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August 25, 2006

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Vice President
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2006 AUG 25 P 3:22
PUBLIC UTILITIES COMMISSION

The Honorable Chairman and Members of
the Hawaii Public Utilities Commission
465 South King Street
Kekuanaoa Building, 1st Floor
Honolulu, Hawaii 96813

Dear Commissioners:

Subject: Docket No. 05-0069
Energy Efficiency Docket

At the Prehearing Conference held August 24, 2006, HECO/HELCO/MECO indicated to the Commission that they would be sponsoring a hearing exhibit related to Panel B: Specific Programs and Parameters and Panel D: Cost Recovery and Incentive Mechanisms. To facilitate the parties/participants review of the exhibit, attached are copies of the report entitled *Demand-Side Management: Determining Appropriate Spending Levels and Cost-Effectiveness Testing*, prepared for the Canadian Association of Members of Public Utility Tribunals, dated January 30, 2006.

If you have any questions on this matter, please contact Dean Matsuura at 543-4622.

Sincerely,

William A. Bonnet

Attachment

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SUMMIT BLUE
CONSULTING, LLC

DEMAND-SIDE MANAGEMENT: DETERMINING APPROPRIATE SPENDING LEVELS AND COST-EFFECTIVENESS TESTING

Prepared for:

Canadian Association of Members of Public Utility Tribunals
(CAMPUT)

January 30, 2006

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ACKNOWLEDGEMENTS

This study was made possible by the invaluable contributions of the following team members.

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- *An approach used by BC Hydro is representative of current state-of-the-practice evaluation efforts.* This consists of:
    - A complete evaluation plan prepared at DSM program initiation.
    - Actual evaluations conducted at major milestones or at program completion.
    - Process, market, and impact evaluations are conducted, and are overseen by a cross-functional DSM Evaluation Oversight Team.
    - For programs including larger individual projects, technical and financial reviews are conducted before an incentive is offered to provide assurance the technology is feasible, estimated electricity savings are reasonable, and the cost-effectiveness is acceptable.

Interest in DSM, Leadership, Pricing, and Other Factors

There are many facets to launching and overseeing quality energy efficiency and demand response programs. Success does nothing to diminish the appropriate level of oversight and vision needed to be effective. Some essential threads:

- *Leadership is needed to push through the challenges that invariably arise and to keep the longer term in mind – a DSM program may not be immediately cost-effective and it will take time for the value of DSM to be realized.* Good leadership can set appropriate expectations and timelines, as well as ensure that the effort is sustained and is one component of a multi-year plan.

- *A stakeholder process encompassing trade allies, customers, and other stakeholders can be valuable to gain new perspectives and support for programs.*

- *Demand response needs to be integrated with energy efficiency since there are complementary aspects in delivery and economies that can be gained through technologies that both save energy and provide the customer with the ability to manage their energy use such that they can participate in a DR program.*

- *Pricing of electricity and gas is important for the economics of energy efficiency and demand response.* Time differentiated rates that recognize the varying value of the resource across hours and also better reflect the full societal cost of new resources will make DSM look more favorable to planners and customers.

1. INTRODUCTION

Like many government agencies interested in energy policy in 2006, the principals of the Canadian Association of Members of Public Utility Tribunals (CAMPUT) are taking a closer look at energy efficiency. Rising and volatile natural gas prices represent one reason for this increased interest, but these add to long-standing reasons for promoting demand-side management (DSM) – a track record of saving energy at a low cost, the expense and difficulty of adding new generation and transmission capacity, increased attention to climate change in addition to pollution control, energy security, and local economic development. Energy efficiency funded by utility consumer payments has merit because the measures produce benefits to all consumers and to society as a whole, not just benefits to program participants, and because without these programs, most of these investments would not occur.

In the U.S., the National Petroleum Council, an advisory group to the Secretary of Energy made up of oil and gas companies, recommended in 2003 that in response to rising natural gas prices, energy efficiency for the electric and gas sectors is their number one recommendation among others that would enhance energy supplies. Efficiency is cited not just for its effectiveness, but because it is a resource that North Americans can control generally independent of global politics or environmental permitting. Fossil fuel markets have remained volatile and gotten even more expensive since then.

For jurisdictions reassessing or beginning an energy efficiency program, significant experience in the United States and Canada offers the opportunity to apply to new efforts the lessons of success and failure, coincidence and mistake, wisdom and shortsightedness. DSM programs have been underway for nearly 30 years. In each state and province, there are distinct features and also patterns consistent among many jurisdictions. The amount of money committed to energy efficiency is a critical element, but there is a long list of important factors that determine the quality of energy efficiency programs. This report will lay out these factors so regulators can get a picture of the whole task before them. Energy efficiency for natural gas utilities is generally organized similarly to electricity utility programs, but there are important distinctions between gas and electric DSM.

States and provinces have discovered that influencing electric customer behavior can be particularly valuable at peak times. While many jurisdictions have used interruptible contracts for decades, increasingly competitive wholesale markets are introducing demand response programs with a regional scope. These are being enhanced with pilots investigating more "dynamic" pricing, improving the match between the cost to produce electricity and the price to consume it.

In this assignment, Summit Blue Consulting[1] and the Regulatory Assistance Project are joining to find out the current state of energy efficiency and demand response in some key states and provinces, ones that can offer insights to CAMPUT. We are looking for common threads, for indicators of success. We are also accumulating data that will support choices to engage in energy efficiency, while illuminating things to watch out for. We will apply what we learn in our interviews, as well as what we already know from work that we do in the U.S. and Canada. It is clear that there is no single best way to implement energy efficiency and demand response, and that electric energy efficiency is distinct from natural gas energy efficiency. Yet there are questions that regularly emerge, and sets of internally consistent choices that regulators make that lead to a coherent, satisfying program. From these kernels of experience, we will provide insights on how Canadian provinces can cultivate a new commitment to efficiency.

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[1] Summit Blue Consulting is located in Boulder, Colorado, and this assignment was performed jointly with its partner company Summit Blue Canada in Ontario.

The balance of this report is organized as follows: Section 2 discusses the objectives of this assignment and the research approach; Section 3 presents a general discussion of the information developed from the research approach; and Section 4 builds on the information from Section 3 to examine important choices facing regulators in relation to DSM.

APPROACH 1: DSM Spending Based on Cost-Effective DSM Potential Estimates

California bases DSM spending levels on the amount of cost-effective potential DSM in their jurisdiction. The California Public Utility Commission (CPUC) requires the four major Investor-Owned Utilities (IOUs) to procure all cost-effective DSM before pursuing supply-side options. The IOUs must meet annual MWh/therm savings goals, which are based on capturing 90% of all feasible efficiency. Funding is based on the cost of meeting the targets and requirements obtained from studies assessing the cost-effective potential of DSM in different target markets. Budgets are established for meeting these targets with the funds coming from a public goods charge, procurement budgets, and rates. An important element of the CPUC decision on spending levels was that the energy savings goals should be updated on a regular basis. The CPUC stated in Decision D0409060 that it is "our objective to capture all cost-effective energy efficiency that we establish numerical targets for electricity and natural gas savings today, and create a process for updating them on a regular basis in the future."

It is also important to note that the CPUC DSM targets are not a simple one-time target, but reflect a trajectory of increasing DSM over a period of 10 years, with updates scheduled every three years. This reflects the design, implementation, and penetration cycles that exist in DSM programs.

APPROACH 2: DSM Spending Based on Percentages of Utility Revenues

Four states, Minnesota, Oregon, Vermont, and Wisconsin have specified DSM spending levels as percentages of utilities' revenues. This percentage was generally arrived at through political processes at state legislatures.

- Minnesota – The State Legislature has determined statutory minimums that utilities must spend on DSM.[6] This is currently set at 0.5% for gas utilities and 1.5% to 2.0% for electric utilities, depending on whether or not a utility owns nuclear power plants. The Minnesota Public Utilities Commission can require electric utilities to exceed their statutory minimum DSM spending requirements through integrated resource plan (IRP) proceedings.
- Oregon – The two largest electric IOUs must spend 3% of their revenues on DSM and renewable energy efforts[7], and the largest gas utility must spend 1.5% of its revenues on DSM. Oregon's electric DSM spending requirements are set by statute, and are essentially fixed without legislative revisions to the governing statute, although current regulatory proceedings on least cost planning may provide some flexibility for DSM funding in the future. The gas utility's spending was determined in a regulatory proceeding.
- Vermont – The utilities are required by statute to capture all cost-effective efficiency, an obligation that is met through a statewide energy efficiency utility (EEU). In practice, however, DSM programs have historically been funded by a 3% surcharge on utility bills, which effectively caps DSM spending and may prevent all cost-effective potential from being captured. In 2005, the Legislature lifted the cap, and it is expected that the EEU's budget will increase, allowing it to capture a greater percentage of potential efficiency. How this will play out is currently uncertain.[8]
- Wisconsin – This state uses a 3% surcharge on IOU customers' electric bills as the largest funding component for its "public benefits" DSM programs, which transitioned from utility managed DSM programs starting in 2000. Wisconsin also uses other funding mechanisms for its DSM programs, including continuing pre-2000 gas DSM program funding, separately funded

[6] Minnesota statute 21B.241 covers the Conservation Improvement Program requirements.

[7] Over 80% of Oregon's electric public purpose charge is used for efficiency efforts; 17.1% for renewable energy.

[8] VSA 30, section 209c.

utility-managed load management and demand response programs, requiring utilities to conduct their own DSM programs as a condition for receiving approval to build new generating plants, and federal low-income weatherization funds.[9] Wisconsin's legislature has diverted about 40% of the funds intended for its Focus on Energy public benefits DSM programs to help balance the state's budgets in the last several years.

APPROACH 3: DSM Spending Based on Mills/kWh of Utility Electric Sales

Two states, Connecticut and Massachusetts, have specified electric DSM spending levels of 3.0 and 2.5 mills/kWh of utilities' total electric sales, respectively. These funding levels were specified by statutes as these states restructured the electric utility industry in the late 1990s, and can only be changed through legislative action. A securitization mechanism adopted by Connecticut's legislature to help balance the state budget will divert approximately 1 mill/kWh of DSM funds for about seven years.

APPROACH 4: DSM Spending Levels Set through Resource Planning Processes

Several jurisdictions contacted were found to require or allow utilities to implement the DSM programs that are found to be most cost-effective over time through an IRP process, or similar proceedings that involve viewing DSM as a resource on par with supply-side resources. Jurisdictions contacted that use this approach as their primary methods for setting DSM spending requirements are British Columbia, Idaho, Iowa, and Washington. Vermont is considering adopting such a process to overlay the current approach (see Approach 2).

These jurisdictions do not use any type of formulaic DSM spending guidelines or requirements. As an example, in Idaho, the largest electric utility (Idaho Power Company) has to file a formal resource plan before the State Commission every two years. This plan must include both DSM and renewables. The overall plan selected is the one that is deemed to be most cost-effective for meeting future electric needs taking into account supply-side, DSM, and renewable resources. A formal modeling approach and a structured stakeholder process are used in Idaho. By performing this planning exercise every two years, risks of changes in the market conditions are mitigated since the plan is revised on a regular basis.

Iowa does not use a formal IRP process, but compares costs of DSM to avoidable costs of new supply to determine the amount of DSM that is cost-effective. Other jurisdictions where a resource planning approach is used include:

1) The smaller gas and electric utilities in Oregon also invest in DSM as a result of IRP proceedings.

2) Gas utilities in Connecticut implement DSM programs approved in the context of supply/demand regulatory proceedings.

3) Gas utilities in Massachusetts present five-year DSM plans proposed by gas utilities in regulatory proceedings.

APPROACH 5: DSM Expenditures Set Through the Restructuring Process

A number of jurisdictions that have gone through restructuring and an unbundling of energy services have set spending amounts for DSM using a variety of governmental processes. Three such jurisdictions that have restructured their electricity markets are New Jersey, New York, and Ontario. In general, these

[9] Wisconsin's "Reliability 2000" legislation was contained in 1999's Wisconsin Act 9 (the 1999-2000 Biennial Budget Act).

levels were set as one component of the political process that resulted in the restructuring orders or legislation.

- New York – Annual electric DSM spending for SBC programs was set by the Public Service Commission as part of the re-authorization of the state's energy "public benefits" programs, [10] and recently extended for 2006 through 2011 at $175 million per year. [11]

- New Jersey – The Board of Public Utilities (BPU) recently assumed responsibility for managing the states' DSM programs from the utilities. New Jersey DSM funding is set at $140 million in 2005, and is projected to increase to $235 million in 2008. Funds for DSM programs in New Jersey and New York are raised by a "systems benefits charge" on IOU utility bills.

- Ontario – The Ontario Energy Board has approved $163 million of total funding for electric distribution company DSM programs for 2005 to 2007, and $25 million for gas DSM programs for 2005 to be recovered in utility rates.

APPROACH 6: Levels of DSM Tied to Projected Load Growth

Several states, Texas, Connecticut, and Illinois, require their electric investor-owned utilities to meet set percentages of their load growth through DSM. These states have restructured their electricity markets.

- Texas – The electric IOUs must meet 10% of their projected load growth through DSM.

- Connecticut – Recently enacted legislation in Connecticut is a variation on this approach, requiring an increasing percent of the state's electric supply to be met with distributed resources, reaching 4% by 2010. Certain DSM savings will count towards this distributed resource portfolio standard.

- Illinois – The Illinois Commerce Commission (ICC) has initiated a proceeding to implement the Governor's proposed Sustainable Energy Plan. [12] The Governor's proposal would require each of the state's electric IOUs to meet 10% of their load growth through DSM starting in 2006 or 2007, increasing over time to a maximum of 25% in 2015.

APPROACH 7: Case-by-Case Approach

Many jurisdictions do not actively regulate DSM spending or do so on an ad hoc basis, such as through rate case settlements. Jurisdictions have varying reasons for not directly trying to develop spending levels tied to some approach to achieving cost-effective DSM spending. Some jurisdictions have experienced utility and/or large industrial customer opposition to DSM.

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[10] Large customers were able to opt out of this public benefits charge arguing that they already have incentives to pursue all cost-effective energy efficiency. Large customer opposition to DSM spending, where some spending shows up in their rates, has been common. As a note, large customers are leading the way in energy efficiency expenditures in Idaho using an innovative approach creating a pool of money that any large customer can draw from for a cost-effective energy efficiency project. Since money is paid into the pool by the utilities, it is a use-it or lose-it proposition for these customers; Idaho has seen them aggressively compete for these energy efficiency dollars.

[11] Order Continuing the System Benefits Charge (SBC) and The SBC-Funded Public Benefit Programs (issued December 21, 2005).
http://www3.dps.state.ny.us/pscweb/WebFileRoom.nsf/Web/5375707FAF2225B2852570D600700767/$File/05m0090_12_21_05.pdf?OpenElement

[12] See ICC web site: www.icc.illinois.gov, "Sustainable Energy Plan".

then, customers are exposed to a high prices on those days and they have the choice as to whether they want to respond or simply absorb the high price.[13]

B. Curtailable Load Programs – These are the conventional load management programs where the utility has interruptible customers and can call on them for a load reduction. This includes such programs as simple large customer capacity call programs and direct load programs common to mass markets (e.g., direct load control of air conditioning or water heating).

California has been focusing on both sets of programs but with a recent emphasis on pricing to achieve load reductions. A 2003 California Public Utilities Decision[14] directed the utilities to achieve the capability to reduce their peak demand by 5 percent using price-responsive load programs in five years. The Commission continues to study the cost-effectiveness of this requirement with a recent set of filings by the utilities (August 2005) and, despite some utility pushback, a 5 percent reduction from price-responsive load programs is still the goal in California.

3. There has been an increased emphasis on demand response in Texas and Connecticut lately, resulting in more funds that were previously focused on efficiency being available for certain demand response or reduction strategies.

4. Massachusetts, New Jersey, Oregon, Vermont, and Washington either have very limited or no local load management or demand response programs available to customers. Utility spending on load management and demand response programs does not count towards DSM spending requirements. Rather, these costs are part of the overall resource procurement for utilities. There is some expectation that this area will become more robust in the near future in several of these states.

5. The Federal Energy Regulatory Commission, which governs interstate electric transactions, has been aggressive in working with the transmission and reliability organizations that perform dispatch and monitor the transmission grid to offer demand response programs. Generally, these organizations have been the Independent System Operators (ISOs).[15] The ISOs that offer reasonably aggressive demand response programs include the ISO New England, the New York ISO, the PJM ISO, and the ERCOT ISO in Texas. The states in these regions vary with respect to how they interact with the ISO programs. As a few examples:

   - New York ISO – The New York State Research and Development Authority (NYSERDA) directly uses monies collected from the Societal Benefits Charge levied by all the utilities to fund energy efficiency programs, but it also has programs that are designed to encourage customer participation in the New York ISO programs through both information and enabling technologies.

   - New England ISO States –ISO-New England encourages electric distribution companies to aggregate customers and participate in their programs by allowing the distribution company to retain a portion of the payments to customers that participate in the demand response programs.

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[13] These price-responsive load programs expose customers to price volatility in return for lower prices on non-event days in off-peak periods.

[14] The most recent CPUC ruling re-affirming these demand response targets is in: California Public Utilities Commission, OPINION APPROVING 2005 DEMAND ESPONSE GOALS, PROGRAMS AND BUDGETS, Rulemaking 02-06-001, Decision 05-01-056 January 27, 2005.

[15] For the purpose of this report, the distinction between ISO and RTO, Regional Transmission Organization, is not material. We will use the term ISO for simplicity.

- PJM ISO States – Pennsylvania, New Jersey, and Maryland have had a long tradition of demand response programs, primarily through rules that allow load providers to count demand response toward meeting their operating reserve requirements. With restructuring and creation of PJM as an ISO and the creation of active wholesale markets, PJM has developed its own reliability and economic demand response programs. Many of the individual state-level programs predate the development of demand response programs at PJM. The PJM ISO programs have been developed to co-exist with and augment the existing state and utility programs. The long term commitment to energy efficiency and DR among the original PJM states (i.e., the Mid-Atlantic States) has resulted in some large demand response programs (e.g., Baltimore Gas & Electric has over 300,000 customers in its demand response programs).

3.1.2 Summary of Research on DSM Spending Levels

The recent American experience with simple DSM spending requirements (e.g., mills/kWh, percent of revenue, or a specific dollar figure) reveals that spending levels have, in most cases, not been at a level sufficient to realize most of the cost-effective DSM in any jurisdiction. This is due to several factors:

- *The inherent caution present in most legislative or regulatory proceedings.* Few legislators or regulators want to become known as someone who authored requirements that could not practically be achieved.

- *Changes in energy prices, particularly natural gas prices, between the time the enabling legislation or regulations were enacted and the present.* For example, Minnesota's DSM spending statutes were last significantly updated in 1994. At that time the wholesale price of natural gas was approximately $2 per million BTUs, compared to the current natural gas wholesales prices of over $10 per million BTUs. More DSM will be cost-effective at today's high natural gas prices than was cost-effective when natural gas costs were much lower. This is true for both electric and gas DSM, as marginal new electric generating units are often fueled with natural gas.

- *Rate structures that penalize utilities for conducting DSM programs.* Decreasing sales through DSM programs also can reduce utility profits unless rate mechanisms that "decouple" utility profits from revenues are in place. Such decoupling mechanisms include allowing utilities to recover the lost profits from the revenues reduced through DSM programs, or tying utility profits to a secondary indicator such as the number of customers served instead of revenues.

- *Concerns about the immediate rate impact of energy efficiency costs.* This is a concern even when there is appreciation for long term cost savings to the utility system. As supply alternatives get more expensive, their rate impacts will become more onerous in comparison with efficiency. In addition, it is possible to ramp up DSM programs and expenditures over a two to three year period which can serve to mitigate price impacts even if these programs are funded by a rider on existing electric tariffs.

A process such as an IRP proceeding or DSM potential study is needed to set DSM targets, and additional procedures are needed to determine the most cost-effective portfolio of DSM programs to attain that target.[16] This will allow for the development of DSM plans that propose levels of program development

[16] The CPUC used overall DSM potential as the basis for setting reasonable targets and left the determination of the most cost-effective portfolio for attaining these targets to another proceeding. "The forum and process for considering what program offerings are cost-effective and reasonable will be dictated in large part by the administrative structure we adopt in a separate

3.2 DSM Benefit-Cost Analysis

There is an extremely large set of options for DSM programs. Depending upon the talent, creativity, and process with which a DSM program is designed and implemented, DSM programs which on paper appear similar can have quite different benefits and costs when actually implemented. In addition, some programs will simply be more cost-effective than others. As a result, regulators have generally mandated some form of benefit-cost analyses of DSM programs to both ensure that the utilities are being efficient in their implementation of programs, and establish that a cost-effective mix of programs are being offered.

In response to these concerns, utilities conduct DSM benefit-cost analyses that fall into two categories:

1. Dynamic analyses that identify the amount of DSM that is most cost-effective relative to other resources, primarily new energy supplies. This is most commonly done through IRP proceedings.

2. Static analyses that evaluate DSM's cost-effectiveness relative to a fixed set of avoidable supply-side resources and avoided costs.

Of the 15 jurisdictions researched for this project, seven used IRP[17] processes to assess DSM, even if the spending level was not directly tied to the outcome of that process. For example, with a fixed spending target, a resource planning process can identify which DSM programs are the most cost-effective within that spending target. Eight jurisdictions were not judged to use formal IRP processes in DSM assessment. The seven jurisdictions that had IRP elements in DSM planning were British Columbia, California, Minnesota, Ontario, Oregon, Vermont, and Washington. [18] Interestingly, almost half of these jurisdictions (California, Ontario, and Oregon) have either partially or fully restructured their electric utilities. For the eight jurisdictions that do not use IRP processes, all but two (Iowa and Wisconsin) are restructured.

Utilities or power planning organizations use IRP processes to select the lowest cost energy system expansion plan from among many possible options. As part of this process, the planning organization develops at least several scenarios for each type of supply or demand reduction resource. IRP planning periods are generally at least 20 years long (some as short as 10 years with others being as long as 30 years). DSM scenarios can be developed by adding or subtracting different types of DSM programs or technologies between scenarios, adding or subtracting customer groups covered by DSM programs, or varying DSM incentives such as customer rebates between scenarios. There are many models that can be used in an IRP context.[19] Typically, they calculate the long-term costs of various combinations of supply and demand reduction scenarios over the forecast period. Monte Carlo analyses can be used as part of the

[17] The use of the term Integrated Resource Planning (IRP) is meant to generally apply to an analytic process that is comprehensive in its analysis of resources, i.e., both supply-side and DSM (and often renewables) are all analyzed with reasonable characterizations of each resource option to assess the tradeoffs between resources and develop a going-forward action plan for meeting load growth. In some regions, the term IRP has become associated with a narrowly defined process that involved specific modeling activities that were viewed as counter-productive by some utilities and planning organizations. It is hoped that this more general view of IRP will avoid the debate that arises in some regions about the use of an IRP approach.

[18] About half of these jurisdictions (California, Minnesota, Oregon, Vermont) use another type of DSM spending requirement as the primary DSM regulatory approach. IRP proceedings are use to fine-tune DSM spending requirements that are (most commonly) defined by statutory requirements for utilities to spend certain minimum percentages of their revenues on DSM.

[19] Many models are used as tools in performing IRP-type studies. Some of the more models used in the jurisdictions surveyed include ProSym or RiskSym offered by Henwood Associates, PROMOD IV and Strategist offered by New Energy Associates, and the Aurora Model offered by EPIS, Inc. However, there are easily a dozen other models in use by utilities and regional planners and those mentioned. The models cited above are some of the models being used in states that were contacted in this research.

to the Pareto efficiency test in economics: a policy or project that makes everyone better off without making anyone worse off.

- The total resource cost (TRC) test, essentially the perspective of all utility customers combined. The benefits for this test are the avoided costs from not having to install new energy supply facilities. The costs for this test are the DSM program administrative costs plus the net (after rebate) incremental costs of the DSM measures. This test is similar to the Kaldor-Hicks compensation test in economics: the winners from a policy or project could compensate the losers enough so that they would at least break even.

- The societal test. The societal test is very similar to the TRC test, except that it includes avoided environmental damages due to DSM programs.

The analyses are to be done using the net present value of DSM program benefits and costs over the lifetime of the DSM measures covered by the DSM programs. The DSM benefits should be based on "net" program impacts, that is, program impacts adjusted for free-ridership and spillover. [21]

Table 3-2 is a summary of results for each of these five tests for Xcel Energy's Minnesota Commercial and Industrial Lighting Efficiency Program for 2005. These results are common for many energy efficiency programs: benefit-cost ratios are somewhat greater than one for the participant test (otherwise why would the customer participate?), the TRC test, and the societal test, and much greater than one for the utility test. This program is cost-effective from all these perspectives. It is interesting to note that the environmental externality benefits only account for seven percent of the total societal program benefits, so the societal test results are very similar to the TRC test results. The benefit-cost ratio for the rate impact test is slightly less than one. This means that this DSM program will cause long-term electric rates to be slightly higher than they would be without the program.

[21] DSM program free riders are those program participants who would have installed the DSM measures even without the DSM program. DSM program spillover effects include savings from program participants and non-participants who installed DSM measures due to a DSM program, perhaps due to the program's informational effects, but did not receive any funding from the DSM program.

relatively high interest in DSM based on recent activity. Due in part to this selection of jurisdictions, Only two jurisdictions, Illinois and Texas, were self-described as having a modest or steady interest, respectively, in DSM. The interviews covered a wide variety of jurisdictions, including both traditional and deregulated energy sector structures. However, there were no indications that a jurisdiction's restructured status determined the level of interest in DSM. Nor were there any significant differences found in terms of DSM drivers, types of programs, and approaches.

Deregulated		***Traditional***
California[23]	New York	British Columbia
Connecticut	Ontario	Iowa
Illinois	Oregon	Minnesota
Massachusetts	Texas	Vermont
New Jersey		Washington
		Wisconsin

Several areas have had a long-term interest in DSM: California, Washington, and Oregon in the West, New York, New Jersey, and the New England states in the East, and Iowa, Minnesota, and Wisconsin in the Midwest. Interest in electricity DSM is generally much higher than in natural gas, although increasing gas prices recently have been reflected in an increasing interest in gas DSM (mentioned in about half the jurisdictions). And interest in electricity DSM has also increased recently, again in about half the areas studied, mainly due to high energy prices, environmental concerns, or supply and transmission issues. Most persons interviewed noted several drivers for interest in DSM, generally a combination of factors shown in the table opposite.

Drivers for Interest in DSM

High Energy Prices: DSM is a more cost-effective resource, lowers bills, and provides a hedge against risk and market volatility.

Environmental Concerns: greenhouse gases, other air pollutants, non-attainment issues and the desire for 'greener' solutions..

Supply and Transmission Issues: potential shortages this winter, growing peak demand, transmission constraints, congestion-related charges, reliability issues, generator retirements, reserve margin concerns.

Other Economic Benefits: job creation and net economic benefits due to energy bill savings, new technologies, and increased energy service company activities

3.4.1 Role of Stakeholders in Driving Expanded DSM

The entities that drive expansion in DSM activities is truly diverse. Most prominent as a key supporter are environmental interveners; they almost always take a proactive stance with regard expanding DSM activities. In addition, there is a set of organizations such as the American Council for an Energy-efficient Environment (ACEEE) that actively supports DSM throughout North America. The ACEEE has spun off regional entities that continue to press regulators, utilities, and legislative bodies to consider DSM as a resource. Beyond these common supporters, the surveys showed the utilities could lead the issue. Regulatory bodies seeking least cost plans for meeting customer needs were often leaders. Province/State governments also were leaders in a number of jurisdictions examined with legislation used as the vehicle to expand DSM activities. The level of interest in DSM by a high-level champion (CEOs in BC Hydro,

[23] Partially restructured.

and governors in California, Iowa, and Illinois) can have a significant impact on DSM activities. The table below shows the number of jurisdictions noting specific groups who are driving DSM.

Who is driving the interest in DSM?	# Jurisdictions citing
Political (government, legislature)	13
Interest Groups (customers, vendors, etc.)	11
Regulators	8
Utilities	7

The regional energy situation can also lead to increased interest by these stakeholder groups. The price spikes that occurred in a number of areas in 1999 and 2000 increased interest, supply shortages drive the search for cost-effective solutions, and the overall increase in energy prices during the past two years is another factor.

3.4.2 Types of DSM Programs and Delivery

This section looks at how DSM programs are being delivered in different regions and the types of DSM programs that are being promoted.

Approach to Electric DSM – Delivery

In general, the utilities – with or without third party contractors – plan, design, implement, and evaluate DSM programs, with regulators providing review and approvals. Most program administrators receive significant input and guidance from stakeholders and technical experts. Examples include formal advisory board arrangements, formal or informal public processes, or technical advisory groups or consultants. The term "collaborative" is often used to described the on-going group of stakeholders, including the administrator, that provides input to the administrator and the regulator.

	Utilities	Independent Administrator	3rd Party	Regulator/ Government
Plan Generic Programs	All other jurisdictions + VT	NY[24], OR[25], VT[26]	NJ, WI	
Design Specific DSM Programs	All other jurisdictions	NY, OR, VT	NJ	TX
Approve Programs			NJ	All other jurisdictions
Implement Programs	BC, IL, IA, MN, ON, WA, CA	NY, VT	CT, IL, MA, MN, NJ, ON, OR, TX, WI	
Evaluate Programs	BC, CT, IL, IA, MN, ON, VT, WA		CT, MA, NJ, NY, ON, OR, WI, VT	CA, OR, TX, VT

[24] Through the New York State Energy Research and Development Agency (NYSERDA)

[25] The Energy Trust of Oregon

[26] Efficiency Vermont, the Energy Efficiency Utility

Coordinated Demand Response Working Group includes the New York Power Authority, Long Island Power & Light, the New York State Dept. Public Service, and NYSERDA.

Approach to Determining Spending Levels

In all the jurisdictions surveyed, the appropriate level of spending is set either by statute or by the regulatory body. In British Columbia, however, BC Hydro determines what electricity DSM programs are cost-effective and the appropriate level of spending.

Who	States/Provinces
Legislature	Connecticut, Massachusetts (electric), Minnesota, New Jersey, New York (electric), Oregon (electric), Texas, Vermont (electric), Wisconsin
Regulators	BC (gas), Illinois, Iowa, Massachusetts (gas), New York (gas) Ontario, Oregon (gas & electric), Vermont (gas), Washington
Utility	BC (electric)

- The future need for additional resources. Some jurisdictions set DSM targets to meet a given percent of future load growth.

- The existing infrastructure to deliver programs and what changes might be required to deliver the target level of the DSM resource. Building up required infrastructure, training trade allies in EE design, maintaining a reliable supply of certified contractors, and working with suppliers to develop the availability of EE materials has been one of the most important aspects of sustaining a long-term commitment to DSM.

- A DSM plan that ramps up programs in different sectors over a period of time beginning with programs that represent "lost opportunities." These are generally new construction programs since it is much cheaper to build in energy efficiency during construction than it is to retrofit.

- The need for processes to assess DSM accomplishments and to perform analyses that help ensure that DSM is delivered in the most cost-effective manner possible.

Even jurisdictions that have undertaken these substantive analyses can arrive at different conclusions. For example, the DSM target for Texas is to meet 10% of new load growth each year (with annual reports required), while Illinois has a Sustainable Energy Plan that calls for increasing percentages each year starting in 2007. The Illinois Commission will also tolerate a maximum percentage rate increase per year of 0.5% to obtain the load reductions. The time table for the Illinois Sustainable Energy Plan calls for:

- 10% of Projected Annual Load Growth to be met in 2007/2008;
- 15% of Projected Annual Load Growth to be met in 2009-2011;
- 20% of Projected Annual Load Growth to be met in 2012-2014; and
- 25% of Projected Annual Load Growth to met in 2015-2017.

Other approaches for setting targets, as discussed in Section 3.1, use an expenditure amount tied to a percentage of total electric revenues. These include:

- Minnesota where the largest utility (Xcel Energy) must spend a minimum of 2% of revenues on DSM;
- Oregon with a Public Purpose Charge of 3% for the two major electric utilities;
- TXU, an IOU in Texas which has to meet 10% of load growth each year by DSM. TXU spent about 2% of annual revenues, though that is not how the target was determined;
- Vermont has set spending caps[30] that changed each year, but the end result is that they spent about 3% of electric revenues for DSM. 3% was not the target but about how much was actually spent;
- Wisconsin targets 3% of electric revenues; and,
- Utility representatives for PG&E in California estimate that spending on electric efficiency in 2004 and 2005 has been between 2.5% and 3% of electric revenues.

While the process and rationale for setting these targets varied substantially in each jurisdiction (see Section 3.1 and Appendix A), DSM expenditures for a number of major utilities and jurisdictions vary

[30] This 3% cap on spending in Vermont has been lifted in 2005 and new funding levels have not been established.

Issue 4: Benefit-Cost Tests and Avoided Costs

Assessing and evaluating DSM accomplishments is important on a prospective basis to develop a cost-effective mix of DSM programs, and on a retrospective basis, benefit-cost analysis is needed to discern whether the expected benefits from the DSM programs were actually obtained. These retrospective studies also can be used to develop a more cost-effective mix of DSM activities and provide suggestions on how to make a specific program more effective (see Section 3.4).

Issue 4: Discussion – Benefit-Cost Tests

A jurisdiction reveals its view on the purpose of energy efficiency by the benefit – cost tests it uses to evaluate programs and measures. Use of the Ratepayer Impact Test (RIM) indicates a strong interest in the satisfaction of individual consumers, but ignores the resource and societal values that flow to all along with the obvious value to the program participant. Many widely used energy efficiency programs do not pass the RIM Test.

Use of the total resource cost (TRC) test instead of a societal test values the economics of energy efficiency compared with other sources, but values at zero other advantages to society that, though perhaps hard to quantify, are worth more than zero. These other advantages may flow from avoided air pollution, water use, or reduced risk from avoided capital construction of generation and transmission, for example. Use of the societal test to evaluate energy efficiency programs represents a view that all effects of energy efficiency programs are important. Precision in the societal test is elusive, and jurisdictions that use it sometimes apply a rough "adder" or "multiplier" to handicap other sources in comparison with efficiency.

Accurate valuation of energy efficiency requires reasonable assessments of system avoided costs. Such assessments must be updated from time to time, and provide a valuable benchmark for managing energy efficiency activities. A valuable element to this process comes from gaining knowledge about the shape of the utility's hourly load curve. Programs that produce savings in particularly valuable hours have more value to consumers.

With increasingly regional electricity markets, stakeholders in New England and, separately, in California, are collaborating on an avoided cost analysis framework that many will share. As a practical matter, the avoided cost assessment matters most if energy efficiency budgets are actively managed and are set based on this assessment. If a set amount of dollars is allocated to efficiency, the challenge becomes how best to use those funds, so avoided cost still remains important for program evaluation.

Further study of energy efficiency value is underway in several states. Utilities are considering the ability of EE (and other distributed resources) to avoid or delay load growth that would otherwise lead to investments in upgraded transmission and distribution, in addition to new generation already captured in most avoided cost calculations.

Another facet of benefit-cost is the prevalence of "potential studies." A potential study provides useful intelligence, telling a decision-maker how much energy efficiency is available from among the regularly occurring "opportunities" and the accumulated "retrofits." Recent studies in the Northeast U.S. indicate the potential of such quantities that annual energy use could be reduced year after year with a modest increase in spending from current levels. The only downside of a potential study is the expense – \$250,000 to \$500,000 or more for a comprehensive regional study. However, as discussed previously in Section 3.1, DSM potential studies can be designed to meet multiple objectives. Information from a DSM potential study is often used as the first step in design of programs since such studies can document current practice and establish energy use baselines. This information can also be used to design an appropriate program for a region and help establish initial customer/trade ally incentives and marketing messages.

Issue 4: Recommendations – Benefit-Cost Tests

The use of benefit-cost tests reflects the importance that regulators in a jurisdiction place on different factors. This is one reason why the tests in common use today, the California Standard Practice Manual tests, incorporate five tests. As a result, there is no exact answer to the question about which test to use and how to construct that test. However, this effort provides the following recommendations for use of benefit-cost test:

1. *The primary test that should be used is the Total Resource Cost test applied to a portfolio of programs, with program specific tests used to address appropriate program design and the mix of programs in the portfolio.* For retrospective analyses, it is important to understand that delivering a DSM program is like introducing a new product into a market: the customer needs to become aware of the offering (marketing), be brought to the point where they are willing to act (sales), and there must be the follow-through delivery of the program (fulfillment). Some programs will likely work better than expected, while other programs will encounter problems that need to be rectified. As a result, it may be unreasonable to expect all the programs to pass the TRC test, but the portfolio as a whole should pass the TRC test.

2. *The Participant Test should be part of implementation to ensure that customers that participate in the program do benefit, but should not have a significant role in setting overall DSM expenditure levels.* Rather, it is useful in the design of specific programs to ensure that the customer perspective in represented.

3. *The other tests commonly calculated can be used to provide different perspectives.* If there is a large discrepancy between a ranking of DSM activities based on the TRC test and one based on the RIM test or the Societal Test, then the planning process should be flexible enough to make adjustments. For example, a societal test may show that one program is much better from an environmental perspective (a cost commonly used in the Societal Test). Also, if one program drops substantially in its ranking (not in its benefit-cost ratio, but in its ranking relative to other programs); then, it may pose some equity problems across customers that could be corrected by making some adjustments in the program. In general, it is recommended that the TRC test be the guide, with the other tests used to see if there are extreme differences that might suggest some flexibility in the design of a DSM program or the mix of DSM activities.

4. *The benefit-cost tests need accurate estimates of avoided costs.* This means that this should include not only avoided costs of generation (i.e., the commodity cost), but also avoided transmission and distribution (T&D) costs. Progress is being made on determining avoided T&D costs in various states that have started to focus on this issue. It is recommended that the best estimates of avoided generation and T&D costs both be used in the application of these tests.

ISSUE 5: DSM PROGRAM ASSESSMENT, MONITORING, AND EVALUATION

Any investment of ratepayer funds should be the subject of ongoing assessment and verification to both provide assurances that anticipated benefits are being attained, and to provide feedback on the programs and their implementation such that they may be improved over time.

this model, the utility would "retail" the ISO programs to ultimate customers. Helping to work out disputes arising from utilities happy with their own programs is one occupation of regulators.

Efficiency through Pricing

Earlier, the issue of baselines was discussed. Another way baselines can change is by introducing a new pricing regime or a new rate design. If consumers are either allowed or mandated to take service with prices that change over the year to be higher when production costs tend to be higher, and lower when production costs tend to be lower, then they may be motivated to spend more on their own to avoid high priced usage. Some suggest that this is a powerful tool that is under-utilized, while others note that some of these systems cost a lot to implement and many consumers are unwilling or incapable of managing usage during different time periods, and would lose. New Jersey and California, for example, are experimenting with pricing pilot programs to evaluate these possibilities.

Generally, the more that rates reflect the long term societal costs of new resources, the more favorably energy efficiency will look to regulators, planners, and customers.

<u>Issue 6: Recommendations – Other Issues</u>

There are many facets to launching and overseeing quality energy efficiency and demand response programs. Success does nothing to diminish the appropriate level of oversight and vision needed to be effective. Some essential threads:

- Leadership is needed to push through the challenges that invariably arise and to keep the longer term in mind – a DSM program may not be immediately cost-effective and it will take time for the value of DSM to be realized. Good leadership can set appropriate expectations and timelines, as well as ensure that the effort is sustained and is one component of a multi-year plan.

- A stakeholder process encompassing trade allies, customers and other stakeholders can be valuable to gain new perspectives and support for programs.

- Demand response needs to be integrated with energy efficiency since there are complementary aspects in delivery and economies that can be gained through technologies that both save energy and provide the customer with the ability to manage their energy use such that they can participate in a DR program.

- Pricing of electricity and gas is important for the economics of energy efficiency and demand response. Time differentiated rates that recognize the varying value of the resource across hours and also better reflect the full societal cost of new resources will make DSM look more favorable to planners and customers.

- Order in Council No. 1123 Special Direction HC2. http://www.bchydro.com/reg_files/heritage/order_in_council_no_1123_sd_hc2.pdf
- Resource Expenditure and Acquisition Plan (the REAP), March 2005. http://www.bchydro.com/rx_files/info/info10201.pdf
- Conservation Potential Review – 2003 - http://www.bchydro.com/rx_files/info/info10236.pdf
- BC Hydro 2004 Integrated Electricity Plan http://www.bchydro.com/info/epi/epi19230.html
- Fortis BC Semi-annual Demand Side Management (DSM) report http://www.bcuc.com/Documents/Proceedings/2005/DOC_7149_B-23%20DSM%20-BCUC%20IR%20111.pdf
- Fortis 2005 Revenue requirements submission http://www.bcuc.com/Documents/Proceedings/2004/DOC_5708_B-1%20FortisBC%202005%20Revenue%20Requirements.pdf
- TGI 2005 Revenue requirements submission http://www.bcuc.com/Documents/Proceedings/2005/DOC_8981_B-3_Advance%20Info%202005%20Annual%20Review.pdf

California

There have been many studies done in CA, analyzing CA EE programs in any number of ways. Studies available at http://www.calmac.org/search.asp (California Measurement Advisory Council website). Especially useful:

  - The California Evaluation Framework http://www.calmac.org/publications/California_Evaluation_Framework_June_2004.pdf Explains (in 500 pages) CA's "consistent, systemized, cyclic" approach to planning and evaluation of EE. Includes a bibliography of literature on EE evaluation protocol that the new Framework is based on.
  - California's Secret Energy Surplus: The Potential for Energy Efficiency http://www.ef.org/documents/Secret_Surplus.pdf
  - 2003 Proposed Energy Savings Goals (CEC): http://www.energy.ca.gov/reports/2003-11-05_100-03-021F.PDF

- The Energy Action Plan http://www.cpuc.ca.gov/PUBLISHED/REPORT/28715.htm
- S. Bender, M. Messenger and C. Rogers. July, 2005. "Funding and Savings for Energy Efficiency Programs for Program Years 2000 through 2004." California Energy Commission. http://www.energy.ca.gov/2005_energypolicy/documents/2005-07-11_workshop/presentations/2005-07-11_FUNDING+SAVINGS.PDF
- F. Coito and M. Rufo. September, 2002. "California's Secret Energy Surplus: The Potential for Energy Efficiency." Prepared by Xenergy for Energy Foundation. http://www.ef.org/documents/Secret_Surplus.pdf

Selected CPUC Decisions:

  - **D0312060** – December 18, 2003 - http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/32828.htm

- New Jersey Statewide Market Assessment, Xenergy 1999. http://www.njcleanenergy.com/html/5library/nj_baseline_studies_base.html

Relevant Board of Public Utilities (BPU) Orders

- Docket # EO04080894: Order - In the Matter of the Adoption of New Jersey's Clean Energy Program Protocols to Measure Resource Savings, Dec. 22, 2004. http://www.bpu.state.nj.us/wwwroot/cleanEnergy/EO04080894_20041223.pdf
- Docket # EX04040276: Order - In the Matter of Comprehensive Energy Efficiency and Renewable Energy Resource Analysis for 2005-2008, Dec. 22, 2004. http://www.bpu.state.nj.us/wwwroot/energy/EX03110946_20040428.pdf
- Docket # EO02120955: Order - In the Matter of the New Jersey Clean Energy Program http://www.bpu.state.nj.us/home/BO_CE.shtml
- Docket #EX03110905 et al.: Order – July 2004
- Docket # EX03110946: Order - In the Matter of Appropriate Utility Funding Allocation for the 2004 Clean Energy Program http://www.bpu.state.nj.us/wwwroot/energy/EX03110946_20040428.pdf

- The 2004 PJM State of the Market Report, March 8, 2005. http://www.pjm.com/markets/market-monitor/som.html

- Harrington, C., and Murray C., the Regulatory Assistance Project, May 2003. Who Should Deliver Ratepayer Funded Energy Efficiency? A Survey and Discussion Paper.

<u>New York</u>

- Department of Public Service System Benefits Charge (SBC) http://www.dps.state.ny.us/sbc.htm

- Public Service Commission (NYSERDA), SYSTEM BENEFITS CHARGE: Revised Operating Plan for New York Energy $mart^{SM} Programs (2001-2006), *June 12, 2002.* http://www.nyserda.org/sbc2001-2006.pdf

- New York Energy $mart^{SM} Program Evaluation and Status Report: Report to the System Benefits Charge Advisory Group, Final Report, May 2005, http://www.nyserda.org/Energy_Information/05sbcreport.asp

- 2002 State Energy Plan and Final Environmental Impact Statement (Energy Plan), http://www.nyserda.org/Energy_Information/energy_state_plan.asp

- State Energy Plan - 2004 Annual Report and Activities Update, http://www.nyserda.org/Energy_Information/2004sep_annual_report.pdf

- NYSERDA, Toward a Brighter Energy Future: A Three Year Strategic Outlook, 2005-2008. http://www.nyserda.org/Energy_Information/strategicplan.pdf

- System Benefits Charge III, Staff Proposal for the Extension of the System Benefits Charge (SBC) and the SBC-Funded Public Benefit Programs, Staff Report, August 30, 2005. http://www3.dps.state.ny.us/pscweb/WebFileRoom.nsf/Web/721B232D106700BE85257069006D3DF4/$File/05m0090.08.30.05.pdf?OpenElement

- Rule 25.183 outlines general reporting requirements, including PUCT report to TCEQ re: emissions.

- Rule 25.184 includes links to templates for all the approved SOP and MT approaches, as well as deemed savings values, and stipulated values.

Vermont

- Act 61 of the 2005 Legislature established the SPEED program. Text can be found at: http://www.leg.state.vt.us/docs/legdoc.cfm?URL=/docs/2006/acts/ACT061.HTM
- 30 VSA 209 (d) and (e) http://www.leg.state.vt.us/statutes/fullsection.cfm?Title=30&Chapter=005&Section=00209
- Docket 6290, establishing the DUP process, can be found at http://www.state.vt.us/psb/orders/2003/files/6290irpextord.pdf
- ACEEE's Special Case Study of VGS' comprehensive programs can be found at: http://aceee.org/utility/ngbestprac/vgsprtflio.pdf
- See ACEEE's study of Exemplary Natural Gas Efficiency Programs at http://www.aceee.org/utility/ngbestprac/ngbestpractoc.pdf
- A. Bishop. 2004. "Efficiency Vermont: Vermont's Energy Efficiency Utility". Power Point Presentation, Vermont Public Utilities Board. Available by request; email abishop@psb.state.vt.us
- Vermont Department of Public Service. 1997. "The Power to Save: A Plan to Transform Vermont's Energy Efficiency Markets." http://publicservice.vermont.gov/energyefficiency/ee_files/efficiency/power_to_save.pdf
- Vermont Energy Investment Corporation, Inc. June 2005. "Response To Request For Proposals For a Vermont Energy Efficiency Utility." http://www.state.vt.us/psb/vol1eeuprop.pdf
- Vermont Department of Public Service. May 2002. "Report and Recommendations to the Vermont Public Service Board Relating to Vermont's Energy Efficiency Utility."
- Efficiency Vermont: 2004 Preliminary Report. http://www.efficiencyvermont.com/index.cfm?L1=292&L2=535&sub=bus
- Efficiency Vermont: 2003 Annual Report. http://www.efficiencyvermont.com/Docs/2003ExecutiveSummary.pdf

Washington

- For more information on PSE's programs, refer to their website at: http://www.pse.com/yourhome/rebates/index.html and http://www.pse.com/yourbusiness/grants/grants.html
- 2004 DSM Reports for PSE, Pacificorp, and Avista
- PSE's 2005 Least Cost Plan, available for download online at https://www.pse.com/about/supply/resourceplanning.html
- Pacificorp's 2004 Least Cost Plan, available at http://www.pacificpower.net/Navigation/Navigation36807.html

Wisconsin

- Wisconsin Legislative Council Staff, "New Law on Electric Utility Regulation—the "Reliability 2000" Legislation, Part of 1999 Wisconsin Act 9 (the 1999-2001Biennial Budget Act), Information Memorandum 99-6"(Wisconsin Legislative Council Staff, Madison, WI, December 2, 1999).
- Wisconsin Department of Administration, Division of Energy, "Wisconsin Public Benefits Program: 2005 Annual Report", p. 3 (Wisconsin Department of Administration, Madison, WI, 2005).
- Telephone conversation, Kathy Kuntz, WECC's Director of Operations, November 2005.
- State of Wisconsin, "Report of the Governor's Task Force on Energy Efficiency and Renewables", p.5 (Wisconsin Department of Administration, Madison, WI, October 2004).
- Telephone seminar presentation by WECC's Kathy Kuntz on September 28, 2005.
- Telephone seminar presentation by WECC's Ed Carroll on September 28, 2005.
- Wisconsin Department of Administration, Division of Energy, "Focus on Energy Statewide Evaluation: Initial Benefit-Cost Analysis" (Wisconsin Department of Administration, Madison, WI, March 31, 2003).
- Information on the Wisconsin Focus on Energy Programs and reports is available at www.focusonenergy.com.
- The Wisconsin Legislative Council staff's report on the Reliability 2000 legislation is available on the internet at: www.legis.state.wi.us/lc/3_COMMITTEES/JLC/Prior%20Years/jlc99/pubs/im99_6.pdf
- Report from the Wisconsin Governor's Task Force on Energy Efficiency and Renewable is available at http://energytaskforce.wi.gov/.

DEMAND-SIDE MANAGEMENT: DETERMINING APPROPRIATE SPENDING LEVELS AND COST-EFFECTIVENESS TESTING

APPENDIX A: SUMMARIES BY JURISDICTION

Prepared for:

Canadian Association of Members of Public Utility Tribunals
(CAMPUT)

January 30, 2006

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APPENDIX A: SUMMARIES BY JURISDICTION

In each of the states and provinces selected for the research, the study team attempted to interview multiple people, in particular a regulator and a representative from an organization responsible to implement DSM. This was possible for most of the jurisdictions, but not all. Sometimes extra interviews needed to be done to gather information either on natural gas or on demand response. These summaries are based on information already known by the researchers, the opinions expressed by the people interviewed, and on both publicly available information as well as documents provided by interviewees.

Every attempt was made to reach an "informed" person, and the summaries were often reviewed by the person(s) interviewed and revised based on their feedback. The interviews were often very long and detailed, with many respondents providing follow up information and clarification of details. The level of cooperation by the participants to this survey was commendable

In some instances, the person interviewed could not recall all details and facts regarding a particular issue. This is, of course, a natural phenomenon in this type of research. When reviewing the state and province summaries, the imperfections inherent in any interview process should be taken into account.

The jurisdictions covered were:

British Columbia

California

Connecticut

Illinois

Iowa

Massachusetts

Minnesota

New Jersey

New York

Ontario

Oregon

Texas

Vermont

Washington

Wisconsin

- Process, market, and impact evaluations are conducted, and are overseen by a BC Hydro cross-functional DSM Evaluation Oversight Team chaired by a Senior Manager from BC Hydro's Engineering Services Business Unit.

- In addition, for programs that include larger individual projects (i.e., > 0.3 GWh/year), technical and financial reviews are conducted before an incentive is offered to provide assurance that the technology is feasible, that the estimated electricity savings are reasonable, and that the cost-effectiveness is acceptable.

- A complete plan is also put in place for measurement & verification (M&V) of savings to assure that a baseline is established and that M&V of actual savings is practical.

- Post completion inspections are conducted for all significant projects and a sample of smaller projects.

DSM Spending

Actual Spending

Fortis spent $2.0 million on DSM in 2004 to achieve 21.3 GWh.[7] TGI projects that it will spend $3 million on DSM in 2005 split 50/50 between incentives to customers and administration, marketing, and research.

	Total BC Hydro ($m)	Incentives ($m)	Net Customer Costs ($m)
2003	58.8	17.4	84.4
2004	57.7	25.7	91.1
2005	74.7	34.1	105.4

BC Hydro plans to spend $75 million on Energy Efficiency programs in 2006 and $81 million in 2007 (less than 3% of this is expensed, the rest is capitalized).

The BCUC asked for a chart showing EE and Load Displacement as a percentage of revenue[8] (see charts on next page); this helps for comparison but is not used internally by BC Hydro.

[7] Fortis BC Semi-Annual DSM Report, March 15, 2005.

[8] REAP, 2005.

Comparison of Utility Energy Efficiency Initiatives in F2006

Utility	Investment ($ millions)	% of Revenue	Electricity Savings (GWh)	% of Sales
BC Hydro	73	2.8	288	0.56
Manitoba Hydro	37	3.7	118	0.59
Hydro Quebec	127	1.3	346	0.25

Table 4-4
Comparison of Utility Energy Efficiency Initiatives in F2007

Utility	Investment ($ millions)	% of Revenue	Electricity Savings (GWh)	% of Sales
BC Hydro	79	3.3	422	0.80
Manitoba Hydro	39	3.9	132	0.64
Hydro Quebec	154	1.5	440	0.25

Appropriate Levels

BC Hydro says that appropriate levels will be determined in this year's IEP with a preferred portfolio - new method. They had lots of options for DSM and increments of DSM were cheaper than supply, therefore they plan to implement all DSM options before any supply options. BC Hydro bases its programs on a technical potential study done in 2003[9]. TGI, in cooperation with BC Hydro, is nearing completion of a Conservation Potential Review providing a 10-year analysis of DSM potential by geographical area and identifying the interrelationship between gas and electricity for the residential and commercial sectors. TGI has also participated in multi-utility studies.

> *"In 2005, TGI participated in a number of multi-utility research initiatives including participating in the CGA Task Force steering committee for the "DSM best practices: Canadian natural gas distribution utilities' best practices in DSM", the "Framework for natural gas DSM as part of the greenhouse gas domestic offset credit system", and the DSM Potential in Canada study. TGI is also working with Enbridge and CANMET Energy Technology Centre - Ottawa (CETC-Ottawa) (in cooperation with several other North American utilities) on testing "near-market" technologies where the identification of reliable savings is needed before utilities could screen the technology for use in DSM. Results of the studies will provide a framework for future program design."*[10]

Cost Recovery and Incentives

Cost recovery

Terasen incentives were capitalized and amortized over 3 years and other costs (design, M&E etc.) are expensed. BC Hydro capitalizes virtually all of its costs. All DSM costs are included in customer rates.

Incentives

Both Terasen & Fortis have tariffs under Performance Based Rates that allow for small incentives to the utility.

[9] Conservation Potential Review – 2003 - http://www.bchydro.com/rx_files/info/info10236.pdf

[10] Terasen Revenue Requirement submission, 2005.

Demand response is a strategy that is growing in prominence in the state. During the 2000-2001 crisis, demand response programs were used to meet peak demand and avoid blackouts. Demand response (which is used broadly and includes traditional load management programs) has evolved somewhat over the last few years. Prior to and during the energy crisis, the IOUs maintained a number of interruptible/curtailable contracts with large C&I customers, as well as some direct load control A/C programs. In response to the energy crisis, the IOUs began to implement a wider array of offerings, such as critical peak pricing and a "Flex Your Power" marketing campaign, still in use, that encourages all customers statewide to use less energy during peak periods, either by switching usage to off-peak hours or by reducing usage entirely.

During the last few years, the IOUs have piloted programs ranging from time of use pricing to advanced metering initiatives. At times the number of potential programs has been confusing to customers. Currently the IOUs and the CPUC are examining the results of the pilot programs and looking to simplify offerings, make them more customer friendly, and ramp up the most promising programs. [8] Programs fall broadly into two categories: day-ahead notification programs and reliability-triggered programs. Day-ahead programs are geared mostly toward large customers, but smaller customers can participate in a 20/20 program, where reducing usage at peak times by 20% nets a 20% rebate for customers. For larger customers, critical peak pricing (CPP) and demand bidding are the two main day-ahead programs. CPP customers are informed the day before critical peak events that their rates will go up the following day. This occurs only during the summer and is usually called about 12 times during the summer months. In exchange for being in the program, during the rest of the summer their peak rates are reduced. With demand bidding, customers are notified the day before peak events, and they can bid the amount of capacity they will reduce the next day. Reliability-triggered programs included expansions of existing A/C programs. A portion of DR budgets is spent on customer education and awareness and on technical advice and assistance.

Distribution system optimization has been piloted in the past and has been under consideration more recently, but is not currently being implemented. PG&E is interested in this approach, but has had difficulty in being able to identify constrained areas in a timely enough fashion to develop EE and demand response solutions to the constraint. This is made more difficult by the fact that growth in California has been extremely dynamic. However, studies are being done and this strategy may be more fully considered in the near future.

Fuel switching has historically not been funded with PGC or procurement funds. However, there has been a recent rules change that allows fuel switching if it reduces source fuel and is cost-effective. For 2006-2008, the CPUC will allow IOUs to offer incentives for switching fuels, but these programs are required to meet dual tests that contain a higher level of stringency than other programs.

Successes and Setbacks

Perhaps California's greatest overall success is its stable per capita energy consumption level, while the US as a whole has risen over the same time period. The main factor credited with this success is the state's historical support for DSM programs, starting in the 1970s. Getting accurate, reliable information in a timely manner has been important to this effort, as has making sure that planning processes are robust. In order to do adequate resource planning, all participants need good information about load forecasts and impacts so that participants feel confident in their plans. One of California's current challenges is to come up with EM&V protocols, to get information on both new and existing programs

[8] D. 0501056 lists specific demand response and other programs. See http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/44091.htm for a list of programs and savings goals.

that can be relied on as utilities embark on their next round of IRP. The state is currently developing a protocol for determining avoided costs from a variety of sources (efficiency, DR, distributed generation).

For PGE, the biggest single success emerged from a partnership with Costco. The company had had a rebate program for CFLs, but found that many customers weren't applying for the mail-in rebates, which weren't a large amount of money per bulb. As a result, the incentive wasn't very effective, and PGE had no way to of tracking who was purchasing the bulbs. They entered a partnership with Costco, a membership-based chain, in which PGE gave Costco the rebate incentive money in order to bring the price of the CFLs down. Costco was able to display the bulbs prominently, sell them inexpensively, and track which members were buying the bulbs. The program was a huge success, and millions of bulbs were sold. PGE went on to establish similar partnerships with other stores, and effectively drove the price of CFLs in their area down dramatically.

One of the utilities' biggest challenges has been in changing past behaviours and ways of thinking, both among customers and among third parties, such as maintenance people, store owners, and other "middlemen" that customers rely on for advice. With air conditioning, for example, PGE has found a limited number of maintenance contractors who understand the importance of proper sizing and maintenance, and who will do it correctly. Ultimately, customers are interested in coming home and feeling cool air. This can be done with a small air conditioner, well-maintained and set on a timer to turn on when a home's occupants need the cool air; or it can be done with a unit much larger than necessary, turned on so that customers feel "instant" cool. Changing the customer's behaviour from inefficient to efficient in this instance requires both the customer and the contractor to think differently about the best way to achieve the end goal. Both the change and the fact that the more efficient action may take more customer effort can be barriers to efficiency. Overcoming these barriers is difficult, but can be done with time.

Design, Implementation and Evaluation

Responsibility

In January 2005, the CPUC developed a new administrative structure for efficiency. The new system returns the utilities to the role of portfolio manager and program administrator of efficiency programs. The IOUs submit 3-year efficiency plans for CPUC approval, showing how individual programs will contribute to meeting individual savings targets. Up to 80% of programs may be done in-house, but 20% of programs must be put out to competitive bidding to encourage new entrants. While utilities are responsible for program design, planning and implementation, program advisory groups and peer review groups are formed to give public input to the utilities during the program planning process and during program implementation as well. In many cases, utilities also enter into partnerships with municipalities, retailers, and other entities, who assist in program implementation, but the ultimate responsibility rests with the IOUs.

EE and DR must both be evaluated in the IOUs' LTPPs, with the burden of proof on the utilities to show that cost-effective EE and DR options have been exhausted before issuing any RFPs for supply. The CPUC approves the IOUs' LTPPs and EE plans, and may request that a utility revise portions of the plan that are deemed unsatisfactory.

Evaluation was previously done by the IOUs, whose evaluations were reviewed by the Office of Ratepayer Advocates. Under the new structure, utilities still do some evaluation designed to help them improve planning and delivery, but measurement of utilities' performance will be done by the Energy Division of the CPUC. The process that will be used is still in development.

Program Design Details

Utilities choose program portfolios based on the potential amount of EE available, as determined by EE potential studies. They establish goals for each sector, based on those studies. SCE and SDGE organize programs by traditional sectors (residential, industrial, etc.), while PGE recently switched adopted an approach that targets specific market segments (schools, office buildings, agricultural).

PGE has chosen a more customer-focused, market-based approach. Their programs are focused on meeting the new targets, and the strategy is to involve a greater number of customers in existing programs. PGE creates "delivery channels" for programs by bringing together a group of programs designed to meet the needs of particular customer segments (hospitals, refineries, other market segments). Third parties, such as industry consultants, are often used to ensure that customers are working with someone who "speaks their language" effectively. Program offerings are designed to be simple, straightforward, and compelling to the customer, and introduced during a customer's planning stages whenever possible.

For residential customers, a market-based approach is also used. Residential programs seek to transform markets for efficient products by affecting all points in the delivery chain, from creating customer demand to ensuring product availability to educating the "middle man" – the contractors, maintenance people, and sales personnel who advise and influence customers.

Screening Programs

The Commission requires the Total Resource Cost test and the Program Administrator Cost (or utility cost) test. Both tests must be met in order to receive rate treatment for program expenses, but they are weighted, with the TRC test given twice the weight of the PAC test. Tests are used by utilities to screen individual programs, but the Commission looks at whether the utility's portfolio as a whole meets the tests. This allows room for pilot programs, as well as educational and marketing efforts.

When determining costs and avoided costs, a greenhouse gas adder of $8 per ton of carbon dioxide is applied to all fossil fuels. Externalities are also addressed by the use of recently developed methodology used to develop avoided costs for use in evaluating energy efficiency programs. Use of this methodology may be expanded to demand response, distributed generation, and other applications, and is being investigated in Rulemaking 04-04-025.

Assessing Programs

The CPUC makes a distinction between resource and non-resource programs, and evaluates them differently. Resource programs are assessed for net resource benefits (which include both environmental and economic values). Non-resource programs, such as marketing, educational, and technical assistance programs, are evaluated by program-specific goals. These may include energy savings, but could also include number of participants or other measures. A utility's portfolio is assessed for cost-effectiveness as a whole, allowing room for non-resource programs within a larger, cost-effective portfolio.

At PGE, programs are assessed for net resource benefits. The goal of all programs is to move the utility closer to its savings targets, while providing reasonable equity among customer classes.

Responsibility for assessing program accomplishments rests with the CPUC's Energy Division. In the past, program implementers were responsible, and contracted directly with evaluators. The methodologies that will be used to assess programs has not been finalized, but the CPUC has made clear its intention that assessment should be done by independent third party evaluators with an "arm's length" distance from any direct interest in the results of the evaluation.

DSM Spending

Actual Spending

New budgets approved for 2006-2008 efficiency programs anticipate average annual spending levels of $650 million for the three major electric IOUs and the one major gas IOU.[9] This amount includes funding for EE from PGC funds, a natural gas wires charge, and from electric IOUs' procurement budgets. This figure is up substantially from the approximately $400 million spent on efficiency annually during the 2004-2005 program cycle.

Budgets include a certain amount of funding for coordinated statewide efforts, including $20.5 million for statewide marketing & outreach and $29.8 million for emerging technologies. These costs are to be shared by the IOUs over a three-year period. An additional 8% of funding (not included in above figures) will be spent on EM&V.

For PGE, utility representatives estimate that spending on electric efficiency in 2004-2005 has been between 2.5% and 3% of electric revenues. Spending on gas efficiency has been approximately 1% of gross revenues. (Demand response and low income efficiency are not included in these estimates.)

For demand response, the IOUs' combined 2005 budgets were about $227 million. PGE's budget was $94 million, SCE's was $103 million, and SDGE's was $30 million.

Appropriate Levels

The appropriate level of EE spending is based on the amount of potential efficiency available, as determined by the most recent study of statewide EE potential. The four major electric and gas utilities are directed to capture 70% of the economic potential and 90% of the maximum achievable potential for EE savings. These percentages are the basis for the CPUC's savings targets for each utility. The amount of achievable potential is expected to increase, not decrease, over time. Savings targets have been established through 2013 and increase annually.[10]

The appropriate level of DR spending is based on capturing all cost-effective demand response. The methodology for determining this is still in development, but is being addressed in the avoided cost docket, Rulemaking 04-04-025.

Cost Recovery and Incentives

Cost recovery

Efficiency programs are expensed. Each utility maintains two accounts, an Energy Efficiency Program Adjustment Mechanism (EEPAM) for PGC funds, and a Procurement Energy Efficiency Balancing Account (PEEBA) for procurement funds. Funds are placed in the accounts as authorized by CPUC-approved efficiency budgets, and costs related to efficiency programs are drawn from the accounts as

[9] See D. 0509043, approving 2006-2008 efficiency programs, goals and budgets. Online at http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/49859.htm.

[10] See D.0404060, Energy Savings Goals for 2006 and Beyond, at http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/40212.htm#TopOfPage.

necessary. By statute, there are certain limitations on the PGC funds (for example, equity must be a factor in use of these funds). Both accounts are one-way. Funds overcollected by the utility stay in the account and are applied to future programs, but undercollections are not recoverable by ratepayers. In this way, the IOUs cannot spend more than their authorized budgets. It is common for funds to be carried over from one year to the next due to programs that fall through.

Demand response costs are recovered through rates. Utilities book their costs in an account, and that account balance is recoverable through rates, pending CPUC authorization. Costs are spread across customer classes, and all customer classes pay for the programs.

Incentives

All utilities now have some form of revenue decoupling, removing the disincentive to procure energy efficiency. Some of the decoupling mechanisms include shared savings with shareholders. The Commission has also indicated that it will develop some sort of incentive for utilities to deliver energy efficiency, although issue hasn't been formally taken up yet.

Resources for the Future

The Energy Action Plan

http://www.cpuc.ca.gov/PUBLISHED/REPORT/28715.htm

S. Bender, M. Messenger and C. Rogers. July, 2005. "Funding and Savings for Energy Efficiency Programs for Program Years 2000 through 2004." California Energy Commission.

http://www.energy.ca.gov/2005_energypolicy/documents/2005-07-11_workshop/presentations/2005-07-11_FUNDING+SAVINGS.PDF

F. Coito and M. Rufo. September, 2002. "California's Secret Energy Surplus: The Potential for Energy Efficiency." Prepared by Xenergy for Energy Foundation.

http://www.ef.org/documents/Secret_Surplus.pdf

Selected CPUC Decisions:

D0312060 -- December 18, 2003 -Authorized $493.86 for energy efficiency programs in 2004-2005, including $245 million from IOUs' procurement budgets (in addition to public goods charge funding). http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/32828.htm

D-0409060 – September 23, 2004 -- Quantified energy savings goals from EAP, requiring that IOUs capture 70% of the economic potential and 90% of maximum achievable potential for energy savings by 2013 through use of EE programs. Sets specific MWH/therm savings goals for each utility. http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/40212-02.htm#P123_13438

D0501055 – January 27, 2005-- Adopted administrative structure for EE programs. http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/43628.htm

D0504051 – April 21, 2005 -- Updated policy rules for post-2005 EE, and addressed EM&V related issues. http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/45783.htm#P75_2023

D0509043 – September 22, 2005 -- Approves EE funding levels and programs for 2006-2008.
http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/49859.htm

Stakeholder Process

Each utility has two sets of advisory groups relating to efficiency planning. Performance Advisory Groups (PAGs) are large groups of interested stakeholders, some with financial interest in the proceedings (such as ESCOs) and some without. Utilities convene and facilitate the meetings. Utilities' efficiency plans are presented to the PAGs for review and guidance. Within each PAG, there is a nested advisory group, called the Peer Review Group (PRG), made up of non-financially interested parties. PRGs are chaired by Energy Division staff. Other members might include the Office of Ratepayer Advocates, other consumer groups like the Utility Reform Network, the Utility Consumers' Action Network, the Natural Resources Defense Council, and CEC staff.

For both groups, utilities identify the members and notify the Commission. PAG meetings are open to the public, while PRG meetings are usually just among members and utilities.

For more information about the stakeholder process, contact Zenaida Tappawan-Conway (CPUC) at (415) 703-2624 or Christine Tam (Office of Ratepayer Advocates) at (415) 355-5556.

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Connecticut DSM Summary[1]

DSM Background and Approaches

Background and Interest

Both electric and gas DSM programs, funded by ratepayers, have been conducted in Connecticut for many years. During the 1990s, electric DSM activities were conducted by investor-owned vertically integrated utilities, with program decisions made in the context of resource planning activities.[2] In 1998, legislation restructuring the electric sector was enacted.[3] DSM activities continued under a new arrangement with the two resulting distribution utilities (DUs) serving most customers in the state.[4] The legislation created the Conservation and Load Management (C&LM) fund, with a statutory surcharge of $0.003/kWh assessed on retail sales of electricity in the service territories of the two DUs. It also created the Energy Conservation Management Board (ECMB), made up of stakeholders and state agency representatives, to guide the DUs in C&LM program development, implementation and evaluation.

The Department of Public Utility Control (DPUC) continued to be responsible for final approval of all C&LM programs.[5] The basic goal of these programs has been to reach all customer classes with cost-effective energy and demand savings through conservation and market transformation initiatives. The overarching concerns referenced in annual reports to the legislature have been increasing energy efficiency, economic development and energy security, while reducing air pollution and other environmental impacts.

During this same time, the three major gas DUs have provided modest conservation programs, approved by the DPUC in the context of biennial supply and demand plans. Stakeholder collaboratives provided input to the utilities. The gas programs have focused primarily on low-income weatherization and related efforts, although some loan funds have been available to other consumers.

The electric C&LM programs have been impacted by a variety of concerns in recent years. Since 2002, significant congestion issues in southwestern Connecticut (SWCT) have led the DPUC to approve initiatives and incentives targeted to reducing demand in that area. Meanwhile, the legislature responded to state budget issues with two different legislative takings of the C&LM funds, reducing total funds available by about one-third for a number of years going forward. Widespread support for the C&LM programs by utilities, advocates, vendors and state agencies prevented a more dramatic loss of funding.

Recently, interest has increased significantly in both electric and gas programs for a variety of reasons. They include relatively high energy prices, anticipated increases in congestion-related charges, transmission problems in SWCT, older generators, and the state's dependence on natural gas for electric

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[1] This summary was compiled by Catherine Murray at the Regulatory Assistance Project and is based primarily on interviews completed during the fall of 2005 with Cindy Jacobs and Margaret Bain of the Connecticut Department of Utility Control, and David Bebrin of Connecticut Light & Power.

[2] A comment was made that jurisdictions do not have to abandon least cost planning when they restructure.

[3] Public Act 98-28. See: http://www.cga.ct.gov/ps98/Act/pa/1998PA-00028-R00HB-05005-PA.htm

[4] Connecticut Light & Power (CL&P) and United Illuminating (UI).

[5] "C&LM" will be used throughout this summary, rather than DSM, to describe statutory energy and demand savings efforts. The word "conservation" is typically used in Connecticut to include efficiency efforts, and will be used in that manner in this summary as well.

installation of an efficient chiller will reduce demand and use less energy throughout the year. Most programs impact lost opportunities (e.g. new construction, major retrofits, new appliance or equipment purchases). Programs also target small business retrofits and municipal lighting. Utilities may use different delivery or financing mechanisms to reach different customers (e.g. state/municipal government versus small business customers).

It was important to the CL&P representative to note that most C&LM incentives to customers are "cost-based," in part to stop program shopping. The same measure gets the same incentive, no matter which "program" it is in. Incentives are designed to remove the market barrier and should never cost more than the value to the system.. A kW or kWh "reward" could exceed actual installation costs and also promote program shopping. It has been the utility's experience that cost-based programs can move the market to obtain efficiencies above "low-hanging fruit" more effectively than rewards-based programs. Also, M&V has to be stricter for rewards-based program; it is easier to get real numbers for cost-based incentives.

One exception to this approach is "rewards" based demand response, where customers are paid to reduce demand when "called" upon due to reliability needs, price signals or other needs of the system. In Connecticut, demand response can generally be distinguished from load management by the short-term nature of the response. Demand response is characterized by a payment structure that results in an immediate, short-term reduction in demand. By contrast, load management measures supported by C&LM funds generally result in persistent, long-term demand savings.

Some C&LM funds are used for demand response, e.g. to supplement the demand response activities of the New England ISO (ISO-NE).[9] ISO-NE is interested in demand response, particularly to ease reliability issues in SWCT, but also offers price responsive programs. ISO-NE is paying for direct load control of air conditioning in SWCT for reliability. It also issued a "gap" RFP in 2003 and 2004, soliciting demand response to mitigate capacity gaps in SWCT due to transmission constraints.

C&LM funds are used for distribution system optimization in SWCT. According to CL&P staff, wires solutions are generally cheaper, except in this area. The utility might offer a retrofit RFP targeted to SWCT, or offer higher incentives to implementers (e.g. the incentive for O&M improvements might be 50% in the rest of the state, but 100% in SWCT if the savings justify it.) Lost opportunity incentives can't be improved since they are already as high as possible everywhere in the state, at 100% of incremental costs. Penetration of C&LM measures hasn't been as high as program administrators would like to see. According to DPUC staff, the new docket addressing retail rates may impact this, since there is a locational focus (the Norwalk/Stamford area, SWCT, and statewide).

New approaches to demand response and load management are likely to result from initiatives and requirements established by the recently enacted EIA. A major emphasis of the EIA is to reduce capacity and congestion-related charges described earlier (FMCCs). Here are just a few examples of new approaches resulting from the EIA:

- The C&LM focus on statewide availability of projects producing integrated energy and demand savings will shift, with preference given to projects that reduce FMCCs.

[9] A C&LM-funded pilot supplemental price response program was implemented in 2005 for certain high price events (see pp 20-21 of Docket 04-11-01). CL&P has budgeted $1.4 million for about 32 MW of demand reduction. in 2006.

- Docket 05-09-09: Examining possible decoupling strategies for both gas and electric. utilities. Rate design options to support energy policy goals may also be considered.
- Docket 05-10-02: The 2006 C&LM plans filed jointly by the two major electric utilities (CL&P and UI).

The Energy Conservation Management Board (ECMB) reports on program results to the legislature every spring. The "Report of the ECMB: Year 2004 Programs and Operations" can be seen at

http://www.dpuc.state.ct.us/Electric.nsf/cafda428495eb61485256e97005e054b/834bce27d18f256a85256ff80051f63d?OpenDocument

Other ECMB information can be accessed at: http://www.state.ct.us/dpuc/ecmb/

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integrated resource plans and for them to develop load response and energy efficiency programs. [7] In addition, the law created modestly funded public benefit funds for energy efficiency and renewable energy. These programs are administered by the state Department of Commerce and Economic Opportunity, and have annual budgets of about $5 million for each program area.

In addition, ComEd has provided funding for several significant DSM initiatives:

- The Illinois legislature required the Company to dedicate $225 million from the sale of its fossil-fuelled power plants to establish a foundation that eventually became the Illinois Clean Energy Community Foundation. This foundation makes grants and provides other types of support for energy efficiency, renewable energy, and natural areas/wildlife habitats.[8]

- As part of its 1999 franchise renewal with the City of Chicago, ComEd agreed to provide $100 million in funding to improve the energy efficiency of city facilities.

- ComEd has worked with the Center for Neighborhood Technologies (CNT), a Chicago non-profit organization, to establish the Community Energy Cooperative. This organization started by conducting energy efficiency and load management programs covering commercial lighting, residential air conditioning, and large customer load management programs. For the past several years, the Cooperative has been conducting an experimental voluntary residential real-time pricing program.

- ComEd's Technical Services Department works with customers on an ongoing basis to help them conserve energy. One specific initiative that ComEd summarized in its presentation to the ICC is the Chicago Industrial Rebuild Initiative. This is a joint project with the City of Chicago's Department of the Environment that helps selected industries identify and implement energy conservation measures.[9]

- ComEd has supported several energy efficiency programs conducted by the Midwest Energy Efficiency Alliance.

DSM Approach

The Sustainable Energy Plan has not been fully implemented, so the approaches used by utilities to comply with its provisions are not yet known. Historically, ComEd's DSM efforts have focused on load management and demand response, except as noted above. As part of a summary of its DSM programs presented to the ICC, ComEd summarized the impacts for all of its load management and demand response programs. In total, these programs could provide about 1,132 MW of demand reduction at the end of 2004, approximately 5% of ComEd's peak demand. The Company's three largest load management or demand response programs are:

1. Voluntary Load Reduction, or VLR. Through this program, ComEd offers electric rate discounts to commercial/industrial customers who reduce their loads during peak periods. Customers are provided

[7] Illinois Commerce Commission, "Illinois Sustainable Energy Initiative, ICC Staff Report" (Illinois Commerce Commission, Springfield, IL, 2005) p. 22. This is also available on the Sustainable Energy Plan section of the ICC web site: www.icc.Illinois.gov.

[8] For more information, see www.illinoiscleanenergy.org.

[9] ICC, 2005, op.cit., p. 39 ComEd PowerPoint slides.

one hour's notice before a load reduction period, and are not required to reduce their loads at such times.

2. Rider 26/27. Rider 26 is a direct load control program for larger commercial/industrial customers. A variety of different types of equipment can be controlled through this program. Rider 27 provides rate discounts to customers with backup generation who agree to operate their generators during peak periods.

3. Nature First, a residential direct load control program for central air conditioners.[10]

The ICC staff proposed to make the Sustainable Energy Plan voluntary for ComEd and Ameren, the only utilities that would be covered by the plan. There are questions about the ICC's statutory authority to enact such requirements in a mandatory manner.[11]

Successes and Setbacks

Full implementation of the Sustainable Energy Plan has been delayed pending resolution of a separate docket on electricity procurement. The Governor has opposed ComEd's plans to hold auctions for procuring power in the future. ComEd "believes it is not prudent to make its filing [on the Sustainable Energy Plan] until this matter has been resolved".[12]

The ICC's DSM focus has shifted somewhat from the Sustainable Energy Plan to natural gas matters, due to the current high prices for natural gas.[13] The ICC held an informational meeting on natural gas on October 25, 2005. The Governor's proposed Sustainable Energy Plan did not contain any provisions directly concerning natural gas.

DSM Program Design, Implementation, and Evaluation/Cost Benefit Analysis

These matters have not been fully resolved since full-scale implementation of the Sustainable Energy Plan has been delayed. However, the ICC's general approach to implementing the Sustainable Energy Plan will likely be for the utilities to make filings outlining their plans to comply with the Plan's provisions, which would be approved or modified by the ICC commissioners.[14] The utilities' plans would include program designs, implementation plans, and evaluation plans. ComEd plans to at least partially outsource program evaluations to third party consulting firms, and may do the same for program implementation, but has not yet decided on its approach to conducting benefit-cost analyses for its DSM programs.[15]

DSM Spending Requirements

One of the notable aspects of the proposed Illinois Sustainable Energy Plan is that it does not impose DSM spending requirements on utilities, as in other jurisdictions like Minnesota. Instead, its DSM requirements are performance based, requiring utilities to meet set percentages of their load growth through DSM programs.

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[10] Ibid.

[11] ICC, 2005, op. cit., p 20.

[12] Letter from Frank Clark of ComEd to ICC Chairman Ed Hurley, September 6, 2005. This letter is posted on the ICC web site, www.icc.illinois.gov, Sustainable Energy Plan.

[13] Michelle Mishoe, ICC, personal conversation, October 2005.

[14] Ibid.

[15] Charles Budd, ComEd, personal conversation, October 2005.

Program Design Details

Programs are designed in a collaborative process that includes workgroups and brainstorming sessions with interested parties. In designing its most recent five-year plan, MidAmerican worked with consultants, built on past programs, and held workshops for each proposed program before writing the plan.

Screening Programs

Programs are screened with the California Standard Practice tests. The Societal Cost test is the primary test and is the benchmark for cost-effectiveness. The other California Standard Practice tests are used (the Utility Cost test, the Participant Test, and the Ratepayer Impact Measure test). When determining avoided costs, an adder is applied to supply options to account for externalities. For electric supply, the adder is 10%, and for gas supply the adder is 7.5%.

Assessing Programs

At the end of each year, actual societal test results are evaluated, to measure true end-of-year performance. MidAmerican also assesses programs by evaluating energy saving impacts vs. budgets and customer participation vs. spending.

The utilities conducted a study of EE potential before the latest round of filings. Various efficiency measures were identified, along with impacts for each measure. Energy savings claims used to measure program results are based on that study. Tracking systems and engineering studies are also done.

DSM Spending

Actual Spending

Total DSM spending was about $90 million in 2004, with over $65 million spent on electric DSM and over $20 million spent on gas DSM. Spending has more than doubled since 2000, when electric and gas DSM totalled about $40 million. This spending has resulted in incremental savings of 650,000 mmBTU and 200,000 MWh (see below).

2004 Energy Savings from DSM in Iowa				
Gas (mmBTU)		Electric (MWh)		Peak Savings (MW)
Incremental	660,884	Incremental	198,059	144
Cumulative	6,211,273	Cumulative	1,417,309	969
2004 DSM Spending in Iowa				
Gas	22,687,726			
Electric				
EE	29,879,414			
LM	33,820,819			
Misc	2,827,544			
Total Electric	66,527,777			
TOTAL DSM SPENDING	**$89,215,503**			

Source: Gordon Dunn, Iowa Utilities Board

Electric efficiency programs in Massachusetts have been recognized nationally by a variety of organizations, including the American Council for an Energy-efficient Economy for exemplary C&I and small business programs.[4]

The process is not perfect. The Massachusetts regulatory processing system is cumbersome. Almost all parties would agree that both the prospective regulatory review of plans, programs, and cost-effectiveness, and the retrospective review of evaluations, cost-effectiveness and determination of shareholder incentives take too long. Prompt review of these filings can provide guidance to the industry, critique performance, and highlight effective approaches. Timely feedback would allow adjustments to be made more quickly. Interview participants suggested that regulators in Canada and elsewhere might consider the merits of frequent but less than perfect review as compared to infrequent and perfect.

Some concern was expressed that the system of performance incentives can create incentives to set more modest goals than might be cost-effectively attained. The dynamic between utilities setting goals they say are realistic while DOER, and sometimes the NUPs, push for them to do more provides a certain system of checks and balances. It has been recognized by many parties that aligning utility business objectives with public policy objectives can produce strong results. This goal and the removal of barriers to DSM acquisition continue to be topics of discussion among the parties.

Design, Implementation and Evaluation

Responsibility -Electric Efficiency Programs

Electric efficiency programs are administered by either distribution utilities (DUs) or municipal aggregators. There is presently only one municipal aggregator, Cape Light Compact ("Cape Light"), managing electric efficiency programs. It plans, designs and implements energy efficiency programs using SBC funds, and negotiates power supply and other benefits for 21 towns (197,000 customers) on or near Cape Cod, as authorized by member towns.

The DUs filed an initial five-year efficiency plan, and now file annual updates with the DOER and DTE. These plans are developed with input from a formalized group of stakeholders, known as non-utility parties (NUPs), and contractors hired by the NUPs with funds provided by the DUs. Sometimes the DUs work with each other or regional groups like the Northeast Energy Efficiency Partnerships to develop programs and problem-solve.

The DOER reviews the plans and files reports with the DTE regarding the proposed programs and funding. The DOER has authority to oversee and coordinate the programs, and it often provides some technical review of the programs. If the DOER concludes that the proposed programs and plans are consistent with the state's goals, and there are no objections, the DTE generally reviews only the cost-effectiveness of the plans and the use of competitive processes.[5] In practice, the DUs generally implement programs while the DTE decisions are pending.

Cape Light files plans directly with the DTE, which then provides program review, as well as cost-effectiveness and competitive process determinations. Cape Light works with member communities and gets approval from its representative board for planning, design and implementation.

[4] See the report at http://www.aceee.org/utility/u032.pdf.

[5] See recent Order in DTE 04-11 for a detailed description of roles and responsibilities, along with statutory and other citations at: http://www.mass.gov/dte/electric/04-11/819order.pdf

Program administrators generally go out to bid and contract for program implementation because there is a statutory mandate to increase the competitive procurement of efficiency services. Some utilities have field staff that market programs to large C&I customers, or provide technical assistance, but they still contract for DSM service.

Program administrators go out to bid and hire third-party contractors to evaluate program impacts and processes. The DOER, NUPs and NUP contractors provide input to the focus, approach and design of evaluation. The DTE must review evaluations before it can award performance incentives to the program administrators.

Gas Efficiency Programs

Local gas distribution utilities file five-year overall program plans with DTE and update them annually. There is a formal DTE proceeding in which DOER intervenes as a party, and makes recommendations for plan or program adjustments.

The DTE reviews cost-effectiveness, approves or modifies budgets and plans, and determines cost-recovery, lost revenue recovery and performance incentives, when applicable.

The gas distribution utilities hire implementation and evaluation contractors in much the same manner as the electric utilities. They may provide some technical assistance with in-house staff.

Program Design Details

The goals for electric efficiency in Massachusetts cover a lot of ground besides cost-effectiveness such as: customer equity, giving due consideration to market transformation, low-income priorities, short-term and long-term savings and other goals, that are sometimes competing. Program administrators try to design a portfolio of programs to find a balance and give sufficient emphasis to each goal. A really comprehensive program may not be the most cost-effective, but it may take advantage of opportunities and accomplish a variety of goals. If only cost-effectiveness mattered one program administrator indicated they would only do commercial lighting.

DOER and others provide feedback to program administrators. DOER is concerned that program design reflects the impacts of new standards and codes. Also, market penetration research is used to determine when certain strategies or measures no longer need the same financial support. Although there is often consensus on this, sometimes there is a tension between utilities' desire to satisfy customers and regulators' interest in cost-effectiveness. At times DOER may want incentives to go higher up the market chain, e.g. to efficiency equipment distributors, because you can pay much less per distributor to get the same effect than paying per customer, potentially spending less to do more.

Screening Programs

In DTE 98-100 Order, the DTE determined that the total resource cost (TRC) test would be used to determine the cost-effectiveness of both gas and electric energy efficiency programs.[6] The Order contains detailed directions for screening programs, but the following basic elements are included in cost/benefit determinations:

[6] For details, see the final Order at http://www.mass.gov/dte/electric/98-100/finalguidelinesorder.htm

Costs

- Program Administrator Costs (including all development, planning, administration, implementation, marketing, monitoring, and evaluation expenses for the Energy Efficiency Programs).
- Shareholder Incentives.
- Program Participant Costs.

Benefits

Energy System Benefits

- Avoided Electric Generation and Gas Supply Costs.
- Avoided Transmission Costs.
- Avoided Distribution Costs.
- Avoided Projected [environmental] Compliance Costs.
- Low-Income Benefits such as, but not limited to, (i) reduced account write-offs; (ii) reduced arrearages, late payments, and late payment administrative costs; (iii) reduced shut-off and reconnect charges; and (iv) reduced credit and collection expenses.

Program Participant Benefits

- Participant Non-Resource Benefits such as reduced costs for operation and maintenance.
- Participant Resource Benefits shall account for the avoided costs of oil, water, sewage disposal, and other resources for which consumption is reduced as a result of the implementation of Energy Efficiency Programs.

DTE has placed renewed emphasis on cost-effectiveness screening recently, and high energy prices have also contributed to increased benefits from efficiency programs. National Grid's 2005 portfolio of programs anticipates a benefit cost ratio of 2.62. (Total costs of $69.1 million, total benefits of $181 million.)

DTE requires electric utilities to update avoided costs every two years. Recently New England utilities and efficiency program managers supported a *regional* study to update avoided cost values used for cost-effectiveness tests given the variety of changes in the energy market, including impacts on market design from actions of the Federal Energy Regulatory Commission and ISO-NE. This avoided cost study included an effort to quantify the impact of efficiency on capacity prices, the DRIPE ("Demand Reduction Induced Price Effect"). DRIPE looks at how demand reductions can affect the wholesale market and how those effects move down into retail prices. DRIPE has not been formally adopted yet, but it seems that capacity has been undervalued in past years and this may represent capacity effects more accurately. This study is not public yet, but it may result in changes to cost-effectiveness analyses in at least some of the New England states.

A new study has been contracted to update the quantification of non-electric benefits related to C&I program efforts, which may also change values used in cost-effectiveness determinations.

Efficiency programs are not just screened for cost-effectiveness. Other regulatory and statutory language results in emphasis on the use of competitive processes for efficiency services, equitable allocation of resources among customer sectors, obtaining short- and long-term savings and other goals.

Assessing Programs

Electric efficiency programs have a variety of statutory and regulatory goals. Program administrators, and the third party contractors they hire, take the lead in assessing progress toward those goals. The NUPs and

The incentive calculation is further nuanced because the performance is weighted by three "determinants." Savings determinants are lifetime energy and demand savings, and specific non-electric benefits. Value determinants are actual positive net benefits; the formula rewards higher benefit cost ratios. Performance metrics determinants include other specific, pre-determined measures of program effectiveness and administrative improvements, such as increasing market share, improving the utility cost indicator, increasing participation in pilot programs, etc. The SBC fund also pays the tax liability. National Grid's 2005 plan budgeted close to $4 million for incentive-related expenses, assuming 100% level of performance, with $2.5 million being the net incentive.[12]

According to one regulator, there will always be a tension for utilities between selling and saving kWh. Reduced sales mean less profit than otherwise could be expected. But the performance incentive appears to be a reasonable motivator to utilities and it allows shareholders to earn a significant return on funds essentially invested by ratepayers.

Since it is acknowledged that efficiency decreases anticipated revenues, there are beginning to be some discussions in Massachusetts about utility revenue decoupling, or other ways to align utility incentives with energy policy.

Resources for Future Reference

Massachusetts Division of Energy Resources. 2004. "2002 Energy Efficiency Activities." http://www.mass.gov/doer/pub_info/ee02-long.pdf

The newest DOER report, including the 2003 evaluated savings report, 2004 preliminary results, and 2005 planned goals should be available on the DOER website soon.

Massachusetts Electric Company and Nantucket Electric Company (aka National Grid). April 2005. "2005 Energy Efficiency Plan." May be obtained from National Grid.

Massachusetts Electric Company and Nantucket Electric Company (aka National Grid). 2004 "Energy Efficiency Annual Report." May be obtained from National Grid.

June, 2001 report "The Remaining Electric Energy Efficiency Opportunities in Massachusetts: Final Report" prepared by RLW Analytics, Inc. (Connecticut) and Shel Feldman Management Consulting (Wisconsin).

http://www.mass.gov/doer/pub_info/e3o.pdf

DTE Order 98-100 re: cost-effectiveness

http://www.mass.gov/dte/electric/98-100/finalguidelinesorder.htm

Chapter 140 of the Acts of 2005 extended the SBC fund for another five years, through 2012. It also established a variety of energy-related tax credits, loans and other initiatives.

http://www.mass.gov/legis/laws/seslaw05/sl050140.htm

[12] See National Grid's 2005 Efficiency Plan, particularly pages 111-114, and Appendix B for a detailed explanation of performance incentives.

The 1997 Restructuring Act, as amended by the 2002 Act, created the SBC to fund energy efficiency, renewable energy, and low-income programs. The 2002 Act extended the fund through 2007. The 1997 Act can be seen at www.mass.gov/legis/laws/seslaw97/sl970164.htm.

The results of the 2002 Act can be seen at http://www.mass.gov/legis/laws/mgl/25-19.htm.

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Minnesota DSM Summary

DSM Background and Interest in DSM

The Minnesota State Legislature is the policy making body regarding DSM in Minnesota. The Legislature started requiring the state's electric and gas utilities to operate DSM programs in 1980. The initial requirements were for the state's investor-owned utilities to conduct electric and gas energy efficiency pilot programs. These requirements were enacted during a period in which new power plants were causing significant electric rate increases.[1] After the first DSM pilot programs were conducted in the early 1980s, the Legislature amended the Conservation Improvement Program (CIP) statute[2] to require the state's utilities to make "significant" investments in DSM. The Minnesota Public Utilities Commission (MPUC) was in charge of regulating the utilities' DSM programs, and judging whether their proposed plans constituted "significant" investments.

The Legislature continues to set policy regarding DSM through the CIP statute, but they are not the only body interested in DSM in Minnesota. Other key DSM actors in Minnesota include:

- The MN Department of Commerce (MDOC) is now the lead regulatory agency implementing the CIP requirements, gaining that responsibility from the MPUC in the mid-1990s.
- The MPUC still plays a role in DSM through their management of the integrated resource planning process in the state. See the "Optimizing DSM Spending" section for more details.
- Environmental NGOs actively intervene in the CIP process, encouraging the MDOC and MPUC to order the state's utilities to exceed their minimum DSM spending requirements, which they have statutory authority to do, as will be discussed in the "Optimizing DSM Spending" section.
- Minnesota's utilities generally support DSM programs, and take an active role in their development and implementation. Xcel Energy develops and implements the DSM programs it offers to its customers, and has consistently expressed interest in managing DSM programs for its customers.
- Third party implementation contractors play a limited role in implementing DSM programs in Minnesota. Utilities can voluntarily subcontract with these organizations, or they can petition the MDOC for utility funding for program ideas they are interested in.
- Xcel Energy's customers are also significantly interested in DSM. Over 100,000 of their one million Minnesota electric customers participate in at least one CIP program annually. Their customers are particularly interested in their gas DSM programs currently, due to the high projected costs for natural gas this winter.[3]

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[1] Much of the narrative in this section is supplied by Summit Blue's Randy Gunn, who has worked on DSM matters in Minnesota for 25 years, most recently as a consultant, but formerly as an employee of Northern States Power Company, which is now part of Xcel Energy Corporation.

[2] Minnesota statute 216B.241.

[3] Personal conversation with Bridget McLaughlin, Regulatory Analyst for Xcel Energy, October 2005.

New Jersey has made one of the most aggressive commitments to DSM and RE over the last 20 years. One result is a booming solar industry in the state with programs oversubscribed.

New Jersey has found many challenges in terms of demand response. Customers are not used to participating in markets in this way, communications methods do not suit some customers and the lack of dynamic prices for customers also dampens the value of demand response. These and other details, cumulatively, serve to make demand response harder to sell, manage and deliver than is hoped by policymakers for the long term. But there is a positive determination throughout the markets and by the regulators to address these challenges directly. PJM can rely on a certain level of demand response, and that amount is growing each year, and the potential is also growing as awareness and technology improves.

Design, Implementation and Evaluation

Responsibility: EE Program Design and Implementation

In a January 2003 Order, the BPU established the New Jersey Clean Energy Council (CEC) as advisors to the Board for planning assistance for the administration of the programs. The CEC includes broad representation from state and federal governmental entities, utilities, private firms, consumer and environmental advocacy groups and academia. The CEC works with Board staff to make recommendations and assessments of the components of New Jerseys' Clean Energy Program programmatic effectiveness, the goals and objectives on a program-by-program basis, incentive level, program delivery, consumer satisfactions and administrative efficiency. The CEC was established in March 2003.[4]

In a subsequent Order dated Sept. 11, 2003[5], the BPU directed the Office of Clean Energy to assume the role of administrator of New Jersey's Clean Energy Program and to establish a fiscal agent to administer program funds. The programs are to be administered without regard to service territories. In a December 2003 Order[6], the Board established an interim funding level for 2004 and in a July 2004 Order[7] the Board adopted a final 2004 funding level of $124 million.

In a May 7, 2004 Order[8] the Board initiated its second comprehensive resource analysis proceeding and established a procedural schedule for the determination of funding levels, allocations, and programs for 2005 through 2008. Lost revenues issues were also to be included, and third parties were engaged to perform technical studies of the EE and RE potential.

The Office of Clean Energy (OCE), through an RFP process, hired program managers to implement the EE and RE programs – one for Residential EE, one for C&I EE, and one for RE. The Low Income will be managed by a utility/Department of Community Affairs partnership. Until these managers are operational the utilities will continue to implement the programs. The Dec 22, 2004 order directed the program

[4] Docket # EX04040276: Funding Allocation & Program Budget, In the Matter of Comprehensive Energy Efficiency and Renewable Energy Resource Analysis for 2005-2008, Dec. 22, 2004. http://www.bpu.state.nj.us/wwwroot/energy/EX03110946_20040428.pdf

[5] Docket # EO02120955: Order - In the Matter of the New Jersey Clean Energy Program http://www.bpu.state.nj.us/home/BO_CE.shtml

[6] Docket # EO02120955: Order - In the Matter of the New Jersey Clean Energy Program http://www.bpu.state.nj.us/home/BO_CE.shtml

[7] Docket #EX03110905 et al.

[8] Docket #s EX03110946 and EX040276: http://www.bpu.state.nj.us/wwwroot/energy/EX03110946_20040428.pdf

Resources for Future Reference

SB7 Electric Discount and Energy Competition Act February 1999 (The Act)

www.bpu.state.nj.us/wwwroot/energy/EX00020091ORD.pdf

Energy and Economic Assessment of Statewide Energy efficiency Programs, New Jersey Clean Energy Collaborative, July 9, 2001

New Jersey's Clean Energy Program: 2005 Program Descriptions and Budget, Utility Managed Energy Efficiency Programs, Updated June 8, 2005

New Jersey's Clean Energy Program: 2005 Program Descriptions and Budgets, Office of Clean Energy Managed Renewable Energy Programs and Administrative Activities, June 9, 2005

New Jersey Board of Public Utilities May 6, 2005. New Jersey's Clean Energy Program: 2004 Annual Report. http://www.njcleanenergy.com/media/OCE_AR_final_0907_4_1.pdf

New Jersey Statewide Market Assessment, Xenergy 1999. http://www.njcleanenergy.com/html/5library/nj_baseline_studies_base.html

Relevant Board of Public Utilities (BPU) Orders

- Docket # EO04080894: Order - In the Matter of the Adoption of New Jersey's Clean Energy Program Protocols to Measure Resource Savings, Dec. 22, 2004. http://www.bpu.state.nj.us/wwwroot/cleanEnergy/EO04080894_20041223.pdf
- Docket # EX04040276: Order - In the Matter of Comprehensive Energy Efficiency and Renewable Energy Resource Analysis for 2005-2008, Dec. 22, 2004. http://www.bpu.state.nj.us/wwwroot/energy/EX03110946_20040428.pdf
- Docket # EO02120955: Order - In the Matter of the New Jersey Clean Energy Program http://www.bpu.state.nj.us/home/BO_CE.shtml
- Docket #EX03110905 et al.: Order – July 2004
- Docket # EX03110946: Order - In the Matter of Appropriate Utility Funding Allocation for the 2004 Clean Energy Program http://www.bpu.state.nj.us/wwwroot/energy/EX03110946_20040428.pdf

The 2004 PJM State of the Market Report, March 8, 2005. http://www.pjm.com/markets/market-monitor/som.html

Harrington, C., and Murray C., the Regulatory Assistance Project, May 2003. Who Should Deliver Ratepayer Funded Energy Efficiency? A Survey and Discussion Paper.

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- *to allow SBC programs to expand in relation to the increased demand for such programs.*

The SBC program portfolio has been primarily administered by NYSERDA, a public benefit corporation created in 1975 by the New York State Legislature. As SBC Program Administrator, NYSERDA consults with interested parties, prepares an "Operating Plan" to fund individual programs within the funding categories established by the Commission, receives and disburses SBC funds, conducts program evaluations, and prepares program reports. NYSERDA is assisted in the evaluation process by the Independent System Benefits Charge Advisory Group ("Advisory Group") and a number of evaluation contractors. SBC operating arrangements were finalized among the PSC, DPS staff and NYSERDA in a March 1998 SBC Memorandum of Understanding (MOU). The MOU also directed NYSERDA to solicit public input in developing its draft SBC Operating Plan for the initial three-year SBC period, and to establish an outside SBC advisory group, which would also function as an independent SBC program evaluator. The PSC's July 2. 1998 Order, approved, with modifications, the SBC Operating Plan.

In 2002 a four-year State Energy Plan was developed with a goal to reduce statewide primary energy use in 2010 to a level that is 25% below 1990 energy use per unit of Gross State Product. Two key drivers for DSM are environmental (need emission reductions for new source permitting) and price stability (30% natural gas and petroleum generation sources mean price volatility). New York uses natural gas and petroleum for 30% of electricity generation; prices for both commodities are set in world and national markets and reflect rapidly changing demand and supply conditions. The effect of these rapid changes in market conditions is high volatility in natural gas and petroleum product prices, which in turn creates greater price volatility in New York.

DSM for natural gas is not included in the SBC funding. DSM for natural gas was developed for Con Edison Gas and National Grid through rate cases. Interest has increased in gas DSM due to dramatic increases in gas prices—a 35 to 45 % increase in heating bills is expected in Albany, for example. A study, examining the potential of natural gas efficiency programs in New York statewide, is currently underway. The report is expected to be completed in early 2006.

Approaches

NYSERDA's programs are designed to work in tandem to achieve the State's energy, environmental, and economic goals. Where possible, NYSERDA integrates its programs and services to best meet its customers' needs. Programs are integrated on many levels by sharing customers, addressing common barriers, and seeking to accomplish common program objectives. Moreover, individual markets might be influenced by several NYSERDA programs. For example, the lighting market is influenced by a number of programs across markets – from upstream manufacturing to midstream specifying and distributing to down-stream consumer purchases and deployment.[5] In addition, many of the SBC programs are coordinated through the community based organizations funded by the U.S. Department of Energy.

> The installation of multiple measures can maximize energy efficiency gains from the interaction of the measures. For example, energy-efficient cooling/ventilation systems, lighting and energy management controls can be optimized to further minimize electricity usage and peak demand.

The New York Energy $mart[SM] public benefits program portfolio covers numerous energy efficiency initiatives, which are described briefly below[6].

[5] NYSERDA Strategic Plan July 2005 http://www.nyserda.org/Energy_Information/strategicplan.pdf

Business and Institutional programs include the following:

- The **New Construction Program** encourages energy-efficient design and building practices among architects and engineers, and urges them to inform building owners about the long-term advantages of building to higher energy standards.

- The **Commercial/Industrial Performance Program** provides incentives to energy service companies (ESCOs) and other contractors to install energy efficiency capital improvements.

- The **Peak-Load Reduction Program** provides incentives to identify and implement measures to reduce electric load during periods of peak electric demand. Incentives are available for four categories of measures: 1) permanent demand reduction, 2) load curtailment and shifting, 3) dispatchable emergency generation, and 4) interval meters.

- The **Enabling Technology Program** supports innovative technologies that enhance the capabilities of load serving entities, curtailment service providers and New York Independent System Operator (NYISO) direct customers to reduce electricity load in response to emergency and/or market-based price signals. The projects in the program, funded as R&D demonstration projects, have provided significant contributions to the amount of curtailable load available.

- The **Technical Assistance Program, including the FlexTech and Energy Audit Programs,** funds detailed energy studies by customer-selected or NYSERDA-contracted consultants. It includes energy feasibility studies, energy operations management, and rate analysis and aggregation. These three program components, which were once managed separately, are now offered as one solicitation.

- The **Smart Equipment Choices Program** is an expansion of the pre-qualified equipment component offered under the New Construction Program, and was designed to encourage the installation of high-efficiency measures through incentives at the time of retrofit or replacement to improve the energy efficiency of existing electrical loads.

- The **New York Energy $Smart^{SM} Loan Fund** provides reduced-interest financing for energy efficiency measures and related facility improvements.

The following programs target the residential sector.

- **ENERGY STAR® Products & Residential ENERGY STAR® Marketing Programs**. These two programs work in tandem to increase awareness, understanding, stocking, promotion, and sales of ENERGY STAR® Products. These programs target the following 16 appliances and lighting products: refrigerators, dishwashers, clothes washers, room air conditioners and through-the-wall (TTW) units, compact fluorescent light bulbs (CFLs), suspended lighting fixtures, portable fixtures, ceiling-mounted fixtures, wall-mounted fixtures, recessed fixtures, exterior fixtures, cabinet integrated fixtures, ceiling fans, dehumidifiers, and freezers.

- **Keep Cool Program.** This program encourages the replacement of old, working air conditioners with ENERGY STAR®- labeled room air conditioners and TTW units. Turned-in units are permanently removed from service and are de-manufactured and recycled. This program is

[6] New York Energy $Smart^{SM} Program Evaluation and Status Report: Report to the System Benefits Charge Advisory Group, Final Report, May 2005, http://www.nyserda.org/Energy_Information/05sbcreport.asp

individuals and organizations interested in energy efficiency and **New York Energy $mart^{SM}** programs.

- **Residential Special Promotions Program.** The program seeks to increase the availability, promotion, and sale of energy-efficient products and services by implementing promotions in markets not currently addressed through other marketing activities. This program is designed to influence the behavior of up-stream and mid-stream market participants, as well as residential customers.

Specific Low Income programs include:

- **Assisted Multifamily Program.** This program is designed to improve energy efficiency in eligible multifamily buildings, reduce energy bills for tenants and owners, and provide increased health and safety benefits to building occupants.

- **Assisted Home Performance with ENERGY STAR®.** This program is designed to reduce the energy burden on low-income New York residents by bringing a "building performance" approach to home improvement. The program follows a market transformation model first introduced by the Home Performance with ENERGY STAR® Program.

- **Low-Income Direct Installation.** This program, now closed, was designed to improve energy efficiency for low-income households by installing electric reduction measures in homes receiving shell and heating system improvements through the federal Weatherization Assistance Program at a time when electric reduction measures were ineligible.

- **Weatherization Network Initiative.** This program is built on the lessons learned in the Low-Income Direct Installation Program. It returns to previously weatherized homes to implement electric measures in one- to four-family homes that did not receive electric reduction measures through the Weatherization Assistance Program and are currently ineligible for additional services.

- **Low-Income Oil Buying Strategies.** This program is designed to improve energy affordability for low-income customers through the bulk purchase of home heating fuel and other procurements that reduce the price of fuel oil.

- **Low-Income Energy Awareness.** This program is designed to implement a public awareness campaign to result in measurable improvements in the enrollment of low-income residents in energy efficiency and energy management programs.

- **Low-Income Aggregation.** This program is designed to improve energy affordability for low-income customers by grouping them together and increasing their buying power, to take advantage of reduced commodity prices through the bulk purchase of energy.

- **Low-Income Forum on Energy (LIFE).** This program provides one of the largest and most comprehensive public forums dedicated to discussing the issues facing the low-income population in the changing energy environment.

In addition to NYSERDA's New York Energy $mart^{SM} Program, funded through the SBC, the New York Power Authority (NYPA) and Long Island Power Authority (LIPA) each offer complementary public benefits programs of their own. The three authorities coordinate program design and service delivery

- Leveraging private sector and federal government investment in energy technologies.

Cost-effectiveness

In the recent evaluation of programs the NYSERDA evaluation team utilized eight scenarios to calculate benefit-cost tests, because there is not universal agreement on the most appropriate method to calculate benefit-cost ratios for energy efficiency programs.

The PSC policy on cost-effectiveness testing, articulated in 1988[8], includes as factors:

- a consideration of the immediate effects on rates;
- the ability to avoid lost opportunities by including energy efficiency measures in new construction instead of undertaking later, less cost-effective, retrofitting;
- the ability of an energy efficiency program to enhance the competitiveness of local industry by reducing its energy costs (which are not considered in current economic tests);
- the environmental benefits or costs of substituting energy efficiency for increased generation;
- the impact of energy efficiency on the total amount paid for energy services by utility customers;
- the benefits of providing conservation services to low-income consumers whose bills are often paid by other customers or by taxpayers and who otherwise might pay for but not benefit from energy efficiency programs; and,
- the increased control over electricity bills offered to customers by some energy efficiency programs.

DSM Spending

Actual Spending

The table on the following page shows the allocation of funding to various electricity DSM programs and the status of committed funding as of the end of 2004. As of June 2005, NYSERDA had committed over \$882 million or about 92% of its SBC I and II allocation of approximately \$962 million.[9] In terms of natural gas, Con Edison's Gas Efficiency Program has \$5.2 million in approved funding and the National Grid gas program, \$5 million.

[8] Case 29409, Proceeding on Plans for Meeting Future Electricity Needs, Opinion No. 88-20, July 26, 1988).

[9] System Benefits Charge III, Staff Proposal for the Extension of the System Benefits Charge (SBC) and the SBC-Funded Public Benefit Programs, Staff Report, August 30, 2005.

Response Programs (TDRP) are real-time price based programs intended to build the Ontario market's demand response capability and infrastructure. The Emergency Demand Response Program is a reliability-IESO DR based program intended to mitigate the adverse impact of shortages of energy under stressed system conditions. The TDRP covers up to 100 MW; there are currently 9 wholesale market participants.

A demand response project by a grocery chain for 10 MW was a successful bidder in a RFP process and the OPA recently issued an RFP for Demand Response for York Region.

Program Design, Implementation, and Evaluation

Responsibilities

LDCs (gas and electric) plan, design, implement, and evaluate programs themselves or through a 3rd party contractor; the OEB approves them. The OPA RFP Process requires bidders to plan, design, and implement DR projects; approval is done through the bidding process and evaluation is prescribed by the terms of the contract.

Screening

Natural gas DSM programs are screened with the Total Resource Cost (TRC) test and, if electricity LDCs want to spend money beyond the 3rd tranche, they apply for funding in their rate case, screening proposed programs using the TRC test. Externalities are not included and a separate avoided cost test has been developed for demand response. The OEB has been very hands off with respect to program design in the gas sector. The utilities and stakeholders have developed a considerable amount of expertise in program design. There is typically some consultation with stakeholder groups in designing programs. The OEB has been similarly hands off with respect to program design in the electricity sector; but has been more proactive in producing the data requirements for utilities to apply in their programs.

Assessing Programs

In the gas sector, distributors developed a process of providing annual evaluation reports which are audited before being submitted to the OEB. The audit reports often forms the basis for the utilities to clear variance balances in incentive or lost revenue variance accounts. In the electricity sector, the OEB approved considerable funds for DSM to be invested over three years and required that each utility file an annual evaluation report of its DSM program. Criteria for effectiveness are MWh and MW savings for electricity and cubic meters for gas.

DSM Spending

The Legislature has assigned the Ontario Energy Board the responsibility to regulate two types of agencies in the funding of DSM initiatives: the OPA and LDCs. The OPA pursues CDM both directly through pursuit of statutory objectives (2006 budget $5.9m) and indirectly through procurement contracts (proposed spending 2005-2011: $6-11 b). LDCs pursue CDM through three mechanisms: 1) voluntary CDM initiatives under the Electricity Act and the OEB Act; 2) authority to contract with OPA under the Electricity Act; and 3) charging distribution rates that may include a CDM component.[2]

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[2] Source: Generic Conservation and Demand Management Issues Proceeding, RP-2005-0020 / EB-2005-0523, Board Staff Submission, December 20, 2005. http://www.oeb.gov.on.ca/documents/cases/EB-2005-0523/boardstaff_submission_211205.pdf

participating in a Bonneville Power Administration pilot using remote control for appliances, in their case, electric dryers. PacifiCorp's 2004 LCP resulted in demand-side RFPs that allow direct load control programs to bid and supply-side RFPs that allow dispatchable standby generation to bid. PacifiCorp included direct load control in portfolio modeling, but looked at costs only, not risk reduction. In general utilities are more interested in DR that acts like a power plant, like direct load control.

The ETO has not been involved in DR strategies. However, they are preparing for more interest in efficiency as a way to reduce peak loads. They know their programs can reduce both broadly defined peak periods and needle hourly peaks. Present programs significantly impact winter peak.

Fuel-switching is not pursued by the ETO as a DSM strategy in Oregon, in part due to uncertainties about future gas versus electric prices. The ETO offers both gas and electric efficient equipment rebates, and provides information about alternatives to customers who are considering fuel switching, but does not use electric or gas PPC funds to convert customers to gas. A PUC staff report on fuel switching is expected in early 2006.

Successes and Setbacks

The two biggest recent successes for ETO have been booming interest in the industrial efficiency programs, in part due to people in the process design business marketing ETO programs to industry, and improving the cost-effectiveness of weatherization. As part of the enabling legislation for the ETO, the legislature greatly reduced the sophistication of the weatherization audit required, finding that walk-through audits gave enough information. A looming challenge is how to balance demand for efficiency with a capped budget. They are especially concerned about losing the momentum gained with industrial and commercial customers.

The OPUC staff sees the ETO approach as an interesting one, bringing a variety of benefits to consumers that do not occur with utility-based programs for several reasons. The ETO can offer both electric and gas DSM programs and integrated programs to consumers; it can capture larger economies of scale than the utilities, and unlike utilities, its goals are in alignment with obtaining all cost-effective efficiency.

Gas utilities have had some DSM successes. They distributed energy-efficient showerheads early on and saturated the market. For several years they have offered $200 rebates for high efficiency furnaces. Some models are eligible for additional income tax credits from the State of Oregon, and the combination of tax credits with rebates has increased the market share of these furnaces. Also, it appears that once NW Natural's margins are recovered (due to decoupling arrangement), it has been more interested in putting conservation messages out there, in bill inserts, etc.

Fossil fuel-fired co-generation for on-site use has been declared energy efficiency by the Department of Justice. There are many parties interested in promoting on-site co-generation. The ETO is attempting to come up with a methodology that reveals when fossil-based co-generation actually decreases avoided costs. ETO hopes to use PPC funds only if it is very cost-effective and where an ETO incentive will be the "tipper."

In Oregon, given the spectrum of possible demand response strategies, only dispatchable standby generation has taken off in recent years. In part this is because many large customers, who are good DR candidates, are now direct access customers. There is no RTO to organize the DR market in Oregon. Only 3,400 customers are on the Time of Use rate that serves as the market-based rate for residential and small business customers of PGE and PacifiCorp. Demand buyback programs are inactive right now. PacifiCorp offered an interruptible tariff for winter peak; there were no takers. PGE has offered a two-part real-time pricing pilot program since January 2004; there have been no sign-ups. There are about 80

Stakeholder Process

Inquiries were made about whether stakeholder processes are positive and productive in Oregon. Respondents noted that the OPUC, the ETO, and Oregon in general have a culture of transparency and inclusion. LCP and related dockets are not contested-type proceedings like rate cases, but follow a negotiation and stipulation model. The stakeholder process is very important and improves the outcome, even if it's messy sometimes. Good facilitation is important. Facilitating public input probably adds a bit to the cost, but it's worth it to create buy-in. The OPUC staff has found that framing issues in white papers and giving participants a chance to respond early in the process is helpful. The ETO has many layers of public involvement (Board of Directors, advisory committees, public hearings) and the website is evidence of transparency. All respondents suggested that CAMPUT members would be welcome to make one-to-one contacts with their peers in Oregon at the Commission, at ETO, and at NEEA for ideas about productive stakeholder processes, as well as DSM issues in general.

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they want to use to meet their goals. Generally a project sponsor is given financial incentives once efficiency measures are installed and savings are deemed or verified.

Load management (LM) is one of the approved SOPs, and recent rule changes are expected to expand participation and result in TDUs achieving a larger part of their overall goal through load management. Some of the rules changes favoring load management are:

- Up to 30% of load reduction goals can now be earned through load management (used to be 15%).
- It is possible for load management in constrained areas to get higher incentive payments.
- The rule that no single energy service provider can receive more than 20% of the incentives under a particular standard offer program has been eliminated for LM standard offer projects due to needs of small utilities.

Several reasons were given for these changes. Concern with reserve margins declining (due to load growth and plant retirement) led to PUCT interest in this area. There was concern that improvements in codes and appliance efficiency standards required an increase in the allowed proportion of demand reduction reached through load management rather than efficiency measures. The rules changes were also an attempt to expand participation in this strategy. Prior to these rules changes, only one large utility and its industrial customers had participated in the load management SOP.

The LM approach of one TDU was described in detail during interviews for this report. TXU Electric Delivery's (TXU-ED's) "Emergency Load Management" program pays for delivery of actual demand savings when requested. TXU-ED requires a 10-year contract with participants. TXU-ED guarantees participants they will be interrupted at least once per year and paid for that interruption. The contract allows the customer to be interrupted up to four times per peak season per year, up to 16 hours each time. TXU-Ed checks the meter every month when curtailment has been called for. Participants are paid at the end of the year, using a special meter to check on the differential with baseline. TXU does not control the load. This is a pay for performance contract. They "call" it via email. The timing is tied to various load conditions in the ISO territory. The Electric Reliability Council of Texas (ERCOT) is the ISO. Although the new rules changes allows the TDUs to increase load management incentives to a higher cap, TXU-ED hasn't yet, because there is plenty of participation at current caps. The present incentive is $16/kW, for a minimum of 100 kW peak reduction.

The PUCT and TDUs are not involved in demand response (DR) approaches, other than the load management SOP. Instead, customers can receive payments for demand reductions/load curtailments through programs offered by ERCOT.[3] In all cases, the customer has a contractual arrangement with its Retail Electricity Provider (REP) for participation and compensation, not directly with ERCOT. The ERCOT works with the scheduling entity for the customer's REP.

Some examples of DR programs are

- "Balancing Up Loads" where energy and capacity payments are made for customer load curtailment that is successfully bid into the "Balancing Energy Market."

[3] See this site for details: http://www.eere.energy.gov/femp/program/utility/utilityman_em_tx.cfm

- "Load Acting as a Resource" where customer load curtailment offers are bid into a number of different ancillary services markets.

The TDUs don't do it, but ERCOT or a REP might use a DR strategy like direct load control. According to some observers, ERCOT is still struggling with how DR interacts with the wholesale market.

The ratepayer-funded efficiency programs are not used to achieve distribution system optimization. In TXU-ED, which carries close to half the ERCOT load, there are some real transmission constraint issues, but these are likely to be resolved with new construction, not load management, efficiency or DR.

The possibility of using electric funds to support fuel switching was built into EE rule. A SOP customer can propose switching from electric to other, if it meets cost-effectiveness guidelines. There was a multi-family gas hot water heating program but it was too expensive, compared to other program options. The TXU-ED program cost about $1200/kW; although it was a technically cost-effective way of reaching goals, the program administrator could meet goals with other approaches costing closer to $350-400/kW.

Successes and Setbacks

The parties interviewed for this project noted several successes worthy of note. All stakeholders have actively participated, which has contributed to the success of programs. Statewide, utilities achieved 11% above goal in 2003. In 2004, utilities were cumulatively 35% above goal. The PUCT presents itself as committed and open to DSM. The stability of the PUCT itself and its level of interest have been cited as contributing to success.

When TXU-ED began implementing programs in 2002, there was a concern that MT programs wouldn't play a significant part in meeting efficiency goals. They estimated they'd reach 75% of demand reduction goals through SOP, and 25% from MT. However, MT has been responsible for close to 50% of demand reductions, and it is very cost-effective.

Design, Implementation and Evaluation

Responsibility

The energy efficiency programs are administered by transmission and distribution utilities (TDUs), but they are implemented by third parties ("project sponsors") under contracts with the utilities.

The TDUs are required to file efficiency plans with the PUCT by April 1 each year. Each plan includes detailed demand forecasts and demand reduction goals for the first year (based on weather-adjusted average historical peak over the last five years), and a more general forecast for the following three years. Each TDU forecasts growth in demand in its service territory and plans to reduce that growth by at least 10%. The TDUs plan their own mix of programs to meet goals. The available budget is determined in rate cases. According to the program manager at TXU-ED (one of the state's largest utilities), each year's plan starts by allocating the available dollars/kW demand reduction to programs. They try to balance programs in order to meet demand reduction goals with funds available, while covering all customer classes, with close to equitable spending levels among classes. It is acceptable to exceed the savings goal. Programs continue until the budget is spent.

The PUCT gives plans filed by the TDUs "silent approval" (i.e. approved unless informed otherwise). To date, every plan has been approved. The PUCT also has used formal proceedings to approve an ongoing slate of standard offer programs (SOP) and market transformation programs (MT) available to be administered by the TDUs. Other than load management programs, the programs are designed to result in

TDUs and third-party contractors do a fairly rigorous sampling of completed projects.[8] Market effects studies, using a consultant, are used to determine impact of Market Transformation projects. In an attempt to minimize the burden of M&V, deemed or simple savings calculations are used for many measures. Some, e.g. Energy Star Homes, require third-party testing and certification. A complicated commercial or industrial project might require full M&V process using the 2001 IPMVP as guide. Incentive payments depend on the results of these M&V activities.

The PUCT has established that IPMVP will be the ultimate basis for all M&V. In Project 30170, the Commission will use an independent contractor to determine if deemed savings are still applicable, verify impact estimates that have been reported, and do a limited process evaluation. The outcome of this effort may be recommendations regarding types of programs, sponsor qualifications, or other improvements.

As mentioned earlier, the PUCT is required to report to the TCEQ on the air contaminant emissions reduction achievements from the energy efficiency programs. The PUCT worked with other agencies to develop the methodology for calculating emissions reductions from energy savings. Energy and demand savings contribute to air quality improvement depending not on where the consumers live, but where the generators are that are not needed.

DSM Spending

Actual Spending

Each TDU proposes spending adequate to meet its savings goal of reducing anticipated load growth by 10% each year. In 2003, programs were ramping up (the goal that year was only a 5% reduction in anticipated load growth), and utilities spent a total of about $70 million. In 2004, the utilities spent $80-85 million total. The amount of spending by customers was not available. Spending is primarily on incentives, which are paid to the project sponsors. The project sponsors can pocket the incentive, use it to reduce costs to consumers, pass it on to consumers, or use it in other ways to produce results.

One TDU, TXU-ED, shared how it set spending budgets in the 1999-2000 rate case. At the time, TDU-ED was required to file its first efficiency plan. The utility projected load growth, forecast basis, and what funds it thought would be required to meet the 10% load reduction goal. TXU-ED anticipated ramping spending up dramatically over a three-year period from $20 million to $60 million. Since rates are not adjustable from year to year, but unexpended efficiency funds are rolled forward, the utility proposed going with a three-year average, collecting $43 million in rates each year. In 2004 TXU-ED spent over $59 million on programs.[9] A settlement was reached last year, rather than a new rate case. As a result next year's budget will be based on $43 million. This amount may change in the next rate case, which is expected this year or next. A ballpark estimate of TXU-ED's efficiency spending as a percent of annual revenues would be about 1.9%, but the utility does not make spending decisions on this basis, and this figure can change from year to year. Other utilities are likely to have different figures.

Program administrators have to make a decision about how high to set program incentives so that the project meets the cost-effectiveness test but is still attractive enough to create the necessary project participation. Incentives available to project sponsors are capped as a percent of avoided cost in rule 25.181(e)(2). The PUCT established a proxy for avoided cost as the cost of a new natural gas combined cycle plant. There are no externalities, no T&D benefits and it's generalized for the whole state, not

[8] According to M. Stockard at TXU-ED, they sample at least 10% of Standard Offer Program projects.

[9] This $59 million included $2.86 million for administration and $56.7million for incentives, including just over $400,000 spent on interruptible contracts. The spending for interruptible contracts may go up with new LM options.

- Click on "log in."
- Enter control #30739, then search, to access efficiency reports and plans.
- Enter control #26310, then search, to view reports to the TCEQ on emissions reductions due to efficiency programs.

Present program offerings for all Texas distribution utilities can be seen at

http://www.texasefficiency.com/

See also the PUCT's January 2005 "Report to the 79th Texas Legislature: Scope of Competition in Electric Markets in Texas" at: http://www.puc.state.tx.us/electric/reports/scope/index.cfm

Discussion of efficiency programs begins on page 67 of that report.

Rules can be viewed at the PUCT website

http://www.puc.state.tx.us/rules/subrules/electric/index.cfm

The most relevant rules are:

- Rule 25.181 covers most of the substance of the program approach, including goal-setting, planning, administration, cost-effectiveness, cost recovery, M&V guidelines, detailed reporting requirements, etc.

- Rule 25.183 outlines general reporting requirements, including PUCT report to TCEQ re: emissions.

- Rule 25.184 includes links to templates for all the approved SOP and MT approaches, as well as deemed savings values, and stipulated values.

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energy sources such as nuclear and hydro (and, to a lesser degree, wind resources that could despoil Vermont's ridgelines). Commercial customers generally see efficiency as cost-effective, although there is some opposition among large C&I customers, who have expressed concern about paying too much into the fund compared to the benefits they receive. Altogether, over 20% of ratepayers have participated in one of EVT's programs.

Regulators and politicians view efficiency as not only a cost-effective resource, but also as a low-risk way to procure energy, while decreasing CO_2 and other emissions. Efficiency has increasingly received bipartisan support, and interest levels were at an all-time high in 2005, when several new developments highlighted Vermont's increasing and evolving commitment to efficiency:

- The legislature removed the cap on Efficiency Vermont's funding. New funding levels and time frames have yet to be determined, but EVT anticipates receiving increased levels of funding for 2007, if not earlier.

- Legislative Act 61 established the "SPEED program" which states that if renewables equal to total incremental growth between 2005 and 2012 are acquired by 2012, the state's renewable portfolio standard (RPS) won't go into effect. Efficiency is indirectly incentivized: if utilities reduce incremental need by acquiring efficiency, their obligation to procure renewable energy will be diminished. The rules for the SPEED program are still being developed, and the RPS won't go into effect until 2012.[5]

- The PSB opened Docket 7081 to review and revise its transmission planning process to ensure that planning is comprehensive and allows adequate time to develop, analyze, and implement cost-effective DSM solutions to transmission problems.

While Vermont has always been interested in efficiency, specific recent events have helped to drive the high level of interest. Vermont is a net importer of energy, with 1/3 of its supply coming from Hydro Quebec and another 1/3 from Vermont Yankee, a nuclear plant. Both energy sources have historically been controversial in Vermont, and both contracts are set to expire soon. In addition, there was a high-profile transmission siting case recently, in which a new transmission line was the subject of considerable public controversy. Currently, there is a fairly high level of public scrutiny surrounding electricity regulation, a certain level of dissatisfaction with past decisions, and a renewed interest in efficiency.

At the same time, EVT has provided a four-year track record of demonstrable savings from efficiency, showing regulators and legislators that EE is a reliable resource. EVT's demonstrated savings are one factor behind the 2005 legislative efforts at efficiency. EVT's activities also create jobs and increase in-state spending, compared to sourcing electricity resources from out-of-state. As a result, efficiency is seen as an option that offers a high level of net benefits to the state, both environmental and economic, without the controversy and public outcry that other solutions have historically faced. As Vermont's future energy needs are discussed, efficiency is increasingly seen as the most politically viable solution, and has been actively promoted by the PSB, the Legislature, and the Governor.

[5] Act 61 of the 2005 Legislature established the SPEED program. Text can be found at: http://www.leg.state.vt.us/docs/legdoc.cfm?URL=/docs/2006/acts/ACT061.HTM

EVT's contracts with the PSB are for three years, allowing discretion in the way programs and services are delivered. Internal feedback and evaluation are continuously used as part of EVT's planning process. EVT also submits an annual plan and holds public hearings on the plan before submitting it to the PSB for acceptance. Shifting of funds between customer classes is limited, and major changes to the annual plans are detailed in quarterly reports submitted to the Board. PSB staff includes a contract manager who monitors EVT activities. A public advisory committee meets quarterly to discuss EVT's activities and address problems promptly.

The DPS is responsible for evaluating EVT's savings. EVT performs internal market and performance assessment and makes this data available to DPS, which evaluates EVT's claims. The DPS is also responsible for assessing market potential, setting baseline goals for EVT, and making recommendations to the Board about future goals for EVT.

Program Design Details

Current program design has a customer focus. The intention is to meet customers' needs in a comprehensive way that avoids customers seeing "program silos".

Programs are also based on EVT's "performance indicators." These indicators serve as internal goals for meeting the Board's overall performance categories. For its 2006-2008 program cycle, EVT has proposed 13 performance indicators which address electricity performance, economic performance, market performance, and minimum requirements: 204,000 MWh savings; 30 MW peak demand reductions; 81,600 peak summer MWh savings; 10,600 annual MWh of committed "pipeline" projects (by term's end); $111 million net social benefits to VT; $1.70 of value for each dollar committed by each county; 3 community-based projects with over 50% community participation; 40,000 MWh savings from industrial customers; 50% of non-res projects completed by small businesses; 40 large grocery stores to stock and promote sale of CFLs; $1.20 in avoided costs for each dollar spent by the state toward the EEC; at least 15% spending on low-income efficiency.

Screening Programs

The Societal Cost Test is used to screen all programs, considering all costs and all benefits. Externalities are included in a variety of ways. In their IRPs, IOUs must compare the cost of DSM measures with traditional supply options. In evaluating programs, EE programs are given a 10% discount to adjust for the reduced investment risk that efficiency poses to customers in comparison with large capital projects. In addition, non-renewable supply options are given a 5% adder in the IRP process and a $7/MW adder in the DUP process. When EVT develops avoided cost analysis, efficiency options are given a 10% discount and supply options are given a $.01/kWh adder to adjust for environmental and economic externalities.

Assessing Programs

The primary measure of success is the amount of net benefit to society. Other measures of success are used (e.g., equity), but net benefits are given the greatest weight, and consequently the largest dollar amount of incentives. Each year, EVT submits its claims regarding net system benefits, annual savings, and peak savings. DPS evaluates the claims and makes a recommendation to the Contract Administrator, a private contractor that resolves any disputes surrounding the claims and makes recommendations to the Board. The Board makes the final determination about EVT's performance and awards incentives accordingly. Incentives are given for other performance categories (e.g., equity and pipeline projects) in which the same verification process is followed, but performance is evaluated every three years. Savings and cost-effectiveness claims are verified every three years by an independent auditor.

DSM Spending

Actual Spending

Total electric efficiency spending (by EVT and Burlington Electric) for 2003-2005 was approximately $15 million annually. Annual savings during this period were approximately 56,549 MWh annually. In its preliminary 2004 Annual Report, Efficiency Vermont estimates 2004 savings at over 58 MWh, with $38 million worth of lifetime economic benefits to Vermont.[10] EEC rates were recently set at 2.8% of total sales for 2006. As previously noted, the legislative funding cap has been lifted, and EVT's annual budget is expected to increase by 2007. According to Blair Hamilton of EVT, the legislature has indicated that it is interested in increasing efficiency services as soon as possible, perhaps as soon as mid-2006.

In 2003, about $5.5 million was spent operating costs (administrative overhead, information technology, marketing, services & initiatives), another 2.8 million in technical assistance, and 5.2 million in financial incentives to customers.[11]

VGS has spent an average of $1 million per year annually on its efficiency programs, saving an estimated 382,000 Mcf annually (4.7% of VGS' 2002 throughput).[12]

Appropriate Levels

According to 2005 legislation and the current least-cost planning process, all cost-effective efficiency should be procured. In 2002, the DPS released a study on efficiency potential[13] showing that the amount of cost-effective potential efficiency far exceeded EVT's ability to capture that efficiency, given current funding levels. As a result of the study, EVT's budget was increased dramatically for 2003-2005. Methods for actually achieving investment in all cost-effective DSM are still a work in progress. A study is in progress to determine methodology for developing avoided costs, and following this, a new technical potential study will be conducted. The study will inform future budgets, although the Board must also consider issues of rate impact and geographic/customer class equity.

Cost Recovery and Incentives

Cost recovery

DSM costs by EVT are expensed. Utilities collect the money as a percentage charge on electric bills. Funds are transferred to a manager, where they are drawn for appropriate purposes by EVT and for EVT support activities.

For efficiency that is conducted as part of DUP, there is a lost revenue recovery mechanism called Account Correcting for Efficiency, or ACE. This mechanism removes the disincentive for the utility to pursue energy efficiency.

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[10] Efficiency Vermont: 2004 Preliminary Report. http://www.efficiencyvermont.com/index.cfm?L1=292&L2=535&sub=bus

[11] From Efficiency Vermont's 2003 Annual Report. http://www.efficiencyvermont.com/Docs/2003ExecutiveSummary.pdf

[12] http://aceee.org/utility/ngbestprac/vgsprtflio.pdf

[13] Vermont Department of Public Service. May 2002. *Report and Recommendations to the Vermont Public Service Board Relating to Vermont's Energy Efficiency Utility.* http://publicservice.vermont.gov/energy efficiency/ee_files/efficiency/eval/eeu_2002report/report.pdf

Efficiency Vermont: 2004 Preliminary Report.
http://www.efficiencyvermont.com/index.cfm?L1=292&L2=535&sub=bus

Efficiency Vermont: 2003 Annual Report.
http://www.efficiencyvermont.com/Docs/2003ExecutiveSummary.pdf

Stakeholder Process

EVT has an advisory committee of stakeholders that meets quarterly to advise the utility, monitor activities, and address complaints in a timely fashion. The advisory committee is a two-way form of communication. The public is also involved in EVT's planning process.

For more information about the stakeholder process, contact Blair Hamilton at EVT (contact information below) or the Regulatory Assistance Project.

Interview Contacts

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Washington DSM Summary[1]

DSM Background and Approaches

Background and Interest

In Washington, interest in DSM is high, with particular emphasis on energy efficiency. Interest levels have tended to vary over time. Washington utilities have been delivering energy efficiency ("efficiency") since 1980, and a Least Cost Planning (LCP) process was begun in 1987. Efficiency spending hit a peak in the early 90's, but subsequently declined during the mid-1990s when electric utility deregulation experiments were considered and when utilities were uncertain about their role in the future. Since then, the utilities' role as administrator of efficiency programs has become clear, and efficiency spending has returned to its prior level. Spending has been relatively steady for the last few years. Based on projections from its LCP, Puget Sound Energy (PSE) anticipates maintaining the current efficiency acquisition levels for the next 10 years.

Currently, energy growth in the region is high, and efficiency is seen as a high-priority, low-cost means of meeting supply needs. Efficiency procurement flows from the LCP process, where efficiency is viewed as a resource that competes with supply options on a cost-competitive basis. The LCP regulations are the legal mechanisms guiding DSM in the state and are designed to ensure that cost-effective efficiency is procured by the utilities.

Efficiency is the DSM mechanism that receives the greatest amount of attention and funding. There are also some interruptible contracts that utilities have maintained for decades with large customers. There is growing interest in demand response, and in recent years there have been some pilot programs, including the installation of TOU meters throughout the PSE service territory, but the pilots have not delivered the amount of savings desired and there are currently no major demand response programs being implemented (other than interruptible contracts). This is an area that may be developed further in the future.

Interest in efficiency comes from customers, regulators, utilities, advocates, and trade allies, all of which have played a role in successful implementation of efficiency programs. The public in general is supportive of efficiency efforts. One of the dominant factors behind the current level of interest at PSE is the growing need for resources.

In Washington, 50% of electric customers are served by municipal and county governments. Three investor-owned utilities (Avista, Puget Sound Energy, and a small portion of Pacificorp service area) serve the remaining 50% of electric loads. Avista and PSE also deliver natural gas.

Efficiency and conservation programs are funded through a nonbypassable wires charge that varies by utility and customer class. Additional funding for conservation is available from Bonneville Power Administration (BPA), in the form of discounts on power purchased from BPA.

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[1] This summary is based primarily on interviews completed during October and November 2005 with Joelle Steward of the Washington Utilities and Transportation Commission and Mary Smith of Puget Sound Energy.

Design, Implementation, and Evaluation

Responsibility

DSM planning is done by the IOUs as part of their LCPs. RFPs are issued by the utilities 90 days after the LCP is filed, to ensure that RFPs flow directly from the LCP. RFPs are required to be worded in such a way that all resources, including demand-side resources, are given equal treatment.

Utilities design their own resource portfolios as part of the LCP process. The WUTC offers technical advice on modeling varying scenarios, and there are guidelines governing the way resources should be compared, but the utilities determine their own methodology for selecting a mix of resources. The WUTC reviews and acknowledges the LCPs. Approval of actions within the LCP, including DSM programs, is necessary in order to recover costs. Some utilities file with the WUTC for DSM program approval, while others operate according to guidelines included in their DSM tariffs.

DSM portfolio management and program design is the responsibility of the utilities. Implementation is the responsibility of the utilities and may be done in-house or contracted out to third parties. Evaluation is the responsibility of the utilities, in conjunction with their advisory groups.

Program Design Details

Program design begins with the LCP. Utilities do an assessment of the potential in their area, and to determine existing options available in the marketplace for various end use processes. Utilities are also guided by their experience of what approaches have historically worked, which market segments are harder to reach, etc. An advisory group of interested parties (Commission staff, customers, trade allies, advocates) is engaged to advise the utilities on selecting programs. Equity among customer classes and end uses is a goal. Efficiency portfolio plans are submitted to the WUTC every two years.

Screening Programs

The total resource cost test and the utility cost test are used. The WUTC applies the tests to the portfolio as a whole, to allow room for pilots, education and training programs, etc. In compliance with the Northwest Power Act of 1980, utilities apply a 10% adder when calculating avoided costs of efficiency resources.

Assessing Programs

Programs are evaluated primarily by calculating benefit-cost ratios, where benefits are determined by actual energy savings. Customer satisfaction and customer response rates are also considered. PSE also evaluates programs from a variety of perspectives to find out success indicators, for example, trade allies' satisfaction and willingness to promote equipment and programs in the future.

Measurement and verification processes are determined by the utilities, and their advisory groups. Methods vary by program. The Regional Technical Forum (RTF) of the NWPCC conducts regional studies that assign deemed savings to certain efficiency measures. Deemed savings are the basis for measuring the outcome of certain programs with "prescriptive measures" (e.g., CFL rebates). For customized applications, engineering estimates of savings are developed on a case-by-case basis, along with tracking and reporting systems that monitor program performance. Anticipated savings, either calculated or based on the RTF's deemed savings, can be compared with actual savings on customers' bills. Process evaluations are also done to determine whether measures effectively satisfied customers' needs and opportunities for improving program delivery or cost-effectiveness.

The Focus market approach is to provide technical assistance, incentives, and market interventions to increase efficiency in equipment and processes. The business programs manager WECC also uses and builds market relationships to increase awareness and use of technologies in target markets with both customers and market partners.

Successes and Setbacks

One notable setback for the Focus on Energy programs for the last several years has been that the Wisconsin legislature has diverted 47% of the funds collected from utility ratepayers for the Focus on Energy programs and diverted them to help balance the Wisconsin state budget. For example, in FY 2005, $62.9 million was raised for Focus programs, and $29.2 million of that was diverted to the overall state budget. [10] This issue will be discussed further in the DSM Spending section.

Notable successes include the results from the residential Appliances and Lighting programs, as well as residential HVAC programs. For Business customers, programs targeted for the Water and Wastewater, Hospitality, and Metal Casting customers have been very successful. [11] PSCW staff also believe that the residential Home Building and Home Performance programs are quite successful. [12]

DSM Program Design, Implementation, and Evaluation/Cost Benefit Analysis

The Reliability 2000 legislation created a Council on Public Benefits to act as an advisory group for the energy public benefits programs. This Council has 11 members, and are selected by the following parties:

- Two members are selected by the Governor.
- Two members are selected by the Senate Majority Leader.
- Two members are selected by the Speaker of the Assembly.
- One member is selected by the Senate Minority Leader.
- One member is selected by the Assembly Minority Leader.
- One member is selected by the Secretary of the Department of Natural Resources.
- One member is selected by the Secretary of the WDOA. [13]

WECC designs and implements the Focus DSM programs, with input from the WDOA and the above council. A consulting team led by PA Consulting conducts the program evaluations and benefit-cost analyses. The Energy Center of Wisconsin conducts certain other types of research funded by Focus on Energy.

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[10] Wisconsin DOA, 2005, op. cit., p. 4.

[11] Telephone conversation with Kathy Kuntz, WECC's Director of Operations, November 2005.

[12] Telephone conversation with the PSCW's Dan Schooff and Carol Stemrich, December 2005.

[13] Wisconsin Legislative Council Staff, 1999, op.cit., p. 29.

DSM Benefit-Cost Analysis

The WDOA contracts with the evaluation contracting team to conduct DSM program benefit-cost analyses for the Focus on Energy programs. The main benefit-cost analysis report was completed in March 2003[14], and focused on:

1. Developing benefit-cost estimates using a test similar to the "societal" test from the California standard practice manual. [15] This test, which they call the "simple analysis", includes environmental externalities as a DSM program benefit, as well as economic non-energy benefits and costs, at least for residential programs. [16]

2. Developing an "economic development" benefit-cost analysis test, that also includes effects of the Focus on Energy programs on the Wisconsin economy. [17]

Avoided energy costs are based on 2002 average statewide retail rates, as reported by the EIA. [18] The analysis methodology assumes that the programs operate for a 10 year period, and then estimates program "end effects" that extend for a 15 year period after that. [19]

DSM Spending Requirements

Funding for Wisconsin's energy public benefits programs comes from three main sources:

1. Funds that investor-owned utilities had previously been collecting for DSM programs. Funding for utility-sponsored DSM programs was phased out from 2000-2002, and this funding was transferred to fund the Focus on Energy and Home Energy Plus program in phases over the same period. Beginning in 2003, all of these utility DSM funds were contributed to the two public benefits programs.

2. Additional fees were raised from electric utilities to support the public benefits programs. Total utility funding for public benefits programs is capped at 3% of electric customer revenues. The total fees for the Focus program were capped per customer at $750 per month.

3. Federal revenue from Low Income Weatherization Assistance and Low Income Home Energy Assistance[20].

In fiscal year 2005, $62.9 million was raised for Focus on Energy Programs, and $57.2 million was raised for the Home Energy Plus program. However, $29.2 million of these funds were diverted to help balance the state budget, so $38.5 million was spent on Focus on Energy programs and $50.3 million was spent on the Home Energy Plus program. [21]

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[14] Wisconsin Department of Administration, Division of Energy, "Focus on Energy Statewide Evaluation: Initial Benefit-Cost Analysis" (Wisconsin Department of Administration, Madison, WI, March 31, 2003).

[15] California Energy Commission, "California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects" (California Energy Commission, Sacramento, CA, October 2001).

[16] Wisconsin DOA, 2003, op. cit., p. III-3.

[17] Ibid, p. 1-2.

[18] Ibid, p III-5.

[19] Ibid, p I-1.

[20] Wisconsin Legislative Council Staff, 1999, op.cit., p. 29-32.

[21] Wisconsin DOA, 2005, op. cit., p. 4.

There were no mechanisms in the Reliability 2000 legislation to optimize spending on DSM programs. However, the Wisconsin Energy Reliability Law mentioned earlier allows the WPSC to require electric utilities to conduct additional DSM programs through certificate of need proceedings for new power plants. The WPS has required Wisconsin Energy and Wisconsin Public Service Company to do so in 2004.

Utilities expense their contributions to the Focus on Energy programs. There are no DSM financial incentives available to them for these contributions.

Resources for Future Reference

Information on the Wisconsin Focus on Energy Programs and reports is available at www.focusonenergy.com.

The Wisconsin Legislative Council staff's report on the Reliability 2000 legislation is available at: www.legis.state.wi.us/lc/3_COMMITTEES/JLC/Prior%20Years/jlc99/pubs/im99_6.pdf

The report from the Wisconsin Governor's Task Force on Energy Efficiency and Renewable is available of the internet at http://energytaskforce.wi.gov/.

The contact information for the main people interviewed for this jurisdiction are:

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- Dan Schooff, Executive Assistant, Wisconsin Public Service Commission, dan.schooff@psc.state.wi.us, 608-267-7897, and Carol Stemrich, WPSC, carol.stemrich@psc.state.wi.us.

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DEMAND-SIDE MANAGEMENT: DETERMINING APPROPRIATE SPENDING LEVELS AND COST-EFFECTIVENESS TESTING

APPENDIX B: DSM INCENTIVE LANGUAGE FROM COMMISSION DECISIONS

Prepared for:

Canadian Association of Members of Public Utility Tribunals
(CAMPUT)

January 30, 2006

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