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Distributed Resources: Incentives

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Distributed Resources Incentive White Paper

I. EXECUTIVE SUMMARY

The Edison Electric Institute ("EEI") retained NERA Economic Consulting ("NERA")[1] to examine ways in which regulation could be enhanced to provide utilities with incentives for the *efficient* deployment and operation of distributed resources ("DRs").[2] Distributed resources for purposes of this paper are defined broadly to include power producing (supply-side) and power use reduction (demand-side) technologies that are installed in a dispersed fashion throughout a utility distribution system, including at end-user locations that either actively or passively respond to market price or system needs. Efficient distributed resources are those that result in net benefits (cost reductions) greater than the costs of installation and operation of the distributed resource.

The primary focus of this white paper is to set forth for consideration several workable models for financial incentives that would encourage utilities to play an appropriate role in efficient DR deployment and operation. These proposals are necessarily tentative in nature. The very nature of DR makes it very difficult to craft robust DR incentive schemes that can work well in a variety of circumstances. The great variety of historical and regulatory environments may result in irreducible differences between utilities and across jurisdictions by dramatically changing the cost/benefit analysis for each type of DR program. Care must be taken in ensuring that the unique circumstances in a particular jurisdiction are recognized. This paper specifically addresses DR in a restructured environment, since implementing DR in the new electricity markets poses a novel and important challenge.[3]

In order to provide background and lay the foundation for those models, **Section II** reviews the case for efficient DR and the roles that various entities may play in implementing DR. **Section III** describes the barriers to DR implementation and **Section IV** provides suggestions for removing some of the barriers to efficient DR implementation.

The key findings of these sections are as follows:

- DR has a place in the mix of resources that can most efficiently satisfy energy needs.

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1 This white paper was prepared primarily by Eugene T. Meehan, a Senior Vice President at NERA, with Wayne P. Olson, a Senior Consultant at NERA. We thank Patrick Mawn for his research, graphic design, and editorial help. The opinions expressed herein are solely attributable to the authors and do not necessarily present a view of the firm or of other NERA professionals.

2 Normally, uneconomic DR would not be implemented; there could, however, be exceptions where DR is implemented because of reliability or other considerations.

3 Restructuring efforts have been implemented in sixteen jurisdictions: Connecticut, Delaware, the District of Columbia, Illinois, Maine, Maryland, Massachusetts, Michigan, New Hampshire, New Jersey, New York, Ohio, Pennsylvania, Rhode Island, Texas and Virginia, representing about 42 percent of the total United States population. Partial restructuring efforts have also been implemented to varying degrees in Arizona, Montana and Oregon. Generally, when discussing the "utility" functions of restructured distribution and POLR utilities, we will use the term "Distco." Nevertheless, there are instances where the term "utility" is used in a context that is relevant to both Distcos and the traditional vertically-integrated utility that operate in the other U.S. states.

- Many parties, including utilities, equipment manufacturers, energy service companies, electricity retailers and customers have important roles to play in encouraging efficient DR deployment.

- Regulatory and ratemaking practices in the era of restructuring have, in many cases, been developed with DR as a low priority relative to other objectives, such as price reductions and freezes and encouragement of competitive market development.

- Barriers or disincentives to DR implementation are identifiable and can best be removed through targeted modifications to rate design and regulatory practices.

Section V addresses comprehensive decoupling mechanisms as a way for regulators to eliminate the disincentives the utility normally has to promote energy conservation while preserving the utility's financial integrity by stabilizing revenue. Although decoupling is designed to deal with the disincentive issue, in practice, it is vulnerable to a number of criticisms.

Distributed resources can provide a number of societal benefits including reduced transmission congestion, avoided fuel and purchased power costs, and possibly deferred transmission and distribution investment. But even "efficient" DR can impose costs on the utility and other customers. For example, distributed generation ("DG") can allow a utility customer to largely bypass the electric distributor, while imposing costs on the distributor because of its obligation to serve the customer when the customer's DG facility is taken off-line or is out of service. Given the fact that most utility costs are recovered on a "throughput" basis, this can result in cost shifting to non-DG customers. Economically correct stand-by/backup rates are part of the solution to this problem, but are not a panacea. Generally, the initiation, operation and maintenance of DG requires significant capital investment, time and effort by the utility.

The focus of this white paper is on the role of electric utilities in developing DR. Incentive mechanisms can facilitate the benefits of DR by improving the market for generation and the regulation of delivery. Likewise, regulators can achieve more efficient electricity provision by implementing various incentives for DR. Accordingly, **Section VI** proposes the following mechanisms for promoting utility involvement in DR through financial incentives:

- Incentives for DR Aggregation Services;

- Rate Basing with Incentive Rates of Return Combined with Long-term Delivery Service Rate Indexing;

- Fixed Incentives for Achieved DR; and

- Incentive for Deferral of Distribution Investment.

We do not represent that each model would work for all utilities in all circumstances. Indeed, some members may find that none of the models works for them. Our purpose is to stimulate thinking and discussion among utilities and policy makers, not to propose specific policies or solutions. Also, the models should not be viewed as discrete and mutually exclusive. Rather, they should be seen as mechanisms that can be combined and reconfigured to meet a variety of needs and circumstances.

II. INTRODUCTION: THE CASE FOR DISTRIBUTED RESOURCES

The *case* for distributed resources is simple.[4] Distributed resources can lower the total cost of meeting electricity demand, including not only production costs but also transmission and distribution costs. Some types of DR can provide a "demand response" at peak periods that can reduce transmission congestion and avoid the use of high-priced power at peak periods. Other types can reduce demand on part of a distribution system, thereby perhaps allowing the utility to avoid or delay capital investment. But, showing the "cause-and-effect" role of DR in avoiding the use of high-cost power and/or avoiding capital investment is not so simple.

Utilities have traditionally developed distributed resources in two forms. These are automated load management (also known as direct load control) and interruptible rates. The former most often involved control of appliances such as water heaters and air conditioners in residential and small commercial applications. The latter most often focused on large industrial users. These applications served multiple purposes. Most importantly they reduced the need for generating capacity additions and the need to finance such additions. Additionally, when they could be relied upon, they could also affect distribution and transmission planning loads and help to defer investments in delivery facilities.

Distributed resources generally can help to lower overall costs because they fit a niche that traditional generation options do not. They can be targeted to a select group of hours and can help to manage demand in those hours in a way that avoids the need for traditional supply facilities. They have a capital-to-operating-cost ratio that differs from generation and hence fits a specific portion of the load curve better than generation. For example, demand-side types of DR may be available that have a lower installed or capital cost than new generation, but at a higher variable cost. Assume, for example, that a peaking unit has a fixed annual cost of $100/kW a year and a variable cost of $75/MWh. A customer may be willing to curtail load by investing $25/kW a year in equipment and not operating when prices exceed $300/MWh. For a certain portion of the load curve it would be more efficient to not build the peaking unit, but to encourage the customer to invest in equipment that enables curtailment in response to market price. By focusing on loads that can be best met by a demand as opposed to a supply response, DR adds an option for meeting demand that cannot be replicated with generation. Any additional option for meeting load cannot raise costs provided that it is efficiently deployed. Further, the dispersed nature of DRs can reduce losses and lower delivery facility peak loadings. For example, there may be load areas where traditional larger scale generation cannot be realistically sited. In order to serve load reliably in those areas, significant transmission or distribution investment may be required. DR, even if not as efficient from a generation-only

[4] While DR can represent a novel solution to a problem that does not mean that it is the most efficient one. As the flowchart in **Appendix B** shows, a cost/benefit analysis of DR relative to all other options available to a unique utility in a unique jurisdiction must be performed to determine whether DR should be implemented. This paper describes the regulatory and incentive—but not economic (*i.e.*, cost/benefit)—barriers that have limited DR development.

perspective, may be the most efficient solution if it can defer the need for a transmission or distribution investment.

A. Economic History of Distributed Resources

Several utilities had developed over 2,000 MW of distributed resources each by the mid-1980s and avoided significant plant expansion and capital expenditures.[5] However, as excess capacity developed and distributed resource potential from existing programs was becoming exhausted, the emphasis on expansion of these programs waned. Currently, two factors—technological progress and the restructuring of electricity markets—provide an opportunity to revisit distributed resources.

Communication technology has certainly advanced to a point where the communication of price signals and the control of load are now much less costly and more effective. Improvements in technology, whether they improve the information available to a DR operator or the performance of a DR, will serve to improve the economics of DR. A broad variety of distributed resource alternatives including real time prices, demand bidding, demand response, load control and on-site generation are potentially cost effective and may potentially reduce the need for investment in traditional generation facilities as well as in delivery service facilities. Accordingly, there are now many different options for DR available to utilities, regulators and to customers. **Table 1** outlines various DR programs, their effects upon the behavior of the customer, and the economic impact these behavioral changes have on the distribution, transmission and generation systems.

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[5] *See*: *Investor Responsibility Research Center*, "Generating Energy Alternatives," 1987 and **Appendix A: Summary of IRRC Study**.

Table 1. Distributed Resource Programs

Type of Program	Description	Examples	Economic Impact / Considerations
Supply - Side			
Distributed Generation	On-site, small-scale electricity production used when their costs are less than the combined cost of central station generation and the costs of upgrades or expansion of the transmission and distribution system.	Generators, small turbines, fuel cells, and renewable technologies such as wind and photovoltaic generators.	Reduces demand for transmission; increases price elasticity and shifts the supply and demand curves
Demand - Side			
Demand Side Management	Efforts focused on reduction of base load through investments in making equipment less energy dependent .	Waterheater insulation, energy efficient appliances, etc.	Reduces overall energy demand regardless of price. (Shifts demand curve)
Energy Conservation	Reduction of non-essential energy usage.	Turning off lights, appliances, electronics when not in use.	Reduces overall energy demand regardless of price. (Shifts demand curve)
Demand Response	Efforts focused on reducing electricity consumption during peak periods.		Make customers more responsive to actual energy costs (via pricing and/or technology)
Load Response Technology	Use of load curtailment hardware/software to reduce demand during peak hours.	Timers and switches on heaters, A/C, etc.	Reduces peak load.
Price Response Rate Design	Customers agree to reduced rates, subject to service interruption (or market pricing) during peak usage periods.	Time-of-Use, Real-time or coincident peak pricing	Last resort for high demand periods, more efficient than random blackouts
Demand Reduction	Paying customers not to consume during high demand periods.	Demand Bidding or "Buy back" programs	May reduce demand, but could have adverse selection problems

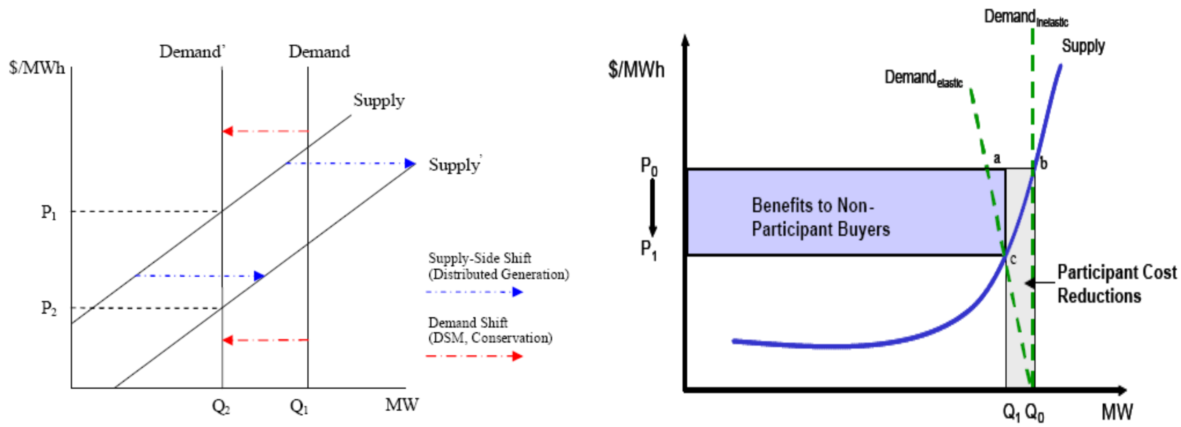
The paramount question is how DR affects customers—the goal, after all, is to have an efficient electric system that provides customers with the service that they expect, at costs that are reasonable, and with the reliability, safety, and adequacy needed to support the modern economy. The DR programs in **Table 1** can impact customer behavior and the electricity market equilibrium in three basic ways:

- by incorporating customers into the supply-side of the market, DR programs can shift the supply curve of the electricity market (*e.g.*, distributed generation);
- by reducing the overall level of base load consumption, DR programs can shift the demand curve of the electricity market (*e.g.*, DSM or conservation); and
- by inducing customers to consume less during times of peak energy usage DR programs can make customers more responsive to energy costs (e.g. demand response programs).

Figure 1 shows the theoretical impact of each type of DR on the market equilibrium. **Figure 1a** shows that "Curve Shifting" DR, representing shifts in either supply or demand, can lower the quantity of electricity consumed and the overall price of electricity. **Figure 1b** shows how "Demand Response" DR changes how consumers react to price signals, which benefits all market participants, not just the DR participants. Demand Response programs are generally designed to expose customers to the higher costs of usage at peak times. A NARUC study explains that "[w]hen customers receive price signals and incentives, usage becomes more aligned with costs. To the extent customers alter behavior and reduce or shift on-peak usage and costs to off-peak periods, the result is more efficient use of the electric system."[6] The net effect on the market demand for electricity is to reduce the amount of electricity consumed when costs are higher. In other words, the market equilibrium is the result of a more elastic demand response.

Figure 1. Theoretical Impact of DR programs on Electricity Market Equilibriums

(a) Impact of "Curve Shifting" DR **(b) Impact and Benefits of "Demand Response" DR[7]**



The basic impact that DR can have on a market is the same without regard to whether the DR is located in an area served by a vertically-integrated utility, in an area where the utility has unbundled and generation is provided through a competitive market with retail choice of supplier in place, or, in areas with or without RTOs and organized spot energy markets.[8] However, the incentives and price signals available to individual parties to encourage and implement DR may well differ in these different environments. In a vertically-integrated situation, the utility is responsible for pricing and planning. The utility may elect to directly invest in or promote DR or to develop innovative pricing structures that encourage customers or service providers to implement DR. The entire range of costs from generation through distribution can be considered when evaluating direct investment or developing pricing structures. In an unbundled situation (with an RTO or ISO), it is more likely that generation price signals will be market based and

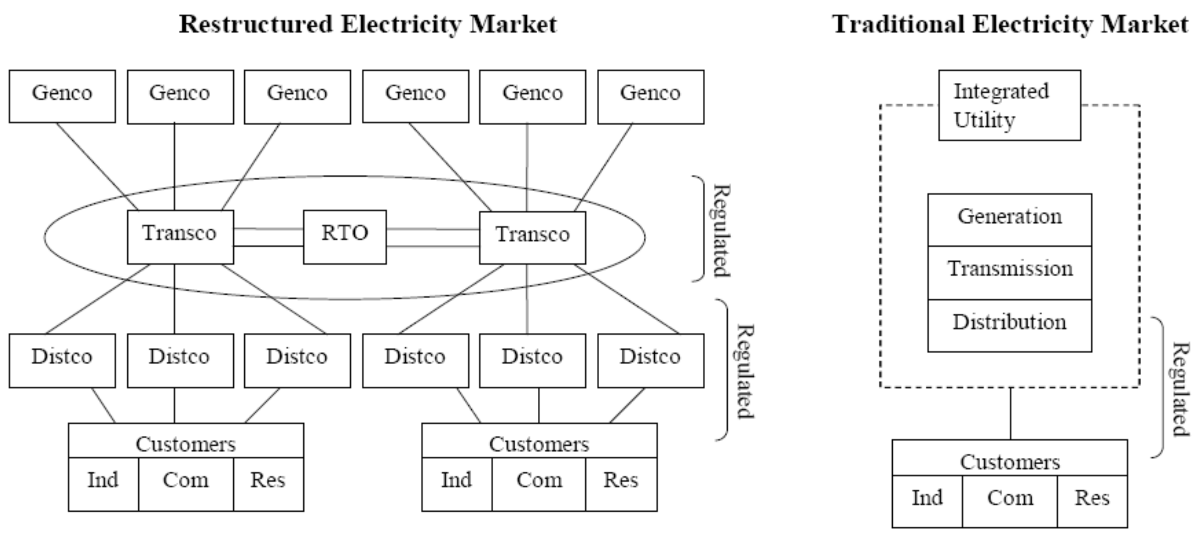
[6] Source: David Kathan. "Policy and Technical Issues Associated with ISO Demand Response Programs." Prepared for NARUC, July 2002, p. 5.

[7] *Id.*, p. 6.

[8] DR that responds to real time prices can also serve to moderate spot price spikes and may mitigate the influence that generators have on spot prices as supply scarcity approaches in real time markets. While these are real benefits of DR, they are not measures of efficiency as the impacts are distributional. That is, to the extent that DR lowers market prices, it lowers both the amount that customers or suppliers pay and the amount that generators receive. One group benefits and the other is harmed and there is no impact on efficiency. Further, to the extent energy prices are reduced, the incentive for investment in generation is reduced and capacity prices may rise. However, to the extent that the price reduction is a limitation on the exercise of market power that produces super normal profits, efficiency benefits may well result from this distributional effect.

also more likely that service providers or retailers will be involved with DR implementation. Further, generation- and transmission-related resources may largely be dealt with at the RTO/ISO level, with minimal involvement of the Distco. **Figure 2** shows how restructuring can create multiple layers of price signals and incentive effects when compared to the traditional, vertically-integrated industrial organization.

Figure 2. Pathways for Incentives and Price Signals in Restructured and Vertically-Integrated Environments



As **Figure 2** illustrates, in order to efficiently implement and encourage the development of distributed resources, each market entity in a restructured electricity market must adopt appropriate incentives, policies and pricing that work in conjunction with one another. The next section describes the role of each entity in DR development.

B. Roles of Market Participants in Distributed Resource Development

DR is a complicated subject—the effects on utilities, customers, ESCOs, the RTO, and other third parties, depends a great deal on exactly what distributed resource is being considered and what effects DR has on the wholesale generation market (especially at peak periods), the transmission grid (especially in congested parts of the transmission network), and the distribution system (especially whether the utility can avoid any costs because of the DR resource). **Table 2** provides a basic description of the "players" in the DR business and their general role in developing DRs.

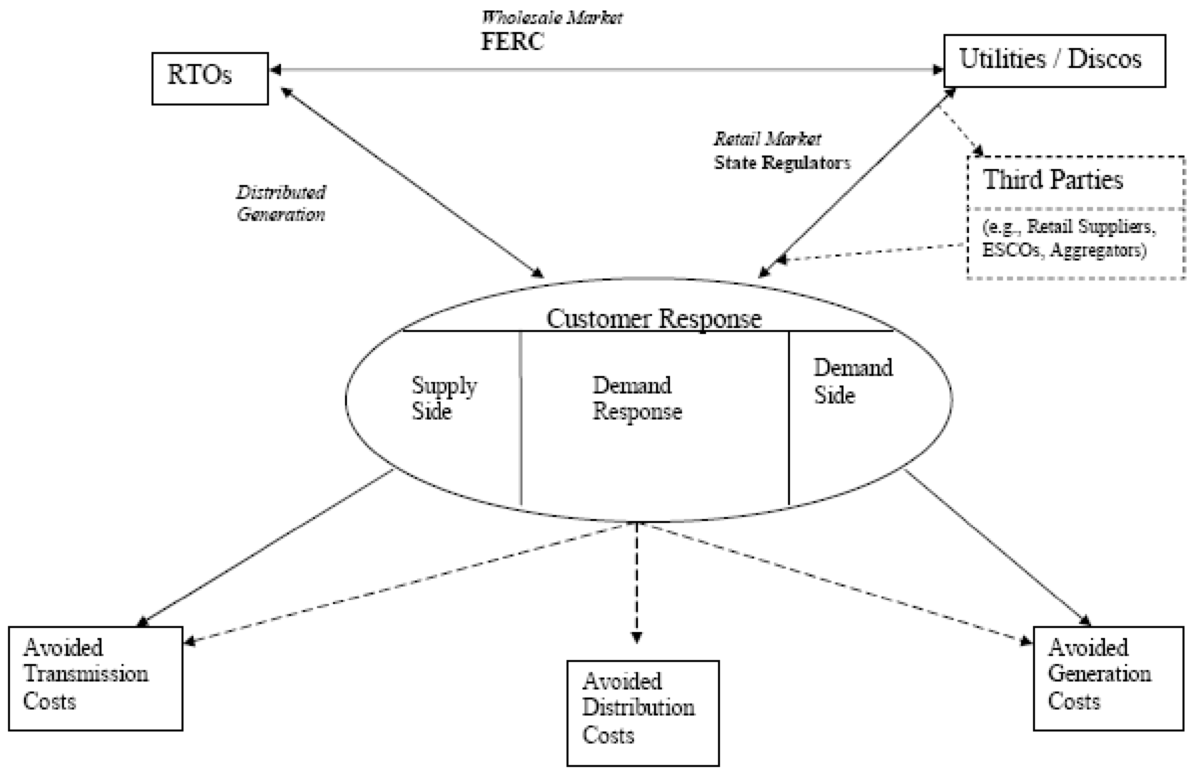
Table 2. Roles of Various Electricity Market Entities in Distributed Resource Programs

Entity	Description of Role
Customers	DR programs must contain economic incentives for customers to participate. When customers are responsible for the initial installation of equipment and the investment of capital (generators, switches and meters), they should be able to retain a portion of the savings resulting from these programs. Customers are also risk-adverse and fear changing from a known rate. Empowering customers ("permission-based curtailment") and clearly written, simple regulation and rates as well as financial incentives can overcome barriers to DR program development.
Utilities	Because utilities have more contact with customers than RTO/ISOs, they are generally better suited to start, evaluate and inform customers about new programs.[1] Utilities can help identify "downstream" locations that are congested and make the necessary investments to improve service. DR investments can be seen as vital capital expenditures in the distribution system necessary to maintain the level of service demanded of electric service providers. Competition between providers will only heighten the importance of these service improvements.
Third Parties	Retail Suppliers, Energy Service Companies and aggregators can manage customers and loads, reduce usage and earn money by taking on the risk from utilities & customers. Because third parties are not regulated like utilities, they can be a source of innovation and risk-taking in the market place.
RTOs	RTOs view DR Programs in two ways: 1) Reliability-based Transmission helps balance needs by moving power to critical areas; 2) Market-based Transmission improves cooperation and flexibility by allowing excess power to be used in areas where it is most valuable. Also, RTOs (with regulators) can manage small generator connection to "the grid" to allow the transmission of excess power and have implemented Demand Response Programs.
Regulators	Regulators can help the development of DR programs by changing the incentives faced by both utilities and customers, such as DR pricing and DR cost recovery.

Notes:
[1] This is not always the case. On occasion, alternative parties will act as the primary "agent" for implementing some types of DR programs. For example, the New York State Energy Research and Development Authority ("NYSERDA") funds activities such as programs aimed at improving energy supply and efficiency, including some DR efforts. And in Maine, the primary Demand Side Management effort has been headed by the Public Utilities Commission through its "Efficiency Maine" programs.

None of the above entities exist in a vacuum. Regulators provide a key role because they have the power to improve and change the incentives faced by each of the above players. **Figure 3** summarizes the flow of information, interactions and how DR programs target customers to reduce transmission, distribution and generation costs.

Figure 3. Interaction of Electricity Market Entities in Distributed Resource Programs



While the interaction of each entity may appear fairly clear in **Figure 3**, the DR programs suffer from a common economic problem: the benefits DRs can have on the electric grid are similar to a positive externality. The full amount of the avoided costs or benefits may not align perfectly with the avoided benefits (*i.e.*, lost revenues) or the costs of implementing, operating and maintaining these distributed resources in a restructured environment. This can also be seen in **Figure 1b**, where non-participants in demand response programs benefit by the participants' increased price elasticity. Externalities, by definition, represent an effect of one economic agent on another that is not taken into account by normal market behavior. The market prices for DR may not reflect the true costs to the supplier or benefits to the consumer of the good or service.

The restructuring of the electricity markets represents a movement along a spectrum spanning possible forms of industrial organization away from complete vertical integration, increasing the number of market entities, each with a unique and independent decision making process. Implicit in the concept of vertical integration is the "elimination of contractual or market exchanges, and the substitution of internal exchanges within the boundaries of the firm."[9] Traditional utilities effectively "internalize" externalities and streamline cash flows through a single entity. While restructuring efforts have increased competition and innovation in electricity markets, DR policies and practices must evolve to reflect these changes. In the next section, we discuss the current impediments to efficient DR development.

[9] Martin K. Perry. "Vertical Integration: Determinants and Effects." *Handbook of Industrial Organization*, Volume I, (Schamalensee and Willig, ed.), Elsevier Science Publishers, 1989.

III. FACTORS THAT IMPEDE THE EFFICIENT DEPLOYMENT OF DISTRIBUTED RESOURCES

In practice, making distributed resources work well would not be easy. In the ideal situation, the prices that each customer sees and anticipates for bundled electricity or unbundled generation, transmission and distribution would reflect the resource costs of providing these services. Customers, with the assistance of energy service providers, would make efficient decisions with respect to DR investment and operation. Price signals alone would be sufficient to encourage efficient DR and other incentives would be unnecessary. For a variety of reasons this ideal situation is not the reality and is not practical. There are many factors that prevent DR from being deployed optimally. Several of the primary factors are described below. A barrier to utility promotion of DR could be reduced by removing disincentives and providing incentives.

A. Rates are Based on Sales Levels and are Designed to Recover Fixed Costs Over a Volume of Usage.

Standard utility rate design—where the bulk of utility revenues are a function of "throughput"—is an impediment to efficient DR development. Local facilities' costs may be recovered through measured demand charges or energy charges. Some types of DR such as on-site generation can result in customers achieving a radically different usage profile. For example, a customer may only consume when its on-site generator is on maintenance or otherwise unavailable. The local facilities needed to meet that customer's full load are still required to be in place, but infrequently used. Under many rate designs, based on volumetric demand or energy charges, the costs of such facilities would not be recovered from customers who implement DR. This would result in cost shifting to other customers, and, in the short-term, a revenue shortfall to the utility. This provides an incentive to the customer to implement DR that is <u>not</u> efficient, and creates a disincentive for the utility to encourage DR (i.e., because it results in revenue losses that exceed cost savings).

While it could be argued that the true cost of providing standby service creates a barrier for DR, it would be wrong to ignore economic reality. A utility customer that has an on-site generator should not be able to avoid paying for the costs that it imposes on the utility. Economically correct stand-by/backup rates are part of the solution to this problem, but are not a panacea.

The general nature of the regulatory and ratemaking framework also can provide an impediment to efficient DR implementation. To the extent that DR causes such sales to decline, revenues would also decline. Generally, cost savings would only result in the longer term. Hence, utility profitability would decline in the short-term if DR results in decreases in billing units. While utilities have long championed conservation for a variety of long-term business reasons, it is possible that DR would decrease earnings in the short-term and that this would serve as a disincentive for the utility to play an active role in promoting DR. Further, as many utilities have unbundled and become primarily distribution companies, costs in the short-term are fixed. To the extent that DR causes short-term revenue erosion, the impact on profits may be significant and cause a significant disincentive to DR. A utility's sensitivity to lost profits, termed the "throughput issue," may prevent the implementation of new technologies and DR programs if DR reduces the load of electricity delivered and utilities do not have the opportunity to share in the benefits of the new technology. The extent to which rate designs may provide financial disincentives to utility encouragement of DR can best be examined by analyzing the degree to which those rate policies result in a balance between lost revenues and cost savings—*i.e.*, net lost revenues.

B. The Rates that Customers Face for Electricity are Averages

Customers in bundled situations as well as customers who buy unbundled services and obtain generation at fixed prices pay average rates for generation that may be time differentiated, but do not reflect real time price volatility and transient price spikes. Thus, these average prices do not precisely reflect resource costs at specific times or for individual customers. A large part of the efficiency benefit of distributed resources comes from the ability of those resources to respond on short notice to price spikes that are of limited duration and where customers can cost-effectively reduce or shift usage. Hence, rates that do not reflect the real time market value of energy are one impediment to efficient DR deployment. When customers are insulated from market price volatility, they may have little or no incentive to invest in DG or DR.

While time averaged rates are the rule for generation, geographically averaged rates apply for transmission and distribution facility cost recovery. The geographic averaging of these rates means that customers do not see price signals that reflect the specific incremental or decremental costs that DR installation and operation would have upon the transmission and distribution system. Even where DR may result in savings from the deferral of delivery service facility investments, this benefit flows to all customers and hence the incentive to make the investment is diluted.

It is important to recognize that there are many reasons why rate averaging has been and is the standard methodology for both bundled and unbundled rates. It would not be practical to broadly eliminate rate averaging. Rate averaging does, however, serve as an impediment to efficient DR development.

C. Lack of a Clear Mandate for Utilities to Participate in DR Promotion and Development.

Due to their high degree of contact with customers, utilities are in the best position to promote DR programs. Unfortunately, there are few financial incentives in place for utilities to do so. This is especially true in unbundled markets where retail supply is a competitive function. This lack of a mandate to participate in DR creates uncertainty over cost recovery if DR activities are promoted by a regulated distribution company. Uncertainty over cost recovery is a significant deterrent to utility involvement in DR activities.

Allowing an active role for utilities in DR is likely to be beneficial. The Massachusetts Department of Telecommunications and Energy ("DTE"), in addressing a similar issue, found that allowing utilities to compete in certain non-core markets helps to ameliorate market power.[10] Increased competition benefits consumers (through lower prices and/or higher quality)

[10] Before the Massachusetts Department of Telecommunications and Energy, "Investigation by the Department… establishing standards of conduct governing the relationship between electric distribution companies and their

and society generally (by improving the allocation of society's scarce resources). As a result, consumers' needs could more assuredly be met by allowing utilities to participate. In some cases, if the utility were foreclosed or restricted from providing these services, the practical effect could be that certain needs of customers might not be met. This would especially be the case where DR-related markets are "thin" because the utilities are for some reason not able to participate. Customers may perceive risk in making long-term commitments with vendors they have only known a short time, perhaps relating to concern about the financial condition of the DR service providers.

D. Fragmentation of Benefits and Mismatch between Distribution of Cost and Benefits

A major disincentive to efficient DR deployment is the disconnect between costs and benefits—the bearer of the cost of DR implementation does not necessarily see the benefits. DR benefits may come from several sources including transmission savings, distribution savings, lower market energy costs (deregulated markets), and lower generating costs (regulated markets). These benefits would be widely dispersed. For example, distributor costs savings may simply lower overall average distributor rates for all customers. The DR customer would see an imperceptible share of any benefit. Similar reductions in market energy prices and/or generation cost savings flow broadly to all customers. The implementing customer, the DR service provider and the utility may all see only a portion of any savings and even that may be temporary or diluted over a broad customer base.[11]

Unlike most economic decisions, there may be little or no alignment between benefits and costs. If the investor is uncertain about who would capture the benefits, investment is unlikely to occur. This issue affects the incentive intensity of the various participants in the DR market. Incentive intensity refers to the degree to which a party can "reliably appropriate the net receipts (which could be negative) associated with the party's efforts and decisions."[12]

IV. MITIGATING BARRIERS TO EFFICIENT DEPLOYMENT

This section of the paper discusses four ways to mitigate the barriers impeding utilities from efficiently developing DR. We clearly distinguish between removing disincentives and providing incentives.

We must again admit that our suggestions are tentative in nature. DR presents major challenges, not the least of which is the difficulties that result from the difficulty in aligning the benefits of

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affiliates and between natural gas local distribution companies and their affiliates." Docket No. 97-96, Order, June 1, 1998.

[11] For example, a utility could hypothetically defer a distribution investment and achieve savings that were significant in relation to the cost of the DR installation. However, the savings would be temporary as the next rate case would factor in the savings and rates would be lower. The savings would also be diluted. When spread over all customers they would not provide a significant benefit to the customer that incurred the DR installation costs.

[12] Oliver E. Williamson, *The Mechanisms of Governance* (New York: Oxford Univ. Press, 1996), p. 378.

DR with those that bear the cost of that DR. Nevertheless, there are some things that can be done to mitigate barriers to efficient deployment of DR.

A. Rate Structure Reform

There are two primary ways in which rate design could provide a financial disincentive to utility encouragement of activities that reduce usage of the distribution system. First, rates could be imperfectly designed from a cost perspective and costs that do not vary with energy or demand may be recovered in per-kiloWatt hour ("kWh") or per-kiloWatt ("kW") based usage charges, as opposed to fixed charges. The utility would have a financial disincentive to encouraging DR if its revenues decrease significantly faster than cost when usage is reduced. Second, there may be a long delay between the time when delivery system costs, if any, are saved as a result of reduced usage of the system and when revenues are lost. In all likelihood, rates will be designed based on long-run marginal or average costs of the delivery system and delivery system cost savings in the short-term may not reflect long-run marginal or average costs. A financial disincentive to encouraging DR would result if its revenue loss occurred upfront but cost savings only emerged much later, if at all.

To deal with these problems, two things are needed. The first step in ensuring that delivery utilities do not have a financial disincentive for implementing DR is to make sure that conventional, and not just standby, delivery service rates are properly aligned with costs. Customers, whether individually or through an energy service company, evaluate whether to pursue DR or energy efficiency based on the price signal that is sent by the delivery service rate design. Rate designs generally must properly assign costs between usage-based charges and fixed charges. Rate design and the corresponding cost recovery that is properly aligned with the potential benefits of a DR program would tend to result in economically-efficient decisions by both customers and energy service companies with respect to DR implementation. While aligning rates associated with geographic costs may generally be problematic for multiple reasons, DR incentives should recognize that DR investment in certain locations may be more beneficial to the system than others and should reward investment at those locations accordingly.

Second, rate designs for standby/backup rates for customers that want to stay on the distribution grid for reliability purposes, but plan to get most of their electricity from DR, are important from the perspectives of the utility customers and the energy service provider. If a DR customer requires essentially-equivalent local delivery facilities, but uses substantially less energy or measured demand than an equivalent customer without DR, the local delivery system capacity requirement may be the same because of the need for standby (back-up, maintenance or supplemental) service at the same level of the customer's non-coincident peak demand.

In this situation, the rate design would not provide for revenues that equal costs, which would present the delivery utility with a financial disincentive to encouraging DR, assuming that the revenue lost from DR is significantly greater than the cost saved, if any, as a result of the DR installation. Even with movement toward more economically efficient standby/backup rates, DR may result in revenue losses that are larger than the cost savings. By offering alternative rate schedules such as standby and interruptible services, utilities are capable of pricing their services more efficiently. By structuring rates to accommodate DR efforts according to their effective marginal (or individual/independent average) costs, utilities can mitigate many of the distortions of homogenous rates that seek to capture average costs.

B. Specific Lost Revenue Recovery

As noted in **Section III.A**, a delivery utility may well have a financial disincentive to encourage DR, if the revenue lost from DR is significantly greater than the cost saved, if any, as a result of the DR installation. The "throughput issue" can be mitigated by developing proposals for specific net lost revenue recovery and incentives in situations where the Commission decides to promote particular programs to further the public interest, such as environmental goals. Cost-based rate design and consistent regulatory policies that assure recovery of costs and lost revenues, however, must be targeted at specific lost revenue.

By specific lost revenue recovery we mean both rate designs that stem revenue loss and specific tracking mechanisms that estimate and provide a way to defer and recover the net revenue lost from DR implementation. While both methods can ensure that the utility is made whole, the latter's estimation and deferral procedures could imperfectly recover DR costs, shifting costs from participants to non participants. In particular, care must be taken to avoid efficiency and subsidy problems that can arise from some types of poorly-designed decoupling proposals (see **Section V** for a complete discussion of decoupling).

C. Clarification of the Utility's Role in DR Programs

While the diversity of DR makes it difficult to generalize about economic benefits, distributed resources *do* have an important role to play—and utilities naturally can play a key role here. By their very nature, electric utilities are load aggregators. For distributed resources to work well within the electric network, a continued utility role in aggregating loads and making DR investments makes sense and should not be discouraged. In fact, incentives to utilities for encouraging efficient DR are warranted.

In the traditional vertically-integrated electric utility industry, electric utilities provide generation, transmission, distribution, and retail sale services on a "bundled" basis within a franchised service territory. In selling electricity to consumers, the utility, as a regulated monopoly, (by definition) "aggregates" the demand of its customers and serves the entire market within a defined territory.

With the introduction of electric restructuring/retail competition, various firms would compete with each other to win retail customers, and in doing so would seek to efficiently aggregate the demand of the customers that they win. The Distco would usually provide provider-of-last resort ("POLR") service to those remaining customers that do not switch. Users of electricity would consider the offers made by retailers, opportunities to aggregate their load with other users, and non-price considerations when selecting their provider. Supply and demand, rather than regulation, would determine the market clearing price as well as the DR programs available for implementation.

In restructured markets, aggregation would continue to take place—but on a competitive (rather than a monopoly) basis. Through the market process of numerous buyers and sellers making individual decisions, competitive markets allow consumer demands to be sorted out, and aggregated by efficient producers at as low a cost as possible. The price information provided by the market gives buyers and sellers the information that they need to make their individual production and purchasing decisions. The potential dynamic benefits of retail competition, such as increased economic efficiency, reduced costs to consumers, technological innovation, and improved quality, reliability, and customer service, can be provided without artificially distorting the market aggregation process.

By combining DR programs of individual customers, both traditional utilities and Distcos can aggregate the benefits provided by DR programs and take advantage of economies of scale and scope to improve the entire system's reliability and performance. By aggregating DR programs, utilities act as the "caretakers" of the electrical grid. In order for these efforts to be successful, utilities must have this clear mandate with incentives to match.

D. Alignment of Costs and Benefits

Rate redesigns that help to eliminate financial disincentives for utilities are also important from the utility customers' perspective. Utility rate designs present customers and potential DR providers with price signals. It is customers acting through energy service companies that individually evaluate and decide on DR as a function of the price signal—*i.e.*, the delivery service rate design. The proper design of utility rates provides customers with the incentive to consume electric services in a manner that is economically efficient and that does not burden the delivery utility's other customers. For example, if usage-based rates are above cost and fixed charges are below, a customer may be induced to expend more on a DR alternative than is economically efficient. While utility profits would fall in the short-run, in the longer run rates to remaining customers would be higher than if the rate design had been aligned with costs and the economically-efficient decision had been encouraged.

If DR programs provide benefits that are desirable to all parties on the electrical grid (such as reduced load at peak times), the cost of adopting, implementing and encouraging their growth could be shared in some fashion among all parties that benefit.

V. PROS AND CONS OF BROAD DECOUPLING MECHANISMS

Proponents of decoupling mechanisms (also known as an Electric Rate Adjustment Mechanism or "ERAM") would argue that decoupling is a way for regulators to eliminate the disincentives the utility normally has to promote energy conservation by linking utility revenue to a target other than sales of electricity.[13] Although this mechanism is designed to deal with the disincentive issue, in practice, decoupling is vulnerable to a number of criticisms. This section

[13] Additional names for decoupling include ERAM-per-customer, statistical recoupling, revenue indexing, revenue cap or revenue-per-customer cap. Revenue caps incorporate decoupling into a multi-year price-cap plan (but great care needs to be taken when designing a revenue cap because a strict revenue cap will have zero marginal revenue for new customers absent agreed-upon growth adjustment factors).

of the paper will first describe a typical decoupling mechanism, highlight state experiences with decoupling and conclude with a prospective analysis of the potential benefits and drawbacks of decoupling.

A comprehensive decoupling mechanism would completely decouple utility sales (kWh throughput) from utility revenue. Comprehensive decoupling mechanisms were implemented in several states (especially in the early-1990s) in conjunction with large-scale utility-funded DSM programs. Comprehensive decoupling mechanisms were most often implemented in situations where vertically-integrated utilities had surplus generation capacity and fuel adjustment clauses. As demand reduction occurred, those utilities would lose revenue much faster than they would experience cost savings. Essentially, in addition to the delivery system costs discussed above, the recovery of fixed generation costs would have been compromised by DSM programs—and comprehensive decoupling mechanisms were seen by some as a way to increase the utility's willingness to promote demand reductions and reduce the utility's incentive to promote increased sales.

Decoupling could be implemented successfully if the utility's regulator is committed to minimizing the potential negative side effects of decoupling. Viable alternatives to decoupling include targeted disincentive removal, such as proper stand-by rates, contract-based rates for local distribution cost recovery, updating rate designs, and specific lost revenue recovery. Each of these alternatives address the concerns raised in **Section III** without decoupling utility revenue from sales.

A. The Mechanics of Decoupling

California has considerable experience with decoupling mechanisms. However, several other states are either in the process of deciding on the appropriateness of a decoupling mechanism or have the issue under review, informally or formally. Two key conclusions are suggested by these developments:

- Regulators are becoming more interested in energy efficiency and demand management programs and the incentives of the utility to implement these programs.

- In the next few years (or even sooner) more states may join California and Oregon by implementing decoupling programs.

Decoupling is used as a means to break the link between revenues and sales. Traditional electric utility rate-of-return/cost-of-service regulation sets the rates that the utility can charge its retail customers in rate cases. Between rate cases, the utility may or may not actually earn its allowed rate of return. While it has the *opportunity* to recover its costs, its actual earnings will depend on the level of customer demand for its products and how well it controls its costs. For example, if revenues decline because of DSM and/or energy conservation, then the utility will not earn its allowed rate of return. Decoupling is intended to address this situation. According to NRRI, "[t]he primary purpose of decoupling is to break the linkage between sales, revenues, and profits by precluding the utility from retaining any revenues that exceed the revenue requirement. When this occurs on a regular basis, the utility does not have the incentive to pursue sales opportunities beyond those contained in its sales forecast. The secondary purpose is to make the utility whole."[14]

Decoupling is a type of "true up" mechanism that provides a rate increase to the utility if revenues are lower than expected or a rate decrease if revenues are higher than expected. Thus, decoupling is analogous to a fuel adjustment clause except it is for revenues—providing assurance that the utility will recover its authorized non-fuel revenue requirements, no more, and no less.[15] A balancing account is created to account for the excesses or deficiencies in revenues, relative to the target. This account is then "cleared" through the utility's tariffs on a periodic basis with customer's seeing a reduction in rates or an increase in rates in order to allow the utility to recover its allowed revenue requirement. This "decoupling" of the kWh sales/revenues link is intended to remove the presumed incentive of a utility to increase electricity sales at the expense of programs that are designed to reduce load. Environmental advocates have touted the benefits of decoupling to the utility, in terms of normalizing the revenue stream, to society through the increased incentive to run energy efficiency programs, and to customers through the benefits of reduced consumption costs.

B. Case Study: California's Success in Implementing Decoupling

California is the only state that has shown a long-term commitment to decoupling. With the exception of its restructuring period (1997-2001), California utilities have had, or have been moving towards, an ERAM since 1982. This long commitment to decoupling may allow utilities and regulators in other jurisdictions to learn from California's experience.

During the 1982-1996 period, California had decoupling programs in place for its major electric utilities. California utilities participated in general rate cases every three years in which a level of fixed cost recovery was determined. An ERAM was used to "true-up" the allowed revenues with actual revenues between cases. The mechanism ensured the recovery of three key components of required revenue:

1. Return on equity, which was adjusted annually to reflect changes in interest rates;

2. Operating costs, which were tied to price indices, and thus grew each year; and

3. Rate base, which was adjusted to reflect forecasted capital expenditures.

California reintroduced decoupling in 2002, following the passage of legislation in April 2001 (§739.10), which directed the CPUC to reinstate its policy of breaking the kWh sales/revenues linkage. Southern California Edison ("SCE") adopted a mechanism similar to the Electric Revenue Adjustment Mechanism ("ERAM") in 2002. The SCE performance-based regulatory (PBR) mechanism was originally covered only until December 2001, but the CPUC elected to

[14] Robert J. Graniere and Anthony Cooley, Decoupling and Public Utility Regulation, NRRI 94-14 (Columbus, OH: National Regulatory Research Institute, September 1994), p. 11 (hereinafter referred to as "NRRI").

[15] *Id.*, p. 18.

extend the PBR mechanism until superseded by Edison's next general rate case (2003).[16] Under the PBR plan originally in place, variations in sales translated directly into variations in revenue. For this reason, SCE requested to make a specific revenue requirement adjustment for customer growth in its PBR extension proceeding. The new balancing account tied to an adopted revenue requirement essentially restores the ERAM that was in place before the CPUC adopted PBR regulations. Like ERAM, the balancing account provides SCE with protection from revenue reductions that arise from conservation while ensuring that SCE obtains adequate, but not excessive, revenues.[17]

In 2004, San Diego Gas & Electric ("SDG&E") switched to a rate indexing mechanism that includes decoupling. The PUC approved a settlement and adopted revised PBR mechanisms for SDG&E's electric and gas distribution. Specifically, base revenues will increase annually by the increase in the Consumer Price Index, subject to minimum and maximum percentage increases. Any utility base-rate earnings that exceed the PUC-authorized rate of return plus 50 basis points will be shared with customers. The PBR mechanism does have a "safety valve"—SDG&E or other parties may file for a suspension of the indexing and sharing mechanisms if base rate earnings for any year are at least 175 basis points above or below the authorized rate of return and the mechanisms will be automatically suspended if base-rate earnings are at least 300 basis points above or below its authorized rate of return. The PBR plan includes formula-based performance measures for customer service, safety, and reliability that specify rewards or penalties for SDG&E.

Research performed on California's use of decoupling in the 1982-1993 period provides little evidence of major problems with the use of decoupling. For example, a Lawrence Berkeley Laboratory report, *The Theory and Practice of Decoupling* concludes that decoupling "has had a negligible effect on rate levels and has, for PG&E, actually reduced rate volatility" and "the clearing of ERAM balances has accounted for only a small proportion of the total change in revenue requirements between 1983-1993."[18]

Despite the apparent success of California's decoupling mechanisms, decoupling revenues from sales has not eased the difficulty of implementing and encouraging DR in California. In an October 2005 decision in a rulemaking on policies and practices for advanced metering, demand response, and dynamic pricing, the ALJ stated:

> One of the struggles that has become clear over the course of this proceeding is between our desire to promote price-responsive demand and how the utilities and the CAISO treat demand response resources for purposes of resource planning and meeting resource adequacy standards. Unlike energy efficiency, which has a long history of success, adopted measurement protocols, and is well integrated into the resource planning process, demand response programs have a shorter

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[16] *See:* California PUC Decision 01-06-038, "Opinion Extending Southern California Edison Company's Performance-Based Ratemaking Mechanism," June 14, 2001.

[17] *See:* California PUC Decision 02-04-055, "Decision Granting Petition to Modify Southern California Edison Company's Performance Based Ratemaking Mechanism," April 22, 2002.

[18] J. Eto, S. Stoft, and T. Beldon, *The Theory and Practice of Decoupling*, LBL-34555, Lawrence Berkeley Laboratory, 1993, p. 42, 46, cited in Carter, *supra* note 1.

> history, are not well integrated into the planning process, and do not have adopted measurement and evaluation protocols.[19]

Thus, despite consistent efforts to remove a utility's disincentive to implement programs that may result in the reduction of load, California is still struggling to encourage DR growth. This suggests that there are other factors besides a utility's incentive structure that are impeding DR implementation.

C. Other Recent Decoupling Experience

The practical, financial and regulatory impacts of decoupling—as well as past experience—show that decoupling has been abandoned in many jurisdictions for good reasons. New York recently rejected the use of decoupling mechanisms, noting the negative impact that large revenue accruals can have on rate stability.[20] Similarly, Maine abandoned its decoupling program in 1993 after only two years due to large deferrals brought about by an economic recession in the region. In its 2004 Report on Utility Incentives to the state legislature, the Maine PUC stated:

> The consensus was that only a very small portion of this amount [the ERAM deferral account, which reached over $52 million] was due to CMP's conservation efforts and that the vast majority of the deferral resulted from the economic recession. Thus, ERAM was increasingly viewed as a mechanism that was shielding CMP against the economic impact of the recession, rather than providing the intended energy efficiency and conservation incentive impact.[21]

Like Maine, numerous states have implemented decoupling pilot programs, but have failed to maintain their usage over a long period of time. In December 1994, the Florida PSC adopted a three-year revenue decoupling experiment for Florida Power, which was expected to allow the commission to monitor the level of residential conservation savings.[22] Currently, both Florida Power and Florida Power & Light have rate cap mechanisms and revenue sharing mechanisms in place instead.

On April 28, 1994, the Montana PSC approved a four-year trial period for a decoupling system for Montana Power which was supported by a group of state agencies and environmental advocates. In 1995, when MPC filed it first adjustment the Commission determined that no decoupling adjustments should be made for the first two years of the program (*i.e.*, 1995 and 1996) and that MPC should file an alternative decoupling index prior to the third year.[23] It

[19] California PUC Rulemaking 02-06-001, "Order Instituting Rulemaking on policies and practices for advanced metering, demand response, and dynamic pricing." Decision of ALJ Cooke, October 19, 2005.

[20] See: Before the State of New York Public Service Commission, Case No. 03-E-0640, Staff Report, July 9, 2004, p. 7-8.

[21] Maine Public Utility Commission Report on Utility Incentives Mechanisms for the Promotion of Energy Efficiency and System Reliability. Presented to the Utilities and Energy Committee of the Maine Legislature, February 1, 2004, p. 29.

[22] Regulatory Research Associates, Florida Regulation-Annual Review, October 1997, p. 9.

[23] Montana Public Service Commission, Order No. 5858a, September 20, 1995.

appears that this program was discontinued at or around the time of Montana's restructuring in 1997. Both Washington and Idaho currently have investigations pending regarding potential decoupling programs.

In 1998, the Oregon PUC approved a distribution-only alternative form of regulation ("AFOR") for PacifiCorp.[24] The AFOR included: (1) a revenue cap for distribution revenues; (2) increased service quality performance measures; and (3) revenue sharing outside a pre-determined earnings range. The revenue cap is designed to break the link between earnings and kWh sales. Temperature-adjusted actual kWh sales revenues are compared to a predetermined revenue cap for that class, with differences collected in a balancing account for recovery the following year, which provides an assurance that PacifiCorp's ability to recover distribution system costs will be independent of retail kWh use. The Order explains that the revenue cap only applies to distribution-related revenues, which are relatively fixed in the short term and therefore would be less volatile to changes in kWh use. Commissioner Joan Smith concurred in part and dissented in part, arguing that a revenue cap would not change PacifiCorp's behavior (*i.e.*, its incentive to sell more kWhs), particularly given that the revenue cap is for distribution only.

In 2002, Portland General Electric proposed a decoupling mechanism, but the Oregon PUC denied PGE's proposal, noting:

> The popularity of decoupling mechanisms, however, has declined in recent years for a variety of reasons… Concerns that decoupling inappropriately shifted business risk to ratepayers led Maine and Washington to eliminate similar mechanisms. Washington also questioned the effectiveness of decoupling, finding no evidence that its mechanism provided a clear incentive for utilities to manage its acquisition of supply and demand-side resources at least cost. Staff has raised similar concerns with regard to the decoupling mechanisms previously adopted in Oregon. Staff notes that PGE's and PacifiCorp's conservation activities actually decreased significantly while those companies were decoupled. In addition, the regulatory landscape has changed dramatically since this Commission first embraced decoupling a decade ago. All six regulated energy utilities in Oregon now have some mechanism in place to protect themselves from revenue volatility due to fluctuating power prices. This Commission has also adopted a number of regulatory mechanisms to provide incentives for utility demand-size management (DSM) acquisition. These include investment cost recovery, lost margin recovery, incentive mechanisms such as SAVE, conservation bonding, and various accounting mechanisms to reduce risk associated with the amounts of DSM on utilities' accounting record...[25]

In this decision, the Oregon PUC shows how the stated goals of decoupling, such as revenue stability and DR growth, can be achieved in other manners through targeted incentives and other regulatory mechanisms. In order to evaluate decoupling in the context of recent experiences and potential alternatives, the next sections will consider the potential benefits and drawbacks to broad decoupling mechanisms.

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[24] Oregon PUC Order No. 98-191, May 5, 1998.

[25] Oregon PUC Order No. 02-633. September 12, 2002.

D. The Pros: Potential Benefits of Broad Decoupling

The problems and economics of electricity provision vary over time and jurisdiction and potential solutions, such as decoupling, should not be rejected outright because they have not broadly succeeded in the past. Much depends on the details of how decoupling is implemented—and the regulator's commitment to staying the course. Decoupling may present a novel, workable, and beneficial solution for a utility.

In theory, decoupling is an incentive mechanism that eliminates the utility's disincentive to promote DSM. Decoupling does so by assuring that the utility does not lose revenues because of DSM. This means that there is a "[m]ore equal footing with supply-side energy sources because the utility is protected against reduced profitability as a result of the promotion of DSM."[26] Advocates of decoupling have suggested a number of potential advantages for decoupling. These include:

1. ***Benefits to the environment***. Environmental advocates argue that decoupling is beneficial by emphasizing the "perverse incentives" that they claim are present with "today's dominant regulatory practices," including "traditional rate design," and "the system of price cap regulation."[27] The argument is that decoupling promotes environmentalism—by making environmentalism less troublesome to the utility by removing a credible threat on revenue and profit losses.

2. ***Preservation of the utility's financial integrity***. According to a survey of regulators conducted by NRRI, "[t]hose commissions that supported decoupling at one time or another seemed to believe that it stabilized the utility's financial position, lowered the utility's cost of capital, and provided low-cost protection against reduced profitability."[28] In theory, decoupling should ensure that the utility earns, on average, no more or no less than its approved revenue requirement. Decoupling can, if implemented consistently over a period of time, reduce business risk by having customers bear more of the risk of lower revenues than expected.

3. ***Decoupling could make it easier to do least cost planning on a societal basis***. By putting DSM on a more equal footing with supply-side options, decoupling may allay a utility's fears that successful DSM programs will eat into its profits. If the regulatory environment provides an assurance to the utility that it will be able to recover decoupling deferrals, than the utility could become less concerned about including DSM in its resource portfolio mix, thereby reflecting the social costs of the discarded supply-side options.

[26] NRRI, *supra* note 14, p. 37.

[27] *See*: Sheryl Carter, "Breaking the Consumption Habit," *Electricity Journal*, December 2001.

[28] NRRI, *supra* note 14, p. 9.

E. The Cons: A Critique of Decoupling and Its Potential Side Effects

Decoupling proposals are based on the assumption that utilities face an incentive to increase the usage of electricity, which harms conservation and load reducing programs, namely the implementation of distributed resources. Critiques of decoupling cite many potential disadvantages of decoupling, including the following:

1. ***Decoupling could fail to recognize the long-term nature of utility investment decisions.*** Electric delivery facilities have average service lives in the 30 to 40 year range and investment decisions by utilities consider long-term business risks. From any current perspective, it is often difficult to envision the risks to capital cost recovery over the long-term. However, when one considers the very long life of utility assets, it is apparent that changes in technology and changes in the competitive environment could threaten a delivery utility's ability over the full life of the facility to charge rates that fully recovered costs. The best way to minimize this risk is to construct and operate the delivery system in the least cost manner. If DR can lower cost and can reduce or defer investment that has a long recovery period, a utility has the incentive to promote those alternatives. Further, a delivery utility has the obligation to provide service at the lowest reasonable cost, while meeting its obligation to provide safe, adequate, and reliable service. Proponents of a comprehensive decoupling mechanism have almost always ignored those realities. Utilities do not make long-term investment decisions based solely on short-term profit impacts. The primary factor in investment decisions are the need to serve customers consistent with long-term costs and risks.

2. ***Decoupling could reduce efficiency incentives by making multi-year rate settlements less feasible.*** Multi-year rate settlements provide strong efficiency incentives in that they encourage cost reductions by providing a utility with the opportunity to retain some of the savings as earnings. However, these settlements are inconsistent with a comprehensive decoupling mechanism, in that under a comprehensive decoupling mechanism the revenue level is fixed. A fixed revenue level would not provide the funds needed to support the growth in delivery systems demand that occurs over time or even to maintain and upgrade existing systems. A comprehensive decoupling mechanism would require more frequent rate cases, which would reduce the incentive to implement cost reductions. A potential solution to this issue would be to incorporate a multi-year decoupling tracker into these long-term settlements that would provide for revenue growth over the course of the settlement.

3. ***Decoupling could increase delivery service rate instability.*** Long-term rate agreements generally include delivery service rates that are predictable and stable, enabling customers to budget and to respond to those rates. A comprehensive decoupling mechanism would tend to reduce this stability. Rates would increase when the economy was weak and sales were down, and decrease when the economy was strong and sales were up. This would tend to go in the opposite direction of distribution system marginal costs and send the wrong price signal to customers, thereby encouraging the inefficient use of resources. This would also tend to isolate the delivery utility from economic

fluctuations in the service territory (assuming it is able to recover deferrals as required by accounting rules).

4. ***Decoupling could undermine system reliability.*** As demand grows and as delivery facilities reach the end of their useful lives, there is a need to install new delivery facilities to reliably deliver electricity. A comprehensive decoupling mechanism that holds revenues fixed without regard to customer/demand growth and the need to replace aging facilities would limit the cash flow available for delivery system infrastructure investments. In this way, a comprehensive decoupling mechanism would make it harder for utilities to maintain the reliable delivery of electricity.

5. ***Decoupling could lead to cost-shifting among customers.*** Where comprehensive decoupling mechanisms are used in place of an appropriate standby rate to protect the utility from a negative financial impact from DR, the utility may be kept whole, but rates rise for customers who did not install DR and fall for these who did by more than the cost savings experienced by the utility. Other customers could subsidize DR customers, resulting in economic inefficiencies and inequalities among customers.

6. ***Decoupling could reduce the incentive to reform rate designs.*** Comprehensive decoupling mechanisms can have the effect of locking in legacy rates that have been rendered obsolete by restructuring, and which should be updated. This is detrimental to economic efficiency as proper rate design (*e.g.*, for distribution service, and for backup/standby power supply) is the most important signal for encouraging economically efficient decisions with respect to energy efficiency and DR. Utility programs are a supplement to the market-based decisions of customers and energy service companies. In order to provide incentives for economically-efficient decision making by these entities, it is essential to have a sound rate design. A comprehensive decoupling mechanism reduces the incentive to implement a more efficient rate design.

7. ***Decoupling could expose the utility to the risk of having to write-off deferrals.*** If deferrals accrue because of a decoupling mechanism, which need to be recovered in rates within two years to meet GAAP requirements, there is a significant risk that regulators will become less enamored of decoupling, putting pressure on the utility to write-off decoupling-related deferrals. While decoupling may remove a utility's incentive to sell more kWh, decoupling can, in reality, present a financial risk to a utility. Some decoupling schemes are "broad-brush" in nature, which can result in large deferrals resulting from a downturn in the economy. Lost revenues from energy efficiency and DR are likely to be small in comparison. When evaluating decoupling, the costs and benefits of decoupling must be compared with those of other more focused lost revenue recovery mechanisms.

In conclusion, the results of past decoupling experiences are, at best, mixed and depend greatly on the particular regulatory, economic and financial factors that characterize each utility's operating environment. It is up to regulators, utilities and other interested parties to evaluate the appropriateness of decoupling as such factors change over time. The next section will propose multiple financial incentives that will target DR growth without broad decoupling.

VI. DESIGNING FINANCIAL INCENTIVES FOR UTILITY INVOLVEMENT IN DISTRIBUTED RESOURCES

If utilities are to play the important role that they are uniquely qualified to play in encouraging the deployment of efficient distributed resources, it is essential that they have an opportunity to earn a return for their efforts to promote the efficient development and use of distributed resources. Utility involvement in distributed resources cannot be optimized or maximized merely by the removal of disincentives or barriers. Removing disincentives or barriers is a necessary step, but it is not sufficient. To elicit the commitment of time, energy, and creativity needed to fully exploit the potential for efficient distributed resource development utilities must be allowed to make a business out of DR (*i.e.* earn a return sufficient to compensate for the risks involved in applying new technologies to create new services for customers in new market environments).

In this section,[29] we explore five incentive design concepts. We do not represent that each model would work for all utilities in all circumstances. Indeed, some members may find that none of the models works for them. Our purpose is to stimulate thinking and discussion among utilities and policy makers, not to propose specific policies or solutions. Also, the models should not be viewed as discrete and mutually exclusive. Rather, they should be seen as mechanisms that can be combined and reconfigured to meet a variety of needs and circumstances.

We have used the following principles to frame our investigation:

1. Incentives should be tailored so that the DR initiatives that result are efficient. Efficient DR has benefits that outweigh its costs. DR investments that are not cost-beneficial are not efficient and should not be encouraged with incentives.

2. While utilities have a unique role to play in encouraging DR, efficient DR programs should not be limited to those in which the utility is the only or the primary developer. The important role of the competitive market and competitive DR suppliers should be recognized and incentives should encompass utility efforts to collaborate with and support these DR suppliers.

3. The recovery of DR investments and expenses should be timely and full. If DR expenditures are recovered through specific rate mechanisms that clearly provide for full and timely recovery, the incentive to invest in DR would be at its greatest.

4. The recovery of earned incentives should be incremental to base earnings. Incentive mechanisms that do not provide incremental earnings would not provide an effective inducement to DR involvement by utilities.

[29] In previous sections of the paper we have addressed ways to remove disincentives to utility promotion of DR deployment such as providing for targeted recovery of lost revenues and implementing rate designs that rely on contract demands as opposed to metered demand or energy to recover the costs of distribution facilities.

5. The particular incentive mechanism can be tailored to the purpose and jurisdiction. Jurisdictions that are open to more complex ratemaking and longer term price indexing plans can achieve incentives that are both stronger and reward efficiency in DR implementation. Other jurisdictions can still provide incentives that should prove effective at encouraging DR deployment, but these incentives may be weaker and less well targeted to efficient DR deployment.

Recognizing that DR advocates are sensitive to the need to capture and integrate as many sources of benefits as possible to maximize the economic feasibility of DR projects, **Table 3** summarizes the kinds/sources of benefits captured by each of the five incentive models.

Table 3. Benefits Captured By the Financial Incentives

	Generation	Transmission	Distribution
Incentives for DR Aggregation Services	X	X	
Rate Basing with Incentive Rates of Return	X	X	X
Rate Basing with Incentive Rates of Return Combined with Long-term Delivery Service Rate Indexing	X	X	X
Fixed Incentives for Achieved DR			
Incentive for Deferral of Distribution Investment			X

A. Incentives for DR Aggregation Services

All distributed resource projects would not require significant investment. In some cases, customers or equipment and service providers may be able and willing to install the equipment and devices needed to implement distributed resources, but may lack the ability to aggregate the utilization of these resources and employ them most efficiently in the market context. These resources are in many cases too small to justify or to qualify for individualized RTO participation.

In these situations, the utility may be well positioned to serve in an aggregation role and coordinate the operation of the distributed resources and the bidding of these resources in the market. Further, in situations where there are penalties for non performance, aggregation and diversity of resources may help avoid such penalties. In these situations, incentives could be developed related to the value that the utility is able to realize in the market in its aggregation role.

The incentive mechanism, which is presented in **Figure 4**, can be described in text as follows:

1. The utility/Distco would assume responsibility for aggregating distributed resources and bidding these resources into the energy, capacity and ancillary service markets;[30]

[30] For traditionally utilities, DR resources could be factored into the system dispatch process.

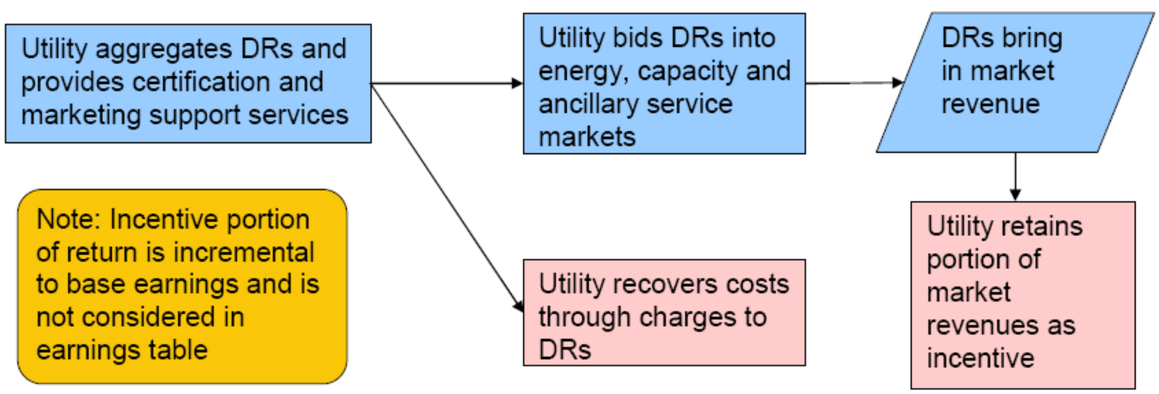
2. Part of these activities may involve helping distributed resource providers certify that they are able to meet RTO program requirements and could involve partnering with customers and service providers;

3. The utility would be permitted to recover the base costs of its aggregation activities through a charge made for aggregation activities;

4. As an incentive to provide the service, the utility would be permitted to retain a percentage of revenues realized from bidding the resources into the energy, capacity or ancillary service markets; and,

5. The incentive portion of revenue obtained from sharing in the market benefits of bidding would be excluded from consideration in earnings determinations in rate cases or earnings sharing contexts.

Figure 4. Diagram of Incentives for DR Aggregation Services



This model would provide utilities with an incentive to offer aggregation and bid coordination services. There may well be instances where utilities are best positioned to provide these services, but have no clear way to recoup costs or make a profit. Absent the opportunity to make a profit, utilities would have no incentive to provide these services and some efficient DR may not be developed. As these services would not likely require significant capital investment, the incentive rate of return is not likely to be a useful model. These services may be provided directly to customers or to distributed resource providers, stimulating the competitive market for these services.

A key part of the utility activity would also extend to benefit coordination. A utility would be well positioned not only to aggregate DR, but to coordinate a range of benefits including capacity market benefits, energy market benefits, deferred transmission and distribution investment benefits and develop procedures for coordinating these benefits.

B. Rate Basing with Incentive Rates of Return

A second mechanism is rate basing of investment in distributed resources with an incentive rate of return. This model is most likely to be attractive in situations where the utility would make a significant investment in distributed resources—*e.g.*, distributed generation. There may well be circumstances in which distributed resources that require significant capital investment provide an efficient solution, but institutional barriers limit the market development of these resources. The utility may be in the best situation to overcome these barriers by direct investment and ownership. In evaluating investment opportunities, utilities would consider both risk and return. The incentive to invest would be at its highest when the risk-return balance provides reasonable risks of cost recovery and returns that are attractive for the risk taken. Distributed resources are likely to pose risks that are novel and difficult to evaluate. For example, the dispersed nature of the investment, the decentralized operating requirements and the significant customer involvement required to make DR work are all factors that can add to risk. To mitigate these risks and provide a financial incentive, utilities should be ensured of a clear opportunity to recover capital investment in DR and to earn an enhanced return on distributed resources, such as distributed generation, which may require significant investment.

The suggested mechanism would involve tracking and capitalization of DR program costs and investments. These capitalized costs would then be recovered over an appropriate amortization period that reflected the expected economic life of the DR equipment. The utility would be allowed an incentive equity return on unamortized DR investment that compensated it for the technical and commercial risks involved. Incentive returns have been found desirable in a variety of situations. The FERC has found that incentive return levels should apply to transmission investments in certain situations to achieve policy goals with respect to transmission. Incentive returns have also been provided by state regulators in connection with achieving DSM goals to promote that policy alternative. Incentive returns have been provided in connection with performance-based ratemaking plans to compensate for new risk taking and reward above-average performance. In connection with DR, the incentive portion of the return would be motivated by three factors. First, there are, as discussed above, risks to DR that exceed normal investment risks and require a higher level of compensation. Second, there is a policy goal to promote efficient DR and an incentive can help achieve that goal. Third, an incentive can be tailored so as to encourage and reward the most efficient deployment of DR. As with all targeted economic incentives, the regulation’s clarity and lack of ambiguity in the incentive structure would improve the implementation and acceptance of the proposed DR program.

In order to ensure that the incentive is powerful in all circumstances, the recovery of the invested capital, an incentive return on the unamortized invested capital, and the recovery of the operating expenses of the DR program would be achieved through a rate rider that would be periodically and automatically reset to provide for timely recovery of DR investment and expenses on an as-incurred basis. Hence, without regard to its earnings position, the utility would receive incremental revenue and profit from the DR investment in order to ensure that the incentive is not diluted by the base financial situation. In order to encourage efficiency in DR investment, the incentive portion of the return would be set based on the expected benefit-to-cost ratio of the investment. The higher the benefit-to-cost ratio, the greater the efficiency and hence the greater the incentive return.

The basic steps in such a model, which are illustrated in **Figure 5**, can be described as follows:

1. The costs of implementing a DR program (including research and marketing costs) would be tracked;

2. Specific investments and overall program costs would be analyzed and prospective benefit-to-cost ratios estimated using procedures agreed to with regulators;

3. Utilities would implement the DR and would maintain an account that capitalized all program development costs and capital investments;

4. Periodically (*e.g.*, monthly or quarterly), a rate surcharge would be calculated and implemented to provide for recovery of costs;

5. The revenue requirement would include all expenses, amortized capital investment and an incentivized return on unamortized capital investment;

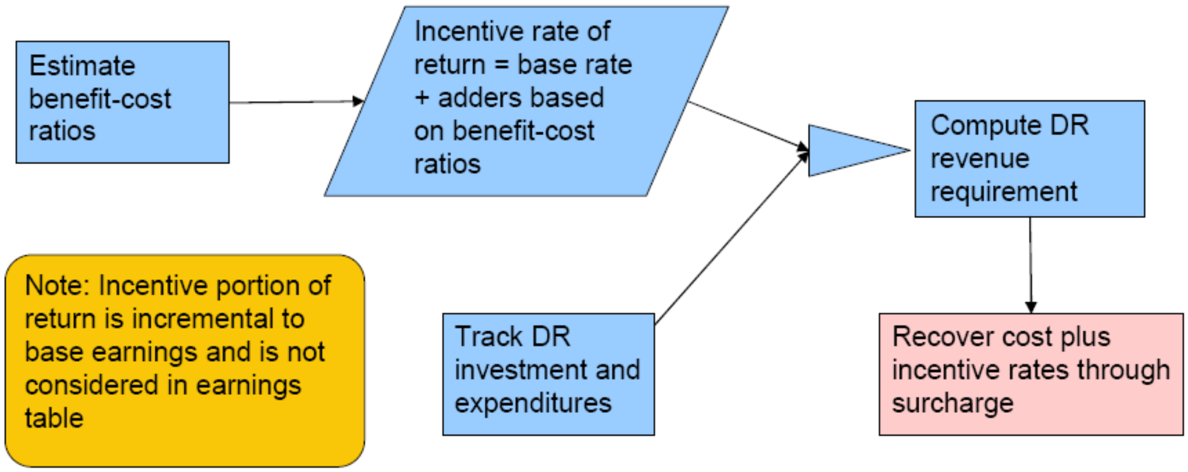
6. The surcharge would apply without regard to the earnings situation and the return element of the surcharge would be excluded from earnings tests, ROE sharing or rate case revenue determination; and,

7. The incentive rate of return would consist of the base rate of return plus adders based on the prospective benefit–to-cost ratios[31] of selected investments. The higher the ratio, the greater the incentive component. This would direct resources to the most efficient distributed resources; these are resources with the greatest benefit-to-cost ratios. For example, investments with benefit-to-cost ratios up to 1.5 may receive a 100 basis points incentive, while investments with ratios between 1.5 and 2.0 may receive a 150 basis point incentive. For investments with benefit-to-cost ratios over 2.0, a 200 basis point incentive may be used. The sliding scale would serve the added purpose of encouraging the most efficient investment. DR with a benefit-to-cost ratio of less than one would not be cost effective (efficient) and, as shown in the flowchart in **Appendix B**, efficiency is the primary concern when evaluating DR programs and thus no financial incentive should be implemented.[32] The benefit/cost ratio for each DR project would be calculated annually. Benefits would be quantified as the sum of the value of distribution capacity which can be deferred through the DR project, and the savings in the cost of power supply to customers served by the project (*e.g.*, achieved by reducing on-peak consumption from the grid and/or reducing transmission congestion). Costs would be quantified as defined above (*i.e.*, research and marketing costs, permitting costs, hardware costs, fuel costs (for on-site generators), and other project-specific operating and maintenance costs).

[31] The determination of benefit-to-cost ratios is outside of the scope of this paper. It is important that these are developed reasonably and that benefit estimation is realistic if the DR that results is to be efficient. Benefits should consider all savings from the market as well as possible savings from transmission and distribution investment deferral.

[32] Please note the incentive levels herein are illustrative and used only to clearly illustrate the concept. In practice, appropriate levels will need to be determined and a more continuous function may be superior to block levels.

Figure 5. Diagram of Rate Basing with Incentive Rates of Return



The key elements of the model are an assurance of full and timely cost recovery to offset technical risk, provision of an incentivized return on unamortized investment to spur pursuit of the most efficient distributed resources and isolation of the return component from other earnings adequacy tests in order to ensure that profits realized from efficient DR development are fully incremental.

C. Rate Basing with Incentive Rates of Return Combined with Long-term Delivery Service Rate Indexing

The rate basing and incentive rate of return mechanism may or not be implemented in a way that captures the potential transmission and distribution savings that could arise from distributed resource deployment. To the extent that T&D[33] savings are incorporated as benefits in the benefit-to-cost test, they would enhance the benefits, increase the benefit-to-cost ratio and increase the incentive. However, specifically identifying T&D benefits is difficult and it may not be possible to specifically identify all such savings. This does not mean, however, that distributed resources cannot provide significant T&D savings. It does mean that in some circumstances such savings may be hard to identify and track to particular distributed resource projects.

Efficiency in DR is best achieved when T&D savings can be recognized as a benefit and factored into the investment decision. One model for this, in situations where benefits cannot be easily identified or associated with single projects, would be to combine the rate basing and incentive rate-of-return model with long-term performance based or price cap type of regulation. Under this system, delivery service prices would be indexed to inflation and productivity. Additionally, within a dead band of minimum and maximum earned returns, prices would be based on the

[33] This section refers to T&D benefits. However, in practice, it may be more applicable to distribution benefits. In restructured states, transmission may be under FERC jurisdiction and not under state jurisdiction. In these states, working transmission benefits into the incentive model may be difficult.

index price. Finally, earnings as opposed to price would float. There are many variations of this type of regulation in the United States and internationally in the electric and gas utility industries.

If earnings went under the allowed level, or if uncontrollable costs increased, rates would recalibrate upward. (Such plans often contain "off-ramps" that provide for re-openers in the event of changes in exogenous factors.) If earnings exceeded the upper end of the dead band, earnings sharing would be activated and prices reduced by a share of any earnings over the upper range of the dead band. The indexing and earnings sharing plan can extend over multiple years. The wider the dead band and the longer the period that the plan extends over, the greater the incentives for implementation of cost reduction would be.

Such regulation fits well with providing a DR incentive. The indexed rates under such a plan could provide for recovery of increasing delivery service costs (*e.g.*, reflecting needed capital additions). The incremental recovery of DR expenditures is achieved through rate basing and recovery of DR investments and expenses through a rate surcharge. The dead band and earnings sharing on delivery rates would provide an incentive for the utility to deploy DR when it is more cost-effective than the "sticks and wires" alternative.

If the rate plan persisted over many years, the incentives to promote and implement DR that substitutes for, or defers, distribution system expansion and optimizes the efficiency of distribution investment and DR would be strong. This is the case because under these types of rate plans, revenues are independent of an individual's utility cost for the term of the plan. Savings on distribution costs and investments would not lower rates during the rate plan period, but would inure to the benefit of customers after that period. Hence, an incentive is provided to implement DR that would be most effective in reducing distribution costs. While this incentive can be combined with rate basing of DR investment, it could also provide the utility with a strong incentive to promote DR by third parties as the savings in distribution costs would still accrue to the utility over the rate plan period and to customers over the long-term.

The rate base portion subject to incentive recovery would be limited to expected savings from energy and capacity markets as well as transmission savings. The residual cost not justified by the cost-benefit analysis would come through the incentive in the long-term distribution rate plan.

Figure 6 depicts this incentive model graphically. In text it can be described as follows:

1. Model B, the rate basing model, with an incentive return is implemented for DR cost and investment recovery;

2. The benefit-to-cost ratios in Model B exclude distribution savings (*i.e.*, incentives related to distribution savings are provided pursuant to the distribution revenue price described in this incentive); and,

3. A comprehensive delivery service indexed rate plan is adopted that has the following features:

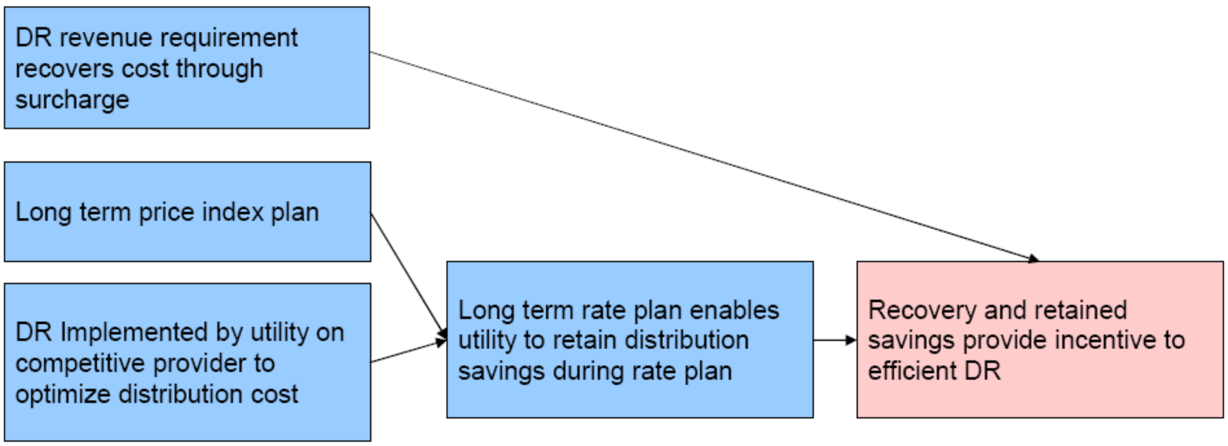
    a) A duration of at least five years and preferably 10 years.

b) Delivery services rates indexed to inflation with a productivity offset.[34]

c) Appropriate off-ramps.

d) An earnings dead band with ROE sharing if earnings exceed the top of the dead band and rate recalibration if earnings fall below the bottom end.

Figure 6. Diagram of Rate Basing with Incentive Rates of Return Combined with Long-term Delivery Service Rate Indexing



DR savings related to distribution savings are not specifically identified, but as they reduce distribution investments and costs, they result in savings that can be shared between customers and shareholders. This model would be effective in encouraging the deployment of DR to optimize distribution and could work equally well in encouraging efficient DR that utilities own as well DR that utilities promote in conjunction with competitive suppliers.

D. Fixed Incentives for Achieved DR

Complex regulatory mechanisms are not well accepted in all jurisdictions. In jurisdictions where such mechanisms would not be embraced, a simpler incentive mechanism would be to provide the utility with a fixed monetary incentive per kW of achieved DR. While the mechanism would not be particularly strong at identifying and promoting efficient DR, it would jump-start DR by promoting utility involvement.

The incentive mechanism, which is presented in **Figure 7**, can be described in text as follows:

1. An agreed incentive for DR, which the utility facilitates, would be developed;

[34] Determination of inflation indexes and productivity indexes is outside the scope of this document. These indexes would determine the growth rate of delivery service rates and would therefore be non-trivial.

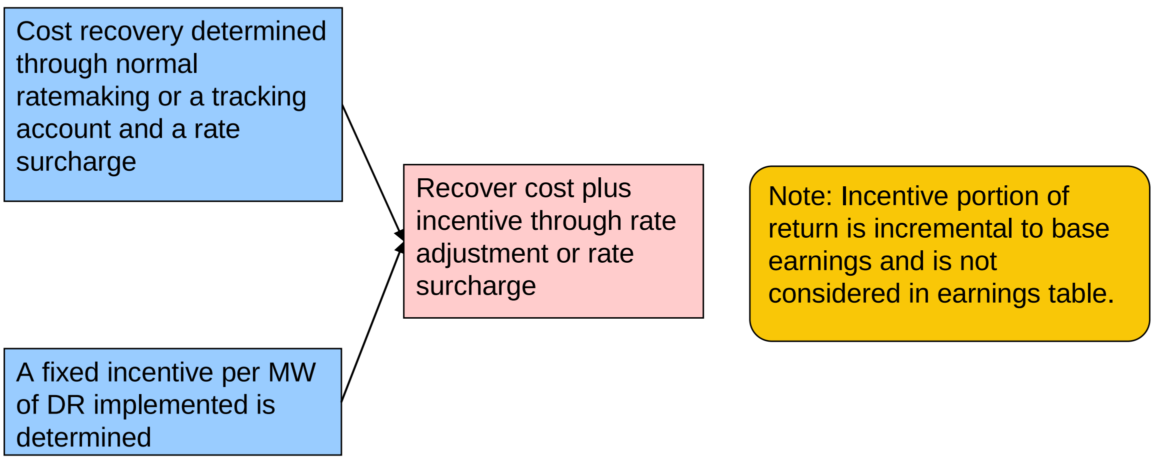
2. DR investment and expenses would be recovered through either normal ratemaking or a tracking account and rate surcharge;

3. An incentive amount per kW of achieved DR deployment would be agreed to;

4. The utility would realize, through a rate adjustment or surcharge, an amount equal to the achieved DR kWs times the agreed upon incentive; and,

5. The incentive amounts would be incremental to base earnings.

Figure 7. Diagram of Fixed Incentives for Achieved DR



This mechanism is a basic model that would most likely apply in situations where there was a desire to jump-start DR and a desire to maintain simplicity in the regulatory framework. The model is the weakest at encouraging efficient DR as it does not base the incentive on the degree of efficiency. As the flowchart in **Appendix B** shows, DR that is not cost justified (efficient) would not qualify for *any* incentive.

E. Incentive for Deferral of Distribution Investment

One of the difficulties with encouraging efficient DR is that the benefits do not necessarily go to those who bear the costs. In particular, savings realized through the deferral of new distribution capacity, if any, seldom go to the individual DR customer.[35] If the utility can identify distribution-related DR savings, these savings could be reflected in utility rates and the utility could share the savings with the DR entity, which would provide the DR entity with a greater incentive to take the actions necessary to allow the distribution savings to come to fruition.

[35] For integrated utilities that do not procure transmission from an RTO, the incentive mechanism could be extended to transmission savings. However, for unbundled utilities, it may be difficult to extend this mechanism to transmission given the jurisdictional issues.

The procedure would work as follows:

1. The utility would identify distribution savings from DR installation;

2. Targeted payments reflecting a portion of the savings would be made available to DR providers and customers who participate in DR programs;

3. The utility would recover those payments through a benefit sharing mechanism that includes the savings;

4. The utility would retain a reasonable percentage of the savings collected through the surcharge and use the remainder to provide an incentive payment to the DR provider/DR customer. While the utility would retain a portion of the savings, utility customers would benefit from the distribution savings as well.

A DR program should only be pursued if it has net social benefits. As shown in **Appendix B**, the first and most essential precondition for evaluating a DR opportunity is the efficiency test. For a DR opportunity to be beneficial, social benefits must exceed social costs—inefficient DR should not be implemented. In this example, the DR would be beneficial to the utility, allowing it to realize distribution savings.

The next question has to do with incentives: do the benefits to the entity implementing the DR exceed the cost to the entity implementing the DR? If yes, the DR would be implemented by the entity with no need for an incentive payment.

If the answer to this question is no, then an incentive mechanism could be designed to implement incentives to encourage socially beneficial DR growth that would not otherwise occur. This would be a straightforward sharing of the expected distribution savings between the utility, the DR entity, and the general body of ratepayers.

There would still be the question of whether the DR program is a “win” (no harm done) for all parties. Here, we take it as a given that the mechanism provides benefits to the utility, which will eventually be passed on utility customers. Absent this DR incentive mechanism, the utility would not be able to rely on the DR as part of its least cost planning and would, therefore, incur greater costs to finance the alternative to meet distribution needs.

This targeted incentive is highly dependent upon the ability to identify distribution savings.[36] It is, however, a potentially important incentive in that it helps to ensure that all benefits of DR are

[36] For example, when instituting a pilot DG program, the NY PSC stated: “[a]lthough the utilities would have discretion to contract for the provision of DG energy into the system, the energy typically would be for consumption by the DG customer only (*i.e.*, "behind the fence"), and the distribution savings would be realized through avoided load growth or avoided distribution facilities replacement. The utilities could also install their own investment in DG as part of this process, when the load source would achieve distribution efficiencies.” (*Source*: NY PSC, Opinion 01-5, Case No. 00-E-0005).

available when making the investment decision, thereby encouraging greater efficiency in deployment.

F. Summary

The models described above are designed to prompt a discussion about DR. They are also intended to be a practical guide to financial incentives that draw upon established regulatory procedures and could be implemented. As noted, the models can be combined. Further, the models can be further refined. When implemented, there are many details that would need to be specified and could be tailored to various situations. As discussed at the beginning of this section, the principles upon which the models are founded are to provide incentives that promote efficient DR, provide models that facilitate DR in the context of a market and an environment where competitive suppliers of DR services can flourish, and provide utilities with financial incentives that compensate for DR risk and spur the development of efficient, distributed resources.

There is a rational economic case for considering DR and providing appropriate incentives for DR. However, it is also important to realize that the economic case calls for encouraging efficient DR. Just as it is economically inefficient to under-invest in DR by not giving it full consideration and not providing proper incentives, it would also be economically inefficient to invest in DR that was not as cost effective as non-DR supply alternatives. The challenge is to properly structure the economic incentives for DR investment so that economically efficient DR investment by utilities, customers and service providers can be achieved and so that DR that is more costly than other options is not encouraged.

Appendix A: Summary of IRRC Study

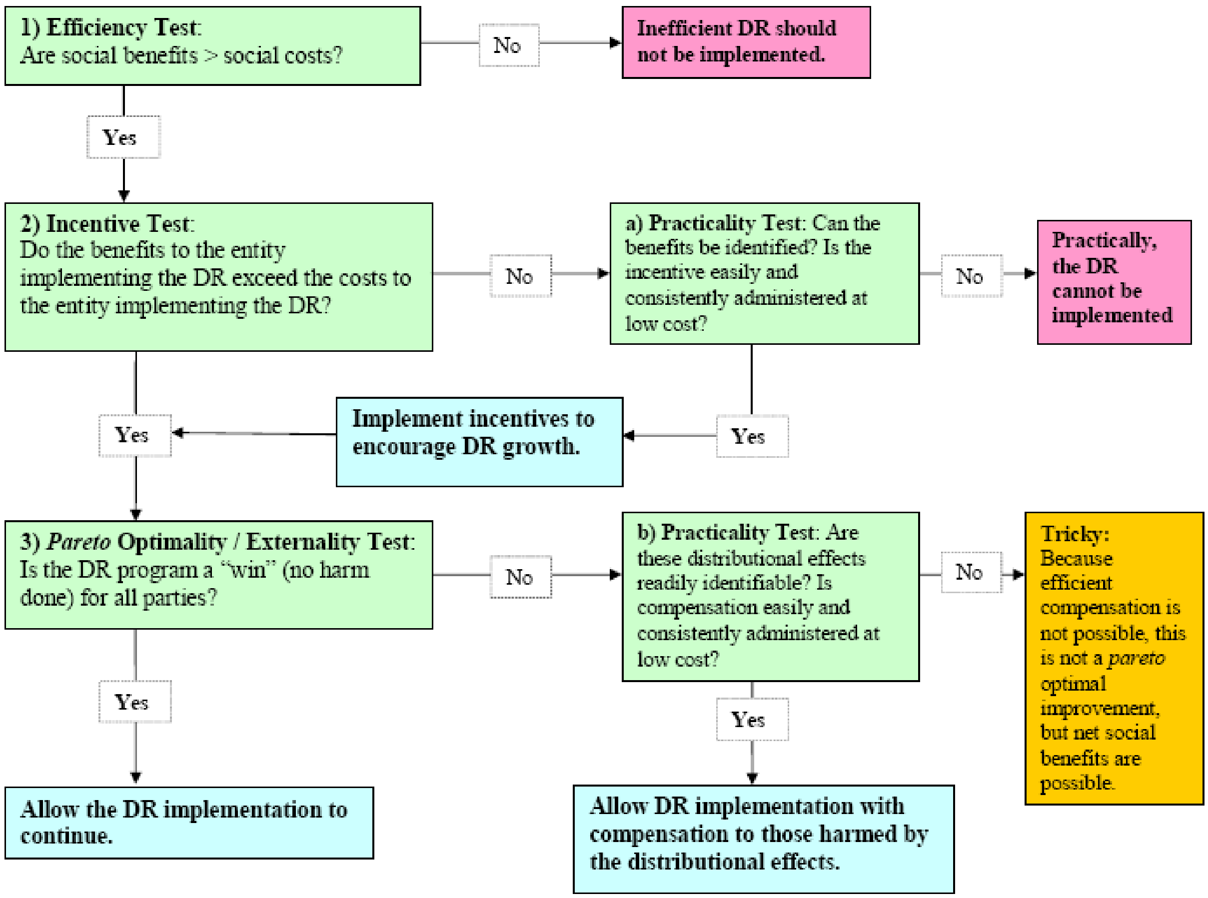
A study published in 1987 by the Investor Responsibility Research Center called Generating Energy Alternatives ("IRRC Study") is still instructive in this regard. Given the limited use of comprehensive RDMs (except for a few states, mostly for a relatively short period in the early-1990s), this study is still relevant. The IRRC Study conducted a survey of 49 utilities with active DSM programs and found the average peak reduction expected from DSM programs during the next decade to be about 25 percent of anticipated growth in peak demand. Since RDM-type regulation was at the time not prevalent outside of California, it is clear from this study that the lack of an RDM is not a deterrent to DSM implementation. We have reviewed this study and found several interesting facts. The five utilities reporting the greatest peak reductions all operate outside of California and without an RDM. Four California utilities were among the top 15 survey respondents with respect to planned peak savings from conservation and load management. However, two of those utilities are not regulated by the California Public Utilities Commission and are not subject to an RDM. As part of that report, 88 investor-owned utilities supplied information characterizing their demand management program objectives.

Three of those 88 utilities did the bulk of their utility business in California operating under an RDM. One of those three listed valley-filling as its primary DSM objective. The other two RDM utilities listed peak clipping and valley-filling as their primary objectives. Valley-filling is the encouragement of off-peak sales. Eight utilities, among them Con Edison, had only strategic conservation, which involves reductions of both on-peak and off-peak sales, as their objective. None of the eight operated under an RDM. Twelve utilities had strategic conservation combined with a peak clipping/valley-filling program as their objective. Again, none of these operated under an RDM. An RDM did not appear to influence management strategies toward conservation. The absence of a comprehensive RDM did not deter utilities from a conservation strategy.

The emphasis that the California utilities placed on conservation declined over time with an RDM in place. This decline in emphasis on conservation coincided with an increase in reserve margins and lower gas and oil prices. This suggests that fundamental economic concerns are a more important determinant of DSM activity than is an RDM. In fact, an RDM is neutral toward conservation. It does not provide a conservation incentive, but is just one unproven way of attempting to address a perceived disincentive.

The report did find that 30 out of the 88 investor-owned utilities have programs designed to promote the overall growth in electricity sales. However, it went on to note that fully one-half of those utilities were in regions where reserve margins exceeded forty percent. Utilities with large capacity surpluses may well have long-term financial and economic incentives to increase load to more fully utilize existing capacity. However, this incentive changes as reserve margins diminish. Further, this is not an issue with respect to delivery utilities.

Appendix B: Flowchart of Key Considerations When Implementing DR Programs



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