rate, the discount is first subtracted, then T&D could be subtracted followed by the customer charges. This leaves the generation component as the remainder. Alternatively, again beginning with the regulated rate and subtracting the discount, T&D and generation could be subtracted next leaving the customer charges as the residual. Finally, the T&D charge could be the residual amount. Because of the way each component is calculated, alternative calculations will not necessarily yield the same answer.

The T&D component will continue to be regulated together by FERC (transmission) and the jurisdictional state commission (distribution and some in-state transmission). Since the T&D component is not subject to competition, it is likely to be calculated based on pertinent costs at least initially and perhaps include incentive mechanisms for future adjustments (using PBR methods, for example). Irrespective of the method used to calculate the rate or make future adjustments, it is important that it is realistically based on T&D costs and does not include any generation costs. Since the bundled regulated rate most likely did not separately determine distribution charges, T&D must be calculated separately. The charge must be as precise as possible to avoid any possible distortions to the competitive generation market. If the T&D charge is too high, then less headroom is available for generation and competition is impeded. If it is set too low the distribution company may not be fully compensated for the cost of operating and maintaining the distribution system, and, the result is that the generation component is set relatively high. If T&D is the residual, some generation costs may be included–meaning generation will be priced too low relative to an actual retail market price.

The largest component of the customer charges, the uneconomic or "stranded" cost, can be collected over varying time periods. This makes it a good candidate for the residual value. Also, because it is based on guesses of the future market price[4] and many other assumptions,[5] the uneconomic cost component is an unsuitable choice for setting the annual collection too far in advance. This uncertainty makes it the best candidate for being the residual that minimizes the distortion on the generation market. Whether there is an annual true-up mechanism or not, the total net present value collected by the utility can be adjusted to allow the decided amount of recovery (from the legislation, commission order, or settlement).

In addition to varying the recovery period, an important design consideration is the inverse relationship between generation price and the "stranded" cost component of the customer charge. That is, a lower generation component should correspond with a higher "stranded" cost charge and vice versa, *if the generation price is the competitive price*. However, a generation price or "standard offer" that is below the competitive retail market price will reduce the number of customers that choose a supplier, meaning less "stranded" costs.

This requires, of course, that the generation component be set in an appropriate manner. Just as the T&D component may distort the generation price component, if the generation component itself is the residual, it may be set too low or too high relative to the retail market price. Too low a price discourages entry, since most customers will stay at the standard offer; too high will result in standard offer customers paying above market prices. The question becomes: How should the generation component be determined?

**Methods for Determining the Standard Offer**

In a competitive market for most goods and services, there is no "default" or "standard offer" service price. If the customer does not make a selection, no purchase occurs and the price may vary considerably from seller to seller. It is known from experience in the utility industry that most customers will not, at least initially, choose a supplier. Policymakers have, at least so far, not allowed customers to simply be without power if they do not choose a supplier. Therefore, a standard offer rate is required for customers that do not make a choice or for continued service until they do select a supplier.

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[4]Note that even if uneconomic costs are based on asset sales, it is still someone's guess of future market conditions.

[5]These additional assumptions include demand growth, plant capacity factors, operating costs, intangible asset values, plant upgrade and refurbishment costs, customer migration rates, technology change, environmental compliance costs, taxes, cost of debt and equity, reserve margin, and estimation time horizon.

Policymakers have basically two general categories of options to determine a standard offer[6] (see box). The first are means that set the generation standard offer at a market determined price. These methods use the market directly to determine the standard offer with no adjustment. The second general category is administratively determined standard offer options. These options use either the incumbent utility's generation costs as a basis or begin with a market measure of some kind and then adjust it to set the standard offer. Under these general categories there are seven specific standard offer options. Each option is discussed below along with advantages and disadvantages and is summarized in Table 1.1.

**Options for Determining Standard Offer**

- Market Based
  - direct wholesale passthrough
  - auction
- Administratively Determined
  - Incumbent generation cost
    - calculated
    - residual rate
  - Adjusted market
    - wholesale price plus adder
    - retail market price index or estimate
    - retail price estimate plus adder

1) Market Based: Direct Wholesale Passthrough

This first option takes the wholesale price determined in the bulk-sales market and passes it through to retail customers. This is basically the approach used by California using its power exchange (discussed in the next section). Since California was developing the power exchange as part of its restructuring efforts, allowing retail customers access to it through the distribution companies became an option. Other states with less developed wholesale markets may not be able to use this option as directly. The advantage to this approach, when a well developed wholesale market is available, is relative simplicity. Assuming that the wholesale market is functioning suitably, it is relatively easy to calculate a weighted average monthly price to charge retail customers. This approach also assures that all customers receive a low standard offer price.

The disadvantage is that the wholesale market price will most likely be well below a retail price level. The wholesale price does not include the cost of marketing, risk management, and other costs to serve retail customers. This makes it difficult or impossible for retail suppliers to offer customers a comparable or a lower price. Also,

[6] Again, as explained above, the term "standard offer," as used here refers to the generation components of the retail customers' price components. This is currently the only component that is subject to competition and customer choice.

**Table 1.1**. Advantages and disadvantages of various standard offer options.

| **Options** | **Advantages** | **Disadvantages** |
|---|---|---|
| Direct Wholesale Passthrough | • simple to implement<br>• changes when market conditions change<br>• wholesale price guaranteed for all customers | • discourages entry by alternative suppliers<br>• hinders retail market development |
| Auction | • market determined price (not administrative)<br>• changes when market conditions change<br>• encourages supplier participation | • requires developing suitable auction rules<br>• requires regulatory supervision and monitoring |
| Calculated Incumbent Generation Cost | • appropriate benchmark for transition period based on regulated costs | • difficult to unbundle from other costs<br>• becomes less relevant as market develops |
| Residual Rate | • relatively simple<br>• requires little information beyond determining other price components | • may have no bearing on what is appropriate retail generation price or incumbent's generation cost |
| Wholesale Price Plus Adder | • observable basis with well developed wholesale market | • arbitrary–"correct" adder is unknown |
| Retail Market Price Index or Estimate | • retail market price provided to all customers | • may have no or underdeveloped market to base it on (especially early in market development) |
| Retail Price Estimate Plus Adder | • market basis when retail market is well developed<br>• increases alternative supplier participation | • may have no or underdeveloped market to base it on<br>• arbitrary–"correct" adder is unknown |

after the transition period is over and uneconomic costs are no longer being collected from customers, this option may be difficult to sustain. This is because the distribution company will not be able to recover its costs of power (either generated themselves or purchased) and provide it to retail customers at the wholesale price. If the distribution company is allowed to recover the difference between these costs through the distribution rate, then the generation standard offer is being kept artificially low and is not reflecting the real cost of providing generation to retail customers. The result is that retail customers on the standard offer do not benefit, since the remaining generation costs are included in the T&D charge. The retail offers and results of the California approach are discussed in the next section.

2) Market Based: Auction

An alternative market-based method is to conduct an auction to determine the standard offer generation price. The auction can be for the entire distribution company's retail load or it can be subdivided by customer category, geography[7] or a portion of the total customer load.[8] A competitive auction is the most direct way to ascertain an overall retail market price for a group of retail customers. The main advantage to this approach is that the standard offer price is determined through a competitive process–assuming, of course, that the auction is well designed. It is in the best interests of the competitive generation market, and therefore customers, to allow the market to determine the generation component, rather than a regulatory process that is likely to either undershoot or overshoot the competitive price target when setting the standard offer. Also, using a direct market mechanism to determine the generation price will allow adjustment to changing market conditions–if the auction is conducted on

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[7]In 1998, an auction mechanism was included in Ohio companion bills that were introduced in both the House, H.B. 732, and Senate, S.B. 237. This mechanism would have divided the state's current utility service territories into retail marketing areas (RMAs). At the beginning of retail competition, the Public Utilities Commission of Ohio would have conducted a bidding process to determine which suppliers serve non-choosing customers in each RMA. Winning suppliers would be based on the qualified suppliers that submitted the lowest price for each RMA. For details, see Kenneth Rose, "Using Auctions to Jump-Start Competition and Short-Circuit Incumbent Market Power," *Public Utilities Fortnightly*, pp. 48-53, vol. 137, no. 3, February 1, 1999. Both bills expired at the end of 1998 without action being taken.

[8]Another proposal in Ohio, introduced in early 1999 as part of companion House and Senate restructuring bills, would have divided the non-choosing load of each current utility service territory into ten equal blocks or ten percent of that load. Bidders would have submitted bids for one or more of these blocks. The auction would have been conducted by a third party selected and supervised by the Commission. Winners would have been based on the lowest price and selected through a simultaneous and open auction process. Customers would have paid the average price of the winning bids and winning bidders would have been paid their bid price. The winning suppliers would have served customers for one year. Customers would have been informed that the price was determined through an auction process and would have continued to receive a bill from the distribution company. After intensive lobbying pressure from incumbent utilities, this auction provision was taken out of the bill (S.B. 3) that was later passed by the Ohio General Assembly and signed by the Governor.

an annual (or sooner) basis.[9] Maine used such as approach for a portion of the state's standard offer customers[10] and Pennsylvania included an auction for a portion of standard offer customers in company settlements.[11] Also, the auction process should encourage alternative suppliers to enter and participate in the market.

Disadvantages include the relative complexity of this approach. Obviously, a flawed auction process will yield poor results. While there has been considerable work in auction design and theory, it must be translated into power auction practice. Another disadvantage can occur during the transition period when uneconomic costs are being collected from customers, where it may be difficult to fit the auction determined price in under the price ceiling if all the other price components have already been determined. This may be caused when the market price estimate in the uneconomic cost estimation is too low, resulting in the customer charge being set too high (and before an adjustment mechanism, if one exists, can lower it). The auction price may more accurately determine the retail market price than the estimate used to calculate the customer charge for "stranded" costs. As discussed above, it is clearly best to determine the standard offer or generation component before the customer charge (using any method) and then adjust the customer charge when necessary. This disadvantage concerns more the timing of the transition design and the relative size of the customer charge than the auction method itself. However, if the timing is not accounted for, it can lead to an auction price that causes the overall price ceiling to be exceeded, rejection of the auction bids because they are "too high," or no or few suppliers even submitting a bid because they cannot bid below the standard offer price. In this case, the problem is not the auction design, but that the charge for uneconomic or "stranded" costs is too high. A well designed auction should accurately reflect the retail price, but the customer charge may be simply too high relative to the retail price, thus causing the price ceiling to be exceeded.

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[9]The timing and frequency of the auctions must balance keeping up with market conditions, providing a sufficient length of time for the winning supplier to have a reasonable expectation of customer commitment, and administrative burden.

[10]In late 1999, the Maine Public Utilities Commission used auctions to designate a "standard offer service provider" for all of Maine Public Service Company's customers and for residential and small non-residential customers in Central Maine Power Company (CMP) service territory. Bids for medium and large non-residential CMP customers were rejected. The PUC also rejected all bids for standard offer service in Bangor Hydro Electric Company service territory. Rejection occurred either because bids did not conform to bidding procedures or were "unreasonably" high. For details see: www.state.me.us/mpuc/.

[11]In February 2000, GPU Energy stated that it received no bids in an auction for default or standard offer electric service for 20 percent of its Pennsylvania customers.

3) Administratively Determined: Calculated Incumbent Generation Cost

This option basically calculates an unbundled generation cost for the incumbent utility supplier. This can be based on recent filings of cost information with the state or FERC or from a recent regulatory proceeding. This option has the advantage of being based on the incumbent's cost, the basis for the existing regulated rates and usually for the transitional price ceiling. For at least the duration of the transition period this is a reasonable basis since T&D, uneconomic costs, and the price ceiling are all based on the existing rate structure. Also, unbundling rates on a cost basis places it where the commission already has considerable expertise and information. While the incumbent's cost may have no correlation with the market price, it may provide an appropriate benchmark for potential competitors during a transition period.

Disadvantages include verification of the generation data. If the utility will remain in the generation business, it may be reluctant to share generation cost information with others. This limits discovery in a regulatory proceeding and the interaction and input from other parties in the proceedings. Another problem that all the administratively determined methods suffer from, is that the generation standard offer determined on the basis of cost may have no relationship to the retail market price. Again, they may either be too high or too low. This will likely reflect the existing rates of the utility. How high or low will depend again on how and in what order the customer charge and the generation component are calculated.

4) Administratively Determined: Generation Cost from Residual Rate

This is very similar to the option just discussed, but is likely to be much easier than making a separate calculation of generation costs. This option leaves the generation component as the residual as discussed above. If all the other price components are calculated first (the discount, T&D charge, and customer charges) then the remainder (the price ceiling minus all the other charges) is set as the generation component or standard offer.

The main disadvantage, as discussed above, is that it may not leave sufficient generation headroom for competition to occur. The remainder after all other price components are subtracted from the rate may be lower than a competitive retail price would be.

The last three options (5, 6, and 7) are a combination of the two market-based options and the last two options that are purely administrative.

5) Administratively Determined: Wholesale Price Plus Adder

This option begins with a wholesale price, as with the first option, but added to it is an additional amount to bring it up to at least an estimated retail price.[12] These include costs to serve retail customers such as marketing, risk management, and other retail business operating costs. These costs are incurred, of course, by the incumbent supplier also, and should be included in the generation price to reflect an accurate retail price. If a customer selects an alternative supplier, the incumbent's retailing costs are avoided. This also avoids the problem of generation costs being recovered in the T&D charge or customer charge, resulting in an unfair advantage for the incumbent supplier (by lowering its generation standard offer).[13] The intended goal is to avoid setting the price below a point that alternative suppliers can enter the retail market, the main drawback of the wholesale passthrough.

The disadvantage to this method is determining the "correct" adder. The exact size of the adder that raises the wholesale price to a retail price is not known. Calculating the difference between the wholesale price and existing retail prices (if available) is difficult because retail prices may vary considerably by supplier resource mix used for generation, market share, and seasonal and daily availability. At best, the adder is a rough approximation of the difference between the wholesale and retail price and at worst, arbitrary. In contrasts, market-based methods such as an auction, can determine the retail price using the relevant market itself, not by administrative estimation.

6) Administratively Determined: Retail Market Price Index or Estimate

A more direct approach is to simply try to estimate the retail price based on available information. This simplifies the process since only one number is being estimated, the retail price, rather than a wholesale price and adder. As more information becomes available over time, better indices and estimates can be made.

The main drawback with is method is that very limited or no retail price information is available before retail access begins. Even as more information becomes available in other areas, it may not be representative of the area that the retail price and generation standard offer is being estimated. This method also suffers from the usual drawback of any estimated price, it is only as good as the method and assumptions used to make the estimate and the end result is still only an informed guess. Also, it should be expected that market conditions will change over time. For these reasons the generation standard offer should be revisited and adjusted often, a

[12]If policymakers want to encourage more suppliers, they may deliberately set it higher than the retail price. See the discussion below on shopping credits.

[13]Of course, this is what occurs when the market price estimate for the "stranded cost" calculation is unrealistically low, which sets the customer charge relatively high and squeezes out the incumbent's competition with a low standard offer.

time consuming and possibly contentious process. If the standard offer is determined in a settlement, in advance of market observations, then an adjustment mechanism is critical to having a workable process.

7) Administratively Determined: Retail Price Estimate Plus Adder

Some have argued that an additional "incentive" is needed to encourage customers to switch from the incumbent supplier and choose an alternative. In this view, the retail price is not sufficient, so some kind of adder is still necessary. This method would combine the price estimation of method 6) above with the adder approach of method 5). If the retail price component was accurately reflecting the actual retail price, then this approach would lead to high customer switching rates. The advantage of the adder is that it would make it less likely that the standard offer would be set "too low" and discourage customer switching. The adder would, in effect, provide an error buffer to the price estimate.

Setting aside (for now) the question of whether there should be a policy goal of maximizing customer switching to alternatives, this method would suffer from similar limitations as methods 5 and 6 above. These include the difficultly in both estimating a retail price because of limited information and varying prices and determining an appropriate adder. While the adder makes the possibility of setting the price too low less likely, setting it too high has its drawbacks as well. This includes that non-switching customers will pay an above market price for their electricity. This issue is discussed in more detail in Section 3 under "Creating Headroom: The 'Shopping Credit' Debate."

8) Hybrid Approaches

Finally, of course, policymakers can choose a mix of approaches. For example, using an auction for some portion of customers and an administratively determined standard offer for the remainder. This may provide some comfort to policymakers who, at least at the beginning of competition, are reluctant to leave it entirely up to an auction to set the price for all customers. However, the disadvantage is that some customers, just through good luck, may receive a lower price (those in the auction pool for example) than others. Retrospectively, it may be difficult to explain why customers with similar usage patterns are paying different prices.

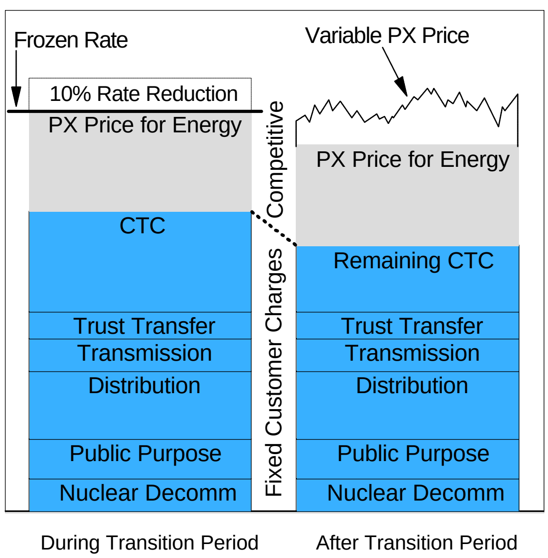
## Section 2: Three State Examples

### California

California was one of the first states to begin an investigation of retail competition. The staff of the California Public Utilities Commission issued a report in 1993 with its findings on retail competition and the Commission issued a rule in 1994 that outlined its plan for introducing competition to the state. In 1995, the Commission wrote a comprehensive order that described the mechanisms for bringing competition to California's retail electricity market. The California General Assembly passed a bill in 1996 that was similar to the 1995 Commission order. Together the legislative and Commission actions provided the basis that supported subsequent Commission orders that implemented California restructuring, which is still ongoing.

While California's restructuring is complex, its main features include establishment of a state-wide Independent System Operator (ISO) (which was approved by the Federal Energy Regulatory Commission), creation of a centralized wholesale exchange or "Power Exchange" (PX), provisions for the recovery of "transition costs" or "stranded" costs by utilities in the state,[14] and allowing all retail customers to select their own supplier beginning in 1998.

**Figure 2.1**. California's unbundled charges for residential and small commercial customers during and after transition period.




Source: Adapted from San Diego Gas & Electric, "What's In Your Electric Bill," www.sdge.com/eso/whatisrate.html.

The California unbundling approach is summarized in Figure 2.1. This diagram is intended as a general representation of the unbundling approach used to introduce retail competition to California during and after a transition period. The transition period was intended to last for up to four years, from 1998 through 2001, or less if production transition costs were collected before that time (as they were for San Diego Gas & Electric). The state

[14]A more detailed description of California's stranded cost treatment is in Eric Hirst, "Stranded-Cost Case Studies," *NRRI Quarterly Bulletin*, Vol. 19, No. 4 (1999), 357-62.

law required a ten percent rate discount for residential and small commercial customers and a rate freeze during the transition period. The Commission determined transmission and distribution rates for retail customers. In addition, these customers are required to pay a nonbypassable “competition transition charge” (CTC) for recovery of the utilities’ “transition costs.” The price that retail customers pay for generation service is determined in the California Power Exchange (PX), except for those customers that are able to arrange their own bilateral trades with a supplier. The total price that a retail customer pays for delivered power to their meter is made up of the components listed in Figure 2.1: generation (usually from the PX or, if a choice is made, from the chosen supplier), CTC, “trust transfer” (to pay for the “rate reduction bonds” for the securitized[15] transition costs), transmission and distribution charges, “public purpose” charges that include subsidies for conservation and renewable energy and low-income assistance, nuclear power plant decommissioning, and, during the transition period, a ten percent discount off the original regulated bundled rate.

In Figure 2.1, the top rectangles represent the PX prices. These are the prices that are passed on to retail customers that do not specify a particular supplier. The average PX price that retail customers paid from mid-1998 to mid-1999 was approximately 3.1 cents per kWh. All of the other customer charges are fixed by the Commission and are set by regulation.

The CTC component allows the recovery of transition costs associated with either utility-owned generation with costs that are above market prices (primarily nuclear) or Qualifying Facilities (QF)[16] contracts with above-market prices. Other transition costs include employee transition costs and the costs required to implement deregulation in the state. The costs incurred to create and operate the ISO and PX are included in the implementation costs. QF contracts were estimated to be approximately half the total transition costs in the state, with about one-third being nuclear plant costs, and the remainder being regulatory assets and other costs.

The CTC is determined as the residual after the PX price and all the other fixed customer charges and the discount have been subtracted from the original bundled regulated rate. While the bulk of the production transition costs are collected within the first four years, renewable energy costs continue through 2005; employee, ISO, PX,

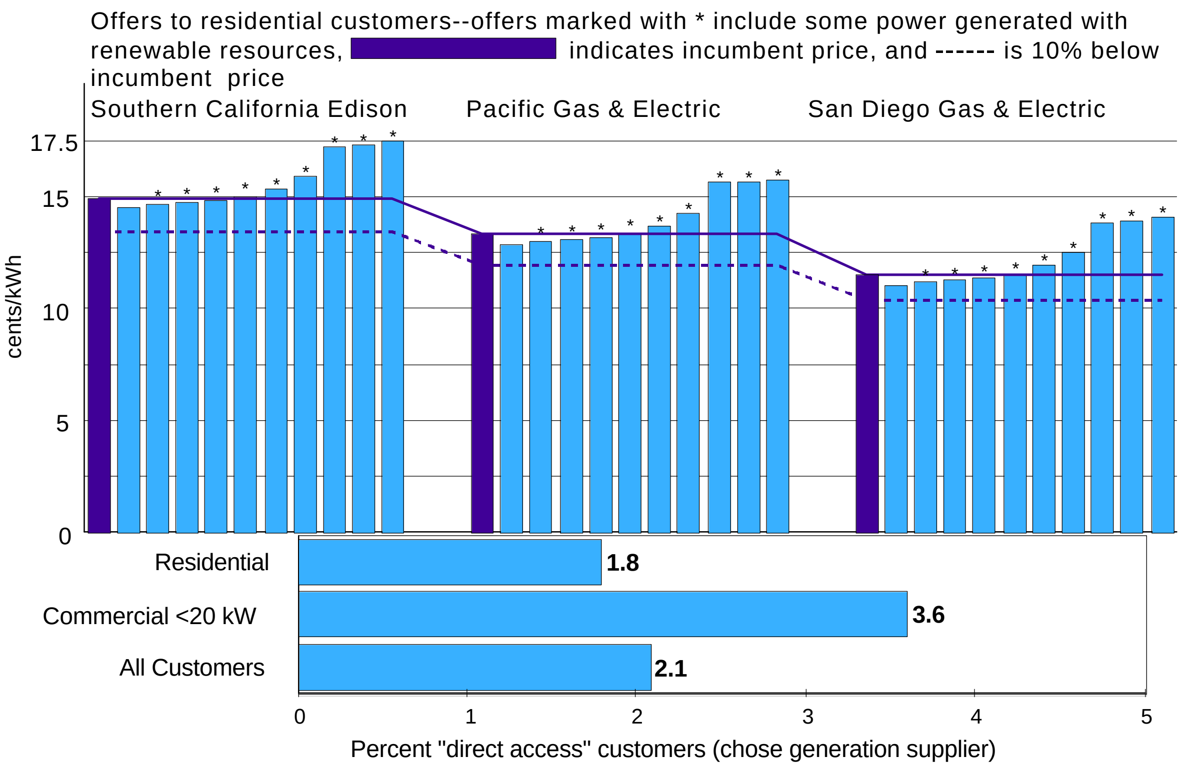
[15]Securitization is a financial process that allows the utility to sell the right to collect a portion of the transition charge or separate customer charge to third party investors. The utility receives the proceeds from the sale of the securities up front and investors recoup their investment through collection of the customer charge over time.

[16]These are contracts utilities signed with generators that are QFs under PURPA. These are primarily industrial cogenerators and small power producers that use renewable resources. California, like some other states, encouraged these contracts beyond what was required under federal law in the interest of promoting conservation and renewable resource development.

and nuclear decommissioning costs will continue though 2015; and some QF contract costs will continue to be collected from customers until 2025.

Figure 2.2 summarizes the offers residential customers have received in the three major distribution companies in California and the percent of residential and small commercial customers that have selected a supplier.[17] Most residential customer offers

**Figure 2.2**. California offers to residential customers in January 2000 and the percent of customers choosing an alternative supplier.




Sources: Wattage Monitor, "New Offer Sheets," January 2000, www.wattagemonitor.com and California Public Utilities Commission, "Supplemental Direct Access Implementation Activities Report," Statewide Summary, January 15, 2000.

include some power generated with renewable resources (marked with an asterisk). As can be seen from Figure 2.2, these renewable or "green" offers are nearly the same or are at a higher price than the price paid if the customer remained with the distribution company. Clearly, customers that choose this option are willing to pay a premium for this "green" or environmentally friendly power. A state rebate for purchasing qualifying green power, however, reduces the customer's cost.

[17] It should be noted that each bar represents an *offer* to residential customers, not a *supplier*. Some suppliers have several different offers.

Whether a retail customer purchases power from an alternative supplier or pays the PX price for generation, the CTC and the other fixed charges are still added to the price for delivered generation. Consequently, to provide retail customers a potential savings, the alternative supplier must be able to price below the PX price (as noted, just over three cents per kWh). Since the PX is primarily a wholesale market, few suppliers have been willing or able to supply retail customers at such a price. The result is that the retail market for generation in California has been very thin for residential and small commercial customers (see bar graph at the bottom of Figure 2.2). However, 19.6 percent of industrial customers over 500 kW have selected an alternative supplier (this is 31.7 percent of that customer class' kWh load).

It could be argued that California's approach has had a significant drawback of discouraging retail suppliers (other than "green power" suppliers) from competing for customers. While this is apparently true, an advantage is that the bulk of the transition costs are being collected at a faster pace than in other states with considerable transition or "stranded" costs and even faster than originally expected in California.[18] Moreover, since the state has been developing the wholesale PX and the ISO, having them function smoothly will facilitate the development of a competitive *retail* market after the transition period. Since California is a relatively large state, setting up a power exchange and ISO was relatively less complicated compared to the task of doing it on a regional basis that includes several states.

With respect to the mitigation of horizontal market power, the Commission had required 50 percent divestiture on non-nuclear generation. However, nearly all non-nuclear generation either has been sold or is planned to be sold in the near future by the three major investor-owned utilities. Table 2.1 shows California's generation market shares in July 1998 and July 1999. The three original investor-owned utilities, Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric, were the principle owners of generating capacity in the state. By mid-1998, their combined share had fallen to 61 percent and to 43.1 percent by mid-1999. The Herfindahl-Hirschman Index (HHI), a measure of market share concentration,[19] also indicates that the California market has become less concentrated overall. This suggests that while a heavy price may be paid during the transition period with respect to little immediate development of retail competition, it may be reasonable to expect that the longer term prospects of a competitive market may be more favorable than in states where generation ownership is still highly concentrated in firms that also own transmission and distribution facilities and where the wholesale market and ISO are not as well formed.

[18]The sale of SDG&E's fossil fuel plants contributed to them being able to end the transition period two and one-half years earlier than the originally expected four years.

[19]HHI is simply the sum of the squared market shares. Using the numbers at the bottom of Table 2.1, The Department of Justice's *Horizontal Merger Guidelines* would indicate that the California market has moved from "highly concentrated" in 1998 to the gray area between 1000 to 1800 in July 1999.

Unfortunately, there are indications that some suppliers in the California market have market power.[20] This is troubling since California is relatively less concentrated than other markets, has had a functioning ISO and PX since 1998, has had considerable new entry by new suppliers, and has a considerable amount of new capacity planned. Market power will be discussed in more detail in Section III of this paper.

**Table 2.1.** California's generation market shares by owner.

| Company | California Market Share (percent of state's fossil generation) | |
|---|---|---|
| | July 1998 | July 1999 |
| PG&E | 37.3 | 27.2 |
| SCE | 15.9 | 15.9 |
| SDG&E | 7.8 | 0 |
| Duke | 8.5 | 10.8 |
| AES/Williams | 12.6 | 12.6 |
| Reliant | 11.9 | 11.9 |
| Dynegy | 5.1 | 9.1 |
| Southern | 0 | 10.1 |
| Other | 1.0 | 2.4 |
| HHI | 2104.8 | 1600.6 |

Source: Adopted from data in Borenstein, Bushnell, and Wolak, "Diagnosing Market Power in California's Deregulated Wholesale Electricity Market."

**Massachusetts**

The Massachusetts Department of Public Utilities in 1995 began hearing arguments for restructuring, and in late 1996 it issued a proposed order. However, implementation was delayed until 1997 when the legislature passed a restructuring law. The renamed Commission, now called the Department of Telecommunications and Energy (the Department), issued its final rules in February 1998. Full retail choice began on March 1, 1998.

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[20]See, for example, Borenstein, Bushnell, and Wolak, "Diagnosing Market Power in California's Deregulated Wholesale Electricity Market," working paper for Program on Workable Energy Regulation (POWER), PWP-064, University of California Energy Institute, Berkeley, California, March 2000.

The form of restructuring in Massachusetts during the transition period is in many respects similar to California. However, there is no Power Exchange. Instead, the Department determined a "standard offer" for retail customers. This is the price for generation service retail customers pay if they continue to receive power from the incumbent distribution company. This standard offer service will be available to customers from each distribution company through 2004. Any customer that does not select a supplier is automatically given the standard offer service. New customers that move into a distribution company's service territory after March 1, 1998, are not eligible to receive standard offer service. These customers receive "default service" unless they select a supplier. Default customers are given a price determined by the Department and may not exceed the average market price for electricity in New England. Prices for generation service from "competitive suppliers" are not regulated by the Department, although suppliers are licensed by the Department.

The legislation required a rate reduction of 10 percent of the customer's overall bundled rate plus an additional 5 percent reduction beginning September 1,1999. The standard offer prices are set by the Department to reflect the discount for these eligible customers. Initially (beginning March 1, 1998), the standard offer rate for all distribution companies was set by the Department at 2.8 cents per kWh. Later, Boston Edison's standard offer rate was increased to 3.2 cents per kWh after completion of the divestiture of its non-nuclear generation assets. Also, Massachusetts Electric Company's standard offer rates were increased to 3.2 cents per kWh after completion of the divestiture of New England Power Company's non-nuclear generation assets. The standard offer rates for 1999 and 2000 are presented in Table 2.2. A "typical" unbundled customer's bill with the various charges is outlined in Table 2.3.[21]

Similar to California, utilities are permitted "a reasonable opportunity" to recover "fully mitigated" stranded costs. Recovery of stranded costs is subject to several restrictions.[22] These include a requirement to sell or transfer to an affiliate all non-nuclear generation assets by August 1999. The proceeds from the sale of these assets are used to offset stranded costs defined as costs incurred prior to January 1, 1996, and fall into the following four categories: (1) fixed generation-related costs, (2) above-market purchased power contracts, (3) generation-related regulatory assets, and (4) nuclear decommissioning costs. For costs incurred after January 1, 1996, the distribution company is allowed to recover (1) employee-related costs related to restructuring, (2) payment in lieu of taxes, and (3) removal and decommissioning costs for fossil-fuel generators.

[21]Currently under discussion in Massachusetts, is whether to raise these standard offers again and, if so, how much.

[22]See Hirst, "Stranded-Cost Case Studies," 362-67.

**Table 2.2**. Standard offer rates by distribution company in Massachusetts.

| Company | Standard Offer Rates (cents/kWh) | |
|---|---|---|
| | 1999 | 2000 |
| Boston Edison Company | 3.69 | 4.50 |
| Cambridge Electric Light Company | 3.50 | 3.80 |
| Commonwealth Electric Company | 3.50 | 3.80 |
| Eastern Edison Company | 3.50 | 3.80 |
| Fitchburg Gas and Electric Company | 3.50 | 3.80 |
| Massachusetts Electric Company | 3.71 | 3.80 |
| Western Massachusetts Electric Co. | 3.10 | 4.56 |

Source: Department of Telecommunications and Energy, January 25, 2000 (www.magnet.state.ma.us/dpu/restruct/competition/standardoffer.htm).

**Table 2.3**. 1999 unbundled charges on a "typical" Massachusetts customer's bill.

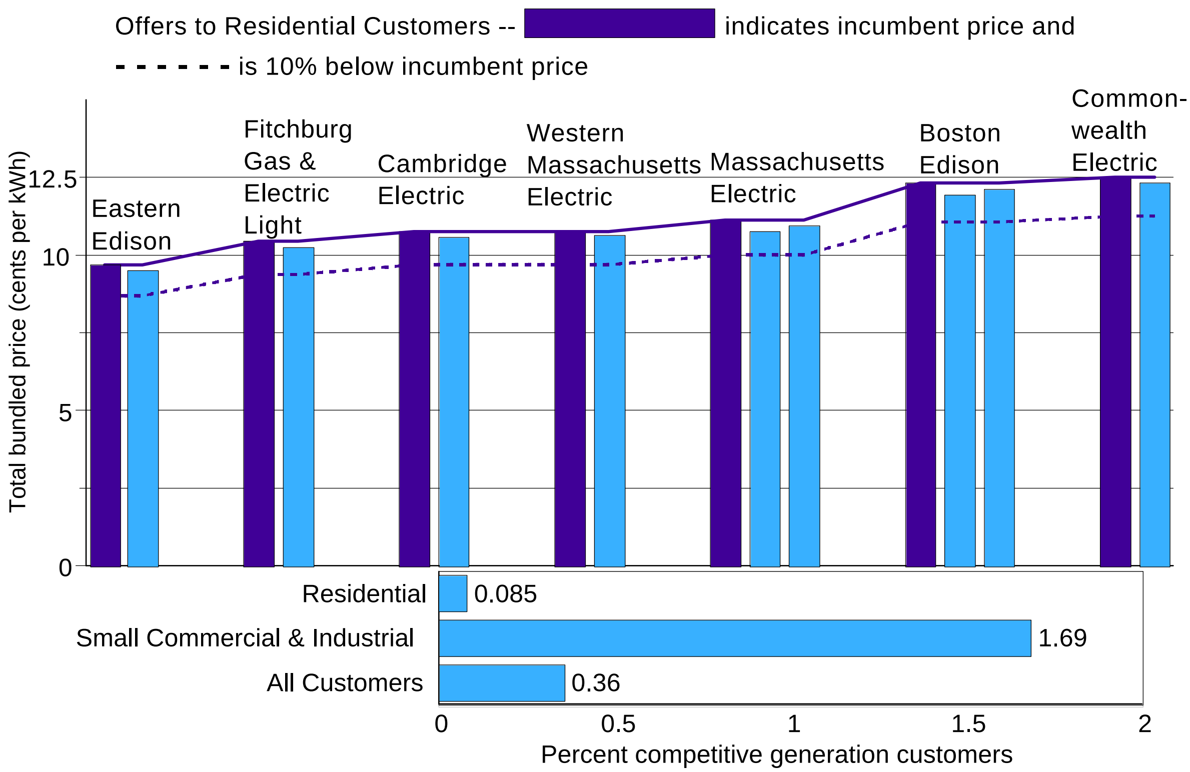
| **Delivery Services** | Rate Component | Amount |
|---|---|---|
| Distribution Service | Customer Charge | $7.00/month |
| | Energy Charge | 3.5 cents/kWh |
| Transmission Service | Energy Charge | 0.3 cents/kWh |
| Transition Costs | Energy Charge | 2.5 cents/kWh |
| | DSM charge | 0.31 cents/kWh |
| | Renewable Energy Charge | 0.1 cents/kWh |
| **Supplier Services** | | |
| Generation Service | Energy Charge (Standard Offer) | 3.5 cents/kWh |
| **Total Energy Charge** | | 10.21 cents/kWh |

Source: Department of Telecommunications and Energy, May 1999.

The Department is required to reconcile projected-to-actual stranded costs at least every 18 months and at least annually for purchased power contracts. Utilities are permitted to securitize stranded costs, but any savings from securitization must benefit ratepayers.

Figure 2.3 graphs offers to Massachusetts' residential customers and the percent of customers that have selected a competitive supplier. As can be seen, the standard offer rates in Massachusetts have had a similar result as the Power Exchange-based prices in California; that is, they are apparently below a price that suppliers are able or willing to provide power to retail customers. Also similar to California, large commercial and industrial customers[23] are switching to competitive power at a much higher rate, at 11.8 percent of customers in this class and 20.8

**Figure 2.3**. Massachusetts offers to residential customers in January 2000 and percent of customers choosing an alternative supplier.




Sources: Wattage Monitor, "New Offer Sheets," January 2000, www.wattagemonitor.com and Massachusetts Department of Energy and Resources, "Customer Migration Data," www.state.ma.us/doer/pub_info/migrate.htm, November 1999 data.

[23] Defined as customers with average monthly usage levels greater than 120,000 kWh/month.

percent of monthly customer class energy usage (kWh) as of November 1999.[24] A major difference is that there are no “green power” offers to residential customers. Since the standard offer rates were lower than the rates of alternative suppliers, the vast majority of customers have, as would be expected, simply stayed with the standard offer service and few suppliers are willing to offer generation service.

The standard offer rate is expected to rise during the transition period. For example, for Massachusetts Electric it is expected to increase to 5.1 cents per kWh in 2004. Depending on actual market conditions in the future of course, this gradual rise in the standard offer rate, given current market conditions, may permit competitors an opportunity to sell generation service to these customers.

**Pennsylvania**

If California’s approach can be summarized as a way to deal with the transition costs quickly and concentrate on the development of a competitive wholesale market and Massachusetts’ approach as one where the transition is used to allow utilities to divest generation and determine stranded costs, then Pennsylvania’s approach could be characterized as placing its emphasis on the development of retail competitive markets right at the beginning of implementation of retail competition. Unlike California and Massachusetts, the Pennsylvania Commission had not made any significant determination on retail competition before legislative action (a PUC docket was opened in April 1994). Also, unlike California, the law passed by the legislature did not prescribe in detail how deregulation should proceed.

Pennsylvania’s legislation was passed and signed by the Governor in late 1996. This set in motion a series of filings by utilities, PUC action, law suits filed by the companies, and finally, by mid-1998, settlements and agreements between the parties.[25] While the exact terms for each company are different, they generally follow the approach the Commission ordered in the first deregulation case for PECO Energy (Philadelphia Electric Company). This approach was to establish a “shopping credit” that customers would use as a “price to compare” with alternative competitive offers.[26]

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[24] These calculations are based on the percentage of all customers or generation used that are classified as “competitive.” The total customer or energy usage was found by adding “standard offer” service customers or generation, “default” service customers or generation, and “competitive” customers or generation. All calculations are based on the Massachusetts Department of Energy and Resources data.

[25] See Hirst, “Stranded-Cost Case Studies,” 367-72.

[26] Unfortunately, the term “shopping credit” has caused some unintended confusion. It was originally intended to refer to the credit back to the customer from the utility when the customer selects an alternative supplier and no longer receives generation from the incumbent utility. Since the customer is usually still purchasing generation from someone, the customer’s actual savings (assuming an offer is found that is below the shopping credit) is the difference between the shopping credit and the competitive price agreed to by the customer, not as may be implied, the entire shopping credit.

This approach first developed for PECO was used later for other utilities in the state and has since been adopted by other states (New Jersey for example). Similar to California, there are transmission and distribution charges and a nonbypassable customer charge for "stranded cost" that all customers pay regardless of from whom they purchase their energy supply.

The Pennsylvania innovation was the introduction of the idea of a "shopping credit." The shopping credit is not a credit paid to customers as the term may imply. Rather, it is a comparison price or benchmark for customers to compare to the prices offered by energy suppliers. If the customer stays with their incumbent supplier, the customer pays the shopping credit price for power.[27] Because the shopping credit is correlated with (but not necessarily based on) the embedded generation cost of the incumbent supplier, it is likely to be near or exceed the retail market price for power.[28] This means that retail customers have the potential to realize a savings if they switch suppliers. This solves the main limitation of the California and Massachusetts models that has been shown to discourage immediate customer savings in the competitive market and customer switching. The Pennsylvania shopping credits or "price to compare" are shown in Table 2.4 for each investor-owned distribution company.

**Table 2.4.** 1999 and 2000 "Prices to Compare" or "Shopping Credits" for Pennsylvania companies (regular residential service).

| Company | "Price to Compare" (cents/kWh) | |
|---|---|---|
| | 1999 | 2000 |
| Allegheny Power | 3.221 | 3.243 |
| Duquesne Light | 4.750 | 4.750 |
| GPU Energy - Met Ed | 4.522 | 4.525 |
| GPU Energy - Penelec | 4.528 | 4.528 |
| PECO Energy | 5.650 [a] | 5.650 [a] |
| Penn Power | 4.471 [b] | 4.471 [b] |
| PP&L | 4.260 [c] | 4.630 [d] |
| UGI | 4.048 [e] | 4.048 [e] |

[a]Average, summer (June - September) first 500 kWh = 5.55¢/kWh, over 500 kWh = 6.21¢/kWh; winter (October - May) = 5.55¢/kWh.
[b]Price for 1,000 kWh at 8kW.
[c]Average, first 200 kWh = 4.80¢/kWh, next 600 kWh = 4.26¢/kWh, and over 800 kWh = 3.94¢/kWh.
[d]Average, first 200 kWh = 5.23¢/kWh, next 600 kWh = 4.64¢/kWh, and over 800 kWh = 4.28¢/kWh.
[e]Price for 1,000 kWh, first 500 kWh = 4.316¢/kWh, next 500 kWh = 3.780¢/kWh, and over 1,000 kWh = 2.983¢/kWh.
Source: Pennsylvania Office of Consumer Advocate, "A Residential Consumer's Electric Shopping Guide," September 30, 1999 and March 31,2000,

[27] The shopping credit is part of the bundled price shown in Figure 2.4.

[28]This assumes, of course, that through the workings of a competitive market, the competitive market price will be lower than the embedded generation cost of the utility under cost-based regulation. Time will inform us if (a) this is true, and (b) a sufficiently competitive market develops that allows this outcome.

In the PECO Energy settlement, residential customers were given a discount in the first two years of eight and six percent respectively. Rates were "unbundled" and separated into generation (the shopping credit), a CTC, and T&D charge. In order to prevent the recovery of the transition costs through the CTC from diminishing the incentive to switch, the "stranded costs" are amortized over a long period (12 years in the case of PECO). In net present value terms, the utility receives the same amount of dollars (a total dollar amount was part of each settlement), but by stretching the payment out over a longer period, the amount collected in each year is reduced.[29] This contributes to the shopping credit being sufficiently high to provide headroom for competition, that is, when the shopping credit or comparison price is above the prevailing market price.

Figure 2.4 graphs the residential offers[30] to customers in each of the investor-owned distribution companies. The bottom bar graphs are the percent of residential and all customers that have selected an alternative supplier. As can be seen from the graph, there is considerably more activity in Pennsylvania than in the other states examined. Residential customers in PECO Energy's distribution territory, for example, had 29 alternative offers at the time this information was collected (late January 2000). Many of these offers were below the price that would be paid if the customer remained with the incumbent supplier. Two distribution companies, Duquesne Light and PECO Energy, had the highest amount of residential customers selecting an alternative supplier, at 22.2 percent and 14.94 percent, respectively. These two companies also had the highest shopping credits.[31] No other utility in Pennsylvania, however, had more than six percent of residential customers choosing an alternative supplier.[32]

Similar to California, stranded costs in Pennsylvania are generation costs above market prices, uneconomic QF contracts, and regulatory assets (such as deferred assets accounts that the companies would have collected over time through rates). Total stranded cost settlements in Pennsylvania came to approximately $11.5 billion.

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[29]The Pennsylvania legislation also permitted utilities to "securitize" a portion of their stranded costs as in California and Massachusetts. The settlements between the PUC and the companies set the maximum limits allowed to be securitized in Pennsylvania.

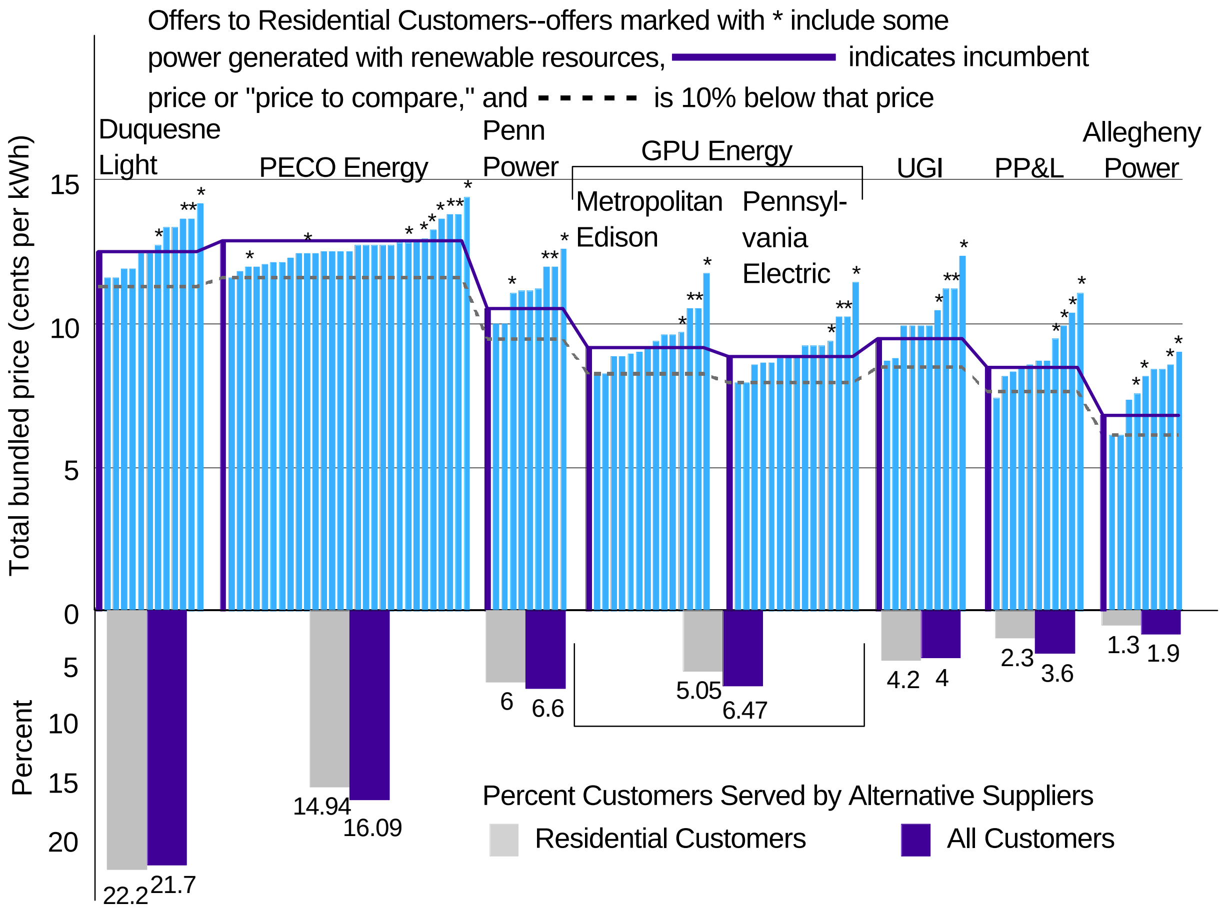
[30]It should be noted that each bar represents an *offer* to residential customers, not a *supplier*. Some suppliers have several different offers.

[31]The correlation between the standard offer or shopping credit price and the customer switching rate will be discussed in the next section.

[32]Second quarter 2000 numbers released by the Pennsylvania Office of Consumer Advocate show that the percent of customers served by a alternative supplier for Duquesne Light, PECO Energy, and Penn Power, and PP&L, have increased to 25.5, 15.26, 6.3 and 2.4 percent, respectively. However, GPU Energy, UGI, and Allegheny Power have all decreased to 4.99, 3.9, and 1.1 percent, respectively.

As was observed in the other two states, industrial customers switching has been much greater than among residential customers. Table 2.5 shows the percent of industrial customers and percent of industrial load that have switched to an alternative

**Figure 2.4.** Pennsylvania offers to residential customers in January 2000 and percent customers choosing an alternative supplier.




Sources : Wattage Monitor, "New Offer Sheet," January 2000, www.wattagemonitor.com and Pennsylvania Office of Consumer Advocate, Jan. 1, 2000

supplier. With the exception of Duquesne Light, the percentage of industrial customers served by an alternative supplier are much higher than for residential customers, including those companies with relatively low percentage of residential customers choosing a supplier. As in others states, offers to industrial customers are not disclosed to the public, so comparisons are not possible at this time. Also not publicly disclosed are the market shares for each supplier. Some have asserted that the affiliates of the incumbent suppliers have garnered the largest shares. This cannot be confirmed at this time.

**Table 2.5**. Percent of industrial customers and industrial load (MW) that are served by an alternative supplier.

| Company | Percent of Customers | Percent Customer Load (MW) |
|---|---|---|
| Allegheny Power | 23.6 | 30.0 |
| Duquesne Light | 16.4 | 13.2 |
| GPU Energy | 32.0 | 69.2 |
| PECO Energy | 62.3 | 63.5 |
| Penn Power | 34.7 | 45.4 |
| PP&L | 11.8 | 63.6 |
| UGI | Not Available | Not Available |

Source: Pennsylvania Office of Consumer Advocate, April 1, 2000 report.
www.state.pa.us/PA_Exec/Attorney_General/Consumer_Advocate/elecomp/elindex.html

## Section 3: Unbundling Implementation Issues, Market Power and Price Discrimination

This section has three main parts. The first three topics are an expansion of important unbundling issues, standard offer supplier, the debate on “shopping credits,” and customer “inertia.” The next part addresses market power and price discrimination and how small customers in particular may be affected. The final part examines preliminary data that suggests that the price differential between small and large customers may be increasing.

### Who Should Supply the Standard Offer?[1]

An issue that follows directly from *how* to set the standard offer is *who* supplies the power. The standard offer supplier may be selected simultaneously when the generation price is determined, such as with a wholesale pass-through or auction, for example. States face three choices when deciding who should provide the standard offer. First, these customers can simply be assigned to the incumbent firm, as most states have, so far, chosen to do. If the incumbent is still a vertically integrated firm with its own generation, that company may continue to serve the non-choosing customers as it did in the past. The price may be a standard offer that is determined by the commission using one of the administratively determined methods described above. If the former utility divested its generation, then either the distribution company contracts for the supply or the customers are given to the new owner of the generation or the generation affiliate of the distribution company (usually the former utility).

However, other than simplicity, there is little compelling reason why the incumbent firm should inherit customers simply by default. Under a competitive system, suppliers are required to compete with each other for the customers' business. This insures that no supplier, incumbent or alternative supplier, has an advantage in terms of access to customers. An alternative to decide who should supply the standard offer follows from using a competitive auction to determine the standard offer as discussed above. If an auction is conducted to determine who will serve these customers, then the winning bidder or bidders supplies those customers at the offered bid price. This is more consistent with a competitive market than automatic assignment to the incumbent.

[1]This section is drawn, in part, from an excerpt of Kenneth Rose, “Market Power in the Emerging Competitive Electric Supply Industry,” testimony before the U.S. House of Representatives, Committee on Commerce, Subcommittee on Energy and Power, panel on “Electricity Competition: Market Power, Mergers, and PUHCA” Washington, D.C., May 6, 1999.

A third alternative also does not assume the incumbent or its affiliate should be the supplier, but uses a random assignment process to decide who should serve customers that have not made a specific selection. After the breakup of AT&T, the Federal Communication Commission (FCC) randomly assigned long distance service customers based on the market share each provider had among the customers that did choose a provider. Georgia used this method to select natural gas suppliers for non-choosing customers in August of 1999 for the implementation of the state's gas deregulation.[2] In Georgia, the number of retail non-choosing customers assigned to a particular natural gas marketer was based on that marketer's share of the total market served by all marketers.[3] Under this type of program, customers are warned that they will be assigned a provider if they do not make a choice (which usually encourages customers to make one) and, of course, customers are not forced to stay with that company if they wanted a different provider. The logic is that customers are assigned according to those that did choose or are choosing. This also creates an incentive for the various market participants to work hard to convince customers to choose them, since they will then have a higher portion of the non-choosing customers in the assignment allocation (assuming they are willing to invest the time needed to build a sizeable market share). An unfortunate side effect of this incentive is that "slamming" may increase since this will give the slamming suppliers a higher market share. Slamming, of course, is a problem that has occurred independent of the method used to select a supplier.

Pennsylvania will use a combination of all three approaches, that is, incumbent assignment, auction, and random assignment. In the case of PECO Energy,[4] the company (the incumbent utility) will initially be the "provider of last resort" for all customers in its service territory that do not choose an alternative supplier. However, beginning January 1, 2001, 20 percent of all of PECO's residential customers, determined at random, are to be assigned a supplier other than PECO. The supplier for this "Competitive Default Service" is to be selected based on a Commission-approved energy and capacity market price bidding process. PECO and its affiliates

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[2]Georgia Public Service Commission, Rules of Georgia Public Service Commission, 515-7 Gas Utilities, Chapter 515-7-4, "Random Assignment of Customers," December 30, 1997. This is the Commission's rule issued under authority from "The Georgia Natural Gas Competition and Deregulation Act of 1997."

[3]The base used to calculate the market share, either the share of choosing customers or share of all customers, can have a major impact on the suppliers' share of non-choosing customers. Obviously, basing it on all customers will tend to favor the incumbent more than basing it on customers that did choose, if there is a high proportion of non-choosers.

[4]From the settlement between the company and the Pennsylvania Public Utility Commission, "Joint Petition for Full Settlement of PECO Energy Company's Restructuring Plan and Related Appeals and Application for a Qualified Rate Order and Application for Transfer of Generation Assets," Docket Nos. R-00973953 and P-00971265, April 1998.

cannot bid or be a part of another supplier's bid. The entire customer group will be a single bidding block and will be auctioned annually (unless the Commission changes the frequency of the bidding). To qualify for this bidding process, a supplier will have to provide at least two percent of its energy supply from renewable resources and increase that amount in increments of 0.5 percent annually. (The commission may lower the percentage if the renewable energy sources increase the cost of the entire block by more than two percent over the cost without the renewable energy sources.) Bids cannot exceed the generation rate cap for the transition period. For non-choosing customers still served by PECO that were not selected for the auction, PECO is required to price residential service between the auction price and monthly rate based on power pool prices. This price also cannot exceed the generation cap (that is, the "shopping credit").

In addition, there are market share thresholds in the PECO settlement that trigger a random assignment process. Beginning January 1, 2001, if less than 35 percent of all PECO residential and commercial customers have selected to receive generation service from the PECO affiliate or alternative supplier (including customers assigned to the auction group), then, for the number of customers necessary to reach a 35 percent target a supplier will be determined by random selection on a one-time basis. After January 1, 2003, the percent threshold is raised and a random assignment process is used until 50 percent of all residential and commercial customers are assigned either to the PECO affiliate or alternative supplier.

Assigning non-choosing customers to suppliers other than the incumbent firms has come under heavy fire from, not surprisingly, incumbent firms. Their main argument is that selecting a supplier for these customers is taking a choice away from customers; that is, *not* choosing is the choice the customer made. Implicit in this argument is that customers are not making a choice because they are content with the incumbent firm. However, it is highly unlikely that all these customers fit this profile. Other reasons likely include not wanting to spend the time and expense to search for information and decide which supplier to select (transaction costs), confusion over the array of options, and the savings are (or are believed to be) too small to bother with. No choice may be exactly what it looks like–no choice–and may occur for many reasons. The initial reluctance or "inertia" of customers to make a choice will be discussed in more detail below.

Another argument is that it is paternalistic or "government deciding what is best" for a customer to assign them to a supplier other than the incumbent. After all, the whole point of a retail choice program is to allow customers a choice. This assumes, however, that the state has no obligation to assist customers in the move from regulated monopolies to competition. These customers have to be assigned to a supplier, whether it is the incumbent or an alternative. Customer assignment does not and should not take away a customer's right to choose their supplier. A standard offer program should be designed to allow customers to choose a supplier of their choice at any time and not lock them in for a long period of time with any supplier they did not select, incumbent or alternative. If customers are being assigned to a supplier, they should be warned before the change is made and allowed some time to make a selection (including, if they wish, the incumbent supplier). Most would probably agree that no one should be forced to purchase generation service from a particular supplier they do not want. Having no choice at all is what the former system of regulated monopolists was about, where customers could only buy from the state or municipally sanctioned utility.

**Creating Headroom: The "Shopping Credit" Debate**

As noted above, with most competitive consumer goods the customer simply pays the listed or agreed-on price for the good–there is no "standard offer," "shopping credit," or "provider of last resort" that the customer automatically receives if no specific selection is made. For goods that are sent directly to the customer, a delivery charge may be added to the price. The main reason for establishing a standard price in retail electric markets is to establish a price for customers that do not choose a supplier, cannot obtain power from a supplier, or the customer's chosen supplier no longer supplies them. This assures that all customers have electric service delivered to their home.

A "shopping credit" is a standard offer or generation price that is set above what would occur if it were set at the residual after all other price components have been subtracted from the price ceiling. The reason for establishing a "shopping credit" is to avoid the problem, described above, of the standard offer being below the retail price for power. Assuming that the T&D charge reflects the actual cost of delivering power to the customer and does not include any cross subsidy to generation, then all the generation costs are included in two components: the competitive part that is open to other suppliers and the noncompetitive part that is a "nonbypassable" charge to pay for potential uneconomic or "stranded" costs. As with any standard offer, the shopping credit is intended to be used by customers as a comparison with offers form alternative suppliers.

Therefore, there are two competing objectives that policymakers are trying to balance when setting the standard offer–customer protection with a reasonable standard price on the one hand and incumbent generator protection from competition with a "nonbypassable" surcharge for potential uneconomic cost recovery on the other. This creates the need for establishing a standard offer that does not discourage entry by alternative suppliers and finds a way around the distortion introduced by the recovery of potential uneconomic costs.

In many respects, the debate on whether to use a “shopping credit” versus a low standard offer obscures the more important point on how to determine the generation component and the goals of restructuring. The generation component should reflect, as much as possible, the generation market price. The most direct way to obtain this price is through a competitive auction process or observation of the market, assuming there is something to observe.[5] This would avoid market distortions caused by tilting the scales toward alternative suppliers or toward the incumbent’s advantage. If policymakers choose not to determine the market price directly through a competitive auction or observation of the retail market, then the dilemma states face is how to establish a “fair” and balanced representative generation price for retail customers that does not discourage competition or burden non-choosing customers. The distortions caused by too “high” or too “low” a standard offer have already been discussed, but bear repeating. If it is too low, the risk is that the retail market will have few or no alternative suppliers, that is, no competition; if it is too high, non-choosing customers will pay a higher generation price than those customers savvy enough or informed enough to choose a supplier. The real question then becomes: How should the optimal balance between these outcomes be achieved?

A decision to simply set the price above the retail price level to induce more competitive firms to enter the market and have a high percentage of customers choosing a supplier, has an additional serious drawback as well. Since most customers, at least initially, do not select a supplier (customer “inertia” is discussed below), an artificially high “price to beat,” may establish a standard or “benchmark” price that only needs to be undercut by a small amount to attract customers. If there is strong and effective competition, then this is not a problem since suppliers will vie with each other for the customers business and the price should be driven to a market level. With more limited competition, however, where only a small percentage of customers are active “switchers,” then the artificially high price may act as a price signal to suppliers. There is evidence to suggest that this has occurred the long-distance telephone market.[6] Therefore, a high official “price to beat” may also raise the unofficial rival price where the incumbent acts as the “price leader”; at least until more competitive market conditions develop.

Incumbent utilities that stay in the generation business, not surprisingly, generally prefer a low standard offer that discourages entry by alternative suppliers. A low generation price does not cause harm to them since, presumably, any losses that may occur are compensated for in the uneconomic cost recovery formula. But this is a

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[5]That auction or observed price can be used as the basis for determining uneconomic costs, increasing the accuracy of the charge customers pay for “stranded costs.”

[6]The “price leadership” of AT&T is discussed in Edwin A. Rosenberg and Michael Clements, *Evolving Market Structure, Conduct, and Policy In Local Telecommunications* (Columbus, OH: The National Regulatory Research Institute, 2000), pp. 51-57.

distortion caused by the uneconomic cost subsidy, not the standard offer. An incumbent supplier usually receives its subsidy for uneconomic cost recovery as the difference between its costs and the market price.[7] If there were no uneconomic cost recovery, the incumbent supplier would also be concerned that the generation price was "too low." On the other side of the market, the alternative suppliers, who receive no subsidies (although they may as an incumbent in their own former territory) want headroom for competition so that customers have an incentive to shop around. Some would call a high standard offer a subsidy also, but the difference between the standard offer and the alternative supplier's price (which is presumably lower that the standard offer) goes to the customer as a savings on generation, not to the alternative supplier. Moreover, for non-choosing customers still paying the high standard offer, the incumbent collects the whole generation charge, again not the alternative suppliers.

There is a concern by some that non-choosing customers paying the higher standard offer for generation are subsidizing customers that have left to receive a lower market price for their generation or that it is "bribing customers to switch." These claims are clearly overstated, however. A customer that switches to an alternative supplier pays the market price for their power and receives no subsidy other than a strong economic incentive to choose. Customers that do not choose are left to pay a higher price for generation, but again the difference between the shopping credit and the market price they could pay (in other words the forgone savings) goes to the incumbent supplier, not choosing customers or other suppliers. Also, these non-choosing customers never pay more for their power than the price ceiling. However, since the customer and T&D charges are the same for all customers in the same classification, non-choosing customers will pay more overall for their power than those that switched.

This serves to underscore the importance of striking the appropriate balance when setting the standard offer, again assuming that a direct market-based approach is not used. Obviously, setting the standard offer at twice the retail market price would maximize customer switching. Customers that shop would likely have an array of offers to choose from. But maximizing customer switching is generally not (and should not be) the only goal of restructuring, and is not generally even a primary goal in itself. Primary goals include protecting non-choosing retail customers, ensuring that the benefits of competition are spread among a wide distribution of retail customers (not just "big" users), adopting policies that encourage the development of generation markets, and minimizing policy-caused distortions on the developing retail market.

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[7]This same distortion may be occurring in bulk power markets where utilities that are not subject to competition receive their embedded costs from captive customers and incumbent suppliers in restructured markets receive the uneconomic cost subsidy. The result is that new entrant suppliers must try to recover their long run marginal cost in the market while incumbent suppliers can compete based largely on their short-run marginal cost or variable costs, that is likely to be less than their long run marginal cost (the difference being made up for the incumbent by the uneconomic or "stranded" cost subsidy where there is retail competition or from embedded rates in states without restructuring).

Not having any or only a few economically impractical alternative suppliers participating in a market is a symptom of an undeveloped market, not the cause. If restructuring policies are designed to encourage the development of a robust competitive retail market, a primary goal of many policymakers, then by definition there will be alternatives for customers to choose from. Having a large number of suppliers should also not be a goal in itself. Some well functioning markets have only a couple of feasible options for customers to select. Competition does not require large numbers of sellers, but it is reasonable to expect some, and something is clearly wrong if none or only a few good options are available to customers.

It is understandable why policymakers want to create headroom for alternative suppliers by stretching out the uneconomic cost recovery. As long as the more important goals that encourage the development of a competitive market are satisfied, the desire for increased headroom will unlikely become excessive. As with many things, however, good intentions alone are insufficient unless tempered with a longer term goal of developing or improving retail power markets. The more closely the standard offer is aligned with the retail market price, the fewer the distortions, either unintentionally or intentionally, introduced into the market by policy. Over time, policymakers may become more interested in moving toward more direct means of determining the standard offer through competitive auctions and market indices as uneconomic costs are recovered and experience with retail markets increase.

**Customer "Inertia"**

The relatively slow response by customers, primarily smaller customers, has been referred to as customer inertia. This is a term, at least as it is used here, to describe an observation of customer behavior, not a problem in itself. The longest running program that provides some insight into what may occur in electric markets is the long-distance telephone experience after the breakup of AT&T. In 1984, the year of AT&T's breakup, that long-distance provider had 90 percent of the operating revenues of the long-distance market. That market revenue share dropped for the first time below 50 percent in 1996, when it was 48 percent, twelve years after the breakup.[8] Since many small residential users make few or no long-distance telephone calls in a month, that market may not be a good analogy for electricity where all customers use electricity to light and heat their homes. However in Pennsylvania, the most robust market so far for electric choice programs, only one incumbent utility's service area has exceeded 20 percent (Duquesne Light) of customers choosing an alternative supplier and five utilities have six percent or less of its customers choosing (see Section 2).[9] Clearly there is a pattern of delayed customer response over time that can be discerned even when there appears to be an economic incentive to switch.

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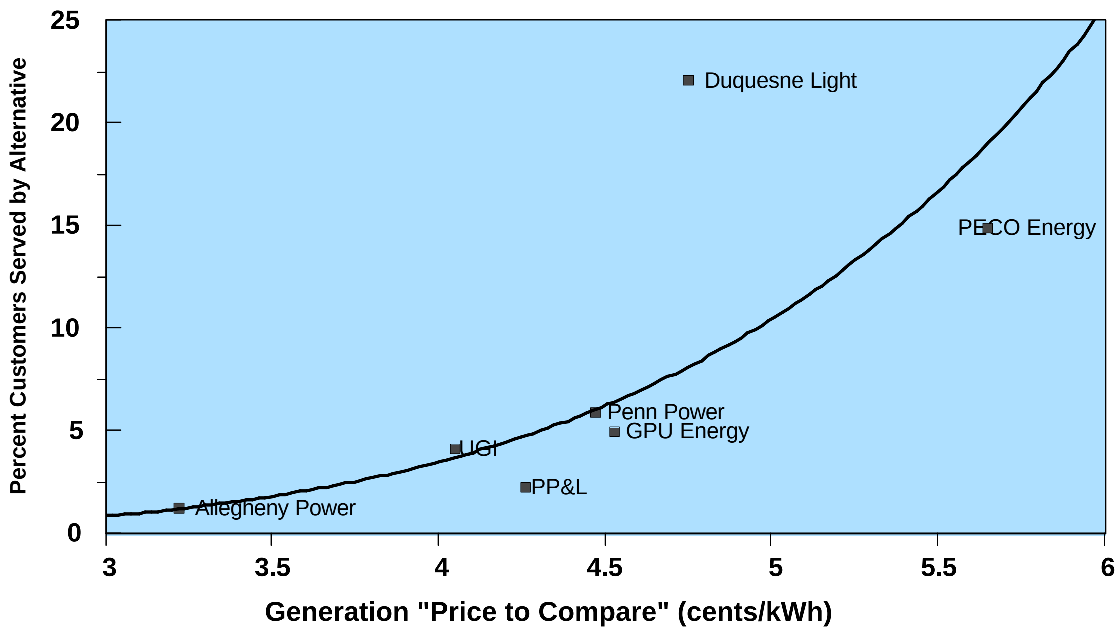
[8]Zolnierek, James and Rangos, Katie, "Long Distance Market Shares, Third Quarter 1997," Federal Communications Commission, January 1998.

[9]Based on figures from the Pennsylvania Office of Consumer Advocate, January 1, 2000 report.

What are the reasons for this pattern of customer inertia? Clearly it is not mysterious or irrational behavior that cannot be explained. The slow response from small customers so far is, for the most part, a rational response to economic conditions customers face in the nascent electric markets. Customer surveys reveal that one of the most important factors that customers consider when deciding to choose a supplier

**Figure 3.1**. There is a strong correlation between the "price to compare" and customers choosing alternative providers in Pennsylvania.




Source: Pennsylvania Office of Consumer Advocate, "Price to Compare," Sept. 30, 1999 and "Percent of Customers Served by an Alternative Supplier," Jan. 1, 2000. See Table 2.4 and Figure 2.4 of this report for prices and percentages.

is, not surprisingly, a lower price for power.[10] If they cannot find a satisfactory alternative, then staying with the incumbent supplier makes sense. The lack of economic alternatives in California and Massachusetts can explain the low response by customers so far in those states.

The fact that Pennsylvania has had the highest switching rate so far can be explained by the "shopping credits" or "prices to compare" that are used in that state

[10]See, for example, Wattage Monitor's "Switching Electricity Suppliers: A Research Study of Pennsylvania's Residential Consumers," Spring 1999, Wattage Monitor Inc. (www.wattagemonitor.com). When customers were asked what issues they considered when deciding whether or not to switch supplier, the top five responses in order were: lowest rate, overall reputation or name of the supplier, environmental "friendliness" of the supplier, additional services offered by the supplier, and special programs/offers of the supplier.

that allow some headroom for alternative suppliers to offer lower prices than a customer pays staying with the utility.  Figure 3.1 shows that after more than a year of customer choice in Pennsylvania, there is a strong positive correlation between the "price to compare" and the percent of customers that have chosen a supplier.[11]

Another explanation for customer inertia is the customer transaction costs.  If customers perceive, correctly or not, that any potential savings will be exceeded by the value of their time to search for alternatives, then, not surprisingly, they will stay with the standard offer or their current supplier.  A survey of Pennsylvania residential customers[12] asked the open-ended question: "What were the biggest impediments in considering or switching to a new supplier?"  The top three answers were: 52 percent said "too confusing, too difficult, too much trouble," 35 percent said "not enough savings for effort expended," and 10 percent said "no intriguing offers."  One way to interpret this result is to note that 87 percent of the survey respondents were implicating transaction costs as the reason for not choosing a supplier, if it is assumed that the most popular response (confusion, difficulty, and trouble) could be alleviated by acquiring additional information and further study.  The second most popular response is a clear indication of transaction costs, the "effort expended," exceeding the potential expected savings.

This suggests that customer education programs that provide information and explanations of that information and terminology will help lower the transactions cost and, if opportunities for savings exist, increase customer participation.[13]

Customer participation may also vary by subcategories of customers.  In general, as noted in the last section, industrial customers have been more responsive than residential customers to seeking alternative suppliers in the three states reviewed in detail.  However, since prices for larger customers are confidential, the greater switching rates may also be a function of the greater potential for savings industrial and large commercial customers have relative to residential customers.

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[11]The R-square for the curve is 0.714 and its equation is $y = 0.00389x^{4.91}$.

[12]Wattage Monitor, "Switching Electricity Suppliers: A Research Study of Pennsylvania's Residential Consumers," Spring 1999, www.wattagemonitor.com.

[13]In a newspaper article in Pennsylvania, a customer was quoted as saying "I don't quite understand it.  I'll just stay with [the current supplier].  I don't see how we could get it cheaper.  You get all this literature to read and then you're back where you started."  Another customer was quoted as saying "Why should I change now?  I'm almost 84 years old and have been (with my current company) all my life."  (*The Lebanon (Pennsylvania) Daily News*, "Wary of Electric Deregulation, Many Choose to Do Nothing," January 24, 1999.)  This suggests that alternative suppliers, marketers, consumer advocates, and others that would like to see customers participate in retail access programs have their work cut out for them.

Subcategories of residential customers may also have different rates of participation. Surveys by the staff of the Public Utilities Commission of Ohio (PUCO) of the state's natural gas pilot programs,[14] suggest that as household income increases, customers are more likely to make a choice of natural gas supplier. Table 3.1 shows the results of the survey by household income category for three incumbent natural gas suppliers. In each case, as household income increases, it is more likely that the customer has selected a gas supplier and less likely that they remained with the incumbent. The bottom row of Table 3.1 reports the number of survey respondents to the questions. As can be seen, the number is small relative to the total number of customers in each gas utility's territory (especially for Cincinnati Gas & Electric). For this reason, additional surveys and analysis are needed before firmer conclusions can

**Table 3.1**. Percent of customers that remain with incumbent natural gas supplier by household income.

| Household Income | Incumbent Natural Gas Supplier | | |
|---|---|---|---|
| | Columbia Gas | East Ohio Gas | Cincinnati Gas & Electric |
| Less than $10,500 | 84.6 | 94.4 | 100.0 |
| $10,500 - $24,999 | 94.2 | 87.8 | 100.0 |
| $25,000 - $49,999 | 79.4 | 81.8 | 94.0 |
| $50,000 - $74,999 | 69.7 | 75.9 | 97.7 |
| $75,000 - $100,000 | 75.7 | 74.3 | 88.5 |
| Greater than $100,000 | 67.9 | 66.7 | 88.5 |
| Number of Respondents | 367 | 376 | 185 |

Source: PUCO Staff, "A Baseline Study of the Columbia Gas of Ohio Customer Choice Pilot Program," April 1998, p. 308; "A Baseline Study of The East Ohio Gas Company Energy Choice Pilot Program," May 1998, p. 332; and "A Baseline Study of The Cincinnati Gas and Electric Company Customer Choice Pilot Program," May 1998,
p. 324.

[14]Public Utilities Commission of Ohio (PUCO) Staff, "A Baseline Study of the Columbia Gas of Ohio Customer Choice Pilot Program: A Customer Perspective," April 1998; "A Baseline Study of The East Ohio Gas Company Energy Choice Pilot Program: A Customer Perspective," May 1998; and "A Baseline Study of The Cincinnati Gas and Electric Company Customer Choice Pilot Program: A Customer Perspective," May 1998.

be drawn. It does suggest, however, that there is a reason for some concern that participation rates may be lower for lower-income customers.[15]

Possible reasons why customers with lower income have lower participation rates may include that they have less access to information,[16] perhaps receive less information from marketers and other gas suppliers, and have less time to devote to studying the options. But, as the PUCO staff observes: “It is not possible to explain from the data collected why these customers are not making a selection. It is important that the reasons for this pattern be identified and an attempt made to encourage their participation in the selection process.”[17]

Transaction costs may also play a role in alternative suppliers’ and marketers’ decisions to enter a market. If the marketing costs per customer are sufficiently high, so that the desired profit (revenues minus costs) and net return cannot be obtained, then the supplier will either not enter a market or not remain in the area much longer. In this case it may not be that customers are “inert,” but that few alternatives are being made available to them. However, unlike customers’ transaction costs, that can be reduced through customer education campaigns, policy options to reduce marketers’ and alternative suppliers’ transaction costs are more complex. Transaction costs for marketers and alternative suppliers are affected by necessary and important policies on interconnection, customer notification and verification, information reporting, sharing, and disclosure, and “back office” interface issues with the distribution company. Costs incurred by marketers and alternative suppliers can be kept reasonable if they are not overly protective of the incumbent supplier, that is, burdensome rules that serve mostly to discourage entry but do not help protect consumers, and are reasonably consistent with other state policies.

Given what occurred in the long-distance market and what has occurred so far with electric and natural gas programs, customer response may follow a pattern shown in Figure 3.2. It should be expected that, over time, an increasing proportion of retail customers will make a specific choice. However, the rate of customers selecting a supplier may change over time and follow a classic ‘S’ shaped pattern. Initially, assuming that there is at least some economic incentive to search for an alternative

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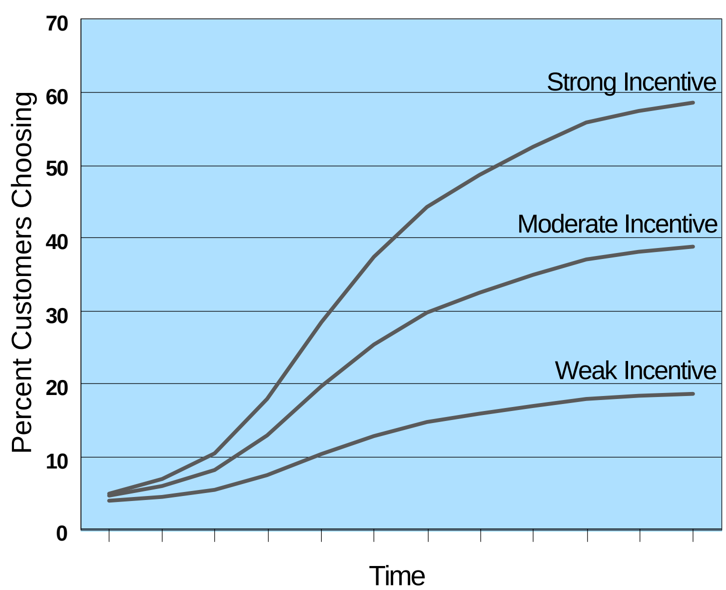
[15]The PUCO staff notes that none of the lower income respondents are Percentage of Income Payment Plan (PIPP) customers (an Ohio low-income customer assistance program).

[16]This may include access to information available on the Internet from gas marketers, the Commission, and consumer advocate. The PUCO compiles a comparison chart of natural gas offers, called “Apples-to-Apples,” that has been well received by customers. While the chart is available through the mail by calling a toll-free number or by writing to the Commission, quickest and easiest access is through the Internet. Low-income customers only Internet options, however, may be at a public library. This would require more time and have more limited access.

[17]PUCO Staff, A Baseline Study of the Columbia Gas of Ohio Customer Choice Pilot Program, 310.

and alternative suppliers are available, the more active switching customers will begin to make a choice shortly after it is made available to them. But the majority of customers will require more time to decide, so the overall rate of change will be slow initially. As customers learn about their options, the rate of change will accelerate for a period. Over time, this will taper off as the more active customers have made a selection and the remaining customers are those who, for whatever reason, are more reluctant to choose a supplier. The height of the curve and the length of time (the segments shown in the Figure) needed to reach a certain level will vary with the strength of the economic incentive. With a strong incentive, the top curve in Figure 3.2, the segments may be months, for a moderate incentive the segments may be quarters, and with weak incentive, the segments may be years. For example, it may take less than six months to reach one-third of the customers choosing a supplier with a strong economic incentive, two years (eight quarters) to reach that level with a moderate economic incentive, and may not even reach 20 percent in over twelve years with a weak incentive. After a period of time all the curves flatten out, so that many customers may not choose a supplier even after a decade or more, even with a strong incentive. The pattern a particular distribution area follows in practice, however, may not be a smooth continuous curve, since the level of economic incentive may change as market conditions change over time. Thus, for example, an area may begin with strong incentives but weaken over time to a moderate level as wholesale prices move up. This underscores the need again for periodic adjustments to the generation standard offer to reflect actual market conditions.

**Figure 3.2**. Long-run customer response begins slowly, accelerates, then tapers off over time, but the height of the curve it follows depends on the economic incentive to switch that customers receive.



## Market Power, Price Discrimination, and Small Customers

A supplier has market power if it is able to raise and maintain the price charged customers significantly above what would occur in a competitive market. This textbook definition of market power is straightforward and not very controversial. However, if the potential exists to raise prices due to market power, the impact will vary by customer class. This goes to the heart of the definition and characteristics of "small customers" and how market power can be exploited by a supplier.

Much of the current discussion of market power is concerned with detection and measurement or prevention and remedies; for example, examining the market price and its possible deviation from prices that would occur under competitive conditions.[18] Additional complications include defining the relevant market area and the methods of analyzing the market to measure market power. These topics are beyond the scope of this analysis. Of interest here is the potential impact on small consumers if a supplier, group of suppliers, or other market participants have and are able to exploit some degree of market power.

Understandably, all market participants, whether large, small, incumbent, new entrant, or other, would like to have market power. Any participant would prefer to have at least some control of price rather than no control at all. In a competitive market, suppliers are "price takers" and cannot decide unilaterally what price to charge customers. The reason this holds is that if a supplier tries to raise its price (keeping service quality the same) and other suppliers do not, customers will more likely switch to the lower priced alternatives. The supplier that raised its price is then forced to lower its price back to the previous level, offer a better value to attract customers, reduce its business size, or go out of business altogether. Well-functioning competitive markets act as a brake on market power and limit the participants' ability to obtain, maintain, or benefit appreciably from market power.[19]

The attainment and ability to exercise market power by a market participant occurs when this self-correcting market process is prevented from functioning as

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[18]There have been indications that prices have exceeded marginal costs during peak times in the California Power Exchange, PJM power pool, and in some markets outside the United States. See for example, Borenstein, Bushnell, and Wolak, "Diagnosing Market Power in California's Deregulated Wholesale Electricity Market," working paper for Program on Workable Energy Regulation (POWER), PWP-064, University of California Energy Institute, Berkeley, California, March 2000; and Yu, Sparrow, and Lusan, "Estimation of Conjectural Variations of Competitive Electricity Prices and Consumer Response," Proceedings of the 59th American Power Conference, Chicago, April 1999.

[19]A firm may acquire some limited market power and benefit for a short time, by discovering a new market niche for example. If other firms are not prevented from entering the market, however, the firm is forced to reduce its price, dissipating its market power over time. In such cases, the full weight and force of state and federal antitrust laws are not usually needed.

described. To obtain this market power, an effective barrier to entry is required that prevents others from entering the market. Entry barriers may result from technological advantages, high sunk costs, limited customer access, high information costs, or government protection. A firm that has the ability to use one or more of these barriers to limit competition can charge a price that the firm, at least in part, has determined rather than one determined solely by the market.

A price-taking competitive firm with no market power determines how much to produce by equating its marginal cost with the given market price. The firm cannot pick its own price and is too small to be able to unilaterally affect the price by itself. The more a firm can charge a price that exceeds its marginal cost and determine what price it wants to charge, the higher the firm's degree of market power.[20] There are, of course, upper bound limits on price that even an unregulated monopolist must contend with: These include that the price cannot exceed what consumers are willing to pay for the product (that is, it cannot exceed demand at the quantity the monopolist wants to produce) or charge a price that is sufficiently high that it creates a strong incentive for other firms to find ways around the barriers to entry or encourages consumers to seek alternatives.

An important characteristic that determines how much a firm can profitably raise prices, and obtain some degree of market power, is the price elasticity of demand. Specifically, the more inelastic the demand (that is, price elasticity of demand is less than one[21]), where the quantity demanded by consumers is relatively unresponsive to price changes, the more likely it is that by raising its price a supplier can increase revenue and profits. This is because, by definition with an inelastic demand, if the price increases then total expenditure (price times quantity) increases. For example, if the price elasticity of demand is -0.2 (very inelastic) and if the price increases by ten percent, quantity demanded decreases by only two percent. Total expenditures increase because the increase in expenditure from the price increase is larger and not offset by the decrease in expenditure cause by the decrease in quantity demanded. For a supplier with at least some degree of market power that allows them to raise the

[20]This can be estimated with the "Lerner Index," which is (Price - Marginal Cost)/Price, which measures the markup of price over marginal cost (as a percentage of price). For example, if the Lerner Index equals 0.5, then there is a 50 percent price markup over marginal cost; if it equals 0.02, there is a two percent markup of price. If the Index equals 50 percent, it may indicate significant market power and require some action; if it is only two percent, it is unlike to raise any calls for government action.

[21]Price elasticity of demand is a measure of how responsive quantity demanded is to a change in price, calculated as the percentage change in quantity demanded divided by the percentage change in price.

price and increase revenues.[22] Since quantity demanded decreased, costs also decrease, meaning profit also increases.

The demand curve an *individual firm* faces is not the same as the market demand, unless a firm is a monopolist. In addition to the elasticity of the market demand, the individual firm's demand elasticity also depends on the firm's market share and the elasticity of supply of competitive firms. Using the formula to derive a firm's elasticity of demand,[23] it can be shown that where there are other firms competing in a market, the firm's elasticity of demand becomes more elastic as the market share of other firms increases, the elasticity of market demand increases, or the elasticity of supply of other firms increases. Therefore, while the market demand may be very inelastic, for example, -0.2, if the firm has a five percent market share, the firm's elasticity of demand is -23.0, obviously very elastic.[24] For the firm that has only a fraction of the market and the supply from other firms and market demand are fairly elastic, the demand elasticity of the individual firm becomes infinitely elastic. This is a restatement of the "price-taking" characteristic of a competitive firm that faces a horizontal demand curve even when the market demand is downward sloping. In this case, even a small increase in price will cause the firm to lose all of its sales.

However, if the market is more concentrated, for example, the market demand elasticity is again -0.2, but the firm's market share is 60 percent, the firm's demand elasticity would be unity or -1.0. Thus, under the same market demand elasticity assumption, any increase in market share would result in the firm's demand becoming more inelastic and being less than one. If the firm's market share is 80 percent, the firm's elasticity of demand is unity when market demand elasticity is -0.6; any increase in market share or decrease in market demand elasticity will again result in the firm's elasticity of demand being inelastic or less than one.

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[22]This is not equating market power with inelastic demand, since market power can be present with elastic (>1.0) demand as well. Whether raising prices is profitable with elastic demand depends on the cost structure of the firm since total expenditures decrease when price increases; with inelastic demand it is always profitable, but the ability to raise prices depends on having at last some degree of market power. As will be shown below, as market demand becomes more inelastic, the individual firm's demand becomes more inelastic as well. Depending on market share and supply elasticity, this may increase the firm's power to raise its price.

[23]The formula to calculate a firm's elasticity of demand is:

$$0_D = 0_M(1/MS) + g_{SF}((1/MS) - 1);$$

where $0_M$ = the elasticity of market demand, MS = the firm's market share, and $g_{SF}$ = the elasticity of supply of other firms. The derivation for this formula can be found in many standard intermediate price theory text books. See for example Edgar K. Browning and Mark A. Zupan, *Microeconomic Theory and Applications*, Sixth Edition, Addison-Wesley Educational Publishers, Inc., Reading, MA, 1999, p. 345.

[24]Elasticity of supply of competing firms is assumed to be unity or 1.0. This will be assumed unless specified otherwise. As noted, the firm's demand elasticity increases (decreases) as the supply elasticity increases (decreases).

All three factors affecting the firm's demand have a considerable bearing on retail electricity markets and whether market power is likely. First, a distinguishing characteristic of electricity demand is that it is very inelastic, especially in the short run (about one year or less, this is discussed in more detail below). Second, most retail markets will be very concentrated, with one firm, the incumbent supplier and affiliates, having a large market share and the remainder of the market served by a few or many other firms with much smaller market shares. And third, short run supply elasticity is also very inelastic. Because of transmission constraints and the length of time it takes to build new generation and transmission capacity,[25] it is difficult for alternative suppliers to present a serious theat in the incumbent's market position. In the short run, it is reasonable to assume the both market demand and supply elasticities are very inelastic. If this holds, then it does not require a very highly concentrated market for the firm to face inelastic demand. For example, if both market demand and supply elasticities equal 0.2 (in absolute value), then a firm would only require one third of the market for its demand elasticity to be one. Under these conditions, if the firm has a market share greater than one third, not an unreasonable assumption, it will have a inelastic firm demand.


**Summary**

**The relationship between market power and the firm's demand curve: Is market power inevitable?**

If a firm can raise and maintain its price above its marginal cost, by definition it has some degree of market power. If the firm faces a very elastic demand curve, it has little power to raise and maintain its price, such as with the classic horizontal demand curve found in economic textbooks. However, as the demand curve the firm faces becomes less elastic, the firm has relatively more power to raise its prices.

There are three factors that determine the firm's demand elasticity–market demand elasticity, supply elasticity of other firms, and the firm's market share. No single factor by itself will mean that market power is inevitable. For example, for a highly concentrated market where a single firm has 80 percent of the market, if market demand and supply elasticities are both a relatively elastic 2.0, the firm's demand elasticity will be a relatively elastic 3.0. However, it is well known that both market demand (because of few substitutes for electricity consumers have) and alternative supply (because of entry constraints) elasticities are relatively inelastic. Also, most retail markets will be relatively concentrated for some time in the future. Does this mean the ingredients are in place for a serious market power problem? In the short run, the answer is probably yes. In the long run, with more elastic market demand and supply and less concentrated markets, market power should taper off over time. However, barring a technological breakthrough, a considerable degree of market power may be present in many areas for years to come.


[25] Both new transmission and generation require a long lead time for financial and construction planning, siting approval, and construction. Siting approval is, of course, never guaranteed even after long delays. Marketers buying in the wholesale market and reselling it in retail markets are also limited by transmission and generation availability constraints. They may also choose to focus on wholesale sales and retail sales to larger customers.

This has serious repercussions for small electric consumers with respect to supplier market power and possible price discrimination.[26] The individual firm's demand does not have to be inelastic in order for it to possess some degree of market power, any slope in the firm's demand curve indicates some amount of power to raise its price. The greater the slope, that is, the more inelastic, the greater the degree of firm market power. If a firm has a demand elasticity of less than one for both the long run and the short run, in addition to having considerable power to raise its price, the firm will always be able to profitably raise the price.

Estimates of market demand price elasticities vary, sometimes considerably, depending on estimation methods, time periods, data used for the study, geographic area, market definition, and other factors. For residential customers short run price elasticity of demand for electricity tend to average around -0.2 and long run price elasticities average around unity or -1.0.[27] This indicates a considerable unresponsiveness to price changes in the short run relative to other goods. Longer term, residential customers are more responsive, some elasticity estimates approach -2, again, however, the average long-run estimate is closer to -1.0. This suggests very inelastic demand in the short run and, while more elastic in the long run, residential demand is still perhaps less than one.[28]

The reason demand becomes more elastic over time is that in the short run, consumers cannot quickly adjust their current stock of appliances such as air conditioners, refrigerators, and other electrical appliances to adjust to the higher price. If the price for power increases by ten or twenty percent, customers usually do not rush out to purchase new efficient lights and appliances. Instead, consumers wait until the existing stock begins to wear out over time. Until then, consumers may be more cognizant of turning lights off when leaving a room, waiting until the dishwasher is completely full before using it, or adjusting the thermostat to be a little cooler in winter or warmer in summer. A larger price increase may result in further and relatively quick

[26]Some have argued that for markets to be "contestable," only a few entrants are required to approach a competitive outcome. However, this assumes costless (or nearly so) market entry and exit, a dubious assumption under current conditions in the electric supply industry.

[27]A Study by E. Raphael Branch, "Short Run Income Elasticity of Demand for Residential Electricity Using Consumer Expenditure Survey Data," *The Energy Journal*, vol. 14, no. 4, (1993), estimated price elasticity at -0.20 and cited four other studies that ranged from -0.11 to -0.55. In *America's Electric Utilities: Past, Present and Future*, Leonard S. Hyman (Public Utilities Reports, Inc., Arlington, VA, 1988), cites a study that summarized 25 studies published after 1975 that found the average short-run price elasticity of demand of the studies to be -0.23, very close to Branch's estimate, and average long run price elasticities of -1.17 – or, interestingly, the average drops to -0.98 if a high outlier is excluded.

[28]Since price elasticity of demand is always, with some theoretical exceptions, a negative number, it is common and more convenient to discuss elasticity numbers in absolute value terms. Therefore, "less than one" means between 0 and -1.0.

measures, such as switching to lower wattage light bulbs. Longer term, consumers can switch from an electric hot water heater or stove to natural gas, add insulation, and replace inefficient older appliances with new ones. Overall, electricity is, for most small consumers, a basic necessity of life with few practical alternatives and with limited short run quantity reducing options in the current relevant price range.

Studies of long-run elasticity of demand for industrial customers show that these customers are as inelastic or even more inelastic than residential customers.[29] However, industrial customers often bargain for better rates or prices by use of the real threat that they will relocate out of the utility's service territory, generate some or all of their own power, or, when choices are available, switch to an alternative supplier. These customers may not be likely to switch fuels quickly between, for example, natural gas, oil, or coal if the price of electricity changes (inter-fuel substitution). Longer term, however, they do consider plant relocation, self-generation, or alternative suppliers–different options for obtaining electricity. These potential options for purchasing and generating electricity should make the supply of alternatives to these larger customers more elastic relative to smaller customers. This would make their elasticity of demand from the incumbent supplier's standpoint, the firm's demand, more elastic. Smaller industrial customers, on the other hand, may resemble residential and small commercial customers in terms of the firm's (incumbent supplier's perspective) demand elasticity because options such as relocation and self-generation may be nearly as limited.

More limited options to relocate, self-generate, and other purchasing alternatives is a distinguishing feature of smaller customers from larger load customers. This makes the supply from alternatives to purchased power for smaller customers relatively more inelastic and therefore, the firm's demand that supplies these customers more inelastic. It has already been shown that raising the price for inelastic customers, when the firm's demand is also inelastic, will be profitable for the supplier or suppliers with market power. The next question is, do the different elasticities between classes and perhaps even within segments of the same class determine the relative impact of market power? If the price of electricity is higher with some degree of market power than it would be under more competitive conditions, then obviously, any customer, regardless of class, would be worse off. That consumers will have less to spend on other goods and there is a general decline in their welfare does not require further verification.

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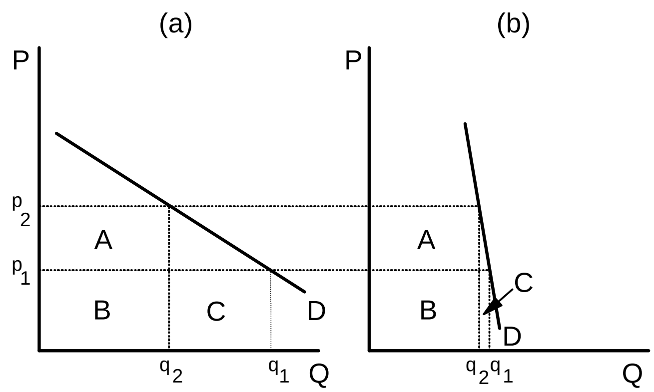
[29]Studies indicate that large customers may have very inelastic short run demand for electricity. The study cited by Hyman reported the average of the short run price elasticity estimates of the 25 studies summarized to be -0.15 and a long run price elasticity average of -0.94. An analysis by Mahmoud A. T. Elkhafif, "Estimating Disaggregated Price Elasticities in Industrial Energy Demand," *The Energy Journal,* vol. 13, no. 4, (1992) estimated elasticities of demand for the industrial sector in Ontario at -0.15 for the short run and -0.70 for the long run. This would indicates industrial customer demand to be even more inelastic than residential customers in both the short run and the long run.

The relative increase, however, in expenditure by consumers is higher the more inelastic the firm's demand. This is illustrated in Figure 3.3 where diagram (a) is the relatively more elastic demand and diagram (b) the relatively more inelastic. For both demand curves (a) and (b), at price $p_1$, total expenditures are the sum of rectangles B and C. When the price increases to $p_2$, total expenditures becomes A plus B.[30] The amount represented by C is no longer incurred because quantity decreased in both cases from $q_1$ to $q_2$. The net change in expenditure depends on the relative size of the rectangles A and C. In diagram (a) the relative change is nearly equal, meaning net expenditure remained about the same after the price change. In diagram (b), however, the net change is clear, because rectangle A is much larger in area than C. As discussed above, when demand is inelastic, expenditures increase when the price increases. Figure 3.3 demonstrates how the relative size of this increase in expenditures also depends on how inelastic the firm's demand is.

**Figure 3.3.** As price elasticity of demand becomes more inelastic, relative total expenditures increase.




That consumers with a more inelastic demand such as in diagram (b) will increase their expenditures considerably more than consumers with price elasticity of demand closer to unity (-1.0), can be useful information for potential sellers with at least some degree of market power. Different price elasticities among consumers of electricity opens up a substantial possibility for price discrimination by suppliers.[31] By charging a higher price to the more inelastic customers, a supplier with market power can be fairly confident that this will also increase its revenue and profits. Again, this is because, for inelastic consumers, expenditures (and supplier revenues) will increase when the price increases, and, since quantity demanded decreases, costs for the supplier decrease, therefore, with revenues increasing and

[30]For simplification, the same prices are used for both the inelastic and relatively more elastic customers' demand to demonstrate the relative change in net expenditures. Actual electric rate structures, usually will start with different prices and it would not be expected that they would move together to the same new price.

[31]Price discrimination at colleges and universities, in the airline industry, and in the electric supply industry is discussed in Eugene P. Coyle, "Price Discrimination, Electronic Redlining, and Price Fixing in Deregulated Electric Power," prepared for The American Public Power Association, Washington, D.C., January 2000.

costs decreasing, profits will increase. Again, the individual firm's demand does not have to be inelastic in order for it to possess some degree of market power. However, the demand elasticity the firm faces for the customer group must be inelastic (less than one) for it to always be profitable to raise the price.

To price discriminate also requires that suppliers can effectively segment consumers, so suppliers can charge and sustain different prices for different customer groups. There is nothing new in the industry about the practice of charging different prices to different customer groups already. Volume discounts or declining block rates, of the type widely used in the industry for many years, is a form of price discrimination. The difference under competition, however, is that the ability to charge a different price to different market segments is the result of a supplier's decision, and perhaps its ability to determine the price due to the extent of their market power, rather than by regulatory edict.[32] There is little doubt that the continued segmentation of customers in a restructured market will be relatively easy.

Price discrimination may not only occur by separating smaller customers from larger uses, but may also occur when customers within the same general class are segmented. For example, residential customers may be segmented into low income and the elderly, whose demand may be more inelastic, from others within the same residential class that may have more elastic demand, such as higher-income and active switchers. The extent to which these customers self-identify, by not switching suppliers for example, may lead to suppliers adopting a pricing strategy that gives the active and more assertive customers a lower price. These more inelastic customers may also be identified geographically, which will determine suppliers' marketing strategies to concentrate or avoid certain areas (a practice sometimes known as "redlining") or using different strategies for different areas.

Upper bound constraints on suppliers with market power may include the threat of re-regulation if the price increases too much and too fast that it generates antitrust or political action or that encourages the development of smaller customer self-generation. Longer-term, these smaller inelastic customers may, like larger customers today, develop more economical options for self-generation. Another means to increase elasticity is through aggregation. Also, price increases to inelastic customers relative to more elastic customers can be limited by allowing resale of electricity by customers. For example, large industrial customers may be able to purchase power at a relatively low price and then resell it to smaller commercial and residential customers. This greatly reduces the ability of suppliers to segment the market and profitability price discriminate. The extent of its use, however, may be very limited by network constraints.

[32]Even under regulation, a utility's possible market power may be exercised after the approval of economic development rates or special contracts for large customers.

Finally, again in the long run, elasticity can be increased through inter-fuel substitution. Smaller customers do have some opportunities for fuel substitution, such as with natural gas, propane, and wood, for space and water heating and cooking. For this reason, electric and gas combination companies may limit consumer adjustment to price changes if the price of the alternatives move deliberately in tandem. In the case of combination companies, the potential is there for an increase in prices if competition between fuel suppliers is weak or nonexistent. Profit maximizing suppliers, unchecked by real competition between fuels, will try to raise prices for inelastic customers to increase revenue and profit in both markets.

State and federal policies directed at preventing or limiting supplier market power may have the greatest impact when directed at increasing the supply elasticity for alternative suppliers. Thus, policies should encourage new entrants or at least not discourage alternative suppliers in retail markets. Some policies, such as those that allow open transmission and distribution access for generation competition encourage entry. However, some policies, such as "stranded cost" subsidies to the incumbent, discourage alternative supplier entry. In the long term, a market structure that encourages entry can limit the extent of market power and a firm's ability to increase prices. This is why market structure is one of the most critical issues that faces policy makers today. How it turns out will determine whether retail competition is a success, failure, or something in between.

**Are Small Customers Benefitting from Competition?**

It is too early to detect any trend in prices or relative benefits to customer groups from electric restructuring. However, recent data from the Energy Information Administration (EIA) indicates that for states that have had retail choice available the longest, average revenue (total revenue collected divided by sales) collected from customers has decreased from 1998 to the end of 1999–the first full year all these states allowed retail choice for most customers. These data are summarized in Table 3.6. While the U.S. average also fell during this time period, average revenues decreased by a higher percentage than the national average for each sector and in each of the four states,[33] with only one exception, residential customers in California. This may be an early indication that electric restructuring is, at least for now, delivering on the promise of lower electric prices (although, to be fair, this would have to be compared to what would have occurred if cost-based regulation of generation had continued).

[33] Although Rhode Island was not summarized in the above discussion, it was added since Rhode Island was the first state to begin phasing-in competition, in July 1997, and began retail access for all customers on January 1, 1998.

**Table 3.2**. Percent average revenue reduction from 1998 to end of 1999.

| State | Residential | Commercial | Industrial | All Sectors |
|---|---|---|---|---|
| California | 0.9 | 5.2 | 7.6 | 2.2 |
| Massachusetts | 5.7 | 8.5 | 11.0 | 8.3 |
| Pennsylvania | 10.1 | 21.7 | 25.0 | 17.7 |
| Rhode Island | 6.4 | 10.8 | 11.8 | 8.3 |
| U.S. Average | 1.1 | 2.8 | 1.3 | 1.6 |

Source: Calculations based on average revenue data from U.S. Department of Energy, Energy Information Administration, "Electric Power Monthly," March 2000, Table 55. www.eia.doe.gov/cneaf/electricity/epm/epm_sum.html.

These data may also reveal something that will likely be the topic of discussion for the next several years: in each of the four states, industrial and commercial customers had larger percentage decreases than residential customers. As noted earlier in the first section, larger customers have historically paid lower prices for electricity than residential and small commercial customers. If these data are indicating the beginning of a general trend, which cannot be discerned at this time, then the price differential between small and large customers will become even greater than it was in the past under cost-based regulation.[34]

Additional caution should be used in interpreting these numbers. In addition to being too early to detect a trend, these data do not include sales of marketers and alternative suppliers. These data indicate the revenue from competitive sales of the incumbent suppliers and their revenue from standard offer sales, but no competitive sales of alternative suppliers. Also, these data include information from both private investor-owned and public utilities. This would include data from public utilities that may not allow retail access. Both these facts may skew the data in one direction or the other. It could, for example, moderate the results, meaning that the customer class difference in percentage decreases are actually greater for areas with retail access.

An alternative way to analyze these data is to calculate a ratio of residential customer average revenue to industrial customer average revenue. The residential customer to industrial customer ratios (R:I ratios) are shown in Table 3.7. An R:I ratio of one would mean parity, that is, the customer classes would have the same average

[34]It may not necessarily be economically inefficient if prices continue to be different for the various customer groups. It merely reflects different levels of usage, elasticities, alternatives, costs to serve, and so on. However, if the gap widens substantially from where it was under regulation, equity questions will be raised that have little to do with economic efficiency.

revenue and an R:I ratio of two would mean residential customers have an average revenue twice that of industrial customers. The U.S. national average remained nearly the same in 1998 and 1999 at 1.84 and 1.86 respectively, (in 1997 it was 1.86). The ratio increased for each state from 1998 to 1999, meaning the average revenue difference between customer classes increased, but in California, Massachusetts, and Rhode Island the 1999 ratio was still below the national average. It could be argued that, for those three states, the ratio was closer to parity under regulation but changed to be more like the national average during the beginning of restructuring.[35] In Pennsylvania's case, however, the ratio in 1998 was close to the national average but increased to 2.12, the highest of any state. Since Pennsylvania has had the most robust competition of any state so far for all customer classes, does this presage a result that will repeat in other states as competition develops? Clearly, further monitoring and analysis is required before firm conclusions can be drawn.

**Table 3.3**. Ratios of residential customer average revenues to industrial customer average revenues, 1998 to 1999.

| State | 1998 | 1999 |
|---|---|---|
| California | 1.61 | 1.72 |
| Massachusetts | 1.29 | 1.37 |
| Pennsylvania | 1.77 | 2.12 |
| Rhode Island | 1.43 | 1.52 |
| U.S. Average | 1.84 | 1.86 |

Source: Calculations based on average revenue data from U.S. Department of Energy, Energy Information Administration, "Electric Power Monthly," March 2000, Table 55.
www.eia.doe.gov/cneaf/electricity/epm/epm_sum.html.

[35]It could be, for those states and many others, that there was a regulatory policy to keep residential prices closer to parity, perhaps due to cross-subsidies from other customer classes. The increasing price ratio may simply reflect the lost cross-subsidy under retail competition. Again, this may be justifiable from an economic efficiency standpoint, but may raise equity concerns.