Retail Cost Recovery and Rate Design
in a Restructured Environment

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EXECUTIVE SUMMARY

This paper examines the currently evolving retail and wholesale electric supply market and offers recommendations on appropriate regulatory policy toward retail electricity rate design and cost recovery mechanisms. Electricity rates need to accomplish two basic goals: impart information that helps customers and investors make economic decisions about their consumption and investment decisions, and ensure that regulated utilities’ costs are recovered. Today’s electricity rates often fall short on the first count, and current cost recovery mechanisms (e.g., base rate cases and fuel adjustment clauses) do not do well on the second count. Utility rate structures have remained largely unchanged during the past two decades, based on averaged costs and considerations of fairness (i.e., balancing different customer groups’ interests and state policies) rather than economic efficiency. These rates give customers very little economic incentive to reduce usage at peak demand periods or, indeed, to use electricity wisely at any time. Concomitantly, on the supplier side, traditional rate structures have also failed to provide the correct signals to guide competitive decisions and infrastructure investments. Utility rates to end-user customers should be designed to provide better price signals by better reflecting cost causation. This will facilitate the demand response necessary to make wholesale competition work more efficiently. It will also signal to investors when, where, and whether to build new infrastructure or enter a market.

New costs of service and new forms of financial risk are emerging for utilities as energy markets evolve. In particular, expansion of the wholesale markets and formation of Regional Transmission Organizations (RTOs) have introduced new categories of costs that are largely beyond the control of an individual utility; rate freezes that were associated with restructuring and mergers are ending; and new issues—such as whether the utility should continue indefinitely to provide a readily-available, fixed-price “provider-of-last-resort” service (POLR)\(^1\) to all retail customers—are arising. However, regulatory cost recovery mechanisms and rate structures have failed to keep up with the utilities’ changing risk profiles and industry structure. These new costs, as well as the costs of mitigating the new risks, must be reflected in the utilities’ cost-recovery mechanisms and rate structures.

Regulatory “ratemaking” risk is also increasing for utilities in both restructured markets and traditional markets. At a time when wholesale market reforms have changed the business environment, including market structures and costs, jurisdictional issues between federal and state entities present new pressures and challenges for the U.S. electricity industry. The U.S. Federal Energy Regulatory Commission (FERC) is pressuring the utility industry to restructure existing Independent System Operators (ISOs) into Regional Transmission Organization (RTOs) that would have broad powers and responsibilities, and is pressuring utilities that are not in an ISO to join an RTO. In rate cases, however, if state regulators are skeptical of the reasonableness of these restructuring costs, they could be reluctant to include them in retail rates. In some regions, utilities have little operational control over transmission assets (e.g., RTO management of transmission), but these costs are real and need to find their way into the prices paid by electricity users.

\(^1\) Also known as Standard Offer or default service, with the selected phrase varying from state to state.
CONCLUSIONS AND RECOMMENDATIONS

Over the next several years, revising retail rate structures and cost-recovery approaches must be a high priority for electric utilities and for regulators. Some key recommendations for how to go about accomplishing this include the following:

Cost Recovery Mechanisms

- **A greater role exists for adjustment clauses to properly reflect costs that are significant and beyond the control of the buying utility.** Such costs include RTO startup, infrastructure and administrative costs, transmission-related congestion costs, and market-driven generation costs. The current design of local gas distribution companies (gas LDCs) purchased gas adjustment clauses (PGAs) provides a good starting template.

- **The importance of timely recovery of regional costs must be recognized.** Given the development of regional transmission organizations, a large and increasing proportion of many utilities’ costs are already beyond the control of the individual utility. An automatic adjustment mechanism could “regularize” the regulatory lag associated with the recovery of externally-driven regional costs.

- **Utilities must be allowed to effectively manage the greater price and quantity risk that they face in increasingly volatile and unpredictable wholesale markets.** Utilities must have the regulatory flexibility to prudently hedge their risks. Utilities’ “portfolio manager” functions in procuring and supplying electricity, including hedging strategies aimed at price volatility risks, must be overseen by regulators without creating undue exposure to after-the-fact regulatory second-guessing.

- **Utility ratemaking policies must ensure timely investment in critical infrastructure.** Regulatory mechanisms that accommodate more rapid recognition of infrastructure costs in retail rates are a useful way to improve investment incentives. Notwithstanding this consideration, well-structured price-cap mechanisms remain appropriate for both the transmission and distribution sectors.2

- **Asset investment trackers can improve infrastructure investment incentives.** Allowing rate adjustments that reflect the utility’s capital investment programs on a more timely basis can accommodate infrastructure investment. Asset investment trackers would allow the utility to recover its costs more quickly, while avoiding the filing of major rate cases.

- **Incentive rate approaches (such as price-cap ratemaking) can provide a reasonable assurance of cost recovery by the utility and directly benefit the consumer.** For example, the price-cap model can provide strong incentives for productive efficiency that would benefit consumers and utility shareholders, drive technical innovation, emulate the incentives that firms face under competition, and greatly diminish the incentive for cost shifting between regulated and unregulated businesses.

Rate Design

- **Retail rate design must reflect the structure of wholesale power costs.** Even in the post-transition period, utilities will likely still be required to offer POLR tariffs for customers who choose not to switch to alternative suppliers, such as competitive power marketers. Given the highly differentiated nature of wholesale power costs, retail rate design and cost recovery mechanisms must reflect the nature of how these costs are incurred by the utility in the competitive wholesale marketplace. This synchronization of wholesale and retail rate design should also address the potential over/under revenue recovery operating

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2 Incentive ratemaking approaches can be used to accommodate the recovery of costs that are largely beyond the control of the utility without dampening the utility’s efficiency incentives. If price-cap regulation is used, for example, an “exogenous cost” or “Z-factor” clause could clearly specify how RTO and similar regional costs are to be recovered.
risk that distribution utilities with continuing energy service obligations face as a result of wholesale market price volatility.

- **Usage-based volumetric rates should not be overemphasized.** Current rate designs, which usually overemphasize usage-based volumetric rates, will tend to encourage uneconomic bypass because customers can avoid paying their appropriate share of a utility’s fixed costs for distribution by using alternative sources of power or using less energy. This could cause an increased burden on the remaining utility customers. Volumetric rates create artificial incentives to bypass the local distribution system, especially if the customer is allowed to return to regulated service at will.

- **Utility rates must reflect both the utility’s economic costs and demand-related considerations.** Cost- and demand-responsive rate designs, such as time-of-day rates, seasonal rates, or even real time rates (possibly offered to end users by intermediaries providing hedges against volatility) would be ways to accomplish this. In addition, demand response programs that result in voluntary load reductions at peak periods can be used at either the RTO or the utility level to improve the functioning of wholesale markets.

- **Retail tariff rates should contain separate demand, energy, and customer charges.** Larger commercial and industrial customers can be priced using separate demand, energy, and customer charges. Use of this rate design with smaller residential and commercial customers is more difficult given the cost of new metering and meter reading expenses. As the costs of metering and related technologies fall, more rate structure options will be possible. The real challenge over the longer term, however, will be political acceptability.

- **To the greatest extent possible, customer- or demand-related fixed costs should not be rolled into energy charges.** The end-use customer often sees too high a price for energy and too low a price for demand and customer charges. Hence, the customer never receives the economically efficient price signal for either one. Moreover, where fixed distribution costs are recovered through usage-sensitive rates, distribution utility cost recovery may be threatened by changes in prices and usage.

- **Time-of-day, interruptible, and seasonal rates are preferred rate designs.** For larger commercial and industrial customers, these rate designs are an important way to improve demand response and thereby increase the efficiency of power supply procurement by the utility or other provider. As metering costs decrease over time, these rate options can be extended to other classes.

- **Retail rates should not be based on highly averaged costs.** The basic problem is that most utility customers still pay an average price for the generation commodity portion of utility service. In states that have retail access, most current POLR rates feature prices structured on average costs. Averaging costs in this way ignores the fact that wholesale power rates are differentiated by many factors, including time period, geography, firmness of service, season, etc. Cost averaging can fail to provide the customer with a price signal that reflects the true economic costs associated with changes in consumption. While this issue will not be an easy one for state regulators, it will become an important issue in future years as questions arise concerning cross-subsidies between congested and uncongested parts of a state’s transmission system.

- **Locational retail rates should be considered as a viable rate design option.** At the wholesale level, certain regions currently use locational marginal cost pricing for wholesale rate design at different pricing nodes. For example, this wholesale rate design is currently used within the PJM Regional Transmission Organization, which covers the Mid-Atlantic Region. Following the principle that retail rate setting should be guided by wholesale prices, a retail LMP rate structure could be used to design retail rates that provide a more economically efficient price signal to the customer.

- **Customer education relating to the need for rate restructuring must be given a high priority.** Customers must be informed about the rationale for rate design changes.
No rate design is able to perfectly fulfill all of the intended roles. Rather, each rate design must be judged on how it balances all of the conflicting objectives and not just on how well it achieves any single objective. As important as it is, rate design is only one aspect of overall rate policies; it can only do so much. After 10 to 12 years of restructuring wholesale electricity markets, it is reasonable to ask how well retail rate tariffs are doing in reflecting to end-use customers the cost of generating that electricity. The design of rate tariffs will help determine whether or not consumers receive correct price signals, whether competition among competitors is efficient, and whether the utility and other market participants have the necessary incentives to invest in utility infrastructure. Further progress in improving the utility ratemaking and rate structure process is needed to move forward.
# LIST OF ACRONYMS

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<td>Distributed generation</td>
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<td>EPMC</td>
<td>Equal percent marginal cost</td>
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<td>EWG</td>
<td>Exempt wholesale generators</td>
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<td>FAC</td>
<td>Fuel adjustment clause</td>
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<td>FERC</td>
<td>U.S. Federal Energy Regulatory Commission</td>
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<td>LDC</td>
<td>Local distribution company</td>
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<td>LMP</td>
<td>Locational marginal pricing</td>
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<td>PGA</td>
<td>Purchased adjustment clause</td>
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<td>PJM</td>
<td>Pennsylvania, New Jersey, Maryland Interconnection</td>
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<td>POLR</td>
<td>Provider-of-last-resort</td>
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<td>PUHCA</td>
<td>Public Utility Holding Company Act</td>
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<td>PURPA</td>
<td>Public Utility Regulatory Policies Act of 1978</td>
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<tr>
<td>ROE</td>
<td>Return on equity</td>
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<td>RTO</td>
<td>Regional Transmission Organization</td>
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<td>SBC</td>
<td>System benefits charges</td>
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<td>TCC</td>
<td>Transmission congestion contracts</td>
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<td>T&amp;D</td>
<td>Transmission and distribution</td>
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INTRODUCTION

“Perhaps no other one factor has contributed so much to the success of the electrical business as the study of the rate problem.”³

“[A] pricing system has developed that is so badly structured at the critical retail level that if it were replicated throughout the economy, we would all be as poor as the proverbial church mouse. Retail customers pay averaged rates, making their demand unresponsive to changes in supply cost.”⁴

Over the past decade, the electric utility industry has gone through a competitive transformation that has fundamentally altered the way in which electricity is supplied in the United States. Changes have occurred both in the structure of the companies providing this vital service, and in the regulation of those companies. Underlying these changes has been a recognition that economic activities must ultimately be aimed at satisfying consumers,⁵ and the goal of electric restructuring has been to permit market forces, through prices, to substitute for regulation in order to obtain the maximum benefits from competition.

The American electric services industry—and economic regulation of this cornerstone infrastructure industry—has adapted to many challenges in providing electricity to American consumers. However, this change has been uneven across the country, reflecting regional and local differences in the costs of utility service. Moreover, rate structures for the residual utility services are largely unchanged, remaining heavily based on the backward-looking, fully allocated, embedded cost approach instead of forward-looking economic costs of service. These rates also reflect political considerations and compromises rather than economic efficiency. In jurisdictions that have experienced market restructuring (i.e., ISOs and RTOs), retail rate structures may be insufficiently tuned to the requirements of competition policies.

While much change has taken place, much remains to be done. As existing utility rate caps expire over the next few years, regulators will be confronted with the need to establish new pricing mechanisms. Changes in wholesale electricity markets, the oversight and operation of the transmission system, and retail competition will also have important implications for the regulation of electric utilities. To work well, FERC regulation of wholesale generation markets and transmission must be well coordinated with state-level utility rate regulation. Not only must the utility have an opportunity to recover its prudently incurred costs, but these costs must be recovered in ways that provide efficient price signals to the cost causer.

This paper explains these changes and suggests ways that regulators need to approach restructuring policy and ratemaking to ensure that utility cost recovery and rate design can better adapt to evolving energy markets.

⁵ Professor Bonbright (supra, note 2, p. 29) explains that in markets based on consumer sovereignty, “the allocation of the community’s scarce resources is made to depend on consumer choices or preferences rather than on governmentally determined decisions as to relative needs or national interests. This goal is basic to the whole modern theory of public utility prices and forms the underlying rationale of a cost-price standard of utility rates.”
THE PAST, PRESENT, AND FUTURE
OF THE U.S. ELECTRIC INDUSTRY

Electric rate structures and cost-recovery methods have, for the most part, not kept up with the new competitive environment. Most electric utilities have tariff structures and rate designs that were established years ago in a heavily regulated environment and often in response to socio-political or other non-market considerations. In addition, a number of utilities have been operating under “transition” plans with relatively lengthy rate freezes that were enacted pursuant to restructuring cases or in conjunction with the approval of a merger. (To compound the problem, such rate freezes have often been set using commodity prices that were significantly below the then-prevailing wholesale market costs.)

WHERE IT STARTED

Prior to the mid-1990s, nearly all investor-owned electric utilities were vertically integrated. A utility served its customers by using its own transmission and distribution system to deliver electricity from a portfolio of its own generators and purchases from third-party generators. Utility networks were interconnected with one another, allowing neighboring utilities to coordinate their generation dispatch and reliability planning—a practice that was especially prevalent in the established power pools. The practice of interconnection resulted in vast electrical networks, which grouped the whole country into only three interconnections.

Due to the large scale economies and highly capital intensive nature of utility facilities in the early years of the electric utility industry, utilities were given monopoly franchises requiring them to serve everyone within a defined geographical service territory and subjecting them to rate regulation. In exchange, utilities were given a reasonable opportunity to recover their prudently incurred costs in rates established by regulators. This is the regulatory bargain or compact.

Under this system, the states have had the authority to regulate retail rates for end users, establish monopoly franchises and demarcate service territories, and certificate the construction of generators and transmission lines. Federal regulators regulated the transmission and sale of electricity in interstate commerce.6

Most utilities provided a bundled service that included generation, transmission, and distribution largely at a single volumetric, per/kWh rate, especially for residential consumers. Rates were typically based on cost of service and were established in contested rate cases before state public utility commissions.

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INDUSTRY CHANGE

Efforts to restructure and deregulate the U.S. electricity sector at both the wholesale and retail level have been under way for many years. Beginning with passage of the Public Utility Regulatory Policies Act of 1978 (PURPA)\(^7\) and continuing under the Energy Policy Act of 1992 (EPAct), the industry began to reshape itself, a process that accelerated during the 1990s when the Federal Energy Regulatory Commission (FERC) promoted wider open access transmission and market-based ratemaking for wholesale activities. EPAct, in particular, brought forth a broad new category of competitors, exempt wholesale generators (EWGs), which compete on an unregulated basis to serve wholesale load.\(^8\)

Some states introduced competition at the retail level as well. While regulatory and legislative changes at wholesale levels affect most utilities, retail restructuring only affects utilities in states that have begun to restructure their electric utility industry and open up retail competition for electricity. Finally, corporate restructuring has fundamentally changed many firms in the industry.

What follows is a description of the changes that have affected the various facets of the industry and some of the ongoing challenges.

Generation Markets

While PURPA and EPAct enabled the entry of non-utility generation into the electric sector, FERC’s wholesale competition policies, beginning with its Orders Nos. 888 and 889 and continuing with Order 2000 and its Standard Market Design proposals, have changed the way markets for wholesale energy work. FERC’s focus on wholesale generation competition in electricity is leading to new industry models in transmission and to changes for electric utilities generally.

The benefits of moving to competition in wholesale electricity generation markets are potentially substantial. Indeed, the hypothesis underlying the restructuring effort is that wholesale competition will lead to greater efficiency in the use of existing assets in the short run, but, more importantly, will lead to the development, adoption, and operation of new, more efficient and reliable technology in the long run. However, these changes have not come without major problems, including: (1) price volatility and limited availability of liquid hedging instruments to mitigate that price volatility; (2) lack of effective demand response; (3) uncertainty about the creditworthiness of market participants; (4) “seams” between geographic markets;\(^9\) (5) the potential exercise of market power, and over-mitigation of market power concerns; (6) inability of generators to recover their fixed capacity costs, along with a lack of properly designed capacity markets; (7) persistent complaints about the lack of truly open access to transmission; and, last but not least (8) continued regulation that ignores or muddies economic principles and favors

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\(^7\) PURPA had major implications for electric utility rate design as well. PURPA included six ratemaking standards and five regulatory standards for state commissions to consider, and to implement or adopt if they found it appropriate. The ratemaking standards related to: (1) cost of service; (2) declining block rates; (3) time-of-day rates; (4) seasonal rates; (5) interruptible rates; and (6) load management techniques. The regulatory standards related to: (1) master metering; (2) automatic adjustment clauses; (3) information for consumers; (4) advertising; and (5) termination of service. For a summary, see Phillips, supra, note 5, pp. 440-441, 450.

\(^8\) EWGs are not allowed to make retail transactions. The possible federal energy bill would likely continue this prohibition, even if PUHCA is repealed.

\(^9\) Seams refers to issues that arise in transactions that cross defined market boundaries. This reflects the inherent interrelatedness of wholesale generation and transmission.
political compromises that are not economically sustainable as regulation tries to promote competition. As these problems illustrate, robust wholesale markets are still evolving.

Transmission
Historically, states regulated most transmission as part of bundled, retail electric utility service. Since states also site and certificate new lines, the transmission network was usually designed to support a geographically compact franchise service territory. FERC has, since Order 888, been active in its efforts to support competition in wholesale electricity markets, including promoting broader transmission access for competitive generators and expansion of the geographic scope of wholesale electric markets. At the core of FERC’s plans are transmission system organizations that operate on a regional, or perhaps even national, scale.

Under FERC’s policies: (1) independent RTOs would operate the system, but would have no financial (commercial) stake in generation or retail sales, and (2) planning and investment decisions would be made with more regional input, such as from RTOs or Regional State Committees. These policies are imposing “regional costs,” such as those associated with RTO formation and operation, which must ultimately be recovered from customers. New wholesale market designs would also stipulate clear mechanisms for determining, assigning, and allocating transmission costs and for recognizing the costs of transmission congestion in generation rates. If these developments continue, transmission costs will become increasingly beyond the control of the retail electric utility that will pass these costs on to its ultimate customers.

Distribution
The distribution sector will remain substantially a monopoly service for the foreseeable future. Nevertheless, the changes in the generation and transmission sectors described above could affect utilities’ sources and costs for energy, their planning and investment procedures, and introduce new forms of competition and risk on the distribution business. For example, the rise of distributed generation creates a new set of challenges for distribution utilities. These small generators, typically installed by customers near their load, raise rate design and uneconomic bypass issues as well as safety and reliability concerns.

In the new environment, base rate proceedings will continue to have a significant role to play in ensuring that the utility has an opportunity to recover the costs of providing basic “wires” distribution service. To provide POLR service, however, a utility will procure electricity from the wholesale market, owned generation, and/or contracts. The simplest and best way to deal with these costs would be to include them

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10 There are exceptions, such as the Northwestern U.S.
11 FERC Order No. 888 established a comprehensive strategy that provides for open-access, nondiscriminatory transmission while addressing the stranded cost and other transitional issues that this fundamental change presents. Continuing this process, FERC Order No. 2000 requires the creation of regional transmission organizations (RTOs) that meet four minimum characteristics: independence, scope and regional configuration, operational authority, and short-term reliability.
12 Also known as independent transmission providers (ITPs).
13 For a discussion of the shifting meaning of “independence,” see Eric Hirst and Mathew J. Morey, “ITP Building Blocks: Functions and Institutions,” Electricity Journal, April 2003, pp. 29–41. Of course, other configurations, such as for-profit independent transmission companies, are also emerging.
14 Transmission congestion costs are measured as the difference between locational marginal prices and can be seen as “shadow” prices of transmission.
in an automatic adjustment mechanism (e.g., a fuel adjustment clause or as an exogenous cost component in a price-cap plan).

Paradoxically, regulatory cost-recovery and rate structure mechanisms themselves can be an important source of risk for utilities because rates, and their relationship to economic costs, help to condition the financial and competitive exposure that a distribution utility faces, and therefore should be a focal point for utility risk management. Put differently, it is part of both the problem and solution.

**Retail Aggregation and Sale**

Retail sale services, including the aggregation of loads, have historically been provided as part of the sale of bundled electricity to end-use customers. Retail competition—a relatively new phenomenon to the utility sector—has been a focal point of activity in a number of states, and electricity may increasingly be provided by non-utility competitive firms. However, the distribution utility and its affiliates will likely continue to play a key role by providing POLR service during the transition period and beyond. Distribution utilities will also be competing to serve customers as full retail competition is introduced.

The growth of retail competition has not been steady: (1) consideration of retail choice programs has varied across the states, with some states establishing choice under regulatory rules and others via legislation; (2) some states have offered retail choice before wholesale markets were restructured, while others have waited until after wholesale market structures were in place; and (3) a perceived lack of success of retail competition, however measured, has led some states to suspend their efforts in this area. Thus far, retail competition has been a hybrid of regulated and unregulated service: utilities have typically provided a regulated POLR service during a transition period. This POLR service has often been provided at a fixed price that is completely insensitive to changes in wholesale market conditions, while alternative providers have had to compete for load and supply. This mixed-model, including a regulated service option, could change as transition periods end over the next several years. While POLR service will continue to have a role to play for some customers, the scope and structure of that service can change over time. Some states, such as Illinois, have already begun to narrow the scope and availability of POLR service to customers that have little practical choice but to take POLR service.

**Organizational Efficiency**

These marketplace and regulatory changes are leading to new organizational structures for the industry and the firms that operate in this industry. A new-style vertically-integrated utility may still have generation, transmission, distribution, and sales functions, or a combination of these, but the lines of demarcation between these functions will be much clearer than they were when traditional utility vertical integration was the norm. The range of activities undertaken by a firm may evolve over time. For instance: (1) generation assets may be acquired by larger generation operators that can achieve economies of scale,

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16 Following EPAct, a number of states, including several New England states, California, Pennsylvania, New York, New Jersey, Texas, and a number of others, began restructuring at the state level so that competition, rather than regulation, would provide efficiency incentives, innovation, and other benefits. Restructuring issues typically included whether, and how, to introduce retail competition, unbundling of rates, stranded cost recovery, POLR responsibilities, and code of conduct rules. As restructuring was implemented, rate levels were often fixed, and in many cases legislatively- or regulatory-required rate decreases took effect.

17 In Massachusetts, for example, transitional Standard Offer Service is scheduled to end in February 2005.
scope, and learning in the operation of generation facilities; (2) transmission system operators will likely need to operate on a more regional or perhaps even national scale in the future; (3) distribution systems will likely seek the benefit of greater horizontal scale; and (4) competitive firms will provide aggregation and retail sale services, which have historically been provided as part of the distribution and sale of electricity to end-use customers. Each of these functions must be dovetailed with the others correctly if the long-term efficiency potential of competition in the generation sector is to be fully realized. This cannot be done unless the prices that decision makers rely on reflect economic reality.

THE CHALLENGES OF CHANGE

The status of both FERC-regulated wholesale competition and state-regulated retail competition varies widely across the nation. In a number of states, electric restructuring has led to both pricing and rate structure changes—with features such as rate freezes, unbundled rates, non-bypassable and competitively-neutral recovery of stranded costs, and the creation of system benefits charges (SBCs). Nineteen states and the District of Columbia currently have some form of retail competition/customer choice available to some or all of their retail customers. Transition periods will be ending over the next several years, reflecting the accomplishment of stranded cost recovery and the (potential) end of the utility’s role as the POLR provider. In addition, merger-related rate plans affecting some utilities will be ending. Finally, all utilities have faced economic uncertainty and challenges over the past several years, mainly because of volatility in wholesale electric markets, greater bypass threats from distributed generation, difficulties in recovering regional costs, and other unforeseen results of electric restructuring.

And, while the pace and scope of restructuring varies from region to region and state to state, the current environment presents profound uncertainties and challenges for utility retail rates and tariffs throughout the entire electric utility sector. Common ratemaking challenges include:

- inflexible utility cost recovery mechanisms\(^\text{18}\) may add substantial financial risk to the utility;
- rates that do not reflect the actual costs of energy may fail to induce demand responses, which can lead to rolling blackouts and other inefficient forms of load reduction, rather than more efficient, cost-based mechanisms that encourage customers to reduce load voluntarily;
- use of locational marginal pricing (LMP) and financial transmission rights (FTR)\(^\text{19}\) in wholesale markets, while economically efficient,\(^\text{20}\) are incompatible with traditional retail rate designs and still unfamiliar in parts of the country,\(^\text{21}\)

\(^\text{18}\) Utility cost recovery mechanisms in many states remain virtually unchanged; i.e., they are not well designed to recover wholesale power costs in rates. For example, many states’ fuel clauses do not treat fuel and purchased power in a symmetrical manner. Further, a number of “retail competition” states have required that the electric utility provide POLR service at a regulated, fixed price. Because these fixed prices do not necessarily reflect seasonal/market fluctuations in wholesale power costs, there can be substantial risk to the utility.

\(^\text{19}\) One practical problem with using FTRs to hedge transmission costs in some areas is that the markets that enable reconfiguration and reselling are thin, and the large number of possible FTRs provides relatively little liquidity. Nonetheless, FTRs have been used with some degree of success in Pennsylvania, New Jersey, Maryland Interconnection (PJM), New York and New England. Tarjei Kristiansen explains that “[i]n PJM, FTRs are called fixed transmission rights, in New York transmission congestion contracts (TCCs), in California firm transmission rights and in New Zealand and New England financial transmission rights.” See: Tarjei Kristiansen, “Markets for Financial Transmission Rights,” working paper, October 2003.

\(^\text{20}\) See: William Hogan, “Contract Networks for Electric Power Transmission,” *Journal of Regulatory Economics*, 1992, 4:211–242. There are several options for initially allocating FTRs. These include giving them away based on historical usage of the transmission network, allocating them to the owners of the transmission line, and using an auction to sell the FTRs.
- administrative costs of supporting regional organizations are under neither the utility’s nor the state regulator’s control, hence calling into question the utility’s ability to recover them from customers;
- POLR responsibilities can expose utilities to market price fluctuations while also providing customers with the opportunity to switch in or out of the utilities’ service, sometimes without penalty;
- depreciation allowances may not consider economic obsolescence resulting from unanticipated technological change or potential large capital additions, and elevates the risk that utility plant will be under-depreciated and stranded; and
- there is a heightened risk of technological bypass by customers switching fuels or adopting alternate technologies (e.g., distributed generation).

Making federal and state regulatory policies work in harmony is essential if progress is to be made in providing efficient, safe, adequate, and reliable service to customers. The risks associated with major ongoing changes in the energy markets cannot be borne by utility investors alone—risks associated with regulatory reform will inevitably be shared with utility customers. It is therefore imperative that new elements and institutions associated with regulatory restructuring—such as new types of regional costs—be addressed when setting utility rates.

How rates are set is critical to all of these issues. These and other issues are summarized in Table 1 shown on page 9.

The ratemaking challenge therefore takes on even greater importance today than it did in the past. The electric utility industry and its regulators have always strived to serve the public interest by setting regulated rates in ways that promote efficient, safe, adequate, and reliable service to customers. Now, this must be done in a way that is consistent with efficient competition while still honoring the underlying regulatory contract. It is critical to the industry, its customers, competitors, and even the broader economy, that rate structures ensure that the utilities’ regulated costs of doing business have a reasonable opportunity for full recovery, that the prices charged to retail customers are consistent with the energy prices in the wholesale (and, in some cases, retail) energy markets, and that there are clear signals to guide more efficient use of electricity by customers.

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21 FTRs have been used in PJM since April 1998, in New York since September 1999, and in New England since March 2003. PJM introduced FTR obligations and options, while New York and New England have introduced FTR obligations, and are now evaluating FTR options. In addition, different jurisdictions have chosen different FTR designs. PJM, New York and New England have chosen purely financial contracts while California has introduced contracts that have both a physical and a financial element. See: Kristiansen, supra, note 19, p. 2.
Table 1: Challenges Presented by the Current Industry Environment

<table>
<thead>
<tr>
<th>Issues</th>
<th>Rate policies that are implicated</th>
</tr>
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| Generation purchases for POLR suppliers may now be from regional wholesale markets that extend well beyond the control area of single utility companies. Wholesale prices in such markets can be subject to volatility given limited liquidity in many emerging wholesale markets. | Generation purchases  
Cost recovery mechanisms  
Risk management, hedging, prudence reviews  
Retail rate structure  
Transmission costs  
Recovery of RTO costs  
Demand response  
Efficient price signals  
Transmission investment |
| The integrated utility model has been dismantled in several jurisdictions and replaced by a more disaggregated supply chain of energy producers. | Generation purchases and cost recovery  
Demand response  
Efficient price signals  
Risk management and hedging  
Infrastructure investment |
| There is continuing regulatory and political pressure to open the utility franchise to potential competitors. | Efficient pricing for contestable markets and services  
Provider of last resort service  
Pricing of standby/backup service |
| Numerous federal and state directives are aimed at further segregating utility business segments through, for example, expanded codes of conduct. | Provider of last resort service  
Economies of scale and scope  
Affiliate issues |
| The recent Northeastern blackout and several smaller blackouts over the past few years, as well as increased demands by customers for better power quality, have led to a national clamor for technology enhancements and grid reenforcement. | Recovery of fixed investment  
Funding for research and development  
Infrastructure investment incentives  
Distributed Generation  
Capital attraction |
| Extreme price volatility in capacity- or transmission-constrained situations. | Generation purchases  
Demand response  
Risk management and hedging  
Automatic adjustment clauses |
| Broad policy directives and/or debates (e.g., national security, mandated reductions in environmental emissions) are being translated into utility mandates. | Fixed investment – both higher levels and recovery in between rate cases  
Liability  
Distributed Generation  
Renewable generation portfolio standards |
| A broad range of market participants, including companies both with and without generation, are in a weak financial condition and suffer credit problems in the aftermath of Enron, the California market failure, trading scandals, and the extreme boom-bust volatility in the commodity market. | Fuel adjustment clauses  
Lack of regulatory certainty and/or sluggishness of regulatory response  
Rate freezes  
Capital attraction  
Regulatory compact |
WHERE DO WE GO FROM HERE? SOME FUNDAMENTAL PRECEPTS FOR GUIDING THE TRANSITION

When setting retail rate structures and/or the level of retail rates, it is crucial that economically correct policy principles be followed. Realistic, objective, and practical methods are needed to determine the utility’s real-world cost of providing electric service to customers—so that a basis is established upon which both utility customers and shareholders are treated fairly, and upon which incentives can be designed for utilities to improve their economic efficiency. In the outline below, the principles are divided into “rate structure” and “rate level” categories, although the principles are inherently interrelated.

Too often, but certainly traditionally, per-kWh charges are used for costs that are largely insensitive to usage, and that should be recovered in flat charges. Because fixed costs comprise such a large fraction of a typical T&D utility’s total costs, this is an important issue. Further, for the most part, retail rates do little to guide customers to respond to high wholesale power costs at peak-demand periods by reducing usage.

In terms of cost recovery, many utilities have ratemaking mechanisms that were designed many years ago, and that may not yet have recognized new categories of costs, such as regional costs, that are largely beyond the utilities’ control and therefore can appropriately be handled by an automatic adjustment clause. In order to accommodate an increasingly competitive market environment, the current rate structures and cost-recovery mechanisms will need to be redesigned to some degree in most (if not all) states. Setting just, reasonable, and (now) efficient retail electric utility rate structures presents an enormous challenge.

Retail Rate Structure Principles

- **Move toward efficient pricing.** Regulated prices should reflect appropriately-specified marginal costs—while also allowing the utility to recover its revenue requirement—in order to provide price signals that will lead to the efficient allocation of resources. These signals are central to virtually every decision that both competitors and customers will make.

- **Cost causality should drive retail rate design.** The “cost causer pays” rule says that costs should be assigned to customers so that the party that causes a cost to be incurred will pay for those costs. Failure to reflect cost causation in rate tariffs would result in cross-subsidies, whereby some customers would subsidize other customers. Perpetuating cross-subsidies undermines both competition and efficiency goals. In our view, it is also fair that people pay for the costs that they cause.

- **Demand response.** Utility rates should be designed to signal the cost of electricity in the market on as close to a real-time basis as practical. Wholesale prices must be passed through and visible to the end customer or the intermediary that serves smaller customers. Then, and only then, can the demand side of the market play its role in moderating price fluctuations, ensuring reliable supply, and encouraging investment.

- **Compatibility with competition.** For competition to fulfill its promise, utility rate structure policies must reflect the real economic costs of doing business. This means that the economists’ dictum that regulated rates should reflect competitive market outcomes as closely as possible acquires new importance. Utilities must provide open, nondiscriminatory, comparable, and competitively-neutral service to wholesale (and, if applicable, retail) suppliers. Compatibility with efficient energy

22 John Maurice Clark (supra, note 2, p. 475) notes that “[j]ustice requires that every consumer or class of consumers should pay all the expenses for which that consumer or group is responsible, provided, of course, the responsibility can be satisfactorily traced.”

23 Cross-subsidies are an inefficient way of pursuing income redistribution or other social goals. Other, better suited, instruments exist.
Retail Cost Recovery and Rate Design in a Restructured Environment

competition will likely require rate flexibility and de-averaging of some utility rates. Special attention must be paid to make sure that rate structures do not artificially distort competition.

- Pro-competition not pro-competitor. In properly functioning competitive markets, competitors vie for customers in ways that are both fair and efficient. Prices that reflect market conditions and underlying costs are critical. Only then will new technologies, such as distributed generation, succeed or fail on their merits. As regulation recedes and competition emerges in sectors that were once regulated, the competitive marketplace should not be “tilted” to artificially favor less efficient competitors or to disfavor more efficient competitors. Doing so would contradict the basic purpose of substituting competition for regulation.

- Reasonable allocation of overhead costs, including joint and common costs. Allocation of costs must reflect demand (i.e., market) considerations. The days when simple allocations based on some version of fully-allocated costs were adequate are long past. Since efficiency and compatibility with competition should be given great weight, other considerations, such as political allocation criteria (i.e., “fairness”) will increasingly be taking a back seat.

Utility Rate Level Principles

- Ensure recovery of all the prudently incurred costs of providing regulated utility services. The revenues generated by a utility providing delivery services should be sufficient to recover the utility’s prudently incurred costs, including a fair opportunity to achieve a rate of return that will allow it to obtain needed capital. These remain traditional natural monopoly services, and need to be regulated as such. This does not preclude the use of incentive approaches, such as price-cap regulation.

- Efficiency incentives. Utility rates must be designed in such a way as to promote efficient use of energy, minimize production costs, provide clear investment incentives, and result in efficient organization of the electric services industry. To achieve these goals, incentive-based rate mechanisms can play an important role in guiding the transition to competition, and in continuing to regulate those portions of the industry that will not be competitive for the foreseeable future.

- Utilities must have the proper incentives to invest in infrastructure. Utilities will have stronger investment incentives when they have a clear assurance that they will be able to recover their costs in a timely manner. Financially sound utilities are absolutely essential to maintaining a reliable electric utility industry infrastructure that is able to expand and upgrade to accommodate and meet the needs of customers and markets over time. Consistent and clear regulatory policies will tend to reduce the utility’s financial risk, thereby tending to lower its cost of capital, a benefit that its customers will share over time.

- Regulatory structures must recognize novel enterprise risks faced by utilities in the new era, involving those associated with the requirement to provide POLR services. Under competition, utilities have become much more exposed to supply imbalances and price volatility. In this environment, risk management is important for both utility management and their regulators. Utilities’ risk management efforts, in conjunction with regulatory oversight, should develop a set of actions that will diminish the risk to a level that is more compatible with the preferences and long-term plans of both the enterprise and its customers. Regulation must provide the utility an opportunity to recover its reasonable costs, including costs associated with risk management.

- **Risk mitigation and hedging.** Utilities that provide price-hedged energy services, and do not simply pass through market costs, should be able to recover the costs associated with their reasonable risk mitigation efforts. Utilities should hedge when they believe it is appropriate to do so in order to provide reasonable service to their customers, e.g., if customers are willing to pay something to reduce their exposure to volatile wholesale electric prices. It should be clearly understood that while hedging will tend to reduce price volatility, it may result in a higher average price. Prudently incurred hedging costs should be recoverable in rates and should not be subject to after-the-fact prudence reviews based solely on outcomes.

- **Maintain the safety, adequacy, and reliability of the delivery services system.** Because electric infrastructure is a critically important component of the economy, regulation must ensure that the high quality and reliability of electric utility service is maintained and enhanced in the future. This is, of course, absolutely essential given the overarching importance of electricity in today's society. Recent grid failures emphasize the importance of this element.

Rate structure and rate level principles continue to be important. Important principles include marginal-cost based pricing, allowing the utility to recover its prudently incurred cost of service in rates, eliminating (or at least making explicit) cross-subsidies, broadening the use of automatic rate mechanisms (or otherwise allowing for rate adjustments in between general rate cases) where costs are largely beyond the control of the utility, sending economically efficient price signals to both customers and competitors, and providing incentives for efficient investment in infrastructure.
ECONOMIC UNDERPINNINGS OF AN EFFICIENT AND COMPETITION-COMPATIBLE RATE STRUCTURE

Prices serve as guideposts to where resources are wanted most, and, in addition, prices provide the incentive for people to follow these guideposts. … [Prices] transmit information, they provide an incentive to users of resources to be guided by this information, and they provide an incentive to owners of resources to follow this information.25

Economic regulation of the electric utility industry has traditionally focused on rate (profit) regulation, entry regulation, and the obligation to serve.26 Rate regulation has traditionally been comprised of three primary sequential aspects: determination of a company’s revenue requirement, cost allocation, and rate design. Typically, rate regulation has resulted in a very specific utility tariff—which establishes the charges that utility customers pay for service. That tariff normally set rates that were highly bundled and averaged, usually across all of a utility’s customers within a specific rate class.

In the absence of competitive markets to set the prices of electric generation, transmission, distribution, and aggregation/sale based on supply and demand, regulation generally approves and/or sets all prices charged by a utility to its wholesale and retail customers, including the specific “form” of the price. Regulation attempts to serve as a substitute for competition, and changes in rate design serve as a bridge between the traditional tariff and the competitive world, attempting to balance the needs and goals of each.

Economically-efficient, realistic, objective, and practical means must be used to determine a utility’s actual cost of providing electric service to customers—so that both utility customers and shareholders are treated fairly and so that utilities have incentives to improve their economic efficiency. Utilities must charge prices that reflect the marginal costs of providing service, while allowing the utility to recover its revenue requirement, to ensure that consumers’ choice and usage decisions, utility investment decisions, and entry and investment decisions by potential competitors are efficient.

As a capital-intensive industry that still has traditional obligations to serve in transmission and distribution—and that often continues to have some sort of obligation with respect to the procurement of generation—utilities must be able to raise capital in all market conditions. Assurance of cost recovery is essential. The utility’s rates for delivery services must be designed to provide proper price signals to customers and competitors alike, while allowing the utility an opportunity to recover its prudently incurred costs in its wholesale and retail rate tariffs.

Events over the last several years make it clear that an inability to recover the actual costs of procuring electricity for customers can severely damage the financial integrity of electric utilities, with serious

consequences for customers and investors alike. Utility cost-recovery procedures today must fully reflect new types of risk that electric utilities face and recognize the need to hedge risks.

Newer regulatory concepts such as incentive/performance-based price regulation and pricing flexibility are helping to accommodate rate regulation to the new world of competition in electricity. Unbundling and rate de-averaging has already occurred in many parts of the country, and other innovations might take into consideration season, time-of-day, geographic location, and degree of service interruptibility. Finally, and somewhat inconsistently, responsibilities to provide provider-of-last-resort service continue even as new policies are adopted on competition.

UTILITY INFRASTRUCTURE AND COST RECOVERY ISSUES

Although the industry has experienced tremendous competitive restructuring, no part of the industry has been completely deregulated. In the residual utility functions of transmission and distribution and, for those companies that are not subject to retail competition, utilities are still subject to the traditional regulatory bargain: they are expected to provide efficient, safe, adequate, and reliable service to their utility customers and, in return, will have an opportunity to recover their prudently incurred cost of service. Nothing has changed in this regard, although new regulatory approaches, such as price caps, are increasingly used.

Traditionally, utility rates have been divided into two categories: (1) base rates and (2) fuel and wholesale purchased power costs. With retail competition, new categories have emerged, with some customers procuring retail generation from competitive providers, while other customers are using the utility’s POLR service. The regulatory processes regarding capital investment, POLR, and other costs must provide shareholders and Wall Street—credit rating agencies, lenders, and institutional investors—with sufficient certainty that the utility will be able to recover from customers whatever prudently incurred costs emerge in the new competitive marketplace. Properly designed incentive ratemaking approaches can provide important benefits and can be designed to be compatible with cost recovery principles.

Uncertainty about how the utility will look after restructuring and how restructuring will impact cost recovery is creating the perception that traditional utility investment has become more risky. As will be explained in the following sections, regulators must design the ratemaking model used to regulate delivery services to ensure incentives are sufficient to operate, maintain, and upgrade the distribution system in the most efficient manner over the long term. There must be sufficient incentives for making traditional utility investments, such as voltage upgrades and low-loss transformers. Regulation must allow a utility to make investments that might increase distribution costs in the short term but reduce the long-term cost of distribution services. An appropriate regulatory model would encourage the distribution utility or its customers to make investments in new technologies that might benefit consumers when it is efficient to do so.

27 De-averaging retail rate structures will not be easy. Bonbright, writing in 1941, recognized that “much of the popular support for the blanket-rate system [highly averaged rate structures] is doubtless based on a belief that locational advantages and disadvantages should be averaged out. I need hardly add that this belief enjoys wide currency with people who live in high-cost locations, whereas it is bitterly denounced by people who live in the low-cost regions.” James C. Bonbright, “Major Controversies as to the Criteria of Reasonable Public Utility Rates,” American Economic Review, February 1941, p. 387. For all of the talk about locational market prices for transmission, for example, it is hard to see that the locational transmission prices will be fully effective in providing price signals and signaling infrastructure investment if they wind up being borne by end-use customers on a highly averaged basis.
Infrastructure Investment Can Be Accommodated by Consistent and Clear Regulatory Policies That Provide a Clear Framework and Reasonable Assurance for Full and Timely Cost Recovery

Regulatory policies that reduce financial risk tend to lower the utility’s cost of capital, which will benefit customers. A reduction in risk will also create incentives to invest in utility facilities. Consistent and clear regulatory policies help provide the necessary investment incentives to electric utilities by providing a clear framework and reasonable assurance of cost recovery. Utilities will have stronger investment incentives when they are able to recover their costs in rates in a timely manner and when the regulatory lag between infrastructure investments and the introduction of their costs in rates is short. If properly structured, incentive- or performance-based regulation can be used to accomplish these tasks.

Although the nature of the utility’s obligation to serve depends on the extent of electric restructuring that has taken place in its state, electric utilities continue to have some form of an obligation to serve. Given the long lead times and useful lives inherent in utility assets—and the basic fact that the electricity has to be there when customers demand it—electric utilities must make significant investments and commitments to meet customer requirements. Electric delivery facilities have average service lives in the 30 - 40 year range and investment decisions by utilities must therefore consider long-term business risks, which means that regulation also has to consider these long-term risks. In states with retail competition, utilities usually retain an obligation to provide POLR service, along with their obligation to provide delivery services.

Under traditional utility regulation, the upside return to the utility is effectively capped at the allowed Return On Equity (ROE). Given this, both economic efficiency and fairness require that downside risk be capped as well. The ability of a regulated utility to attract capital in good markets and bad is largely a function of the confidence that investors have in a jurisdiction’s regulatory compact. Regulators must reasonably address traditional prudence issues and the overall returns to investors.

In fashioning rates, regulators need to ensure that the utility’s revenue requirement includes all prudently incurred costs, including the cost of capital. An electric utility’s base rates have traditionally been adjusted via rate cases, with regulatory lag between rate cases providing at least some efficiency incentive to the utility. Utility base rates should be set in ways that achieve allocative efficiency; that is, reflect its economic costs and provide incentives to achieve productive, or operational, efficiency. Finally, rates need to encourage utilities to make the investments that are critical to maintaining reliability and increase efficiency over time—so-called dynamic efficiency. While incentive rate plans can achieve these objectives and have become more common in recent years, traditional rate cases still have an important role in ensuring allocative efficiency and providing a fair starting point for an incentive rate plan, if applicable.

There Is a Greater Role for Adjustment Clauses for Items That Are Significant and Beyond the Control of the Buying Utility

If new categories of costs arise from the emergence of competitive markets and if the utility has only limited control over them, regulators need to have a mechanism in place to provide for their recovery. Automatic adjustment mechanisms, such as fuel adjustment clauses (FACs), can provide the utility with a reasonable opportunity to recover certain of its costs of procuring electricity on behalf of customers, where those costs are not within the control of management. Adjustment mechanisms are commonly used for costs such as fuel and purchased power, which constitute a large proportion of a utility’s costs; can be
volatile and unpredictable; and, critically, are, to a considerable degree, beyond the control of the utility. If costs are not within the control of the utility there should be no penalty or gain as a result of changes in conditions; allowing the utility to recover these costs automatically will actually strengthen the incentive intensity where management does have substantial control over costs.

The design of local gas distribution companies’ (gas LDCs) purchased gas adjustment clauses (PGAs) may provide some lessons for the changes that are needed in the pass through of wholesale power and transmission costs in the electric industry. Gas LDC PGAs include gas commodity costs, demand-related costs, pipeline transportation charges, gas inventory charges, and gas storage costs. Because gas pipeline transport-related costs are typically recovered in a PGA clause in the gas industry, the industry has been better able to accommodate industry changes, including dramatic changes in how gas transport services are procured by gas LDCs.

In the electric utility industry, many of the FACs that are currently in use need to be modified to be more similar to gas LDCs, thereby allowing for pass through of a broader array of wholesale power costs and electricity transport costs. In states where there is retail competition, but the utility provides POLR service, the price of this service might be set in a way that provides “pass through” of the utility’s provision of POLR service. In both the FAC and POLR cases, the cost recovery mechanisms must provide for the recovery of the full range of costs that the utility must incur as part of its efforts to procure electricity for retail customers.

To better accommodate the pass through and recovery of new regional costs, a broader range of costs should be recovered through mechanisms that are similar to electric FACs. Notably, state and federal jurisdictional rate treatments can work at cross purposes, or at least be mismatched with each other. The changing structure of industry regulation requires better coordination between federal and state ratemaking; for example, FERC regulation might increase a utility’s transmission costs, but the utility might not be able to pass those increased costs through to retail customers because of an inflexible retail price cap. There might be other ways in which FERC-imposed costs might not be fully recovered in the bundled retail rate as well. Among the new regional costs that need to be recovered are:

- RTO startup and infrastructure costs;
- RTO administration costs;
- Transmission access and congestion costs; and,
- Generation market costs, including cost of required reserve margins.

Regulated utilities will also utilize new forms of risk management as they procure electricity for retail customers. For wholesale power costs, utilities will need to hedge the cost of electricity, the price of which can fluctuate markedly depending on fuel market costs, power plant outages, and other market conditions.

29 These costs would be essentially the same as “exogenous costs” (also referred to as “Z factors” in the economic literature) that can appropriately be passed through in rates because prices in a competitive market would adjust to allow these types of costs to be recovered.
beyond the utilities’ control. Additionally, electricity transport costs can be volatile depending on the extent of congestion on the transmission system.

To summarize, given the changing structure of the electric utility industry, a number of costs are increasingly beyond the control of the utility. With the exception of fuel adjustment clauses, it is relatively rare for electricity rates to be structured so as to allow recovery of unexpected, uncontrollable large costs, such as storm restoration, RTO startup costs, or infrastructure security costs before the next rate case.\(^{31}\) Broadened use of adjustment mechanisms to include new categories of costs would be sensible.

**Regional Costs—Case Study**

Some utility costs are becoming more regional in nature, leading to a need to revise the ways that utility rates are set at the state level. Traditionally, the retail rates of vertically-integrated utilities were set at the state level, with base rates set in rate cases, while fuel and purchased power costs were usually passed through some form of automatic adjustment clause. In the future, FERC will be responsible for approving rates for unbundled transmission services. But state regulators will have a role to play in ensuring that transmission costs find their way into the prices paid by retail end-use customers, especially when the utility continues to procure electricity on behalf of retail customers.

This can best be understood by reviewing how rates are set in a region, such as New England, that already uses locational marginal prices. In a state with retail competition, a utility’s rates typically include charges for distribution, stranded costs, transmission, and POLR generation. Distribution rates reflect the costs of delivering electricity and providing service to customers. Stranded costs include costs prudently incurred prior to restructuring that cannot be recovered in the competitive market, typically uneconomic generation, purchased power, and regulatory assets.

POLR service includes the costs of providing electricity service to customers that have not voluntarily switched to a competitive provider. POLR providers typically make all arrangements and are responsible for all costs associated with delivery of its capacity and energy to the transmission delivery point. Transmission costs are determined annually by the FERC and reflect the costs of maintaining transmission facilities used to transport power throughout the region. These costs would be borne by POLR providers, with their prices including the anticipated transmission costs.

With the implementation of the latest FERC-approved market structure for ISO New England, customers in different areas pay different amounts, reflecting “transmission congestion,” as measured by differences in locational marginal prices, which rise in congested areas to reflect the limited generation/transmission supply. Customers also pay marginal line losses. By assigning congestion costs to the region that is congested (e.g., Connecticut), these changes can benefit a state, like Maine, that does not have transmission congestion. For example, the average wholesale price of generation in Maine was $41.89 per MWh in 2003, while the average New England Hub price was $46.27, roughly $4.36 higher.\(^{32}\) Passing through the higher costs in Connecticut will provide a price signal to induce the alleviation of congestion in that region, whether by locating new generation in congested areas, demand response, or building new transmission.

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\(^{31}\) Price-cap plans are a partial exception. Because such plans usually extend over several years without the possibility of a rate case, the durability, and therefore the incentives associated with the plan, can be helped by providing for the recognition of large costs (or benefits) that are beyond the control of management. This is sometimes referred to as a “Z” factor.

In New England, however, transmission system upgrades above a certain kV level are rolled into the regional transmission rate rather than being assigned to customers that caused the costs. Assigning costs to the congested region would raise costs in that area, but allow prices in other regions to be lower. To provide effective price signals, costs of transmission upgrades should be borne by the cost causer, where identifiable, rather than being socialized. Further, these higher costs must be passed through to end-use customers. Failure to do so would harm the utility that serves customers in that region, even though it does not have operational control of the transmission, rather than provide an incentive for resolution of the congestion.

**Risk Management and Retail Load Obligations—Case Study**

In the new business environment, firms must assess and manage new categories or levels of risk. The central tasks for implementing risk management are risk identification, quantification, and mitigation. Risks will be specific to the market sectors in which the business operates, the company’s circumstances, the strategic direction of the company, and in particular, its regulatory environment, including the rate structures that have been approved by regulators. While some risks will be experienced industry-wide, others will be more idiosyncratic, and required assessment on a utility-by-utility basis.

Paradoxically, regulatory cost-recovery and rate structure mechanisms themselves can be an important source of risk for utilities because rates, and their relationship to economic costs, help to condition the financial and competitive exposure that a distribution utility faces. Cost recovery and rate mechanisms should be a focal point for utility risk management. Put differently, it is part of the problem as well as the solution. In the new environment, utilities continue to have a significant amount of control over their costs of providing basic “wires” distribution service. If the utility procures electricity for retail customers from wholesale markets, however, the utility would have only limited control of these wholesale power costs and the related transmission costs. If retail prices are not correctly designed, the utility could be subject to uneconomic bypass, endangering its financial stability. Finally, the value of an economically correct price signal would be lost.

Utilities hedge when they believe it is appropriate to do so in order to provide reasonable service to their customers (e.g., if customers are concerned about the volatility of electricity prices). While hedging is an effective tool for reducing the utility’s and its customers’ exposure to price volatility, that benefit comes at some cost. As the National Regulatory Research Institute states:

> Hedging, in its purest form, does not provide a means to reduce the expected price of [electricity or] gas for a utility. Rather, from the consumers’ perspective its primary function is to stabilize prices. Generally, risk-averse consumers should be expected to pay extra for shouldering less risk, such as exposure to volatile prices.34

Hedging may cause a utility to lock in a price that turns out to be higher than the prevailing market price. That is, hedging may in some cases raise costs higher than they would have been absent the hedge, while in other cases hedging can lower costs from what they otherwise would have been. Careful regulation is

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required here so that the prudence of a hedging program is judged on its structure and operation, and not on “Monday-morning-quarterbacking.”

The ownership of generation also acts as a physical hedge to POLR risk. Where retail competition is not present, and ignoring customers’ ability to bypass the distribution system through the use of distributed generation, the utility-owned generation provides a physical hedge that mitigates price risk. Ownership of generation can reduce the utilities’ exposure to markets or contracts in providing electricity service to customers. Utilities that operate in states that have retail competition will face even greater electricity procurement challenges. Some of these utilities will have little owned generation and will purchase their supplies on the market, subjecting themselves to extreme price risk, especially at peak-demand periods. Here, utilities are exposed to both “price” and “quantity” risk. Further, while utilities may have some ability to hedge the risks of their electricity procurement efforts, it will be difficult to hedge completely. For example, in some states that have retail competition, retail customers may be able to switch back to regulated POLR service during high-price periods in the market, which would expose the utility to risk that is not easily hedged. These risks must be acknowledged, and regulatory mechanisms must be developed to mitigate or compensate for these risks as regulators set rates.

**Asset Investment Trackers can Improve Infrastructure Investment Incentives**

Electric utilities need clear incentives to invest in infrastructure. Utility regulation, unfortunately, can sometimes send mixed messages to a utility, its investors, and creditors. In recent years, very simple rate cap mechanisms have been used in many states, often in conjunction with electric restructuring or merger activity, which can discourage capital spending. As these simple rate caps are replaced in future years, mechanisms that better accommodate investment in infrastructure can be developed in order to “smooth” what would otherwise be “lumpy” rate adjustments.

In the natural gas distribution business, regulators in Ohio, Kentucky, Arkansas, New Hampshire, and Alabama, among others, have developed cast iron/bare steel distribution pipe replacement programs. In the natural gas industry, replacement of fully depreciated cast iron/bare steel distribution plant with modern plant is capital intensive and costly. These adjustment mechanisms allow for changes in rates in between general rate cases. Given the financial implications to the gas utility and the potential for increased rates for utility customers, these regulators have approved non-traditional ratemaking approaches that serve to moderate utility financing costs while providing proper incentives to operate efficiently. With programs like these, electric utility regulators can accommodate the need for investment in infrastructure by developing mechanisms that allow the costs of capital expenditures to enter rates quickly, while also providing efficiency incentives.

By allowing ongoing rate adjustments to reflect the utility’s capital investment programs, targeted cost-recovery mechanisms such as these can facilitate infrastructure investment. Larger but less frequent rate increases are avoided by allowing the utility to recover its costs more quickly. When evaluating whether to use a targeted cost-recovery mechanism, regulators should consider the impact on the utility’s operating efficiency and investment incentives, the size of the infrastructure investments that are involved; any special concerns, such as security and safety, that go beyond ordinary commercial considerations; the impact on the utility’s revenues and financial integrity; the potential to reduce regulatory litigation costs; and the extent to which a capital investment program could help to provide allocative efficiency, rate predictability, and rate stability. For high-priority infrastructure investments, a targeted capital investment cost-recovery plan can be a suitable mechanism.
RATE STRUCTURE ISSUES

The goal of electric restructuring is to permit market forces, through prices, to substitute for regulation in order to obtain the maximum benefits from competition. Where competitive markets do not exist, regulatory and industry experts have turned to micro-economic principles to bridge the gap between competition and regulation; electricity rates based on marginal cost principles are central to this effort. Realignment of rate structures is among the most difficult tasks a regulator can undertake, since there will be losers as well as winners—even when in the aggregate, there is a gain in social welfare. Policymakers and regulators will have to work hard to move beyond the limitations and rigidity of much current electricity ratemaking policy and practice.

An important caveat is that prices set at short-run marginal costs are unlikely to yield enough revenue to cover a utility’s total costs. Therefore, efforts to develop economically efficient utility rates have also explicitly included mechanisms to recover total costs for the utility.

In any market, prices guide customers’ and competitors’ choices. If energy resources are to be used efficiently and if we want infrastructure investments to be directed in the right quantity, type, and location, then prices for each of the utility services (e.g., distribution, transmission, generation, aggregation/sale) should reflect the true economic (e.g., forward looking) cost of the particular service as closely as possible, while also recovering all of the firm’s costs. Economic efficiency, broadly conceived, requires that utility rate tariffs be designed in such a way as to: (1) encourage efficient use of electricity; (2) minimize production costs; (3) provide clear investment incentives; and (4) result in efficient organization of the electric services industry. This is a tall order for regulated prices.

Since prices are the carriers of information critical to decisionmaking, they must be designed (or simply allowed) to provide appropriate price signals. The same prices also give each participant the incentive to invest in facilities or buy a service, as appropriate. Pricing that reflects marginal costs provides important benefits:

- Consumer welfare is maximized when prices are based on marginal cost because consumers will only buy if the value they place on the service is at least equal to the additional resources society must commit in order to produce that product or service. Put more colloquially, their choices take account of the real consequences of those choices.

- Marginal cost-based pricing will give potential new entrants the right signals about where, when, and whether to enter a market. Correct distribution price signals will give new entrants clearer incentives to target customers appropriately; that is, where they are truly the low cost/high value producer. Thus, marginal cost based pricing supports wholesale (and in some states, retail) competition for both the electricity commodity and distribution services themselves.

- Aligning prices as closely as feasible with their underlying economic costs improves all firms’ incentives to invest appropriately in infrastructure and deploy new and innovative services. Pricing based on marginal or incremental costs plays an important role in allocating resources efficiently.

Utility tariffs that do not reflect the marginal costs of providing utility services run the risk of driving outcomes that will ultimately increase costs to consumers, or foreclosing arrangements that would have been more advantageous to consumers. For example, utility rates that recover operating costs on an average cost basis do not encourage customers to reduce consumption at peak hours when the resource and societal costs are highest, nor to shift consumption to off-peak periods when those costs are lowest. Similarly, rates that recover fixed costs primarily on a volumetric basis lead to uneconomic levels of consumption and, potentially, bypass of the utility system.

Marginal cost-based pricing for delivery service rates is essential to economic efficiency and the proper development of competitive markets. At the most general level, this means that prices must, as nearly as possible, reflect forward-looking economic costs, not simply historically-based fully-distributed costs. Following this approach, utility rate tariffs can be designed in a way that efficiently meets the needs of both utility customers and suppliers in the emerging competitive electricity market, while, at the same time, supporting a viable and highly reliable delivery service business. Of course, pricing structures must also allow the delivery utility to recover all of its prudent costs of providing generation-related services to customers.

**Traditional Utility Pricing Has Important Limitations**

In contrast to prices derived from competitive markets, the traditional regulatory ratemaking process is fundamentally backward-looking, static, and reliant on economically arbitrary cost allocation rules. The resulting rates often do not reflect market conditions and cannot respond to changes in those conditions. Such a process cannot be expected to yield the proper cost-based signals to market participants. In addition, it can be overly rigid and inflexible.

*Embedded-cost studies and fully-distributed cost allocations do not reflect forward-looking costs and should be used with caution, if at all*

A detailed embedded cost-of-service study, which often provides the basis for a utility’s rates, relies upon numerous declarations and/or assumptions—many of which are arbitrary and uncertain. Despite the uncertainty inherent in any cost-of-service study, and regardless of arguments for or merits of the embedded cost approach, the end result is a single set of utility rates that stays in effect until the next rate design case is completed—usually a number of years. While some states use marginal cost-based cost-of-service studies for pricing, the markups over marginal costs that are necessary to recover all of the utility’s costs usually follow arbitrary rules, such as “equal percent marginal cost” (EPMC), that have no efficiency or market basis.

Regulators who use fully-distributed cost methodologies attempt to assign certain costs—ostensibly using objective criteria—to services or customer classes that do not directly influence the levels of those costs. The use of fully-distributed cost methodologies for determining the proper allocation of costs between a utility and a non-utility venture for shared facilities and services can deviate substantially from the requirements of economic efficiency.
Economists have criticized this practice for years.\textsuperscript{36} In short, regulators should use incremental pricing methods for setting prices of all kinds. In some cases, it may be possible to use market-based methods to allocate costs, which would provide an additional degree of assurance that the remaining costs are covered in as non-distorting a way as possible. Following sound cost allocation principles can help to ensure that the competition that takes place is efficient and that it is not wasteful of society’s scarce resources.

\textbf{Rates tend to be highly averaged across large groups of customers and services, and the levels of variable and fixed charges are often out of sync with the level of variable and fixed costs}

Most utility rate designs recover much of the utility’s revenue requirements, including the delivery system and customer care costs, on a volumetric basis (i.e., cents per kWh charges that differ by customer class). Most typically, only a small portion of a utility’s revenues are typically collected through fixed capacity or monthly charges, despite the fact that the bulk of a utility’s costs are fixed rather than variable. Volumetric prices are usually based on an average of costs over a lengthy time period—either the entire year or, at most, differentiated on a seasonal basis, despite the fact that marginal costs—primarily generation—can vary widely over short periods of time.

The result of this mismatch between the form of prices and costs is that customers and utilities alike are presented with incentives to make decisions that may not be in the best interest of all customers, the economy, or society. This creates a risk of driving outcomes that will ultimately increase costs to consumers, or foreclosing arrangements that would have been more advantageous to consumers. As stated before, both average-cost rates and rates that roll fixed costs into a volumetric rate mask the true costs of electricity. A more economically rational approach to rate design—at least for delivery services—is to recover fixed costs via monthly customer charges or some other form of access charges, and variable costs via usage-, time-, and demand-sensitive components, depending on the underlying cost characteristics.

\textbf{Cross-subsidies}

Regulators should be mindful of the need to avoid following regulatory policies (such as cost allocation methods) that create or continue cross-subsidies. The term “cross-subsidization” is often discussed in “loose” terms.\textsuperscript{37} A careful definition of cross-subsidization that focuses primarily on efficiency and competitive considerations suggests that a set of prices charged by a multiproduct monopolist is free of cross-subsidies if the revenues for each of its services is above the \textit{incremental cost} of providing the service.

\textsuperscript{36} For example, many years ago Baumol, Koehn, and Willig pointed out that:

Fully allocated cost figures and the corresponding rate of return numbers simply have zero economic content. They cannot pretend to constitute approximations to anything. The ‘reasonableness’ of the basis of allocation makes absolutely no difference except to the success of the advocates of the figures in deluding others (and perhaps themselves) about the defensibility of the numbers. There just can be no excuse for continued use of such an essentially random or, rather, fully manipulable calculation process as a basis for vital economic decisions by regulators.


\textsuperscript{37} Cross-subsidization is sometimes said to “occur when some service (or group of services) is either (i) not generating revenues sufficient to cover its fair share of costs or (ii) generating revenues that cover more than its fair share of costs.” Ronald R. Braeutigam, “Optimal Policies for Natural Monopolies,” \textit{Handbook of Industrial Organization}, Vol. II, edited by R. Schmalensee and R.D. Willig (Amsterdam: North-Holland, 1989), pp. 1337-38. If the proportional difference between price and marginal cost varies across services, a cross-subsidy is sometimes said to be present; thus, if the electricity price for industrial customers is 30 percent above marginal cost, while the price to residential customers is 20 percent above marginal cost, it is sometimes argued, and often incorrectly, that industrial customers are cross-subsidizing residential customers.
and below the *stand-alone cost* of providing the service.\(^{38}\) Thus, “incremental cost” and “stand-alone cost” provide a “zone of reasonableness” within which economists would consider a set of prices to be subsidy-free.

Given its highly bundled and averaged nature, and its monopoly setting, traditional utility rate design leaves room for cross-subsidies to exist and persist. In some cases, cross-subsidies may have flowed between the distribution and generation businesses, or between residential and industrial customers. Such cross-subsidization might have been a deliberate regulatory or industrial policy. However, with the development of a competitive market in the provision of electric power and energy, these subsidies will, of necessity, disappear or at least decrease. If they do not, the introduction of competition will not realize its full potential.

**Rates can be strongly influenced by negotiated deals and social policies**

Two other characteristics of traditional regulation related to rate structure should be noted briefly. First, the rates set are sometimes largely the result of a bargaining process, rather than a reflection of cost conditions. This is because the (former) exclusive franchise position of utilities can accommodate considerable latitude in assigning costs to one or another class or service, especially when participants in the regulatory process present a rate settlement to the regulator. Second, and directly following from this bargaining process, traditional regulated rates commonly include special considerations for social programs, ranging from low-income assistance to conservation program support.

These practices conflict with and cannot be supported, in the traditional fashion, by competitive markets for electricity. For example, layering social costs onto delivery rates incrementally raises costs to customers of utility services while not affecting the costs for other competing services. Competition reduces the scope of bargaining—to the extent that social programs continue to be funded; doing so through competitively-neutral charges will be of critical importance.

**Rates are often designed using a static, short-term perspective rather than a dynamic and long-term perspective**

Traditional rate regulation is static rather than dynamic. Moreover, rate design regulation tends to be overly rigid and inflexible. To make rate design more dynamic, regulators can allow pricing flexibility programs, real-time pricing programs, and pass-through of wholesale power costs on a basis that is more reflective of monthly variations in wholesale prices.

**Rate Design for Distribution Tariffs: The Basics of an “Optimal” Economic Design**

“The concept of ‘cost’ has no meaning in economics or logic except in terms of causation.”\(^{39}\)

Electric utility rate structures must reflect the marginal costs of providing service to customers, augmented to ensure that the utility can recover its costs.\(^{40}\) With or without retail competition, rate design should

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reflect the underlying cost structure. The “signaling” role of prices, after all, is to present the right price signals to utility customers and competitors so that society’s resources will be allocated in the most efficient way possible. The elements of a distribution utility’s rate structure include the following:

- **Marginal customer costs, which should be recovered in a fixed monthly charge.** These costs vary with the number of customers on the system and by customer class. These costs do not vary with changes in kWh usage, and cost recovery should also not vary with usage.

- **Marginal cost of local distribution facilities in a neighborhood,** which should be recovered through a fixed monthly charge per kW of design or contract demand. These costs vary with the design demand of the customers in a neighborhood. Once distribution facilities are sized to accommodate design load, they typically remain in place for a very long period of time. These costs do not vary with month-to-month changes in demand.

- **Marginal cost of distribution and transmission facilities,** which should be recovered through a time-differentiated energy charge per kWh or through a time-differentiated demand charge per kW of monthly peak load in the various costing periods. These costs vary by voltage level and by time of use.

- **Marginal cost of energy and generation capacity costs,** which should be recovered through a time-differentiated energy charge per kWh. These marginal costs are the wholesale market prices for electricity, as well as related transmission costs, depending on how the market is set up.

- **Access charge to “plug the revenue gap,”** which should be recovered through a customer-specific, fixed monthly access charge. Plugging the revenue gap is necessary to allow the utility to recover its prudently incurred costs of doing business. These costs should be recovered in a flat rate.

**Table 2: Cost Categories and Tariff Elements**

<table>
<thead>
<tr>
<th>Cost Category</th>
<th>Varies by</th>
<th>Includes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Marginal customer costs</td>
<td>Number of customers on the system</td>
<td>Meters, service drops, customer service and accounting</td>
</tr>
<tr>
<td>Marginal distribution, facilities costs</td>
<td>Design demand of customers in neighborhood</td>
<td>Secondary lines, distribution transformers, and primary lines that are sized based on design loads</td>
</tr>
<tr>
<td>Marginal cost of distribution substations and transmission facilities</td>
<td>Voltage level of service and by time of use</td>
<td>Distribution substations, transmission facilities</td>
</tr>
<tr>
<td>Marginal energy and generation capacity cost</td>
<td>Voltage and by time of use</td>
<td>Wholesale market prices</td>
</tr>
<tr>
<td>Access charge (to fill revenue gap)</td>
<td>Based on historic usage</td>
<td>Revenue requirement above marginal costs</td>
</tr>
</tbody>
</table>

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40 This section is based largely on Hethie Parmesano, “Rate Design for Retail Access,” presentation to the Marginal Cost Working Group, October 1996.

41 This table is based primarily on information provided in Parmesano, supra, note 40.
While seemingly straightforward in theory, designing delivery service rate structures is not simple in practice and no rate design can perfectly fulfill all of the intended roles perfectly. Rather, each rate design must be judged based on how it balances all of the conflicting objectives and not just on how well it achieves any single objective. Some objectives may be more prominent and more easily reached, such as providing the correct amount of revenue (i.e., a revenue requirement that meets the “just and reasonable” standard) and collecting revenues equitably from the various customers. Other objectives, while conceptually correct, may be more difficult to implement and might receive less attention. A continued focus on rate designs that signal marginal cost is needed. As Alfred E. Kahn has pointed out, “[t]he central policy prescription of microeconomics is the equation of price and marginal cost. If economic theory is to have any relevance to public utility pricing, that is the point at which the inquiry must begin.”

Competitively-Neutral Rate Design for Distribution Tariffs—Removing Inefficient Incentives to Accommodating Distributed Generation

Distributed generation (DG) are parallel and stand-alone electric generation units located within the electric distribution system at or near the end user. While centralized electric power plants will likely remain the major source of supply for the near future, DG can complement central power by providing incremental capacity either to the utility grid or to an end user. In some cases, installing DG at or near the end user can benefit the electric utility by allowing it to avoid or reduce the cost of transmission and distribution system upgrades, or, possibly, because the DG unit can produce electricity more cheaply. Consumers are attracted to DG for its potential for lower costs, higher service reliability, high power quality, increased energy efficiency, and energy independence. Distributed generation also can employ renewable and “green power” technologies such as wind, photovoltaic, geothermal, or hydroelectric, and may also be environmentally beneficial.

Cost is (and should be) the primary driver of whether, when, and how DG is used. A decision to install DG will depend on the price level and the price structure of the traditional resource, the cost of installing and operating the DG, and the back-up and standby rates for DG users who wish to be able to turn to system power for reliability or maintenance back-up. When a monopoly utility installs such facilities, all the costs are internal to the firm—and the correct tradeoffs between generation and transmission investment (for example) will be made. In a market/competitive situation the same tradeoffs need to be considered, but now prices must carry the information that was handled administratively before. In principle, correct pricing should make the utility indifferent with respect to whether the customer uses DG or the electricity grid as the source of its electricity. When the utility is able to recover the fixed costs of standing ready to serve the DG in standby/backup rates, and can recover the fixed and the variable costs of serving the customer from the grid, it will be held harmless from the customer’s decision to use DG. But, this can only happen if prices do in fact carry the needed information to the new decisionmakers—the customers.

42 For example, marginal delivery system costs can vary by location and customer, and there will be very specific locations where reductions in usage could have significant cost saving impacts and others where there will be little or no cost savings for the foreseeable future. But, rate design is usually not geographically differentiated; generally applicable rates tend to only signal customers as to the average condition. This represents lost potential opportunities. Cost-based de-averaging, where feasible, is an area that should be explored further in the future, especially as locational marginal pricing for transmission becomes more widespread.


45 In practice, however, DG is often diesel-fired, which is problematic from an environmental standpoint.
To the extent that DG allows the delivery utility to defer the need to invest in new delivery service facilities and thereby keep rates for all customers lower than they otherwise would be, the utility should be indifferent to DG alternatives that provide equal reliability. This outcome would be more efficient than expanding the delivery infrastructure. However, the delivery utility may not be able to reduce or delay any costs because of DG. It may not, for example, be possible to target DG to precisely those delivery service areas that are congested, which means that the utility may experience revenue losses that exceed cost savings in the short run. Thus, given the extent to which delivery service rates are not properly structured to reflect marginal cost and any timing lag between reduced usage and cost savings, the utility might not benefit from the installation of DG. The rate design for delivery services will play a critical role in whether bypass of the distribution system is efficient or inefficient. Properly designed rates would encourage DG installations that reduce or delay distribution costs; improperly designed rates could provide incentives to customers to install DG that is inefficient for the system as a whole and wasteful of resources.

There are two primary ways in which rate design can inhibit rational decisions about investment in DG. First, an imbalance between fixed charges and volumetric charges can create incentives for inefficient investment in DG by end-user customers. Current rate designs tend to recover fixed, non-variable costs in volumetric charges as opposed to fixed charges, so the customer would have an (inefficient) incentive to invest in DG and generate its own electricity because reduced energy purchases from the utility enable the customer to avoid payments on the fixed-cost portion of the utility service. Concomitantly, the utility would have an incentive to discourage such investments because its revenue reductions are larger than the reduction in delivery system costs. This is a case of a rate design simply encouraging inefficient behavior.

Second, long lags between cost incurrence and cost recovery can discourage utilities from investing in DG. Even when DG is efficient, there may be a long delay between when delivery system costs are saved as a result of reduced usage of the system and when revenues are lost. In all likelihood, rates will be designed based on long-run marginal costs of the delivery system and delivery system cost savings in the short term may not reflect long run marginal costs. In other words, a financial disincentive to encouraging DG would result if its revenue loss occurred upfront but cost savings only emerged much later, if at all.

To deal with these problems, proper rate designs are needed. First, rates for conventional delivery service, and not just standby service, should be aligned with economic costs (always recognizing that the utility rates must allow the utility the opportunity to recover its costs of providing utility service). Customers, whether individually or through an energy service company, evaluate whether to pursue DG or energy efficiency based on the price signal that is sent by the delivery service rate design. In particular, rate designs must properly assign costs between usage-based charges and fixed charges. As already noted, ensuring that delivery service rate design reflects marginal costs is desirable for many reasons. Rate design that is properly aligned with costs will tend to result in economically-efficient decisions by both customers and energy service companies with respect to DG implementation. Similarly, rate designs for standby/backup rates for customers installing DG are important to both the utility’s customers and to energy service providers.

46 For a similar view, see Eugene T. Meehan, Affidavit on behalf of five New York utilities, New York State Public Service Commission Proceeding on Motion of the Commission to Investigate Potential Electric Delivery Rate Disincentives against the Promotion of Energy Efficiency, Renewable Technologies and Distributed Generation, Case No. 03-E-0604, October 24, 2003.
47 Account must be taken of revenues from backup/standby service as well. This is discussed below.
If a DG customer requires essentially-equivalent local delivery facilities, but uses substantially less energy or measured demand than an equivalent customer without DG, the local delivery system capacity requirement may be the same because of the need for service at the same level of the customer’s non-coincident peak demand. In this situation, volumetric rates that recover fixed costs would not provide for revenues that equal costs, which would present the delivery utility with a financial disincentive to encouraging DG, assuming that the revenue lost from DG is significantly greater than the cost saved as a result of the DG installation. Even with movement toward more economically efficient standby/backup rates, DG may result in revenue losses that are larger than the cost savings.

Getting Demand Response Into the Picture—Wholesale Prices Must Be Reflected Through to Retail Rates In Order to Properly Guide Both Users and Competitors

The major rationale underlying wholesale competition policy over the last 15 years is that competition will lead to a more efficient industry, as well as shift risk from customers to firms. As a result, prices would be lower than they otherwise would have been. But the economy will experience the full benefits of competitive restructuring of the industry only if market-based prices “shine through” to retail rates. For the wholesale market to operate to its full potential, generation prices must reflect underlying costs, and the retail distribution and wholesale transmission platforms must be priced and operated as efficiently as possible. Only then will competition deliver the maximum benefits to consumers.

Given some troubling episodes in recent years, particularly those in California, there has been concern about how well wholesale competition can work and has worked. In some regions, most of which already had power pools in place that could be converted to RTOs/ISOs, there has been significant progress on the wholesale side. In other parts of the country it is less clear how well wholesale markets are developing. Price spikes in California and the Western U.S., as well as occasional volatility in New York, Ohio, and elsewhere, emphasize that it is important to consider the full range of factors that underlie how well wholesale competition is working. One conclusion reached by most analysts is that increased demand responsiveness at the end-user level—demand responses that emerge in response to utility rate designs—is critically important to making wholesale competition work better.

Calls for greater “demand response” have been widespread. In recent wholesale market price spikes, because retail prices were often completely insulated from the higher prices, or were only partially responsive and often with a lag, customers’ response to peak conditions were limited, at best. Customers with fixed price contracts were insulated from hourly price spikes and did not lower their demand. Other means of reducing demand, such as rolling blackouts, became necessary. On the other hand, where reliability was provided, it was through costly investment in peaking units. In addition, lack of demand response can enhance market power that may exist under very tight capacity conditions. A NARUC-sponsored study explains that:

One of the fundamental lessons that has been learned from the ongoing California electric crisis is the importance of providing correct price signals to customers. Inelastic demand combined with a tight electric supply demand created a “sellers market” for electricity. Even modest drops in electric demand in this period could have produced significant impacts on market clearing prices. 48

Demand response should be introduced in wholesale markets through some form of direct recognition of wholesale power costs in retail rates. This could be accomplished through some form of dynamic pricing, such as real-time pricing. Until metering and related costs, as well as customer acceptance problems have been addressed, however, it may be most applicable to larger customers. Alternatively, customers could be induced to reduce their demand at the time of peak demand or system emergencies through payments/incentives based on market-clearing prices.

There are a number of ways to get demand response into the picture while also assuring that utility charges to customers reflect cost causation. All of these involve allowing the customer to “see” the cost of electricity and make decisions, based on that information, to reduce or shift electricity use. Examples of ways to build demand response into utility rate design range from the cutting-edge to the prosaic, including:

- **Traditional utility rate design.** Cost-based rates can be differentiated by time-of-day, geography, firmness of service, season, and other factors. Some of these options require upgrading the meter.

- **Adjusting prices for energy provided to customers by the utility on a monthly basis.** This would help to assure that electricity prices reflect wholesale power costs, which can vary substantially over the course of a year. This could be done through a monthly FAC or monthly POLR re-pricing.

- **Targeted demand response programs.** Programs that “pay” customers to not use electricity, especially at peak periods, can help to reduce wholesale price volatility.

Demand-responsive retail rate design and cost recovery mechanisms of the future must reflect the nature of how these costs are incurred by the supplier in the competitive wholesale marketplace. This synchronization of wholesale and retail rate design should also address the potential over/under revenue recovery operating risk that distribution utilities with continuing energy service obligations face as a result of wholesale market price volatility.

**Pricing Principles for Retail Competition**

The pricing of POLR service must be handled properly if it is to be compatible with competition. From an economic standpoint, it is very important that restructuring policies be implemented in ways that lead to efficient competition. In the states that have implemented retail competition, the competitive playing field should be fully open to entry by potential competitors and should not be tilted in ways that artificially favor entry by less-efficient competitors. Of particular concern will be the regulatory treatment of customers who, having initially switched to an alternative supplier, now seek to return to the POLR provider because of a price advantage.

First, the utility should be able to recover from customers, on a regular basis, the wholesale power costs, transmission costs, and any other costs associated with providing POLR service to those customers that choose not to switch. This can be accomplished through an automatic adjustment mechanism.

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49 Larry Ruff provides an important caveat to the concept of paying customers to not use electricity, stating that “[n]ormal markets allow consumers to sell what they do not consume as long as they own it, but no rational market pays consumers for not consuming what they do not own, even if they can prove that they would have bought it but didn’t.” Operationally, this means that customers might be “bribed” by an amount up to, but not exceeding, the difference between the wholesale market price of energy and the (implicit) regulated or contract price that they would have paid for that energy. See: Larry E. Ruff, *Economic Principles of Demand Response in Electricity*, Prepared for the Edison Electric Institute, October 2002, p.4.
Second, the “back-out credit” (sometimes known as a “shopping credit”) should reflect the costs that are avoided by the utility as a result of no longer providing POLR service to some customers. These costs would include avoided wholesale power costs, avoided transmission costs, and any avoided retailing costs that would be applicable.

For customers that switch to a competitive provider, the back-out credit should also reflect the seasonal and other variations in avoided (e.g., marginal) wholesale electricity costs, perhaps by allowing the price of the back-out credit to float on a weekly or monthly basis. Transmission costs, too, should reflect cost causation. In cases where transmission costs are higher in a part of the service territory because of congestion, those transmission costs should be assigned to the cost causer. Requiring that the back-out credit reflect actual incremental avoided costs of POLR service will ensure that the “contested function”—the provision of retail electricity service to users of electricity—is distributed among competitors in a way that minimizes total costs.

If and when credits for other unbundled services, such as metering or billing are developed, avoided cost concepts should be used—the credit must be based on the net forward looking costs that the utility avoids as a result of no longer providing a given service to some customers. Artificially “supersizing” the credit for any unbundled service—e.g., basing it on average embedded costs that are higher than the utility’s net avoided costs—would make it possible for inefficient firms to enter the industry successfully and would be harmful to consumers and society generally. Credits that are less than avoided cost, of course, cause the reverse problem and are similarly inefficient.

The back-out credit would reflect the going-forward cost of generation in the market that the utility would avoid by taking service from another provider. Other retailers would incur the same sorts of costs to serve customers. Thus, if a competitive retailer can find cheaper sources for wholesale power than the utility or can contract more efficiently, it can offer lower-priced service. Similarly, the retail component of the retail generation credit would reflect the utility's efficiency in minimizing the overhead costs it incurs to provide retail service. If the utility is inefficient in managing these costs, relative to competitive retailers, they will be able to offer lower priced services because they do a better job at managing their margins.

Efficient retail competition benefits end-use customers by reducing costs. Pricing standard service in an economically efficient manner allows retailers to enter and profit in the market if and only if they are able to deliver benefits in at least one of two forms. The retailer must either: (a) be more efficient than the utility in the provision of retail electricity service and thus offer a lower price to gain market share; or (b) innovate to introduce value-added products and services that inspire switching because customers demand these products and are willing to pay a premium to receive them. In the first approach, the utility’s price

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50 That term often connotes a back-out credit that has been set at an artificially high level in order to stimulate switching.

51 Given the characteristics of electricity, this would not necessarily be easy to do. Nevertheless, if transmission costs are higher in a load pocket area, higher prices in that area would signal generators, merchant transmission carriers, or energy service companies to find ways to reduce that congestion.

52 Kahn and Taylor apply the concept of competitive parity to identify the regulatory rules that are needed to provide efficient competition between the controller of a bottleneck facility (or essential input) and its actual or potential competitors. See Alfred E. Kahn and William E. Taylor, “The Pricing of Inputs Sold to Competitors: A Comment,” 11 Yale Journal on Regulation, pp. 225-240. While competition in retail electricity markets raise somewhat different competitive and regulatory issues, Kahn and Taylor provide an analytical framework that can be applied to the pricing and policy issues that arise in implementing retail competition.
for standard service becomes the benchmark to beat. In the second retailer strategy, the utility’s basic service sets the minimum standard to be improved upon.