Rate Design Is the No. 1 Energy Efficiency Tool

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I. Energy Efficiency Makes Headlines, but Too Little Attention to Rate Design

Headlines in the national media, not to mention the trade press, have been documenting the new focus on energy efficiency. Global climate change concerns, efforts to remove barriers to development of renewable energy sources, concerns about meeting growing demand for electricity, and efforts to make new electricity markets more competitive all point to an enhanced role for energy efficiency measures in the electricity sector. Typical recommendations include reinstitution of integrated resource planning (IRP),[1] new appliance and building standards, subsidized investment in efficiency-enhancing equipment, standby or buy-back rate or interconnection subsidies for distributed generation (DG),[2] and revenue ''decoupling'' mechanisms.[3]

Often lost, or underemphasized, is the fundamental role of economically efficient electricity pricing in eliciting energy efficiency

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activities by energy users. For example, in a March 2007 report to Congress, the U.S. Department of Energy listed rate design as the final of 10 recommended mechanisms for enhancing energy efficiency (and tempered that recommendation with the note that ''this goal must be balanced with other ratemaking objectives.'')[4] In fact, rate design should be at the top of the list. Efficient rate design is an essential starting point if the goal is to maximize the cost-effectiveness of other efficiency efforts.

There is nothing new in the *theory* of efficient pricing; consumers make economically efficient energy-related decisions when they face prices equal to marginal cost. What are new are affordable metering and communication technologies, better information about marginal costs, an understanding of the importance of clear price signals, and a sense of urgency.

II. Economically Efficient Electricity Pricing

When a consumer is considering cranking up the air conditioning on a hot summer afternoon, she should be weighing the extra charges on the next electricity bill against the value of the extra comfort that afternoon. If the effect on her bill of that extra consumption matches the extra cost incurred by the utility to supply the extra kilowatt-hours, then she will be making a decision that is not only right for her, but also efficient in terms of society's resources. This requires an electric rate design that charges for the extra consumption at the utility's marginal cost, and recovers costs that do not vary with usage in fixed charges or some bill component (such as an early energy block) that is not likely to significantly affect consumption.

Unfortunately, the prices most U.S. consumers pay are not well-correlated with the marginal cost of providing electric service.

Rate designs that relegate local distribution and customer-related costs that do not vary with consumption to fixed charges (e.g., a monthly customer charge or charge per unit of contract capacity or design demand) and recover generation, transmission and upstream distribution costs that do vary with usage in charges that vary by season and time of day result in more efficient consumption decisions than traditional rate structures with low or no fixed charges and no time-differentiation.[5] Even more efficient are rates that change as system and market conditions change. Examples include critical peak pricing (CPP) and real-time pricing (RTP).

- CPP charges a pre-set high price for energy consumed during hours declared (usually a day ahead) to be critical, in terms of high cost, reliability, or both.
- RTP charges prices that vary hourly, depending on system or market conditions, and are set typically either a day ahead or an hour ahead.

Unfortunately, the prices most U.S. consumers pay are not well-correlated with the marginal cost of providing electric service. As a result, the reductions in electricity bills from reducing electricity use, or shifting use from peak to off-peak periods, do not match the costs the utility (and more generally society) avoids when less energy (or less peak-period energy) is used.

III. Efficient Electric Rate Design Supports Other Energy Efficiency Initiatives

Recent legislation, state energy plans, and stakeholder reports have identified a number of initiatives that are designed to improve energy efficiency. In many cases, improving the efficiency of electricity rates would complement these other activities. Consumers may still need help identifying opportunities for improving energy efficiency in their homes

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or businesses, or coming up with the initial investment, but they do not need a subsidy if the savings on their electricity bills match or exceed the cost of making the changes.

One initiative is to encourage *DG investment*, particularly projects using renewable technologies. Simply reforming regular rates to reflect the structure of marginal costs can improve the cost effectiveness of DG. Rate structures with high demand charges tied to maximum level of use (sometimes over an entire year or more) reduce the cost-effectiveness of investing in self-generation that may not be available in all hours. Time-differentiated marginal cost-based rates encourage design and operation of DG facilities that maximize electricity production in the critical on-peak hours. Rates with energy charges that reflect marginal energy costs provide a signal to consumers to install and operate their own generating facilities when the cost of doing so is less than the utility's marginal cost of supplying that energy.

Another efficiency-promoting policy is to encourage *short-notice demand response* to enhance system reliability and counteract market power by generators bidding in the wholesale energy market. Customers respond to electricity prices by changing their behavior, appliance stocks, and building characteristics when the prices warrant such changes. Introducing marginal-cost-based time-of-day rates (and RTP and CPP programs) increases the benefits of energy efficiency activities, promotes load shifting (from high-cost to low-cost periods), and improves system reliability without requiring investment in new capacity.

Many utilities have (or used to have) *direct load control programs* under which the utility controls off particular electrical equipment (such as air conditioners and water heaters) during critical hours, and rewards participating consumers with bill reductions. Setting the bill credits to reflect the utility's avoided costs helps maximize the efficiency of the programs. Offering RTP and CPP programs may reduce the need for direct load controls, as consumers will have the incentive to control their own electricity use during the high-cost periods. However, it is unlikely that all customers will have the metering and communication equipment required for RTP and CPP, and direct load control programs help fill that gap.

Even with efficient price signals, consumers may not make cost-effective equipment choices.

Appliance standards and building codes help buyers make efficient choices by screening out inefficient options. However, the standards and codes must be carefully set, based on estimates of marginal costs and expected use over the life of the appliance/building.

Requirements to consider both supply and demand-management investments when developing plans to meet future electricity requirements is known as *integrated resource planning* (*IRP*). When customers face efficient prices, they will undertake cost-effective demand-side investments on their own, provided they have sufficient information. Thus, a component of demand-response becomes embedded in the load forecast that the utility is planning for, and less investment (demand- or supply-side) is required than would otherwise be the case.

Even with efficient price signals, consumers may not make *cost-effective equipment choices*. For example, individuals may have difficulty assessing costs and benefits over multi-year time periods, and firms often require investments with a two- or three-year payback. However, with the financial incentives in place in the form of efficient rates, energy efficiency programs can concentrate on providing information and even up-front funding. There is no reason for other consumers to provide subsidies; instead the programs can be designed so that the recipients repay the up-front

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funding with the savings on their bills.

If a utility collects unavoidable costs in rate components that vary with usage levels, it loses money when consumers cut back on electricity use. Various mechanisms have been developed to ''decouple'' revenues from kilowatt-hour sales to remove the utility's disincentive to promote energy efficiency in the presence of such a rate design. For example, rates might be adjusted annually to maintain a particular amount of revenue per customer. Redesigning rate structures can eliminate or significantly reduce the need for complex *decoupling mechanisms*, which tend to have unintended consequences.

IV. Steps in the Implementation of More Efficient Rate Structures

It is one thing to understand the theory of efficient pricing and another thing to actually implement it. However, the job is getting easier as wholesale markets simplify the task of estimating marginal generation and transmission costs, advanced metering infrastructure makes time-varying pricing feasible, and the industry recognizes the value of straightforward, easy-to-understand prices. Implementation involves a series of key steps and, often, some compromises.

The first step is to update marginal cost methods and studies to ensure that marginal cost estimates reflect current market structure, fuel price forecasts, and technological options. The updated marginal costs will also be available to analyze the cost-effectiveness of other energy efficiency initiatives.

In the revenue allocation step, class revenue requirements ideally should be based on class marginal cost revenues. This may require using an equal percentage markup above or discount from full marginal cost to match the total revenue requirement, or a differential class adjustment if necessary to reflect differences in demand elasticity by customer class.[6] If the goal is efficient pricing for all customer classes, it does not make sense to use embedded cost results to set class revenue requirements. Doing so introduces another constraint that will make efficient pricing that much more difficult. If moving to a marginal cost-based revenue allocation would result in very large cost shifts among classes, it may need to be done gradually.

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The next key step is to use marginal costs as the basis for rate structures. Metering constraints, of course, affect the degree to which this goal can be achieved. The prices of simple time-of-use meters have fallen dramatically over the past decade or so, meaning that standard TOU rates should be cost-effective for virtually all customers. In addition, the numerous operational and other benefits that smart meters provide to the system mean that the complex metering and communication systems required for RTP and CPP no longer must be justified solely on the basis of customer response to these special rates.[7] As a result, all customers should face seasonal rates, and most customers should face some form of time-of-day rates, all based on marginal costs.

Smart metering and associated communications capabilities also greatly expand the potential for direct load controls, and allow customers to automate their own response to CPP and RTP prices. Recent experience proves that demand response is greatly enhanced when consumers have the right equipment to, for example, automatically manage their air conditioning, space heating, and water heating demands as electricity prices change.[8]

Marginal capacity costs are usually estimated on an hourly basis. If prices could vary from hour to hour, these capacity costs could be recovered on a per-kWh

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basis.[9] When pricing periods include multiple hours, as in standard time-of-day (TOD) rates, the marginal costs in the hours making up the period must be aggregated in some way. Marginal energy costs are typically averaged over the hours in the period.[10] Marginal capacity costs can be treated the same way and added to marginal energy costs, eliminating the need for a demand charge billed on metered demand. Alternatively the hourly marginal capacity costs within a period can be summed to yield time-differentiated demand charges.

Utilities tend to favor demand charges because they are considered to provide greater revenue certainty than energy charges, but the concept of demand charges is actually a remnant of embedded cost pricing in an era when TOD metering was not feasible. Typically, embedded capacity costs are allocated on the basis of some measure of class contribution to system peak. These costs are then collected from customers within a class based on their own monthly peak demands, under the assumption that the individual customer's maximum demand is closely related to its contribution to the class peak used as the allocator. Demand ratchets, which provide even more revenue certainty for the utility, recover capacity costs based on some combination of maximum demands in the billing period and in previous billing periods. Demand charges (and particularly those with ratcheted billing demands) obscure the price signal and give the impression that capacity is free in any hour when the customer believes it has already set its billing demand for that billing cycle. As a result, rate designs with capacity costs recovered on a per-kWh basis tend to send more efficient and effective price signals.

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Ideally every customer should face a price for marginal consumption that is equal to marginal cost. Normally, charging marginal cost for all units of sale does not produce the approved total amount of revenue; prices for some rate components, or some units sold, or some customers must be adjusted to hit the revenue target. Theoretically, the inverse elasticity rule dictates optimal adjustments, but inadequate information about relative elasticities (and cross elasticities) within a class usually requires a more qualitative approach that takes metering constraints into account and includes the following general guidelines[11]:

- Making adjustments to the fixed components of the rate is a first step, because consumers are least likely to change their consumption due to distortions in the fixed monthly charges.
- Blocked rates are a good solution for some customers, particularly those without TOD metering; the first block can be set above or below marginal cost to close the gap, with the tail block set at or close to marginal cost. This leaves the price signal for marginal consumption at marginal cost, provided that the size of the first block is lower than the total consumption of most consumers.[12]
- An inverted block structure may work as a proxy for TOD energy charges; setting the tail block at on-peak marginal cost and the earlier blocks at lower levels may be the best available way to get the on-peak price signal to large residential customers, who may have the most elastic demands and tend to user higher-than-average shares of their energy in the on-peak hours.
- Inverted rate structures with block sizes set for specific ranges of kWh consumption are generally not equitable for commercial customers because kWh usage various widely within the class. An inverted block structure with the first block set based on

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some percentage of an individual customer's use in a base period and the tail block's price set at marginal cost gives the efficient price for marginal use by all customers in the class.

- For rates with metered demand charges, comparable adjustments to energy and demand charges will avoid distorting the relative signals for energy and capacity.
- Consistent absolute (not percentage) adjustments to time-of-use charges within a season will avoid distorting the incentive to shift load from one pricing period to another.

Another key step is the design of rate adjustment mechanisms. Efficient price signals established in a rate case can be undone if poorly designed adjustments are subsequently applied to base rates. It is important to design pass-through rate adjustments carefully so they do not distort the marginal cost signals incorporated in base rates. Fuel and purchased power adjustment clauses have a long history, but it is only relatively recently that serious attention has been paid to time-differentiating the adjustments.[13] Furthermore, today's market structures put more costs out of utilities' control and create a rationale for including more than fuel and purchased power costs in the adjustments. Costs of hedging fuel prices, paying administrative and congestion charges imposed by an ISO, implementing demand-side management programs, complying with environmental regulations, and financing construction of new generation and transmission plant between rate cases are all examples of costs that are being recovered in adjustment clauses. However, many of these costs do not reflect changes in marginal cost, and a flat adjustment to per-

kWh prices for changes in such costs may move price signals farther away from efficient levels. Careful analysis is required to determine the best way to allocate and recover these costs between rate cases.

Several states have gone to great lengths to establish energy auctions or other energy contracting processes for overlapping periods so that customers not choosing a competitive supplier of generation service will face prices for default service that are an average of market prices for several periods of years. These processes ensure that the (usually) large numbers of customers taking default service pay prices that are above the efficient level when market prices are low and below the efficient level when market prices are high. It is not clear that this approach achieves the optimal balance between the need for efficient energy use and the desire for stable prices. Such price smoothing tends to make it difficult for competitive suppliers to attract customers from default service (or to keep them when default prices fall below market prices) and tends to keep a large segment of the demand side of the market from reacting to high market prices, thus leaving the energy markets less efficient.

V. Conclusions

Electric rates that reflect marginal costs and include the maximum amount of time-differentiation consistent with metering can go a long way toward promoting efficient energy decisions by consumers. Rate design should be the first energy efficiency tool employed because, at a relatively low cost and without raising issues of cross-subsidy, it can achieve significant efficiency gains. This means keeping marginal cost studies up to date (including reflecting market conditions), using class marginal cost revenue calculations in setting class revenue requirements, creating rate structures that mirror marginal cost relationships, and carefully designing rate adjustment mechanisms to preserve efficient price signals.

In spite of concerted efforts to improve the efficiency of electric rate structures, it is likely that some customers will still not face optimal RTP and CPP rates, or even if they do, they may not have the information or inclination to respond. Certain energy efficiency programs can overcome these barriers to energy efficiency, but can be on a smaller scale and at a lower cost than if electric rate structures are not reformed:

- Programs that help consumers figure out ways to control their electricity bills by changing appliances and behavior are important.
- Appliance labeling, building codes, and informational programs, including easy tools to let consumer compare the alternatives, can help to overcome the problem of customer myopia about the energy costs associated with their appliance and building purchasing or renting decisions.
- Customers without the metering and other equipment needed to participate in critical peak pricing and other dynamic rate programs may be candidates for direct load control programs.
- Customers who are not able to come up with the extra upfront funds to purchase energy efficient appliances may be interested in programs that provide financing, with repayment coming from the energy savings created by the new appliance.
- Programs aimed at developers and landlords may be needed to solve the problem of the developer/landlord incentive to install low-cost equipment with high energy consumption because the home buyer/renter pays the electric bills.

In addition, there may be ''infant industry'' arguments for providing subsidies to particular efficiency technologies to kick-start a promising industry. Such situations may call for non-rate energy efficiency programs by utilities (or separate agencies set up by government).

Appendix A. Elements of Marginal Cost of Electricity Service

Local Distribution Facilities

The marginal cost of the local distribution network – based on the sum of a relatively few customers' maximum loads expected over the life of the equipment – should be recovered in a fixed monthly payment based on design demand. These facilities are marginal when service is first extended to the neighborhood and whenever it has to be replaced, but (if the design demands were accurately predicted) not with minor changes in demand by one or more of the customers using them.

Customer-Related Costs

Similarly, metering, billing, and customer accounting and service costs that vary with the number of customers being served should also be recovered on a fixed monthly basis, since they are not related to the amount of energy used.

Distribution Substations and Trunk Feeders

Distribution capacity beyond the local network is used by many customers and is expanded as load grows. The marginal costs of these facilities should be recovered in time-differentiated charges. Changes in load outside the peak load hours on this equipment do not affect the need for distribution capacity, but changes in load in peak hours do. The annual marginal cost should be time-differentiated based on an estimate of the relative likelihood that load growth at the substation level will require capacity additions.

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Transmission

For a utility that is a member of an RTO/ISO, marginal financial transmission cost is a function of FERC-regulated charges for use of the transmission system and for services provided by the RTO/ISO. A utility with a FERC-approved Open Access Transmission Tariff (OATT), but not in an RTO/ISO, has a financial marginal cost defined by the network service rate in its OATT. Although such a utility does not write itself a check for transmission service, its share of the transmission revenue requirement is determined by its use of the system and the FERC formula for the network service tariff.[14] The transmission charges should be time-differentiated based on the relative likelihood that load growth in a given hour will affect the cost of transmission service, given the structure of the OATT or other applicable charges.

Generation

Marginal generation cost for a utility that regularly participates in the wholesale energy market is the market price. Depending upon the organization of the regional market, this may be a single price per kWh, or a combination of a per-kWh price from the energy market and a separate price per kW based on reserve-sharing rules and the cost of capacity in the region. Naturally these market prices will vary by hour, and rates that change with market conditions, such as real-time pricing and critical peak pricing programs, maximize efficient price signals. However, rates that change by season and more general time-of-day pricing periods are far superior to rates that apply in all hours.■

Endnotes:

1. Typical IRP processes treat projects that reduce demand on an equal footing with investments that meet demand growth, and seek to develop a least-cost plan that involves both types of investment.

2. Distributed generation comprises relatively small electricity generators, typically renewables or combined heat and power facilities (cogeneration), that deliver power to the distribution grid. They are typically owned and operated by non-utility entities.

3. These mechanisms aim to protect utility profits when consumption is reduced as the result of conservation efforts, thus removing what would otherwise be a disincentive to encourage such reductions.

4. *State and Regional Policies That Promote Energy Efficiency Programs Carried Out by Electric and Gas Utilities: A Report to the United States Congress Pursuant to Section 139 of the Energy Policy Act of 2005*, USDOE, March 2007.

5. See the appendix for a detailed description of the components of the marginal cost of electricity service.

6. The inverse elasticity rule or ''Ramsey Pricing'' states that prices should be adjusted away from marginal cost in inverse proportion to the elasticity of demand.

7. Austin Energy is installing smart meters for 100 percent of its more than 360,000 customers. http://powermarketers.netcontentinc.net/newsreader.asp?ppa=8knpp%5E%5BllfnwrnUSigy30qbfem%5E%21.

8. See, for example, Michael J. King, Kathleen King and Michael B. Rosenzweig, *Customer Sovereignty: Why Customer Choice Trumps Administrative Capacity Mechanisms*, Elec. J., Jan.–Feb. 2007, at 38–52.

9. A kW for an hour is a kWh.

10. Some analysts use a load-weighted average, although this produces an efficient price signal only if the loads used as weighting factors are class loads, and only if demand elasticity for the class within a period increases with load.

11. The specific situation of a utility or individual class may require a different approach.

12. A special form of blocked rates sets the first block at a ''base-line'' level, and charges (credits) any deviations from the baseline level at marginal cost. This structure, typical of RTP rates, prices all marginal consumption by all customers at marginal cost. This approach can also be used for non-RTP rates. See, for example, *Making Every Electricity Consumer a Market Participant (Putting Demand Back in the Equation)*, Elec. J., April 2003.

13. Oklahoma Gas and Electric's 2005 rate case includes a time-differentiated fuel adjustment clause. Xcel Energy has time-differentiated energy cost adjustments.

14. The marginal *resource* cost may be different from the marginal *financial* cost in either of these situations, but the former is difficult to estimate when regional transmission planning is involved.