THE MID-ATLANTIC DISTRIBUTED RESOURCES INITIATIVE

REGULATORY SUBGROUP

SCOPING PAPER ON:

- **DYNAMIC PRICING: ALIGNING RETAIL PRICES WITH WHOLESALE MARKETS**
- **THE THROUGHPUT ISSUE: ADDRESSING THE ADVERSE IMPACT OF DISTRIBUTED RESOURCES ON UTILITY EARNINGS**
- **ROLE OF DISTRIBUTED RESOURCES IN SYSTEM PLANNING**

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INTRODUCTION

The retail electric utilities within the MADRI footprint have undergone significant restructuring over the past several years. Vertically integrated utilities that previously owned generation, transmission and distribution facilities have given way to an unbundled industry, dominated by market-based generation sold to load-serving entities that, in most cases, own the distribution system and may own transmission facilities. Holding all other things equal, the unbundled network functions very much like the old vertically-integrated system, except in three important respects.

First, greater reliance on market mechanisms has presented a number of pricing challenges. The greater variability of wholesale power markets has not, thus far, translated into corresponding pricing reform for retail consumers. Nor have competitive markets succeeded in embracing a robust demand response mechanism. Finally, market structures have not adequately facilitated the introduction of distributed resources.

Second, restructuring of the industry has coincided with significant technological changes in the industry and the opportunity for new uses of old technologies. The emergence of distributed generating technologies and more easily dispatchable load has increased the likelihood that customers will either self-generate some or all of their power requirements or will engage in some form of economic demand response in the form of load management, load reduction or increased energy efficiency (collectively Distributed Resources or DR). At even modest penetration rates, DR can have large implications for utility profitability. There is general agreement among MADRI participants that the utility's sensitivity to lost profits, termed the "throughput issue," coupled with its position as a monopoly provider of the local wires services, presents the wrong incentive structure to the utility and the opportunity to erect insurmountable barriers to these new technologies.

Third, the unbundling of the industry makes it more difficult to understand the integrated system for planning purposes. In a unified structure of ownership and operations, it is relatively easy to identify the economic trade-offs of any number of options. For example, the costs and benefits of DR can be easily compared to traditional "wires and turbines" solutions to system needs.

In an unbundled industry, this is considerably more difficult. Opportunities are harder to identify because each of the operators of the unbundled components are "specialists" within their own realm. Each specialist knows well the important aspects of its own arena of responsibility, but is much less likely to have a comprehensive view of the entire system. In fact, within MADRI there is no single entity, other than arguably the regulators, who has responsibility for a comprehensive look at the industry. However, even the regulators' scope is limited geographically (to each state) and functionally (between federal-wholesale and state-retail).

This paper is intended to describe the impact of these three important issues, pricing issues, the throughput issue and the system planning issue, as they relate to DR. The purpose of this paper is to provide a starting point on these issues for the work of the MADRI Regulatory Subgroup. The objective of the paper is to assist the subgroup to identify the functional and jurisdictional gaps facing DR with an eye toward assuring that the legitimate values of DR are captured for customers. The goal of the workgroup is to identify regulatory strategies to meet these objectives. Some of these strategies may seem unfamiliar or counter-intuitive. Focusing on real incentives of investors and decision-makers enables a thoughtful assessment to show, regardless of first impressions, what changes in regulation would improve the cost-effective deployment of DR.

DYNAMIC PRICING: ALIGNING RETAIL PRICES WITH WHOLESALE MARKETS

OBJECTIVE

MADRI aims to maximize the capability of distributed resources to compete in the wholesale market and to improve the economic efficiency and environmental profile of the electric sector. Among the means to achieve these ends are the delivery of RTO- (or LSE-) managed load reduction programs and end-user pricing, the object of which is to better align behavior in the retail and wholesale markets. Put another way, what can be done to reveal to customers and LSEs the value (cost) of energy savings (consumption) during times of high loads or system constraints? This section introduces some of the policy issues and possible approaches associated with the latter area of inquiry, namely what kinds of retail pricing structures can better reflect underlying wholesale costs, what the barriers to them are, and what key policy and technical questions regulators will face as they consider alternative rate structures. We leave for a later time the many technical questions associated with advanced metering capabilities, which are required for most of the more dynamic pricing designs.[1]

RETAIL PRICING OPTIONS

Electric service in the MADRI region is priced in a variety of ways. Pricing structures run along a continuum that marks the trade-offs between innovative and more complex pricing on the one hand and information needs and ease of administration on the other. The further one deviates from average embedded prices, the more "dynamic" the rate structure becomes. That continuum, and the associated metering and telemetry needs, can be roughly divided into three broad segments:

- *Energy-only pricing.* Rate designs that do not require special metering capability beyond that of the traditional revenue meter, which measures energy consumption only and is typically read once a month: flat, seasonal, block, etc.;
- *Multi-part and time-of-use pricing*. Rate designs that depend upon more sophisticated metering – multi-part (energy and demand) and time of use – but are still mostly read only monthly; and
- *Real-time pricing*. Rate designs that send customers different prices on short notice for different hours of the day and for different days, to in some way reflect changing conditions in the short-term market – *e.g.*, real-time pricing (RTP) – and make use of sophisticated metering and communications systems that link them to any of several entities (the load serving entity, utility, or system operator).

[1] "Dynamic pricing" is a term used to describe any rate design that aims to give customers a truer signal of the economic costs of meeting their demand than simple average cost rates. Thus, a shift from average rates to time-of-use rates to demand and energy charges or to the various forms of real-time prices is considered a move toward more dynamic pricing. Others hold a more narrow definition: dynamic pricing "is any electricity tariff that recognizes the inherent uncertainty of supply prices." Stephen S. George and Ahmad Faruqui, Charles River Associates, *The Economic Value of Dynamic Pricing for Small Consumers*, presentation at the California Energy Commission Workshop on "Achieving Greater Demand Response in the California Electricity Market," March 15, 2002.

Along this continuum, there are a variety of approaches to retail pricing that will evoke changes in customer behavior. Whether the changes can be relied upon for managing system loads in the short run depends in part on the degree to which the rates reflect the real-time variability of wholesale prices. While time-of-use and seasonally differentiated rates can have positive long-term impacts on system load factor, resource needs, and efficiency, they provide little incentive to adjust load in response to actual hourly or daily prices. In contrast, critical peak and real-time pricing can produce voluntary responses among customers at times of system peak, but their efficacy is a function of customer sophistication, ease of response, and program design. What follows here is a simple menu of pricing and program options that will create greater responsiveness among customers, all of which are, in varying degrees from state to state, already in use in the MADRI region:

- *Time-of-use rates*. These daily energy or energy and demand rates are differentiated by peak and off-peak (and, possibly, shoulder) periods. One variation is the overlay of a real-time "critical" peak period, in the manner of programs in California and Florida.
- *Seasonally differentiated.* Those months during which consumption drives system peak see rates that reflect, in some measure, the costs of the capacity (generation, transmission, and distribution) needed to serve that peak. Seasonal differentiation can be applied not only to simple energy-only rates, but also to TOU and multi-part rates.
- *Multi-part rates.* These rates separate the charges customers pay for energy and capacity. Historically, demand charges were linked not to coincident system peak but simply to the customer's peak demand during the billing period.
- *Block rates.* These are typically energy-only rate designs in which the unit price for incremental consumption changes as defined thresholds of usage within a period are passed: e.g., the first 200 kWh priced at $0.XX/kWh, the next 400 kWh at $0.YY/kWh, and all succeeding usage at $0.ZZ/kWh. Such rate designs whose prices increase are called inclining (or "inverted") block rates. While these rates do give customers some idea of the cost of incremental production, it is rough at best, since there is an imperfect relationship between the rate charged and the time of use (coincidence with system peak or other constraint). However, insofar as incremental consumption is often driven by end-uses whose operation tends to coincide with system peaks (e.g., air conditioning in summer peaking states), inclining block rates can send strong signals to consumers to manage their on-peak consumption wisely.[2]
- *Distribution-only service.* In restructured industries where commodity sales are separated from delivery service, the design of rates for distribution remains a regulatory responsibility. Treating distribution as if its costs do not vary with the time or amount of usage (which, in the long

[2] This suggests that regulators and utilities might want to reexamine the economic justification for declining block rates, where they exist.

run, they do) can lead to the adoption of large, fixed, recurring rates that are unavoidable, regardless of changes in demand. This can inhibit customer willingness to take otherwise cost-effective demand reduction actions.

- *Real-time pricing.* RTP links hourly prices to hourly changes in the day-of (real-time) or day-ahead cost of power. One option is "one-part" pricing, in which all usage is priced at the hourly, or spot, price, adjusted as appropriate for delivery, congestion, line losses, and other relevant costs. Unlimited in this fashion, RTP places all price risk on the customer and, consequently, few customers have taken service under it. Providers have developed risk mitigation (risk-sharing) products to address this concern: for example, price caps and floors, options for locked prices for limited periods, and triggers (where the spot price is paid only when it exceeds a specified minimum for a specified period). A second approach is "two-part" pricing. There is an "access" charge for using a pre-determined baseline quantity (e.g., baseline kWhs * embedded rate/kWh), and spot prices (or credits) for variations from the baseline. The baseline is often set on a customer-specific basis. The two-part RTP rate is a more common form of price-risk sharing, and it provides a certain measure of revenue certainty for both the provider and the customer.
- *Interruptible.* Programs (in the form of tariffs or customer agreements) that give utilities or LSEs a right to interrupt service at times of peak or system stress are a powerful load management tool. They come in a variety of forms – for example, discounted or marginal energy rates, reduced or eliminated demand charges, bill credits, etc. – to reward the customer for a reduced or capped contribution to peak capacity needs. On the flip side, there are often penalties for failure to interrupt. Interruptible rates are an overlay on any of the other rate designs.

BARRIERS TO DYNAMIC PRICING

There are a number of obstacles to the implementation and success of alternative, time-based approaches to pricing. They affect not only customer behavior, but also that of utilities and policymakers. Key barriers include the following:

COST BARRIERS

- *Capital, telemetry, and administrative costs.* The capital costs of advanced metering, regardless of which entity bears them – distribution company, LSE, or competitive meter provider – can inhibit investment, particularly in an uncertain regulatory environment. Telemetry and other ongoing costs might not be high, but added to capital cost, raise the threshold savings rate needed to make an advanced metering program cost-effective.

- *Cost-effectiveness.* Rates and the metering technologies that support them are directly linked, and no decision on prices can be made without consideration of the capital and administration costs that they impose. What rate structures will serve a desired objective, and what are the metering and communications technologies that enable them? Perceptions about the cost-effectiveness of advanced metering, particularly for lower-volume customers, can discourage large-scale investment.

CUSTOMER BARRIERS

- *Customer risk aversion.* Price volatility is seen by many customers as an undesirable risk and, thus, as an overall increase in one's electricity costs. Often, customers are willing to pay a premium to avoid time-varying costs.
- *Elasticity of loads*. Some customers may not fully appreciate the extent to which they can manage their own loads.

UTILITY AND LSE BARRIERS

- *Utility revenue loss*. Regulators and utilities have long experience with implementing changes in rate design on a revenue-neutral basis (which often includes elasticity-related adjustments as well). However, revenue loss is especially problematic with voluntary dynamic pricing programs, which can result in unwanted customer self-selection: those whose load profiles are better than the class average will be more likely to go on a TOU or RTP program than those with worse-than-average load profiles. This reduces their total costs, but makes both the utility and (after a rate re-design) its remaining customers worse off (since the diversity benefits of those "good" customers have been lost to the customer class). Also, absent any new price-responsive behavior on the part of these "free-riders," there will be no peak load reduction benefits. Of course, there may be customers with worse-than-average load profiles who opt for the new rate; presumably they do so because they can alter their consumption and pay less than they would otherwise pay. This will provide benefits to the system as a whole, but likely also a short-term net revenue loss (until the higher incremental costs associated with the customer's original usage pattern can be avoided).
- *Load profiling*. It is in the interest of an LSE whose non-interval-metered customers' loads are better than the average (i.e., higher load factors or lower demands at high-cost time) to support improved methods of load profiling.[3] LSEs whose customers' loads are worse than the average have

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[3] Load profiling is necessary to the wholesale settlement process. In the absence of individual customer information that describes the customer's hourly usage, an estimate of the customer's load profile must be made in order to determine the contribution of the customer's demand to the LSE's overall load at different hours of the month. Customers are grouped according to the general characteristics of their usage (for example, low-use residential, high-use residential, small commercial, large industrial, etc.), and a load profile for each customer class is determined (typically through a "load study" using statistical methods). All customers within a class are deemed to have the same load profile; they differ only in the amount of

the opposite incentive, since some part of the higher costs their customers cause is being paid by others.

- *Calculation of the customer baseline for RTP*. While there is no empirical evidence to suggest that customers somehow "game" the determination of the baseline (for those RTP programs that use them), avoiding this possibility remains a challenge for LSE and utility administrators of RTP and interruption programs.
- *Billing and collection.* More complicated pricing structures can challenge the capability of the utility's billing and collection system to settle accounts.
- *Compensation for costs of delivering RTO demand response programs.* LSEs and distribution companies that market and manage RTO demand response programs incur costs to do so. Insufficient payment for doing so will inhibit performance of the programs.

REGULATORY AND LEGISLATIVE BARRIERS

- *Policymakers' perceptions.* Concerns (not necessarily justified) that, for the most part, customers cannot adjust their usage as price changes have led to regulatory preference for voluntary, rather than mandatory, programs.
- *Fairness.* Not all customers will benefit equally from the new rates. This will depend on how prices actually change and on the degree of customer-responsiveness. To the extent that, in an environment of average embedded cost pricing, demand on-peak is subsidized by off-peak consumption, one can argue that a pricing scheme that more fully allocates costs to those who cause them is inherently more fair. On the other hand, electricity is an essential service in modern society, and public decision-makers will also consider universal service goals in making rate design decisions.
- *Other pricing policies*. Other pricing policies may prove to be barriers given their impact on behavior. For example, rate caps imposed by the ISO or state or federal regulators may inhibit price responsiveness.
- *Lack of coordination with demand-side management (DSM) programs.* The absence of customer means, both technical and financial, to shift loads can be a barrier to demand responsiveness. DSM incentive

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energy they use during a billing period. The distribution company then sums the load profiles of customers served by individual LSEs serving load within the service territory to establish each LSE's overall load profile. Every month, the system operator uses each LSE's composite load profile as reported by the distribution companies to allocate the total amount of energy purchased by the LSE (adjusted for losses and "unaccounted for" energy) across the period's hours in order to establish the LSE's responsibility, hour by hour, for the system dispatch.

mechanisms for customers to install, for example, storage heating and cooling systems, load controls, and other measures that enable them to shift load while mitigating adverse impacts on the quality of energy end-use can facilitate customer price response, but typically require regulatory and legislative support.

TECHNOLOGICAL BARRIERS

- *Lack of interval metering.*
- *Lack of requisite communications equipment.*
- *Lack of customer energy management systems, such as load controls, energy storage, and distributed energy systems, which give customers added flexibility in their usage.*

Lastly, the existence of default and standard offer service in a competitive retail market can add complications. The legitimate desire of policymakers to protect the lower-usage customers from the volatility of the wholesale market has resulted in rate designs and up-front rate reductions that can inhibit customer demand response. Typically, standard offer service has been provided at average, non-time-dependent rates, often at a discount to pre-restructuring rates. Since, under such circumstances, all of the price volatility risk is borne by the default provider (during the period rates are in effect), one might argue that a risk *premium* rather than a discount is warranted. In any event, standard offer service customers are insulated from the variability of short-term market fluctuations and consequently have no incentive to adjust their loads in response to price. In addition, to the extent (as in Massachusetts) default and standard offer service are provided by multiple suppliers but are settled under the same load profiles, the incentive to take actions to improve customers' load is further muted. Insofar as the average load profile is modified to reflect any improvement, the benefits are shared among all standard offer service providers, not just the one taking action.

RETAIL DEMAND RESPONSE: CONSIDERATIONS AND OPTIONS

What follows is a list of general principles and related issues that policymakers can consider when designing and implementing retail rates, programs, and metering systems in support of demand response:

- *Improved economic efficiency.* Markets and rules should produce least-cost outcomes. Economic efficiency is improved when prices more closely approximate marginal cost. What is the relationship between long-run end-use efficiency and short-run demand response? Does investment in one discourage more cost-effective investment in the other?
- *Overcoming barriers to efficient choices*.
- *Simplicity*.
- *Roles of the RTO, utilities, load-serving entities, and customers*. To whom is the price signal most efficiently sent, the LSE or the end-user? Who has the

comparative advantage in bearing the risks? Where should the policy effort be focused, and what can be done to assist LSEs and customers to extract the highest potential value from demand-response?

- *Integration* of retail pricing with RTO load response (*e.g.*, interruptible) programs and needs. Experience suggests that rate designs that signal the economic costs of producing and delivering energy to customers are not enough, in all circumstances, to elicit all cost-effective demand-response potentially available. Do remaining barriers justify the payment of additional incentives?
- *Improved system dispatch*.
- *Environmental impacts*. Should the environmental benefits of avoided emissions and construction be recognized in planning and program design? If so, how?
- *Cost-effectiveness*. This pertains not only to the cost-effectiveness of the rate design itself, but also of the metering system necessary to support it.

With these considerations in mind, the central question for policymakers is what rate structures should be put in place that will promote the most efficient consumption of electricity, given other policy objectives (fairness, simplicity, environmental sustainability, etc.). Answering it is further complicated by the existence of retail competition and default service in states whose industry has been restructured.

The continuum of rate design options sketched out earlier runs from those that send consumers only the barest of economic cost signals to those that reveal almost fully the time-dependent costs of production and delivery. Experience with them shows that, as one moves along the continuum, customers find more ways to respond to the signals: in short, customers' willingness to purchase – their demand elasticity – is revealed. But with any rate design change there will be winners and losers, even if the overall result is to the good, and so the challenge will be to capture the benefits of more economically efficient pricing while ensuring that less elastic customers are treated fairly.

Although one might argue that simply placing all customers on real-time prices would take care of the economic efficiency problem (*i.e.*, all cost-effective demand response would naturally occur), it is not, even if true, a practical solution. For policymakers, the changes in rate design will not be taken in giant leaps, but in shorter, less disruptive steps along the continuum – for instance, a shift from year-round average cost rates to seasonally-differentiated or TOU rates. In this context, some of the considerations for policymakers include the following:

- *Purpose*. What objectives are new retail rate designs and programs intended to serve? Some program designs might lower peak demand without lowering overall consumption; others might encourage customers to invest in long-term efficiency measures. Some rate designs may stimulate entry of competitive LSEs into the market, while others would reinforce the role of incumbents and default providers. Some programs may better serve environmental and system reliability goals than others. There are many variations on these questions.

- *Mandatory or voluntary?* Should a new rate design be mandatory? Customers' acceptance of a new rate is largely a function of their ability to adapt to and benefit from it. At first, this may be more a question of perception than reality. Mandatory seasonal or time-of-use rates for lower-volume customers and RTP for large-volume customers could achieve significant savings, but could also impose significant costs upon inelastic users. This could be addressed through the use of a risk-sharing mechanism or through the targeted marketing of a voluntary program.
- *Low-volume versus high-volume customers*. Price elasticity can vary with total amount of usage in a period. Since for most customers there is a minimum amount of usage that is unavoidable (*e.g.*, lighting, HVAC, computing, refrigeration), there is less discretionary demand among low-volume users that can be manipulated through pricing or demand-response programs.[4] Would it be appropriate, for instance, to set minimum usage thresholds (either in kWs or kWhs) for the more dynamic pricing structures?
- *Utility revenue loss*. Voluntary tariffs for dynamic pricing can lead to short-term net revenue loss for utilities, even if they lead to lower system costs over time. The magnitude of such losses, if any, will depend on a variety of factors including the number of participants, size of the reductions, the ability of the company to offset the losses through other sales (off-peak or off-system), and so on. There can also be net revenue losses generated by mandatory programs. Even though the problem of self-selection is overcome, there still remains the question of whether the company, after customers respond to the dynamic prices, still carries entitlements to generation for which revenue has not been received. What can and should be done to account for such losses and provide incentives to LSEs and wires companies to lower the total power costs faced by their customers?
- *Potential benefits*. Will the new rate structure yield net benefits?
- *Retail competition, default service, and load profiling*. Does the existence of default service pose special challenges? As a general matter, regulators cannot impose particular rate structures upon competitive offerings, so the prevalence of dynamically priced commodity electricity will depend upon market conditions. It will also depend on the availability of the advanced metering needed to support it. In contrast, default service remains effectively a monopoly service. Regulators can approach it as they do vertically integrated service and implement rate designs and other programmatic requirements aimed at eliciting customer demand response. Where there is no interval metering, however, the challenges posed by load profiles remain.

[4] This is not to say that the minimum usage could not be further reduced through increased efficiency. Rather, that for any given level of efficiency, some minimum level of end-use is unavoidable. Lighting, whether inefficient incandescent or efficient compact fluorescent, will still be required to meet the consumer's illumination needs and refrigerators, whether efficient or not, will still run to maintain a required level of cooling, etc.

- *Load profiling and settlement*. What changes, if any, can be made to the present system of load profiling and settlement that will allow for more economically efficient pricing in the absence of more sophisticated metering capabilities?

Possible Action Steps

There are a variety of steps that policymakers can take to promote improved demand responsiveness among retail customers. The following is a list (by no means comprehensive) of actions states might take:

- *Consider imposing more dynamic pricing structures on default service customers.* PUCs can consider, through generic investigations or less formal stakeholder processes, the costs and benefits of time-sensitive rates and advanced metering on these “mass market” customers. If they have not already done so, PUCs could also consider imposing, pending the outcome of a generic investigation, particular rate designs that have been shown to produce a significant and cost-effective demand response, such as inverted block rates for residential customers, TOU and critical peak prices for commercial customers, and mandatory RTP for large industrials.
- *Consider directing distribution utilities to perform additional load research to support development of dynamic pricing structures.* Load profiles emerging from such research could support alternative rate designs, settlement methods, and demand response programs (e.g., aggregated interruptibles and controlled loads) for mass-market customers. Research on the load shapes of specific end-uses could also be performed, to support quantification of the value of curtailable load programs such as interruptible water heating, air conditioning, or swimming pool pumping.
- *Target energy efficiency programs to the more price-inelastic customers, particularly those whose end-uses are highly peak coincident.*
- *Consider other reforms that would improve the incentives of default service providers to encourage more efficient consumption by their customers.* One such reform might be settlement procedures that more fairly allocate wholesale generation costs to the default service providers whose customers cause those costs.
- Assure that those who deliver RTO-level demand response programs are fully compensated for doing so.

THE THROUGHPUT ISSUE – ADDRESSING THE ADVERSE IMPACT OF DISTRIBUTED RESOURCES ON UTILITY EARNINGS

RELATIONSHIP OF DISTRIBUTED RESOURCES TO UTILITY EARNINGS

The term “utility” is somewhat ambiguous these days, in light of industry restructuring. For the purposes of this paper, “utility” means the regulated entity regardless of its form. The regulated entity, or utility, may be a wires-only distribution company (DISCO), a vertically integrated company, or something in between.

This paper examines the impacts of DR deployment on utility profitability. “Deployment” is used instead of “investment” because DR may be installed and owned by the utility, customer, energy service provider, or any other entity. In each case, there will be predictable effects upon the utility’s profitability.

Profits can be expressed in absolute terms, such as $100 million, or as a rate, such as dollars per share or percentage return on equity (ROE). Focusing on the absolute return can be very misleading. Rate of return is the more important measure of profitability. Profitability improves if the rate of return (earnings per share) goes up. For example, through increased sales or a merger or acquisition, a firm can grow and see its earnings climb from $100 to $150 million. But, if its costs or related capital requirements grew faster than its revenues, its rate of return and earnings per share would decline. Shareholders would not be happy with management if earnings went up by $50 million but earnings per share, and hence ROE, dropped by 10%. For our purposes, “profits” (or earnings, etc.) refers only to ROE and not to absolute levels of profits.

Our concern in this paper is with the incentives that cause utilities to take, or avoid taking, specific actions. Thus, the question we focus on is: What happens to a utility’s profits if it does “X” or if its customers do “Y”? The incentive (or disincentive) is the action’s incremental effect on profits.

In terms of utility profitability, not all DR is the same. Where the utility owns the DR and is allowed to recover its costs in the same manner as other utility assets, then it has no negative impact on earnings and can potentially improve earnings. For example, a utility-owned micro-turbine located at a substation to provide greater capacity or to provide voltage support, “looks and feels” just like any other utility investment. As a “rate-based” investment it earns the same profits as any other investment. It may also improve earnings if the utility avoids incremental costs that are greater than the incremental prices paid by consumers.

DR on the “customer-side” of the meter has a completely different impact on the utility. Simply put, customer-side DR reduces sales by the utility to the end-user. Retail electricity prices are typically composed of a combination of customer charges, energy rates and, for non-residential customers, demand charges. Energy and demand charges are, appropriately, volumetric prices – that is, the amount charged to the retail customer increases as usage increases. Absent other adjustments or changes, the profits of a utility will rise or fall with changes in sales volumes.

Rate cases have only one consequence that lasts beyond the final day of the rate case: Prices have been set. Once the rate case is completed and prices are set, everything said in the hearing process is irrelevant to the fundamental question of how utilities make money. From the day prices are set, utility profits are ruled by a simple formula:

PROFIT = REVENUE - COSTS

The REVENUE part of the formula is easily computed, but it has nothing to do with the line from the rate case order labeled "revenue requirement" or "allowed revenue." The utility's actual revenue is governed by the following relationship:

REVENUE = PRICE * QUANTITY

Prices were set at the end of the rate case and are fixed until the end of the next rate case. In arithmetic terms, price is a constant, so revenue is directly related to quantity, or sales. Ignoring the subtleties of rate design (i.e., the structure of prices — energy charges, demand rates, and customer charges), if sales go up 2%, revenues will go up by the same percentage.

Utility prices are typically set in a rate case that implicitly (if not explicitly) relies on the unit cost theory. The unit cost theory says the test year rate case defines the relationship between revenues, expenses, and investment and says furthermore that this relationship remains constant. The unit cost theory allows regulators to choose to use a historic test year, a fully projected test year, or any test year in between. Thus, we can use a historic test year, say 2003, to process a rate case in 2004, and set prices that will be in effect in 2005. Or we can use a projected test year, say 2005, to process a rate case during 2004 to set prices for 2005. According to the unit price theory, both exercises will yield the same prices. The future test year will have a higher revenue requirement (the numerator) than the historic test year numerator, but it will also have higher sales (the denominator). With the numerator and denominator moving in lockstep the end result is that prices in 2005 will be the same.

While the theory is a useful framework for setting prices, the reality is that utility costs and revenues do not move in lockstep as sales change. In fact, it is far more accurate to say they are independent. Statistical analysis of utility costs (excluding fuel and purchased power) has consistently shown that there is no meaningful relationship between costs and kWh sales in the short run.[5]

This has profound effects on how utilities make money. Revenues are directly related to sales, and costs are relatively independent of sales. This means profits and sales are directly related. If sales go up 2%, revenues go up 2%, and profits, in nominal terms, go up by an amount equal to 2% of sales. Because the typical utility has significant debt leverage, the impact on equity earnings is greater than the 2% change in revenues. Likewise, if sales drop, revenues and profits drop, according to the same relationships.

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[5] See J. Eto, S. Stoft, and T. Belden. "The Theory and Practice of Decoupling." LBL-34555, January 1994.

This holds true for sales changes caused by DR as well. The predominant condition is that, where REVENUE and COST are independent, profits increase if revenues increase and profits fall if revenues fall. This means that any distributed resource that causes revenues to fall hurts utility profits. Any supply- or demand-side resource located on the customer's side of the meter will have this effect. So will all net metering installations. Thus far, net metering has not occurred in large amounts and so utilities have generally tolerated net metering. However, large amounts of net metering are not sustainable from a utility earnings standpoint and may present a significant issue in the future.

THE SPECIAL CASE OF DISTRIBUTED RESOURCES IN HIGH COST AREAS

Distribution utilities may face some special circumstances where the deployment of DR, whether utility-owned or not, can increase profits. This can occur where the prices paid by customers are less than the marginal cost of providing service. For example, in a city-center context, where all distribution facilities are underground, the marginal cost of upgrading the distribution system can be very high. However, the customers served by those facilities typically do not pay a price based on the incremental cost of serving them (individually or as a localized group). Rather, their prices usually reflect the average cost of providing service to all customers in their class throughout the service area, including lower cost zones. Prior research indicates that the variability or marginal distribution costs within a single distribution company can be quite high and can range virtually zero cost at the low end to as high as millions of dollars per MW at the high end. These costs are extremely sensitive to the configuration of individual lines and feeders and to the growth rates in sales on those lines and feeders. This topic is explored further in the Planning discussion, below.

Where growth rates are small or upgrade investments are especially large, the incremental sales associated with an upgrade to the local distribution grid will be insufficient to cover the incremental cost associate with that upgrade. As a result, the utility profits increase (or do not go down by as much) with the deployment of DR because of the avoided costs that the utility enjoys, at least until the next rate case. After rates are adjusted, these costs tend to be shifted to other customers.

REGULATORY REFORM OPTIONS

There are a number of regulatory options available to try to align utilities' profit motive with the deployment of DR.

PERFORMANCE BASED REGULATION - PRICE CAPS VS. REVENUE CAPS

A number of states have experimented over the years with performance based regulation (PBR). While performance based regulation can take many forms, the predominant structural feature that distinguishes one class of PBRs from another is whether it is price or revenue based. Performance based regulation generally establishes a fixed period of regulatory lag, generally in the three to five year range. During this period the utility is subject to either fixed prices (price caps) or fixed revenues (sometimes fixed revenues per customer), either of which may be adjusted by a predetermined formula. Price based approaches make DR deployed on the customer side of the meter very unattractive to utilities, as every lost kWh sale is a loss of revenue. On the other hand, revenue based approaches make utilities indifferent to customer side DR, because a constant level of revenues assures constant earnings regardless of sales volume.

TARGETED INCENTIVES FOR DISTRIBUTED RESOURCES

PBRs can be designed to have targeted incentives for the deployment of DR. DR can be in the public interest because of the cost savings they offer; therefore, one logical regulatory approach is to create a targeted incentive by allowing the utility a share of the savings. If a utility can demonstrate that it has reduced its distribution cost by installing distributed generation or targeted demand side investments, regulators could allow the utility to keep some fraction of the savings as a reward mechanism. Targeted incentives of this nature worked successfully for demand side options in the past.

PRICE REFORMS

One of the reasons that utility profitability does not align well with the deployment of DR is because the prices charged for the services displaced by DR do not reflect the cost of those services. If all utility prices were exactly reflective of marginal costs, the deployment of DR would have a very different impact on utility profits. For example, recall that average distribution rates are about 2.5 cents per kWh and that in high cost areas distribution rates are as high as 20 cents per kWh. In theory, regulators could simply de-average distribution prices, requiring the utility to charge something approaching zero in areas that have excess distribution capacity, and something near 20 cents in areas with constrained distribution facilities. Such prices would send the “right” price signals to consumers and would likely cause DR to be installed precisely where they make the most sense. De-averaging prices along these lines, however, is impossible for the compelling practical and political reason that averaging of prices is a keystone of universal service.

De-averaged buy-back rates are a practical alternative that achieves most of the same economic price signals without the unacceptable policy approach of de-averaging all distribution prices. Geographically de-averaged buy back rates means the utility stands ready to buy back power (or power savings). The amount of power they offer to buy will be limited and the prices will vary by location of the power supply. The prices paid for buy backs would be high for customers that are located in high cost areas and low for customers located elsewhere. For example, customers in an area with 20 cent incremental distribution costs might be offered a 15 cent buy back rate. This would certainly produce a strong economic incentive for customers and others to invest in distributed generation in the right location. Because the company paid 15 cents instead of the 20 cent cost it would have incurred in upgrading the facilities there is an opportunity for savings to be shared with the utility. Regulators should recognize the importance of providing the utility with a positive incentive through a sharing formula to pursue these opportunity savings.

Many utilities, especially wires-only companies, have sought to transform retail rates from a volumetric scheme to a fixed charge. They argue that because their costs are largely fixed, that the customers' bills should be likewise fixed. There are two significant regulatory problems with this approach. First, if a customer can no longer reduce its bill by reducing consumption, it will have a greatly reduced incentive to manage energy use. With no price signal relating increased usage to increased bills, customers are likely to avoid efficiency or other DR investments, with the longer-run effect of increasing average usage per customer.

The second and more serious problem with the fixed price approach is that it relies on the incorrect presumption that the utility's costs are fixed. While it may be true that those costs do not vary with usage in the short-run, this is not true in the long-run. In the long-run, all costs are variable and are ultimately driven by usage. Therefore, it is important to maintain a volumetric rate structure, even for seemingly "fixed" costs. Failure to do so results in greater consumption and increased costs.

PRICING FLEXIBILITY

A number of utilities have asked and received "pricing flexibility" to discourage individual customers from installing distributed generation. This is very similar to a pricing practice that was fairly widespread a few years ago referred to as "co-generation deferral rates." In both cases, utilities argue that the distributed generating facility is not actually cost effective when compared to the utility's own marginal cost of supply, and that the co-generation (or in this case distributed generation) appears cost effective to the customer because retail prices are well above the utility's actual marginal cost. In these cases utilities have asked for flexibility to lower prices to the point that would discourage customers from installing non-cost effective on-site generating options. We expect that many states will be tempted to approve these pricing practices, in part because the revenue loss that occurs when customers self-generate will (or may) be borne by other customers.

One option for regulators is to allow pricing flexibility for low cost areas along the lines just described, but only if a utility simultaneously increases the prices (perhaps through de-averaged buy back rates) for high cost areas. It does not make sense to have a utility actively discouraging the installation of distributed generation in low cost areas if it is not simultaneously encouraging distributed generation in areas where costs are clearly above retail prices.

RESISTANCE TO CHANGE

Even if all the intellectual and economic arguments in this section are appealing, one more obstacle remains before a different regulatory approach to utility earnings is implemented. Regulators, utilities and intervenors are all familiar with the existing approach to regulation. Staffing is organized to execute it, and the experiences of the responsible managers are nearly or entirely related to it. While it is impossible to measure this inertial effect, it certainly exists and explicitly identifying it is part of evaluating whether to decouple profits from sales.

STRANDED COST BALANCING ACCOUNTS

How stranded costs are recovered plays a role in who has an incentive or disincentive to deploy DR. If stranded costs are recovered volumetrically customers will have an incentive to invest in DR. Conversely, the imposition of exit fees will discourage customers from installing DR.

The details also matter from the utilities' perspective. Most states collect stranded cost on a per kWh charge. In some states the stranded cost charge is fixed and can be imposed for a stated period of time. Lost sales in these states due to customer side DR or any other reason reduce the utility's stranded cost recovery. In other states the total amount of stranded cost recovery is fixed and tracked in a balancing account. The per kWh charge or the duration of the charge is allowed to change until the account is reduced to zero. The latter approach reduces the utilities disincentive to the deployment of DR.

MATCHING COSTS AND BENEFITS

One of the most challenging problems stems from the fact that DR produce benefits that typically flow to more than one entity, e.g., customer and utility. This produces a split incentive where no single entity sees all the benefits from DR. As a result, no one entity is in the position to conduct a comprehensive cost benefit analysis. The following table illustrates the range of benefits and the individuals or entities that see the benefit.

Matching Costs and Benefits

Type of Benefit	Who Sees Benefit
Capacity and energy	Participating customer directly, but also other customers if market prices are lowered by reduced demand, possibly utility
Reliability	Participating customer, but also customers generally
Environmental	Public except for private values such as credits
Heat	Participating Customer
Distribution	Mostly utility in the short-run, distribution customers in long-run

Utilities are generally able to take advantage of most, but not all of the benefits of DR. In particular, utilities can directly or indirectly benefit from the capacity and energy value of the electricity, the system reliability improvements, and distribution cost savings. They may be able to take advantage of transmission benefits but they are unlikely to realize the benefits of customer reliability or the non-electric benefits provided by co-generation or efficiency.

CONCLUSIONS ON PROFITABILITY DRIVERS

To address utility profitability issues related to DR the primary variables must be taken into account: utility structure, nature of the DR, and the form of regulation. With respect to utility structure, it appears that the structure of the utility is not a critical factor. At one extreme the utility may be a wires-only disco and at the other extreme it may be a vertically integrated monopoly. In any case, the basic conclusion is the same.

The nature of the DR matters a great deal. DR installed on the utility side of the meter do not jeopardize profitability. The primary, and perhaps only, negative impact on utility profitability of deployment of DR occurs when DR are installed on the customer side of the meter. This is true whether it is a demand side or supply side type of resource. From the utilities' perspective, demand or supply side resources installed on the customer side of the meters have the same effect, sales go down and revenues go down.

The form of regulation also matters a great deal. The most important variable is whether the utility is subject to PBR and more important whether the PBR price or revenue based. Price regulation generally discourages DR and revenue regulation does not.

The effect of utility ownership of DR on profitability is a complex issue which is made even more confusing by the commonly held and erroneous view that adding to rate base (investing in capital, "gold plating") improves profitability. There are a few simple economic concepts that inform us on this issue. First, profitability (as distinguished from profits) improves when the rate of return, or earning per share go up. Adding $1 million to profits doesn't help if the associated costs mean the rate of return dropped from 10% to 9%. It follows that profitability goes up if the rate of return on new investment exceeds the rate of return on existing investment. As a general rule, profits go up if the utility can grow revenues without growing costs.

Apply this to a situation where DR are located on the utility side of the meter and hence revenues are unaffected. In this case, investment in cost effective DR can substitute for even higher levels of investment in distribution plant. Less investment with the same level of revenues means higher profits. It also follows that if another entity built and owned the DR, the utility would see the same revenues and would have no investment. This logic suggests that the most profitable course of action when revenues are unaffected is to have someone else own the DR. The next most profitable option is utility ownership where it is less costly than investment in distribution plant. The least profitable option is to invest in poles and wires even though less investment in DR would do the job.

If the DR are on the customer side of the meter, revenues are affected. In this case, ownership will not influence the outcome for the utility by much. As a general matter, any benefits of utility ownership of resources installed on the customer side of the meter are outweighed by the revenue losses to the utility.

Although ownership of the DR may not matter much, control of the DR (when they run) matters quite a bit. When a generator runs (or when load management opportunities are triggered) will dictate whether transmission and distribution costs are incurred or whether transmission and distribution investment can be deferred or avoided.

LIMITATION OF PROFITABILITY

Getting utility profitability aligned with the deployment of cost-effective DR is an important step, but it does not guarantee success. Even if regulation is able to completely align utility profits in the deployment of DR, there may be other factors that overwhelm the power of any incentives. Such diversionary factors may include rate impacts, competitive and other risks, and issues of control or the lack thereof, each of which can undermine the incentives created in a PBR.

Consider the experience that many regulators had during the mid 1990's. A number of powerful PBRs were established that encouraged utilities to invest in energy efficiency. Utilities responded and energy efficiency investment and performance increased dramatically. Then conditions in the industry changed and utility executives became preoccupied with utility restructuring, competition, and stranded cost recovery. The shift of utility focus to these issues substantially detracted from the effectiveness of PBRs and notwithstanding the profitability of investment in energy efficiency, utility investment in efficiency dropped substantially.

ROLE OF DISTRIBUTED RESOURCES IN SYSTEM PLANNING

The impact on and relation of DR to system planning is not well understood. The coincidence of the electric sector restructuring with the introduction of new DR technologies presents a challenge in terms of identifying the various values of DR to a now disparate set of "users."

PRE-RESTRUCTURING PLANNING PARADIGM

Restructuring of the industry has had a major impact on system planning. In the previously vertically integrated structure, the utility operated as a cohesive whole and was able to manage and plan for all aspects of operations. Virtually all of the trade-offs between various planning options were visible to the utility and, to large extent, to the state regulator. The highest value choices were usually easily identified and utilities were expected to pursue them on behalf of the consuming public.

EFFECT OF RESTRUCTURING ON PLANNING PROCESS

An unintended aspect of restructuring was to unbundle the planning process in a way that makes it more difficult to both identify economic choices and to implement them. In the MADRI area, the system is operated by PJM which operates but does not own the transmission system of its members. PJM may actively involve itself in identifying transmission needs, but may not have access to information about more economic demand-side options that might defer or alter those needs.

Generation is largely owned by independent power producers or by affiliates of LSEs. In today's environment, generation generally no longer undergoes any form of need review and may be added at any time by any party. As in the case of PJM, generators may not have access to information about more economic demand-side options that might defer or alter the need for generation. In addition, generators may view more economic demand-side solutions as a direct competitive threat.

LSEs are in a better position to identify alternatives to transmission or generation expansions but often face uncertainty over whether they will continue to serve as the default or standard offer provider and over whether individual customers will change suppliers. This makes them reluctant to engage in long-term strategies to reduce total costs to consumers and introduces a bias in favor of short-term or "spot" purchasing strategies.

An overlay to all of these segments of the market, prohibitions on cooperation imposed over concerns about anti-trust or market power issues, has drastically reduced the level of communication and cooperation among market players. This applies to planning coordination among utility affiliates and between independent owners of generation and LSEs.

Emergence of New DR Values

While restructuring has clouded the planning process, it has potentially unleashed previously unrealizable values for DR investments. Proven demand-side strategies such as energy efficiency and distributed generation, have values and opportunities that were previously difficult to identify and even more difficult to realize. For example, peak-oriented energy efficiency gains were previously "valued" on the basis of average costs. Because vertically integrated utilities paid no premium for on-peak energy, other than in the fuel cost, the value of on-peak energy savings were understated. Worse, customers failed to see any temporally-based values from the reduction of on-peak usage because even the fuel costs were usually averaged into their bills. With restructuring, and a greater reliance on energy markets, the energy value of demand-side resources can be more readily quantified.

DR can also be more readily identified as an economic choice for a variety of ancillary services such voltage and VAR support. To some extent, the potential for these values has already been accommodated at the wholesale level in PJM's ancillary market structure. However, to the extent these values are local to the distribution system, DR has not, on the whole, been incorporated into the local distribution company's operations. In addition, PJM's focus thus far has been on the short-term market values of DR in the form of price responsive demand. There is no mechanism in the PJM market for recognizing long-term capacity values for DR.

Reconstituting the Planning Process (or Putting Humpty dumpty Together Again)

The process of identifying all of the various values for DR and connecting them with associated beneficiaries is handicapped by the unbundled nature of the industry and the lack of coordinated planning. Of all of the stakeholders in the industry, state regulators alone are in the best position to "see" the greatest scope of the market landscape and are, by definition, vested with the interests of the broadest public interest. While their scope is not complete, it is far and away greater than any other stakeholder segment. As such, the state regulatory forum is likely the best starting place for piecing together a comprehensive planning process.

To the extent that formal planning occurs today, it appears to be concentrated in two areas. First, at the wholesale level, PJM must necessarily involve itself in an extensive forward look at the transmission system and its overall ability to balance load and supply. This planning process, however, is not an "all-source" top to bottom review. It is focused on transmission and, collaterally, generation planning. It includes no distribution level planning and virtually no demand-side resource planning.

At the retail level, regulators generally oversee some form of standard offer service or default service (collectively SOS) for significant portions of the consuming public, especially for residential and small commercial users. This may or may not involve active planning. In most cases, SOS is either some form of pass-through of the short-term market or is, at best, a medium-term purchase of power. Ideally, SOS service should undergo some form of planning review that includes power purchasing strategies (e.g. portfolio management, etc.) as well as demand-side opportunities.

State regulators also oversee the distribution level wires business and often have some responsibility administering or reviewing public benefit programs such as energy efficiency initiatives. Distribution level planning, however, is not an area which has historically received a lot of regulatory attention. State regulators are well positioned to directly oversee distribution planning and expansion.

The details of distribution planning are not generally well understood in the regulatory community. Regulators should consider enhancing their review and requirements for distribution level planning and expansion. By clarifying their understanding of distribution level costs, regulators can greatly increase their ability to formulate sound policy strategies for dealing with DR issues. To accomplish this, regulators should consider requiring utilities to undertake an IRP-like approach to distribution costs and to disclose the important cost drivers for those costs. Some of these are discussed below.

ORGANIZATION OF DISTRIBUTION COSTS

For regulators, distributions costs are a bit of a black box – they may know the total costs for distribution, but they lack an understanding of what drives those costs. In order to get a handle on the underlying structure of distribution costs, certain simplifying assumptions can be made. Distribution system costs can be divided into two groups: (1) transformers and substations and (2) lines and feeders.[6] Transformers and substations are both the first and intermediate interfaces between transmission and customer-level service. Feeders generally connect the highest voltage transformers to intermediate level transformers. Lines carry the lowest distribution voltage power to individual customer transformers and drop lines.

HIGH AND LOW COST AREAS

Costs for new generating technology are fairly predictable and, given today's moderate new unit sizes, can be well matched to a utility's aggregate load growth. It is much more difficult (particularly in the short term) to match distribution system investments to load growth. In fact, while green field expansion of the system often requires a parallel expansion of generating supply, distribution replacements and upgrades can be required even when total system load is declining.

There are a number of factors that influence the relative expense of distribution investments. One of the most critical drivers is the rate of growth on the affected part of the system. A line that is at or near its capacity may need to be replaced with a higher capacity wire or upgraded to a higher voltage. If load on the line is growing at a rapid pace, the levelized cost of the investment may be reasonably low because it can be spread

[6] Meters and other customer premises equipment are an additional category of distribution costs. However, these costs are determined principally by the nature of the customer and do not vary in any significant way as a function of distribution system solutions.

across more consumption units within a short period of time. On the other hand, if load is growing slowly, the levelized cost can be several magnitudes above the average embedded cost of the system, sometimes hundreds of thousands of dollars per kW, and, on occasion, even millions of dollars per kW. Greenfield expansions can likewise be drastically affected by the rate of growth available to absorb the new investments. "Build it and they will come" strategies work only if "they" come relatively soon.

Geographic conditions can also drive costs. Upgrading major feeders in an underground, congested urban setting can be expensive, especially when compared to installing an overhead feeder in a suburban environment. Mountainous or rocky terrain is more expensive to work in than flat plains or sandy soil. Regardless of the general characteristics of a utility system, almost every system will have a combination of relatively high- and low-cost areas.

Finally, the technological "fix" for a given problem is critical to cost determination. Some solutions are almost cost free. For example, when faced with capacity constraints or high losses, loads on one substation might be lightened merely by throwing a switch that reroutes power to the same load, using an alternative path. Other solutions, such as installing an underground "super feeder" in an urban downtown or installing a major new switching station that requires numerous related investments in new feeders and transformers, might be extremely expensive.

Distribution utilities should be required to report the nature of the distribution system investments they are making (or plan to make) and identify specific projects that are particularly high in cost, especially as compared to the magnitude (*i.e.*, high $/MW) of the problem being solved. For some utilities, it may be that only a few, well-defined parts of the system are high cost. For other utilities, it may be that a more generalized area (or areas) can be classified as high cost.

EXISTING PROBLEM AREAS

"Problem" areas may also exist on the system; often they may be quite well known. These might be areas that suffer from chronic voltage support problems, experience high losses, are adversely affected by loads with poor power factors, or have a high number of outages. In these cases, the distribution investments are likely to be less oriented toward bigger (or newer) wires and transformers and more toward system "add-ons" like capacitors or local generation. Regulators will want to become educated about the causes of these problems and about the engineering and planning solutions that utilities typically use to address them. Regulators will want to explore alternative solutions, including changes in customer usage patterns (*i.e.*, energy efficiency, load management, innovative rate designs, etc.) or improved customer equipment.

ENVIRONMENTAL IMPACTS OF RESOURCE CHOICES

The technology and configuration choices made at all levels of the system will have both the short- and long-run environmental impacts. One of the important matters to consider when reviewing both traditional and non-traditional planning solutions is the environmental consequences of the alternatives. Not all new technologies are equal, and many are not environmentally benign. For example, a decision to rely on customer-owned emergency generation for peaking power might result in drastic increases in the operation of high-emissions diesel generation. This often occurs on very hot days that coincide with already high power plant emissions, especially when power comes from older resources, installed over the past several decades. On the other hand, energy efficiency avoids emissions altogether. The environmental impacts of alternatives should be disclosed and considered in the system planning process.

Effect On Markets

System expansion plans that rely heavily, or exclusively, on traditional central station power also tend to rely heavily on associated transmission and distribution system expansions or upgrades to deliver power. Failure to include these costs as part of the price of central power generation creates an implicit subsidy for such supplies. This is especially troublesome when there are higher emissions than would occur with DR such as energy efficiency or combined heat and power.

Development Of Policy Objectives

After the facts about distribution investments are understood, regulators are well positioned to consider a policy framework within which utility managers can work. Perhaps foremost, utilities should consider all viable approaches to distribution system expansion and improvement. A clear standard of prudence encompassing both supply- and demand-side solutions should be applied. Preferably, this standard will be based on least-cost planning principles.[7]

Rules Of Practice With Periodic Review

Regulators should consider new or modified rules for the distribution utility, written in light of the policy framework sketched out above. Regular reporting and disclosure of distribution system expansion plans are key to assuring that alternatives are being fairly and systematically considered. No less than once a year, the utility’s distribution investment projects should be disclosed to the regulator and the public. Historically, annual rate cases provided the opportunity to examine such plans, though issues of greater controversy generally pushed distribution plans out of view. With rate cases occurring with less frequency, implementing this regular reporting process assures adequate attention to quality distribution planning. Preferably, the customers (or any third party) should be given an opportunity to comment on plans and offer alternatives, perhaps in a competitive bidding regime. It should be made clear by the regulators that plans must include an assessment of long-run marginal costs, thus allowing for easy comparison across alternatives.

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[7] See *Portfolio Management: Protecting Customers in an Electric Market That Isn’t Working Very Well,* Harrington et al., The Regulatory Assistance Project, for The Energy Foundation and the Hewlett Foundation, October 2002, available at: http:www.raponline.org.

Perhaps most important is the development of an analytical discipline that is routinely applied by distribution system operators. Where the utilities remain vertically integrated (and where operators of unbundled distribution systems also function as the primary default service provider), the job will be made easier and can be readily adapted to the traditional regulatory process. For other configurations, regulators will need to develop a review process that assures that supply-side acquisitions are conducted in a way that takes account of distribution system costs and provides a means for evaluating alternatives to those costs. Utilities need not only to understand the economic trade-offs, but they need also to be held to a standard of conduct that requires that those trade-offs be taken into consideration.

Finally, adequate skills are needed within the regulatory agency. Distribution system costs have rarely been the focus of regulatory scrutiny. Staff will require additional training and direction to fulfill the regulator's responsibility of assuring least-cost system expansion and upgrades. While much can be borrowed from integrated resource planning, distribution system analyses will nonetheless require new skills and techniques.

THE MISSING LINK

One of the most significant challenges remaining is the coordination of the planning processes that occur at the state level with those that occur at the RTO level. This is likely to be the largest challenge facing the industry on a going-forward basis. There is no clear-cut mechanism for reconciling these two separate processes and there are a number of obstacles that are present.

While state regulators have the broad public interest mandate to consider most, if not all, of the important factors in the electric sector, they lack the jurisdiction to directly integrate wholesale level planning into their regulatory processes. As a result, a high level of cooperative planning and information sharing is required. At the same time, competitive market issues, including classification of information as proprietary and concerns over anti-trust and market power issues are likely to confound efforts to make information more readily available.

Yet, this type of information sharing is also critical to the establishment of a transparent market. Unless the value of distributed resource alternatives is clearly and readily identified, a number of economic opportunities are likely to be missed, resulting in overall higher costs to customers and to society. All affected stakeholders should endeavor to overcome these obstacles.

Ultimately, a formal or informal protocol may be required to close the gaps in the planning process. This may take the form of a memorandum of understanding between regional stakeholders, such as PJM, and state stakeholders, such as state regulatory commissions. However, it may require more formal action, perhaps by the FERC, to clarify the need for and scope of information sharing by generators, transmission owners and system operators.