Performance Metrics for Market Transformation Programs: Incentivizing Progress without Strangling Creativity

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ABSTRACT

For the past decade, many state utility commissions have provided financial incentives to utilities for the successful implementation of demand-side management (DSM) programs. With the growing emphasis on the market transformation approach to DSM, regulatory incentive structures also need to evolve. This paper discusses strategies for developing and configuring these incentives, drawing on experiences in the two regions—New England (particularly Massachusetts) and California. As a result of this review, we reach several tentative conclusions as follows: (1) incentives are useful in states where utilities are the prime administrators of market transformation programs; (2) incentives are complex and must be developed with care; (3) increased emphasis should be placed on market effect metrics; (4) good data and market/evaluation research are an important foundation for incentives; (5) incentive metrics are often best set through negotiation, but parties need to have adequate time and flexibility; (6) a modest level of incentives appears to be acceptable to a wide range of parties in the regulatory process; and (7) current incentive approaches have difficulty addressing the dynamic nature of the markets they are trying to change, and as a result, there is a need to experiment with modifications to current incentive mechanisms.

Introduction

This paper represents a joint effort by a diverse group of participants active in planning, implementing, and evaluating public benefit energy efficiency programs and policies in California and New England. This paper is based on a larger report by many of the same authors (Nadel et al. 2000). In this paper we focus on programs that seek to reduce market barriers and permanently transform markets for energy-efficient goods and services so that these goods and services become normal market practice in the future. In some regions these programs are administered by distribution utilities, in other regions by non-profit and public sector organizations. Regardless of the program administrator, for programs to succeed, there is a need for program implementers and contractors to be rewarded in some fashion when they do a good job. For non-profit administrators, helping the public and receiving continued funding may be reward enough. But for private administrators, money is the key reward. This paper discusses strategies for developing and configuring these incentives, drawing on experiences in the two regions. We particularly focus on Massachusetts and California, as these are the states where regulatory incentives for market transformation are most advanced.[1] Our intent is to offer insights to program implementers and overseers on how to best structure these incentives to improve chances of program success.

DSM Performance Incentives—A Brief History

Many utilities have been offering programs to help their customers reduce energy use since the 1970s and 1980s. By the late 1980s, as programs grew in size and scope, it became clear that given the way utilities are structured and regulated in the U.S., most utilities have little incentive to do a good job convincing customers to use less of their product. Under traditional regulation, as sales go down, profits also tend to go down, and visa versa. This happens primarily because utility revenues as based on volumetric (kWh) charges, while most non-fuel costs are more fixed than variable (Moskovitz 1989).

To address this problem, a number of state utility commissions and their regulated utilities began developing schemes to *decouple* profits from sales (so that utilities would be at least neutral as to future sales levels) and to offer positive incentives for doing a good job implementing energy efficiency and other demand-side management programs.

At that time, a number of different performance incentive schemes were developed, with the most common being to reward the utility with an incentive based on a small percentage of the net societal benefits achieved by the programs they implement (Nadel, Reid, and Wolcott 1992). In total, as of November1991, incentive mechanisms were approved by utility commissions in 21 states (Reid 1992).

Evaluations of these performance incentives found that the incentives were having the desired effects. For example, a 1991 study of incentives in nine states found that utilities with incentives increased their DSM spending and savings by more than nearby utilities without incentives. In most cases, the differences were statistically significant. (Nadel and Jordan 1992).

Restructuring and Market Transformation Programs: The Need for New Incentive Paradigms

In the mid-1990s, two trends began that have profoundly influenced utility DSM programs—utility restructuring and the emergence of the market transformation paradigm to program design. Utility restructuring began in 1994 with the publication of the "Blue Book" in California that outlined the rationale for restructuring California's electricity industry. Since then, restructuring legislation or regulatory orders have been enacted in 23 states. Under restructuring in most states, energy efficiency and other public benefit programs (programs traditionally funded through rates and that provide important benefits to the public including programs to promote energy efficiency and provide special services to low-income households) are funded by a small charge on distribution service. In most states, public benefit programs are administered by distribution utilities with regulatory oversight from

[1] In addition to these two states, New Jersey and Vermont have recently adopted performance incentives for market transformation programs and Connecticut is in the process of updating the structure of their performance incentives. In the Northwest, metrics are also set, but these are used to help evaluate performance and not to financially reward program administrators.

utility commissions and other regulatory bodies (e.g., the California Board for Energy Efficiency, which was established as part of California's restructuring legislation).

The move towards market transformation programs also gained traction in the mid-1990s. In the 1980s and early 1990s, the dominant DSM paradigm was *resource acquisition*—under that utilities sought to maximize the acquisition of cost-effective energy savings in order to reduce the need for acquiring new generation resources. Resource acquisition programs tended to emphasize the use of rebates and direct installation of energy-saving measures in individual homes and commercial/industrial facilities (utility contractors would install measures in customer facilities). Under restructuring, some (but not all) of the rationale for resource acquisition disappeared; with restructuring, provision of new generation resources is left to the market, and there is less need for regulatory intervention since ratepayers are no longer required to pay for new power plants regardless of whether the plant is used or not.

The market transformation paradigm offered an alternative approach that better leverages the activities of the market to (in a successful program) achieve large energy savings at costs below current avoided costs. Under the market transformation paradigm, the focus is on market barriers, and taking steps to permanently reduce or overcome these barriers, so that over time, efficient goods and services become the norm, with no or reduced need for continued market intervention.

Market transformation strategies are a major focus of program efforts in the Northeast and California. In California and New England, primary responsibility for program implementation now rests with the distribution utilities. However, in both regions, coordination across utility service-area boundaries is increasing.

Under the market transformation paradigm, the emphasis is no longer on maximizing the number of measures installed in the short term, but instead is on making demonstrable progress in addressing and overcoming specific market barriers. In fact, in the early years of a market transformation initiative, the number of measures that are actually installed may be scant; instead, the emphasis may be on better training for service providers and increasing availability and stocking of more efficient equipment.

With the change in emphasis, performance incentives also need to change. Since market transformation initiatives do not focus primarily on short-term energy savings, incentive metrics based on energy savings are not appropriate. Instead, market transformation program evaluators focus on *market progress indicators* such as the number of trained service providers, changes in awareness of and attitudes about targeted measures, and changes in local stocking, prices, and market share of targeted equipment and services. Performance metrics for market transformation programs need to move towards a similar market-focused approach. In the following sections, initial experiences with performance incentives for market transformation programs are discussed.

Establishing Metrics

In New England and California, incentive metrics are primarily set through a negotiation process involving utilities, regulators, and/or non-utility intervenors (the parties vary somewhat from state to state). In the following sections, we discuss the metric-setting process separately for Massachusetts and California. In order to help illustrate this discussion with concrete examples, metrics used in the different regions for a sample program (clothes washers) are summarized in Table 1.

Table 1. Summary of Clothes Washer Metrics Used in Two States in 1998-2000

	California (PG&E)	Massachusetts (WMECo)
A. Studies		
1998	Survey of participating customers (16%)	Plan and complete joint baseline study (33%)
1999	Estimate baseline market share by 7/99*	Plan and complete 3rd party evaluation report (33%); Complete draft market transformation plan by 9/99 (33%)
2000	None	None
B. Program Activity		
1998	Implement program within 90 days of approval ($60k); Pay 5000-18,000 rebates (84%)	Finalize and implement program, provide at least 350 rebates (67%)
1999	Pay at least 2000 rebates/month for 6 months*	Provide 750-1075 rebates (33%)
2000	None	None
C. Market Share		
1998	None	Double market share relative to baseline (alternate to achieving rebate target)
1999	None	Achieve and document a 15% market share for ENERGY STAR® washers (alternate to achieving rebate target)
2000 (pro-posed)	Achieve a 16% market share for ENERGY STAR washers (100%)**	Achieve and document a 20% market for ENERGY STAR washers (~50%); Increase to 16% the percentage of non-participants who have heard of the ENERGY STAR program and can accurately describe it (~50%)

Note: Percents are percent of maximum incentive for clothes washers devoted to each metric in each year (i.e., if the maximum clothes washer incentive is $500,000 and half of this is devoted to a single metric, then for that metric the figure “50%” will be shown.

* PG&E’s clothes washer incentive for 1999 depended on achieving both metrics. If only one milestone was achieved, no incentive would be earned.

** While this is the only clothes washer specific milestone proposed for 2000, PG&E proposed several global appliance milestones that relate to washers such as milestones for the number of participating retailers and the number of appliance salespersons trained.

Massachusetts

The Massachusetts restructuring act, with its energy efficiency wires charge, passed in the late fall of 1997. Under the Act, all utilities are required to submit five-year energy efficiency plans. Just prior to passage, a regional organization, Northeast Energy Efficiency Partnerships (NEEP), was formed to coordinate regional market transformation initiatives that individual utilities could participate in. As preparation of the energy efficiency plans began, the question arose how to propose financial incentives for encouraging the utilities to support the nascent regional market transformation efforts.

As financial incentives for utilities were considered, it became clear that generally kWh savings weren't the correct "metric" for market transformation activities. Thus began a protracted set of meetings among utility staff, non-utility party (NUP) consultants, and several NUP principals. The goal of these multi-utility/NUP meetings was to establish common metrics for the utilities, as the state utility commission was encouraging the state's utilities to cooperate on regional market transformation initiatives. Due to the difficulties of reaching agreement on many issues, it took nearly six months to resolve 1998 metrics, with negotiations continuing well into the program year.

The negotiated resolution on 1998 metrics ultimately included many compromises. Most of the market transformation metrics in the first year were related either to providing a given number of rebates, or to accomplishing a specific activity. Utilities and NUPs were reluctant to set metrics based on market share, as in many cases there was insufficient data to determine the overall size of the specific market. Many of the rebate-based incentives were scaled to performance, with half of the incentive amount available for accomplishing half of the rebates, and the full incentive available at 85% of goal (assuming that some variability in accomplishing goals was beyond the control of the utilities).

Development of the metrics for the 1999 program year came with several advantages—the regional initiatives had been active for a longer time and everyone (utility staffs, consultants, and NUPs) had real world practical experience with them. Still, there were differing perspectives and interests, which led to a protracted process lasting nearly six months and extending into the program year. In the end, the overall content did reflect a desire to establish metrics for the development of market transformation plans, progress reports, and multi-utility targets. There were also individual utility targets related to the regional initiatives (e.g., lighting).

California

In California, the process begins when CBEE reserves a percentage of total program costs for potential utility earnings, also referred to as incentives. While incentive levels varied slightly by utility, in 1998 and 1999, PG&E's incentive level was 12%. A set of earnings milestones (California uses the term *milestone* rather than *metric*) are then negotiated between the CBEE (with assistance from its technical consultants) and each utility. Simply stated, the more milestones you achieve, the more you earn.

The CBEE established a sub-committee to work with utilities in developing and negotiating the performance incentive metrics. Each California utility negotiates its own milestones and earnings incentives separately with the CPUC, so there is some variation in incentives from utility to utility. The utilities propose an initial mix of performance incentive metrics based on some broad guidelines by the CBEE, followed by a series of negotiation meetings.

In some cases, the milestones are based simply on successful program management and in other cases are directly related to specific market effects. While several members of the CBEE prefer a shift towards market effects-type milestones, this has proven very difficult and contentious. The initial set of milestones negotiated in 1998 focused primarily on successful program management and deployment. In 1999, a shift was made to four specific types of milestones that distinguished activities among program roll-out, program activity, aggressive implementation (based on spending the budget for a particular program), and market effects. The first three could be classified more as managerial milestones while the last one is truly market effects based. These different types of milestones can be viewed as a continuum from least risky and a weaker indicator of actual market transformation, to more risky and a stronger indicator of market transformation.

Results to Date

In Massachusetts, the metrics ended up being very strong drivers of utility actions for 1998 and 1999, with attendant positive and negative effects. On the positive side, specific actions that had incentives associated with them, such as producing market progress reports and long-term market transformation plans, were given high priority and largely accomplished in a timely manner.

On the negative side there were two noticeable effects. First, if a specific activity did not have incentives associated with it, it often received little notice. It should be understood that there were some considerable mitigating circumstances from a utility perspective, including a shortened program year (after the metrics were finally resolved), a variety of new activities that consumed staff time, and some major structural changes such as proposed mergers. As an example, evaluation or market research for programs with no metrics for evaluations were not scheduled in 1999.

A second negative effect was that some utilities pursued achieving rebate activity goals to the exclusion of other program elements that were equally meaningful from a market transformation perspective. In one case, rebates for residential lighting products were kept at (relatively) high levels even after the product cost dropped, and special events were used to promote these low cost products while normal retail development was largely ignored.

Overall, in 1998 and 1999, utilities tended to earn the majority of the available incentive pool but not the entire pool. For example, in 1999, Western Massachusetts Electric Company (WMECo) achieved 93% of its maximum performance incentive for regional market transformation programs (in addition, the utility continues to receive incentives for kWh savings from more traditional DSM programs). While most metrics were achieved, they fell short in two programs due to such factors as lower housing starts than expected and difficulty achieving desired participation levels in markets for several measures.

In California, each utility has its own set of incentive milestones. In the discussion below we use Pacific Gas and Electric to illustrate how incentives have worked. Of the total potential utility earnings in program year 1998, PG&E claimed more than 95% of the total potential incentive earnings. In a few cases, PG&E met part of its target and only qualified for the lower tier payment. For example, for residential efficient lighting fixtures, PG&E's milestone had three tiers for documented shipments to retailers. Under this structure, PG&E received $178,000 if sales exceeded 60,000 units, an additional $36,000 if sales exceeded 125,000 units, and a still further $66,000 if sales exceeded 190,000 units. This is a good example of a milestone that somewhat balances the utility's risk by allowing them to get "partial credit" for the success they did achieve in an immature market.

In 1999, PG&E claimed 89% of the total potential incentives earnings. The incentives that could not be claimed were due to the spending milestones—for many programs, including several major programs, participation rates were not high enough to use the full program budget. More specifically, the following observations can be made relative to the utility's success/failure in meeting the milestones and the challenges in performing the required studies. First, the milestones, especially the roll-out and program activity type milestones, were successful in keeping the utilities and their contract implementers focused. Second, better coordination is needed among the CBEE technical consultants, utility measurement and evaluation staff and their evaluation contractors, and the utility program managers and their implementation contractors. The evaluation studies are critical to setting baselines and tracking market progress yet the program planning and implementation cycle has been somewhat disconnected from the program evaluation process. An integrated approach between measurement study planning and program planning is required to properly document market movement associated with milestones. Third, aggressive spending milestones, which are intended to incent utility administrators to spend a large portion of the program budget, are dependent upon market response to the program. In 1999, utilities were asked by stakeholders to launch new, complex programs such as the Standard Performance Contract Program and the Residential Contractor Program, which take time to build momentum in the marketplace. Utilities with large budgets such as PG&E were not able to meet these milestones in 1999 due to program planning and approval delays, inadequate time to build program momentum, and imbalances between program budgets and reasonable program participation expectations.

Changes for 2000

The process for the 2000 metrics was easier in Massachusetts than in previous years, as no one wanted to duplicate the six months of negotiations that had occurred in prior years. However, while most issues were resolved in 1999, several issues have dragged on for months with the result that as of mid-May 2000, the full metric package for 2000 has yet to be finalized. In Massachusetts, in negotiating metrics for 2000, there was a decided shift away from incentives for development of market studies or plans. While metrics for these types of specific activities had worked fairly well in 1998 and 1999, there was a philosophical shift, on the part of the NUPs, away from paying for activities that should be part and parcel of overall program activities. While in 1999 metrics paid for developing long-term program visions and preparing new types of evaluation products, the NUPs believed that these activities needed to simply be included as part of overall program operations. Many residential program metrics are now based on market share data. Market share numbers are most likely to be used when overall market size data is tracked by somebody else, such as the Association of Home Appliance Manufacturers (AHAM). Because of more limited market data in the commercial sector, metrics tend to be based on rebate activities or accomplishment of key program goals (e.g., offer and enroll customer in training, complete pilot projects).

In California, the focus in 2000 has shifted somewhat towards market effects, with this category now accounting for approximately 45% of the available proposed incentives in PG&E's service territory. Many of the proposed 2000 milestones involve an entirely new metrics rather than mere tweaks of percent market share or adjustments of dollar amounts from 1999. While some inter-year flexibility and adjustment is advisable, wholesale changes of this sort cause a lot of extended and complex negotiations with no guarantee that the new metrics are a significant improvement on the old.

Discussion

Based on the above discussion and experiences, several common issues emerge across regions that merit further discussion:

Statewide vs. Single Utility

Many programs in Massachusetts and several programs in California are now statewide. Compared to stand-alone utility programs, these statewide and regional programs provide additional milestone-setting challenges and the trend in both California and Massachusetts is to establish the same milestone for each utility when there is a statewide program (common metrics across states are much less common). While common milestones seem ideal, some flexibility must be maintained. For example, when there are significant differences in market share or consumer awareness in different service territories, it may make sense to base the milestone on an agreed-upon parameter (for example, market share) but to set different numeric targets for each region. This will reduce the potential for a utility that did its job in its service territory not attaining a milestone due to the poor performance in another utility's service territory.

Negotiation Schedule

In California, the program planning process is often complicated by compressed schedules and filing deadlines that are not in sync with program planning timelines. For example, in a few program areas, the negotiations over program year 2000 milestones occurred prior to completing conceptual program design. This resulted in some programs being designed around the milestones. The preferred sequence would be to set broad program goals, design the program, and then discuss and agree upon appropriate near-term milestones.

Duration/Timing

A lot has been written previously about the benefits of having multi-year program designs and funding approvals, due to the fact that market transformation may take five plus years for many technologies and markets (for example, see Nadel and Latham 1998). Still, California and Massachusetts continue to go through an annual program planning and milestone setting process. This one year horizon has the unfortunate result of leading the negotiations toward short-term measurements that may not necessarily be indicative of market transformation.

A further compounding factor in California is the delayed approval of program plans by the CPUC. Under the current system, several rounds of filings and hearings may be required prior to a CPUC final decision. As a result, the new year's programs often are not approved until well into the first quarter or even second quarter. This prevents the implementers from providing the targeted stakeholders (such as the manufacturers and retailers) with the needed information to manufacture, ship, and stock the desired products in time to meet the program roll-out timeline and objectives. The programs are often then placed in jeopardy of underachieving and missing milestones. This dynamic is another reason why an institution with its earnings on the line is less likely to agree to market-based incentives. Likewise, for the past three years, metric-setting negotiations in Massachusetts have not been completed until well into the program year, resulting in similar problems.

Manage by Milestone Tunnel Vision

Rigid milestones may lead to strict "management by milestone." This can easily cramp program designer and implementer's creativity as the program year unfolds. Since milestones are often focused on one aspect of a program, a program manager has incentive to give that aspect priority over other possibly important parts of the program.

Number of Metrics

Establishing the number of incentive metrics per utility presents another challenge. A large number of metrics makes the portfolio complicated and costly to verify. For example, it is not cost-effective to spend $10,000 tracking and verifying a $40,000 metric. In Massachusetts, in 1998, for some utilities there were so many metrics that some metrics were worth as little as $400 to the utility. On the other hand, reducing the number of metrics requires high level market effect-type metrics because it is only at the level of market penetration and other high-level metrics that the many factors contributing to a successful program come together in a single metric. This places large earnings on the few metrics that are established, which in turn puts more money at risk for utilities and/or raises concerns when regulators see large earnings tied to a single measure. Ultimately, most regions are moving towards having a small number of metrics per program. For example, in 1998 PG&E had more than 100 total metrics and in 1999 the number of metrics was reduced to about 50. The Northwest, on the other hand, has always had several metrics per program (typically on the order of three to five), but since metrics are not used for determine financial incentives in a formal regulatory proceeding, it is easier to have a few more metrics (Nadel et al. 2000). Overall, the emerging consensus appears to be that in most cases it makes sense to have a few incentive metrics for each program, except some of the smaller/simpler programs that may have only a single metric.

Interdependence of Regions and Markets

The success of some programs is dependent upon the actions of other regional market transformation organizations. While California is indeed a very large market, often national manufacturers are reluctant to produce a new energy-efficient product simply for the California market (let alone the Massachusetts market). Many programs require the coordination, participation, and funding by several large groups such as California utilities, NEEP, and the New York State Energy Research Development Authority (NYSERDA), which cover large geographic areas, populations, and market transformation budgets. However, because participation of other regions is beyond their control, utilities in Massachusetts have been reluctant to use national-level metrics, even if key market effects (e.g., increased product offerings) are needed at the national level.

"All or Nothing" versus Tiered Metrics

In some cases a simple, yes-or-no type of milestone is appropriate. You get the money if you did "x", you get no money if you didn't. In most cases, however, a tiered approach is more effective. For example, two or more tiers of earnings for a particular milestone (less money for a partial accomplishment) can be established. This allows utilities to continue to strive to deliver results even when a program's most difficult objectives become unattainable during the program year. Some examples of tiered metrics are shown in Table 1. This structure helps utilities better manage their risk and has been accepted by regulators in California and Massachusetts.

Energy Savings

Except in a few cases, the current class of metrics does not include direct measurements of energy savings. In our opinion, this is entirely appropriate as market transformation programs are designed to achieve long-term changes in the market, and measurements of short-term energy savings frequently have little bearing on long-term success. On the other hand, the lack of short-term savings information makes it difficult to simply communicate to legislators, regulators, and others what is received for their investment. While short-term energy savings measurements are not adequate to fully capture the value of market transformation, improved projections of current and projected future energy savings may be needed to satisfy the requirements of some policy makers.

Establishing Incentives for Market Effects

In Massachusetts and California, utilities have been reluctant to accept market effects metrics because achieving these metrics depends in part on developments in the market that are out of the control of program administrators. However, for programs to be successful in transforming markets, it is these types of metrics, rather than program activity metrics, that are most important. California will use market effects milestones to a significant degree in 2000. As utilities gain some experience with these metrics, hopefully they will become less controversial. Still, because market effect indicators pose greater risks to the administrators, it may make sense to revise the rewards accordingly. One option is higher incentive pools. Another option, which has been adopted in California, is to allow the sum of individual program incentive pools to exceed the total pool, so utilities have multiple opportunities to earn the maximum total incentive. For example, six metrics can be set with each worth $100,000 but the maximum incentive capped at $500,000. In this way, even if one metric is not reached, the maximum $500,000 incentive can be earned. By giving administrators several opportunities to win a prize, riskier metrics become easier to accept.

Incentive Amounts

In both California and New England, there were extensive discussions about incentive amounts in the early 1990's, leading to a resolution in which the maximum utility incentive that could be earned was approximately 10-12% of the DSM budget. In 1998-1999, these same percentages continue to be applied. However, in 2000, in both California and Massachusetts, some non-utility parties have argued that utilities are required by law to implement public benefit programs, and that incentives should be reduced. As a result, the maximum incentive in Massachusetts is likely to be reduced to around 9% of the DSM budget,[2] while in California, a draft Public Service Commission decision calls for a 7% maximum incentive. Utilities are opposing this reduction and as of this writing, a final decision has not been made. If the incentives are reduced in California, the metrics may also need to be revised, since utilities are inclined to take fewer risks if the rewards are smaller.

Also, if smaller incentives are approved in both states, it will be very useful to evaluate the results of incentives at year end, in order to determine whether the smaller incentives still motivate good program implementation, or whether the smaller incentives are not as effective are larger incentives in motivating the desired behavior.

Lost Revenues

In many states, in the early 1990s mechanisms were introduced to reimburse utilities for a portion of lost revenues attributable to utility-operated energy efficiency programs. These lost revenue recovery mechanisms often complement incentives—the incentives offer rewards for successful DSM programs while the lost revenue mechanisms remove much of the disincentive to DSM programs provided by traditional rate regulation. However, these lost revenue recovery mechanisms have proven complicated, contentious, and expensive. As a result, the general trend is toward gradually phasing out lost revenue recovery mechanisms (for example, Vermont is now doing this). We endorse this trend, but recommend that lost revenues be considered when setting the overall incentive pool.

[2] The incentive percentage depends in part on the interest rate on Treasury Bills, and thus could be somewhat higher or lower than 9% depending on how interest rates change.

Conclusions and Recommendations

Based on the discussion above, it is clear that we are still on the steep part of the learning curve regarding incentives for market transformation. Still, based on the experience to date, several tentative conclusions and recommendations can be made as follows:

1. *Incentives are useful in states where utilities are the prime administrators of market transformation programs*. Incentives are attractive to private utilities and clearly drive behavior to meet incentive goals.

2. *Incentives are complex and must be developed with care*. Care must be taken to identify program objectives and develop incentive designs that reward achievement of those objectives without having perverse or unintended effects. Metrics should be worded so that it is clear how achievement of the metric will be assessed. The number of metrics should be large enough to reward key achievements but not be so large that pursuing and monitoring achievements becomes difficult to manage. Typically, each major program should have a few metrics.

3. *Increased emphasis should be placed on market effect metrics*. Incentives in California and Massachusetts have tended to emphasize activities and not market effects. Since the objective of market transformation programs is achieving market effects, such effects need increased emphasis when establishing performance incentives. In setting market effects metrics, a multi-year approach may be useful, in which firm milestones are identified for one year and tentative milestones identified for several subsequent years so as to provide direction for long-term activities and to streamline the annual metric-setting process (the process would begin with tentative long-term metrics set the previous year). However, it should be recognized that market effects depend on much more than utility actions and thus utilities take a greater risk that incentives will not be earned, no matter how well a utility pursues a program's objectives. To address this increased risk, higher incentives should be considered, or utilities could be given multiple chances to earn the maximum incentive (e.g., the maximum incentive is earned if at least 80% of milestones are met).

4. *Good data and market/evaluation research are an important foundation for incentives*. Good baseline data and market research are needed to establish reasonable expectations of program performance. Unlike resource acquisition programs where measurement studies were conducted primarily after program implementation, market transformation studies must occur before and during program implementation to properly set baselines and track market movement. Therefore, it is critical that program planning and evaluation functions become integrated. Verification evaluations are also needed to assess program performance and help determine if metrics have been met.

5. *Incentive metrics are often best set through negotiation, but parties need to have adequate time and flexibility*. Since incentives are complex, careful consideration and discussion of alternatives should be allowed for. Given the complexities, negotiation among the principal

parties will often achieve the best results. But negotiations take time and require all parties to be flexible. In negotiations that involve a large number of stakeholders, a third-party mediator or facilitator should be considered. Use of a third-party facilitator can reduce the risk of the process bogging down and allows all parties to focus on their key objectives without having to manage the complexity of the negotiation process. In addition, adequate time should be allowed so that negotiated settlements are finalized before the program year begins, so as to maximize the time available for pursuing milestones.

6. *A modest level of incentives appears to be acceptable to a wide range of parties in the regulatory process.* Incentive amounts should be high enough to get senior management attention but not so high as to cause ratepayer/intervenor backlash. Until recently, maximum incentives on the order of 10-12% of program budgets met these criteria. In 2000, experimentation is beginning with 7-9% incentives but it is unclear whether these incentive levels will be high enough to have the desired impacts.

7. *Current incentive approaches have difficulty addressing the dynamic nature of the markets they are trying to change, and as a result, there is a need to experiment with modifications to current incentive mechanisms*. Current incentive approaches involve setting incentives at the beginning of the year and then evaluating specified milestones at the end of the year. But due to the dynamic nature of markets, there will sometimes be a need for mid-year program modifications, a situation that current incentive approaches are not designed to address. More importantly, success in market transformation often depends on developing creative interventions, but rigid predetermined metrics do not encourage this creative process. Thus, new approaches need to be developed and tried to complement existing incentive approaches by allowing creative and successful approaches to be rewarded, even if they are not a formal part of incentive milestones.

One possible model would to for each state to create an "expert evaluation panel." The expert panel would be the equivalent of an arbitration body composed of qualified but disinterested parties. The panel would serve in an advisory capacity and report to the state regulatory commission. This panel could facilitate the metric-setting process, help ensure that the needed studies and data required to determine if the metrics were obtained are being collected, and make final recommendations to the regulators on whether the metrics were met and what level of compensation (e.g., earnings) should be paid. Under this scenario, the expert panel would have the authority to make mid-course adjustments in the metrics and incentive levels. Such an approach has been successfully used for the evaluation of research and development programs (for example, see CCST 2000) and is worth considering for market transformation programs. For this approach to work, the panel's mandate would need to be carefully defined so that it could get its work done in a timely manner using the available resources.

These conclusions and recommendations are based on initial experiences with regulatory incentives for market transformation programs. As further experience with these incentives is gained over the next few years, these conclusions and recommendations can be refined and expanded. What is clear at this point is that incentives do motivate actions, and that further testing is needed to determine the best combination of metrics to motivate implementers to achieve the desired accomplishments. States and utilities should be encouraged to innovate and experiment so that incentive designs and market transformation programs can improve and prosper.

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