Gaining Momentum or Running Out of Steam? Utility Shareholder Incentive Mechanisms--Past, Present, and Future

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Five and a half years ago, the Wisconsin Public Service Commission established the first DSM shareholder incentive mechanism in the United States. Since then, state regulatory commissions have approved shareholder incentive mechanisms for 36 utilities in 17 states. Five other state commissions have approved generic incentives, and another five state commissions are currently considering incentive proposals.

While some states grapple with the question of whether to consider incentives, the commissions that first approved incentives are moving on to the details of second- and third-generation mechanisms. Thus, now is a good time to reflect on the lessons learned from the mechanisms put in place to date and to seek answers to key questions being raised: Are incentives working? Which work and which do not? Now that over half the states either are considering or have in place some form of shareholder incentive, will the remaining states follow, and if so, how quickly?

This paper reviews the different incentive mechanisms that states have developed to motivate utilities and how those mechanisms have worked. The paper draws on several sources: research into the evolution of specific mechanisms from their conception to their current form; research for a NARUC-sponsored status report of state regulatory barriers to and incentives for DSM; and the experience of the authors helping to design more than 15 such mechanisms.

We draw a number of conclusions. First, DSM expenditure trends indicate that the institution of incentives increases utility DSM activity. Second, utilities and regulators are fine tuning incentive mechanisms in ways that increase the utilities' risks without increasing their rewards for success. Finally, most of the utility commissions historically receptive to regulatory innovation have already approved or are currently considering incentives; thus the task of initiating consideration of incentives is up to utilities and intervenor groups rather than to the remaining commissions.

Introduction

In the past several years, recognizing that traditional ratemaking contains inherent financial disincentives to utility investment in DSM resource options, state regulatory commissions across the country have established DSM shareholder incentives (Moskovitz 1989; Reid and Chamberlin 1990). These incentives have been initiated by every possible source--utilities, legislators, regulators, and intervenors. In Massachusetts, New Hampshire, and Rhode Island, for example, the three retail utilities of the New England Electric System concurrently filed identical proposals for a shared benefits incentive mechanism along with their 1990 conservation and load management program filings. While the respective commissions responded differently to the proposals, each approved a DSM incentive mechanisms within a year.[1]

In Connecticut, it was the state legislature that got the ball rolling by authorizing the Connecticut Department of Public Utility Control (DPUC) to grant utilities an additional 1% to 5% rate of return on ratebased DSM.[2] The DPUC later approved an incentive mechanism for one utility as developed by a collaborative effort initiated subsequent to the legislation.[3] In New York, the Public Service Commission (NYPSC) invited the utilities under its jurisdiction to develop proposals to reform ratemaking "such that DSM programs that benefit customers are also rewarding to stockholders."[4] The NYPSC approved seven unique incentive mechanisms in the following 18 months. In California, a collaborative process considered, among other things, shareholder incentives for the state's four largest regulated utilities. The collaborative process developed from *en banc* hearings held in response to pressure from such intervenors as the Natural Resources Defense Council; the collaboration resulted in four utility incentive mechanism proposals, which were approved later that year by the California Public Utilities Commission (CPUC).

Out of these diverse processes have arisen a variety of incentive mechanisms that differ in overall type as well as specific features. The term "mechanisms" is used in this paper to identify detailed vehicles by which a utility may earn shareholder incentives as set forth in regulation as opposed to generic legislative or regulatory actions that approve an incentive in concept but do not specify how the utility may earn the incentive. At last count, 24 utilities had shared benefit mechanisms,[5] 6 had bonus-per-unit or "bounty" mechanisms, 5 had mark-up on expenditure mechanisms, 3 had bonus return on equity in rate base mechanisms, and 3 had bonus return on ratebased DSM expenditures mechanisms.[6]

This paper examines the past, present, and future of utility shareholder incentives for DSM. We first provide a general review of incentive development across the country. We then look more carefully at the three states with the most experience implementing incentives for insight into how incentives are evolving. Finally, we look to future trends and some DSM incentive issues of increasing importance.

Background

What Are DSM Shareholder Incentives and Where Are They in Place?

The term "DSM shareholder incentive" is used in this paper to signify a monetary bonus or reward that utility shareholders are eligible to earn based on utility performance in DSM activities. Thus far, the incentives put in place fall into one of five categories: shared benefits, bonus return on equity in rate base, bonus return on ratebased DSM expenditures, mark-up on expenditures, and bonus per unit of savings. At last count, 36[7] utilities in 17[8] states had shareholder incentive mechanisms of some kind or another. Another five states have approved the concept of incentives but must develop utility-specific mechanisms in order for utilities to begin earning incentives.[9]

State regulatory commissions have been experimenting with shareholder incentives for DSM since 1987. Over time the momentum for incentives has grown. In December 1989, four state commissions had approved incentive mechanisms for one or more utilities.[10] In the following year, five more states joined their ranks.[11] By December 1991, regulatory commissions in eleven other states had approved either utility-specific mechanisms or generic incentives for DSM.[12] However, since the end of 1991, the rate of development has slowed somewhat. In January 1992, the Washington Utilities and Transportation Commission (WUTC) approved an incentive for Puget Power & Light's 1991 DSM programs.[13] In February 1992, the Florida Public Service Commission (FPSC) declined to initiate rulemaking on shareholder incentives for Florida utilities and closed the docket.[14] At this writing, no additional states had taken up formal consideration of shareholder incentives.

Who's Left?

Fifteen states have not yet formally considered DSM shareholder incentives of any kind.[15] These fifteen states fall into one of two groups: states with a formal or informal integrated resource planning (IRP) process or least-cost planning (LCP) process under implementation or in practice; and states that have no IRP or LCP. This somewhat simplistic grouping is based on the observation that a regulatory commission that has not assigned a value to demand-side options in the planning process--either implicitly or explicitly--is unlikely to consider it necessary to level the playing field for supply-side and demand-side resource options or to provide an incentive for utilities to invest in DSM.

Of the fifteen states, only three fall into the first group--Kentucky, North Dakota, and South Carolina. However, while these three have the regulatory groundwork in place to take the next step toward establishing incentives, only the regulatory commission in South Carolina has indicated that it might take up the issue in the near future. None of the commissions in the other twelve states have indicated any immediate plans to change their regulatory framework to include IRP or LCP.

Are Shareholder Incentives Working?

The jury is still out on whether incentive mechanisms work effectively in all applications to encourage utilities to more aggressively pursue cost-effective DSM. Our review of several utilities' DSM program expenditures before and after implementation of incentives indicates that utilities are responding to incentives. For example, DSM expenditures rose 44% to 77% above preincentive levels for four utilities regarded as having aggressive DSM programs.[16] This comparison, however, does not account for the effect of other factors (such as need for additional capacity) on DSM expenditures.

A more in-depth study found that utilities with incentives have increased their DSM-related expenditures and savings more than have utilities without incentives (Nadel and Jordan 1992). The most comprehensive review yet of existing incentive mechanisms may be a report due to be completed at the end of 1992 for the California Public Utilities Commission (CPUC). The CPUC has directed the Commission Advisory and Compliance Division (CACD) to examine the effectiveness of existing incentive mechanisms for utilities in the state and to make recommendations for improvements.[17] The resulting report will undoubtedly contribute to the ongoing discussion of incentive effectiveness.

The Evolution of Incentives in Three States

Utility and commission experience with incentive experimentation is as varied as the utilities and states themselves. For example, whether a state uses a future or historic test year or the frequency of general rate cases can influence the specific features of an incentive. In addition, two utilities in the same state can have substantially different levels of experience with DSM, making attainable goals for each utility noncomparable. Despite the distinct nature of each case, however, certain lessons can be drawn from the experiences of others.

In this section, we briefly describe the evolution of incentives in three states--Wisconsin, California, and New York. In the case of Wisconsin, utility DSM has been developed to the point where the commission determined that shareholder incentives are no longer needed. In contrast, the evolutionary processes in New York and California continue as regulators and utilities experiment with adjustments to incentives in search of a framework under which all the utilities in their respective states can work, despite their inherent differences.

The Wisconsin Experience

Background. It is risky to draw broad conclusions from comparisons among the experiences of individual states without recognizing differences in regulatory climate and procedures. Wisconsin is a case in point. Every major electric and gas utility in Wisconsin is required to file for rate relief on an annual basis. The Wisconsin Public Service Commission (WPSC) uses a future test year in each of these annual rate cases. DSM expenditures are treated in one of two ways. DSM investments in customer equipment (e.g., rebates or loans on customer hardware) are capitalized over ten years and earn the utilities' approved rate of return. DSM administrative expenditures as well as expenditures on energy audits or informational materials are expensed using a balancing account mechanism to ensure full recovery of expenditures, regardless of whether the utility over- or underspends the budgeted amount in any given year.

Incentives. Wisconsin is often forgotten by those keeping a tally of utility incentive mechanisms. As early as 1977, the WPSC was allowing utilities to recover DSM expenditures through the conservation escrow account.[18] In 1986 the WPSC allowed Wisconsin Electric Power Company (WEPCO) to capitalize certain expenditures.[19] That same year the WPSC established the first shareholder incentive mechanism for WEPCO[20], allowing WEPCO to earn an additional 1% return on the unamortized balance of its capitalized conservation investments for each 125 megawatts of demand savings it could achieve through its conservation programs.

At the same time the WPSC was experimenting with the WEPCO incentive, it also tested several other incentive mechanisms for Madison Gas & Electric, Wisconsin Power & Light, and Wisconsin Public Service.[21] These mechanisms have since either expired or were effectively discontinued due to lack of customer response. In 1988, the WPSC discontinued the WEPCO incentive mechanism, effective December 1990, for a variety of reasons associated with measurement and evaluation issues.[22] No specific shareholder incentive mechanism has been established since for any utility. However the WPSC indicated in a 1991 order that if WEPCO demonstrates significant achievement above its net benefit goals, the WPSC would consider recognizing that achievement in the utility's return on equity.[23]

Outcome. Based on their experience with four types of incentive mechanism, the WPSC has concluded that shareholder incentive mechanisms are not necessary in Wisconsin to encourage utilities to increase cost-effective DSM activity. Instead, the WPSC has chosen to test incentives for utility employees in lieu of shareholder incentives. Consequently, in 1991 the WPSC instituted a utility employee incentive scheme for WEPCO. This approach allows nonmanagement utility employees who are in positions to affect the achievement of DSM benefits to earn incentive bonuses based on performance.[24] The effect of these employee incentives has not yet been evaluated.

The California Experience

Background. In 1982, California was the first state to "decouple" utility profits from energy sales through the electric revenue adjustment mechanism (ERAM). Utilities in the state are also entitled to recover prudent DSM program expenditures through rates using a system of balancing accounts. Thus, significant financial barriers to utility DSM were already eliminated when the California Public Utilities Commission (CPUC) became the second state regulatory authority to establish a utility shareholder incentive mechanism.

Incentives. In September 1988, the CPUC approved a penalty/reward mechanism for San Diego Gas & Electric.[25] That mechanism--a bonus-per-unit incentive--used a trigger system whereby once the utility had achieved predetermined levels of expenditure or service delivery in one group of programs, it would become eligible to earn a reward (or pay a penalty) based on its performance in certain other DSM programs.

Early the following year, several of California's major energy policy stakeholders prompted the CPUC to endorse a collaborative process in which utility, regulatory commission, and consumer group representatives (along with representatives from other parties with a stake in energy efficiency) would develop a consensus approach to propose to the CPUC. The final product of the ensuing six-month collaborative process was a "blueprint" in which all parties agreed to support a major expansion of utility-sponsored DSM as well as to establish a link between utility investments in efficiency and utility profits--a shareholder incentive.[26] The individual utility incentive proposals that resulted from the collaborative were approved by the CPUC, with some modification, seven months later in August 1990.[27]

Incentives--Round 2. One year after the order approving the four shareholder incentive mechanisms, the CPUC instituted a rulemaking and companion investigation (referred to as the DSM OIR/OII[28]) to develop rules and procedures related to utility gas and electric DSM programs. The intended purpose of the DSM OIR/OII is to examine: (1) positions agreed to by participants in the collaborative process but not yet adopted as formal CPUC policy; (2) critical policy areas where participants in the collaborative process failed to reach consensus; and (3) issues not specifically addressed by the collaborative participants.

In December 1991, the CPUC completely revised the Southern California Edison (SCE) incentive mechanism--a bellwether of the commission's evolving position on several key incentive issues.[29] The original SCE mechanism allowed shareholders to earn a return on a portion of DSM program expenditures and a 5% mark-up on expenditures for specific direct assistance and audit programs. The new mechanism adopted the shared savings approach. It allows SCE shareholders to earn a share of DSM savings based on the utility's pretax allowed rate of return on forecast DSM program expenditures. The CPUC also set forth in the order its intent to pursue "comparability" between what the utility may earn on capital invested in supply-side resources and demand-side resources.

Two months later, in February 1992, the CPUC issued rules governing utility DSM programs that addressed such major issues as measurement and evaluation, program eligibility for incentives, cost-effective indicators for programs, and shareholder incentives.[30] In that decision, the CPUC enumerated several general principles for governing shareholder incentive mechanisms, the most notable of which were to: (1) use the shared savings approach; (2) include threshold and penalty components in mechanism design; and (3) "limit the level of potential shareholder earnings from DSM, keeping in mind the 'comparable earnings' [between supply- and demand-side expenditures] guideline." The CPUC went on to state that "the role of shareholder incentives is to offset any regulatory or financial biases against DSM (or in favor of supply-side resources) the utility might have in procuring least-cost resources" and that incentives need not go beyond removing such disincentives. The CPUC also concluded that shareholder incentives for California utilities will be based on *ex post* estimation of savings as of January 1, 1994. The methods and procedures for such estimation will be developed in the interim.

Current Status. The CPUC has affirmed its commitment to the pursuit of an effective and equitable shareholder incentive mechanism for California utilities as long as such an incentive is deemed necessary. As the February 1992 rules and revised SCE mechanism indicate, the CPUC is clarifying the objectives of incentive mechanisms and modifying utility mechanisms accordingly. In doing so, the CPUC has settled on a single type of incentive mechanism--shared savings--for all utilities. At the same time, it has indicated (1) that the value of utility incentives is likely to decline in the future as incentives are made more "comparable" with shareholder return on supply-side investments (as in the case of the SCE mechanism) and (2) that uncertainty of recovery will increase as incentives are to be based on *ex post* rather than *ex ante* savings estimates.

The New York Experience

Background. The New York Public Service Commission (NYPSC) has the task of regulating seven large investor-owned electric or combined utilities. This regulatory responsibility, while large, also provides the NYPSC with the opportunity to experiment with a variety of incentive mechanisms concurrently. Thus, despite the fact that New York was not the first state, or even the second, to establish DSM incentives for utility shareholders, it has been one of the most influential players in the ongoing development of incentive mechanisms. Since it approved a different incentive mechanism for each of seven utilities in the state, New York has been a much-scrutinized microcosm of experimentation.

Incentives. In 1988 the NYPSC invited the seven utilities under its jurisdiction to develop proposals to reform ratemaking "such that DSM programs that benefit customers are also rewarding to stockholders."[31] The utilities responded to the challenge, and between January 1989 and July 1990, the NYPSC approved incentive mechanisms for each of the seven utilities.

The NYPSC recognized early on the benefits that could be gained by promoting diversity and innovation. It also acknowledged uncertainty about the impacts the experimental incentives would have on utility DSM activity and profits. Only two types of incentives were approved initially--six shared savings mechanisms and one bonus return on equity in rate base mechanism at Long Island Lighting Company (LILCO). However, the specific features of each mechanism differed. These features include the method for calculating net resource savings, the time period during which savings were calculated (annually or on a present value basis), the period over which program costs were amortized, whether the incentives were based on savings estimated *ex post* or *ex ante*, whether the incentives included or excluded free riders, and the presence and size of an annual incentive cap or penalty provision. This diversity provided the opportunity to gauge how variations in incentive design would affect the value of incentives across utilities and subsequent utility response, as well as to learn what methods lent themselves to less complicated administration.

Incentives--Round 2. Within 12 months of the approval of the last mechanism, the NYPSC began a second round of experimentation with mechanism design. The first change was to replace LILCO's original bonus return on equity mechanism with a shared savings mechanism.[32] The reason for this change was that the original mechanism contained unintended incentives for the utility to emphasize peak clipping over energy efficiency investments and to underestimate the effect of DSM programs on load forecasts. The next change was to replace the shared savings mechanism at Orange & Rockland with a new type of bonus return on equity mechanism.[33] That mechanism uses a matrix approach to tie different bonus rates of return to the achievement of predetermined DSM targets. A similar mechanism design was later approved for Consolidated Edison.[34]

Impact. While the NYPSC has not conducted a thorough study of incentive mechanisms in the state, it has concluded that incentives have had an impact on utility commitment to more aggressive DSM programs.[35] Utility DSM program budgets have significantly changed since the establishment of shareholder incentives for New York utilities. In 1988, the New York utilities were forecasting DSM expenditures in the year 2000 to be $1 billion; they now expect to spend $3.5 billion in 2000. Forecast demand and energy use forecasts for the year 2000 have also changed. In 1988, the utilities were forecasting 5% and 1% DSM-related reductions in year 2000 peak demand and energy use, respectively. More recent forecasts, however, expect at least a 10% reduction in peak demand and 7% in energy use.

Current Status. Recently the NYPSC staff began considering what incentive features to include in a uniform incentive mechanism for New York utilities. Two major reasons for making incentive mechanisms consistent across utilities are equity and administrative ease. Preliminary staff suggestions for such a mechanism include: allowing utilities to earn a share of net resource savings achieved based on a uniform calculation of lifetime net resource savings; a penalty provision for failure to achieve DSM goals; no annual incentive cap; no adjustment for taxes; statewide *ex ante* savings measurement criteria; and no retrospective adjustment of incentives based on subsequent refinements of measurement criteria. To date, the NYPSC has not taken formal action to realign the seven mechanisms into a standard format according to these or other guidelines.

What Trends do These Experiences Reveal?

It is clear from the preceding discussion that commission preference for the shared benefits type of incentive mechanism is growing. However, it is also clear that shareholder incentives across the country are not likely to evolve into one generic mechanism any time in the near future. The evolution of shareholder incentives for DSM will differ according to the preferences of regulatory commissions in each state. Regulatory commissions continue to experiment with incentives--whether they are for shareholders or utility employees--to encourage utility DSM activity.

Despite the differences among commissions' actions, our review of incentive development has identified one trend in incentive modification that is worth noting. As commissions revise existing incentives, they are unevenly raising the stakes for utilities. For example, many of the most recently approved incentive mechanisms and generic commission orders have included penalty provisions for below-target performance (Washington, Iowa, Maryland, District of Columbia). In some cases, utilities are being asked to assume increased risk through more strict *ex post* savings estimation, while at the same time potential rewards are being reduced (California). Similarly, some commissions are reducing incentives (New York) while others are endorsing the establishment of thresholds where they did not previously exist (New Hampshire). In contrast, we found no examples of a commission having altered an incentive mechanism in a way that improves a utility's ability to earn an incentive.

Future Trends and Upcoming Issues

The most common type of incentive mechanism allows utilities to earn a portion of the benefits (net or total) derived from DSM activities. However, the mechanism by which those benefits are shared is not the same across existing mechanisms. Some utility mechanisms, such as those in effect in New Hampshire and Rhode Island, use relatively simple utility shareholder-ratepayer splits to determine the size of the incentive. Other shared savings mechanisms--in increasing numbers--are more convoluted, incorporating elements intended to encourage the utility to minimize program administrative costs, or to invest in the most cost-effective programs first, or (as in the case of Southern California Edison) to base DSM investment targets on interclass equity. Moreover, the share of savings earned by the utility ranges from 5% to 25%.

As utilities become more experienced in investing in DSM resources, and as the internal barriers to such investment activities (e.g., lack of corporate support) decline, we are likely to see the concept of "comparability" become more predominant. However, the idea of treating shareholder incentive mechanisms as similarly as possible to supply-side investments raises a number of highly charged issues that will likely be resolved differently in each regulatory jurisdiction. Already the question of the tax treatment of incentives is being debated in some states, including California.

Cost allocation approaches and revenue decoupling mechanisms are two increasingly important issues associated with DSM. While these issues are not components of a utility shareholder incentive mechanism per se, they warrant attention because of their influence on a utility's DSM strategy and subsequent performance. We discuss each of these issues briefly. Our intent is not to resolve either issue in this paper, but to encourage further discussion and innovative thinking about possible solutions.

DSM Program Cost Allocation

Traditional cost allocation methods assign cost of service by sector based on the relative energy and demand requirements of each sector. As DSM becomes a larger part of utilities' resource plans and DSM program expenditures increase, people are questioning the equity of assigning such costs to rate classes using the traditional method. Alternative methods include using uniform surcharges for all classes or allocating costs to classes eligible to participate in specific programs.

The basis of the cost allocation issue is an equity-efficiency tradeoff. Equity dictates that every ratepayer should be offered the opportunity to participate in a DSM program. However, the importance of rate class price sensitivity in DSM program cost allocation should not be underestimated. If DSM program savings are achieved at the expense of price-sensitive (e.g., large industrial) users who consequently go off the grid, who benefits? Programs intended to benefit residential customers can ultimately harm them by decreasing the customer base and thus increasing the fixed charges that must be recovered from each remaining customer.

From an efficiency perspective, the total resource cost (TRC) test is the appropriate screen to ensure that a DSM program's resource benefits exceed program costs. However, rates may increase to reflect ratepayer impact measure (RIM) losses and shareholder incentives associated with those programs (Hirst 1991). This poses a problem for utilities facing increased competition. Situations in which a 1 mil per kilowatt-hour increase in energy costs can drive certain customers off the grid are no longer uncommon. This scenario is the basis of the position taken by the Electric Consumers Resource Council (ELCON) and other groups representing large users.[36]

Neither traditional cost of service methods nor uniform surcharges to all classes resolves the interclass equity issues. (Allocation of program costs to participating classes addresses interclass equity, but does not eliminate intraclass equity issues). Short of negotiating shared savings arrangements with each participant so that participants pay back the cost of efficiency improvement from their bill savings, cost allocation by participant class may be the most equitable solution. However, this method can be improved upon.

Allocation of DSM program costs to participating classes isolates a rate class from the rate impacts of programs offered to other rate classes. While that isolation remains intact between rate cases, its integrity can be compromised during the next rate case unless certain precautions are taken. For example, in the course of allocating costs during the next rate case, traditional allocation methods would redistribute revenue loss due to DSM among rate classes. This might mean raising industrial energy rates to pay for the revenue impact of successful residential energy efficiency programs that did not pass the RIM test.

We see two possible solutions to the equity-efficiency tradeoff associated with DSM cost allocation. One way to mitigate cross-class subsidization would be to allocate lost revenues across classes based on pre-DSM allocators--that is, add the DSM savings to each sector before assigning the costs to be borne by each sector. Another possible solution would be to use different cost-effectiveness tests for different rate classes depending on their respective price sensitivities. For example, where price sensitivity is low--the residential class--the TRC test would be used to maximize efficiency. Where price sensitivity is high--the industrial class--the RIM test would be used to minimize rate impact.

Revenue Decoupling Mechanisms

Revenue decoupling mechanisms were first conceived as a means of making a utility's profits independent from energy sales. Traditional ratemaking practices, which allowed utilities to increase profits if actual sales exceeded forecast sales, contradicted commission orders for utilities to implement cost-effective DSM programs that decreased utility sales, and thus revenue. Two methods of decoupling utility profits from sales are currently in place today. One method, the electric revenue adjustment mechanism (ERAM), keeps track of the difference between the utility's nonfuel revenue requirement and actual revenue and periodically adjusts rates to compensate either the utility or ratepayers for under- or overcollection of revenues. The second method, ERAM-per-customer, calculates a preestablished revenue per customer based on nonfuel revenue requirements divided by test year customer count. This method compensates either the utility or ratepayers for the difference between revenue-per-customer times the actual customer count and actual revenues.

Regulatory interest in decoupling mechanisms has grown in recent years. Most recently, regulatory commissions in Maine and Washington approved ERAM-per-participant mechanisms for one utility in each state. Because of this increased attention on decoupling mechanisms, we wish to expand the discussion to consider two views not yet raised: the effect of decoupling mechanisms on utility sales growth and investment opportunity.

One of the arguments in support of decoupling mechanisms has been that they remove the incentive for a utility to increase sales and thus accrue earnings in excess of the test year rate of return. This is true in the short run. However, decoupling mechanisms do not eliminate the long-run incentive for a utility to grow if that utility places a value on growth. If sales increase between rate cases, despite a decoupling mechanism, the utility's rate base will increase and revenue requirements will be adjusted accordingly in the next rate case proceeding. Thus the utility is not penalized by growth.

There is no consensus on whether or not shareholders benefit from sales growth. This is a question for the investment analysts, and we do not intend in this paper to advocate either position. Instead, we wish to underscore the fact that the presence of a decoupling mechanism does not affect the outcome of that debate. That is, if shareholders gain value from growth--for whatever reason--a decoupling mechanism does not hinder that growth. It only limits the return that can be earned on investment associated with that growth.

In cases where a DSM shareholder incentive is in place, utility shareholders may earn a return on both supply- and demand-side resource investments. This approach is generally considered to be equitable, especially by commissions that are modifying shareholder incentives to more closely mirror supply-side earnings. Yet, establishing comparable rates of return does not ensure equal potential to earn. That is, if the scale of investment opportunities in DSM resources is smaller than in supply-side resources, shareholders will not maximize their wealth by investing in DSM. The magnitude of an investment's net present value, and not the internal rate of return of the investment, is what determines its value to shareholders. This is particularly true when two investments are mutually exclusive, as is the case for supply- and demand-side investments at the most simplistic level.

Conclusion

The development of shareholder incentives is still evolving. Despite the fact that commissions have been experimenting with incentives now for over five years, we are far from reaching a consensus either among or within states on the type or features of the most effective shareholder incentive. In fact, there is no need to reach such a consensus. Given the diversity of regulatory climates among the states and the distinct planning needs of each utility, it is not inevitable that a single incentive mechanism should or can provide the desired incentive for every utility in the country. Experience with incentives thus far has shown that a variety of mechanism designs can successfully evoke aggressive utility pursuit of cost-effective DSM resources.

The next few years promise yet more issues for utilities and regulators to confront. The idea of "comparable" treatment of demand-side and supply-side investments will undoubtedly spawn both resistance and innovation as it attracts a wider audience in the regulatory and utility communities. Similarly, as increasing attention is focused on DSM cost recovery and rate-related issues, stakeholders will be challenged with the task of balancing equity with efficiency in a manner that can satisfy all parties.

Endnotes

1. Massachusetts Department of Public Utilities, Order in D.P.U. 89-194 and 89-195, March 30, 1990; New Hampshire Public Utilities Commission, Order No. 19,905 in DE 89-187, August 7, 1990; and Rhode Island Public Utilities Commission, Order in Docket No. 1939, issued May 16, 1990.

2. Public Act 88-57, effective October 1, 1988.

3. CDPUC, Order in Docket Nos. 89-08-11 and 89-08-12, January 24, 1990.

4. NYPSC, Opinion No. 88-20 in Case No. 29409, July 26, 1988.

5. We use the term "shared benefits" incentive mechanisms to include both "shared savings" mechanisms that award utilities with a share of net value of savings and those mechanisms that award utilities with a share of the gross value of savings--e.g., Granite State Electric and Narragansett Electric.

6. Note that some utilities have more than one type of incentive mechanism in place, e.g., the California utilities.

7. Arizona Public Service, Boston Edison (MA), Boston Gas (MA), Central Hudson Gas & Electric (NY), Central Maine Power, Colonial Gas (MA), Concord Electric Co. (NH), Connecticut Light & Power, Connecticut Valley Electric Co. (NH), Consolidated Edison (NY), Consumers Power (MI), Duke Power (NC), Exeter & Hampton Electric Co. (NH), Granite State Electric (NH), Long Island Lighting Co. (NY), Massachusetts Electric, Minnesota Power, Narragansett Electric (RI), New York State Electric & Gas, Niagara Mohawk Power Corp. (NY), Northern State Power (MN), Orange & Rockland (NY), Otter Tail Power (MN), Pacific Gas & Electric (CA), Potomac Electric Power Co. (Pepco) (DC), Pepco (MD), PSI Energy (IN), Portland General Electric (OR), Public Service Co. of Colorado, Puget Power & Light (WA), Rochester Gas & Electric (NY), San Diego Gas & Electric (CA), Southern California Edison, Southern California Gas, United Illuminating (CT), and Western Massachusetts Electric.

8. Arizona, California, Colorado, Connecticut, District of Columbia, Indiana, Maine, Maryland, Massachusetts, Michigan, Minnesota, New Hampshire, New York, North Carolina, Oregon, Rhode Island, and Washington.

9. Hawaii, Iowa, New Jersey, Ohio, and Vermont.

10. California, New York, Rhode Island, and Wisconsin.

11. Colorado, Connecticut, Massachusetts, Michigan, and New Hampshire.

12. Arizona, District of Columbia, Indiana, Iowa, Maine, Maryland, Minnesota, New Jersey, Ohio, Oregon, and Vermont.

13. WUTC, First Supplemental Order in Docket No. UE-910689, January 14, 1992.

14. FPSC, Order No. 25775 in Docket No. 900834-EI, February 24, 1992.

15. Alabama, Alaska, Arkansas, Delaware, Kentucky, Louisiana, Mississippi, Missouri, North Dakota, Oklahoma, South Carolina, South Dakota, Tennessee, West Virginia, and Wyoming.

16. San Diego Gas & Electric, Pacific Gas & Electric, New York State Electric & Gas, and New England Electric System.

17. CPUC, Decision 90-03-068, Ordering Paragraph 1.h, August 29, 1990.

18. WPSC, Order in Docket No. 6680-GR-3, Madison, Wisconsin, October 10, 1977; statute confirming WPSC authority to use escrow accounting, Wis. Stats., 196.374(3) 1983a 27.

19. WPSC, Order in Docket No. 6630-UR-100, WEPCO 1987 Test Year Rate Case, Madison, Wisconsin, December 30, 1986.

20. Ibid.

21. See Reid, M. W., and Brown, J. B. *Incentives for Demand-Side Management*, January 1992. National Association of Regulatory Utility Commissioners, Washington, D.C. or Newman, P., Kihm, S., and Schoengold, D. Forthcoming. "Spare the Stick and Spoil the Carrot: Why DSM Incentives for Utility Stockholders Aren't Necessary." Chapter 11 in Nadel, S. M., Reid, M. W., and Wolcott, D. R., Eds. *Regulatory Incentives for Demand-Side Management*. American Council for an Energy-Efficient Economy, Berkeley, California.

22. WPSC, Order in Docket No. 6630-UR-102, WEPCO 1989 Test Year Rate Case, Madison, Wisconsin, December 29, 1988, and Order in Docket No. 6630-UR-103, WEPCO 1990 Test Year Rate Case, Madison Wisconsin, December 1989.

23. WPSC, Order in Docket No. 6630-UR-104, WEPCO 1991 Test Year Rate Case, Madison, Wisconsin, 1991.

24. Ibid.

25. CPUC, Decision 88-09-063, September 28, 1988.

26. *An Energy Efficiency Blueprint for California: Report of the Statewide Collaborative Process*, January 1990.

27. CPUC Decision 90-08-068, August 29, 1990.

28. CPUC Order Instituting Rulemaking (OIR) on the commission's own motion to establish rules and procedures governing utility demand-side management. R.91-08-003, and CPUC Order Instituting Investigation (OII) on the commission's own motion to establish procedures governing demand-side management and the competitive procurement thereof. I.91-08-002, August 7, 1991.

29. CPUC, Decision 91-12-076, December 20, 1992.

30. CPUC, Interim Opinion On Rules Governing Utility Demand-Side Management Programs, Decision 92-02-075, February 20, 1992.

31. NYPSC, Opinion No. 88-20 in Case No. 29409, July 26, 1988.

32. NYPSC, Opinion in Case No. 90-E-0038, August 14, 1990.

33. NYPSC, Opinion No. 90-24 in Case Nos. 89-E-175 and 89-E-176, September 26, 1990.

34. NYPSC, Opinion in Case No. 90-E-0932, April 19, 1991.

35. James T. Gallagher, 1991. "DSM Incentives In New York State: A Critique of Initial Utility Methods." *Proceedings from the 5th National Demand-Side Conference*, Boston, Massachusetts pp. 220-226.

36. Electric Consumers Resource Council. 1990. *Profiles in Electricity Issues: Demand Side Management (DSM)*, Number 14. ELCON, Washington, D.C. December.

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