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)

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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

British Columbia DSM Summary[1]

DSM Background and Approaches

Background and Interest

There were two waves of interest in DSM in British Columbia (BC), one during the early 90s and one that started in 2002 with a report from the Task Force on Energy Policy[2] leading to the Energy Policy[3]. The interest in BC Hydro's Power Smart Programs is at an all time high right now – all proposed DSM programs are cheaper than supply options. There are two other utilities in BC: Fortis, a small electricity utility, and Terasen Gas Inc. (TGI), the natural gas utility. The level of interest in DSM has not changed for TGI or Fortis.

Interest in DSM at BC Hydro has also been internally driven by a CEO passionate about the subject, not by the regulator. BC Hydro was on a rate freeze that was just recently lifted and was ramping up Power Smart programs even before the Energy Policy (2002) because of incremental costs of supply. The reasons that interest is about at an all time high are: 1) strong sustainability push, 2) financial advantages - lower cost to utility, 3) environmental, and 4) feasibility - DSM helps to deal with NIMBY and BANANA issues. TGI is now interested in energy efficiency because of high costs of gas but is also concerned about losing market share. DSM at Fortis is driven by the customers.

BC Hydro does not exactly do least cost planning but rather develops integrated electricity plans. Last year they did the analysis but did not select any preferred portfolio as it wasn't needed. The basis to select the portfolio is trade-offs between social and reliability issues in the context of various stakeholders. Integrated Electricity Plans were done for BC in the past; however, BC Hydro felt the commission went too far, took them to court, and won. After the rate freeze was lifted, BC Hydro developed their Resource Expenditure and Acquisition Plan (REAP) and filed it with the BCUC. The approval of the document was just completed through a negotiated settlement. This process is reasonably new and is still evolving. The REAP document had a short-term horizon and intervenors wanted to see longer range plans. To address this issue, BC Hydro plans to file an Integrated Electricity Plan in November 2005.

The Utilities Commission Act which empowers regulators was amended in 2003 to provide more impetus on DSM; however, it merely directed utilities to file DSM plans with the BC Utilities Commission. Energy efficiency and load displacement are also empowered indirectly through an Order in Council—Heritage Special Direction #2.[4]

Approaches

BC Hydro is only concerned with energy use savings, i.e., GWh/year for electricity utilities. Fortis also has targets for peak kW reduction.[5] Programs are provided for all customer classes—residential,

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[1] This summary is based primarily on interviews completed during October 2005 with Jim Fraser of the British Columbia Utilities Commission, and John Duffy of British Columbia Hydro.

[2] Strategic Considerations for a New British Columbia Energy Policy: Final Report of the Task Force on Energy Policy, March 15, 2002.

[3] Energy for Our Future: A Plan for BC, 2002

[4] Order in Council No. 1123 Special Direction HC2. http://www.bchydro.com/reg_files/heritage/order_in_council_no_1123_sd_hc2.pdf

[5] Workshop presentation – resource plan.

commercial, and industrial. Some energy efficiency, conservation, load management, and demand response are all used by all utilities, but BC Hydro is more multi-faceted, e.g., now has TOU rates approved. Peak reduction is more locally driven; for example, TGI in central BC.

BC Hydro set a ten-year DSM goal in F2002 to save approximately 3,600 GWh per year by F2012 to be achieved through a combination of Energy Efficiency (75%) and Load Displacement (25%) programs. A third category, Peak Reduction, has been created to recognize a possible new line of initiatives. The REAP document provides descriptions of all BC Hydro programs[6]. Now expect 6,000 GWh by 2012. BC Hydro is focused on energy savings—mostly efficiency rather than conservation—rather than capacity. They are also promoting fuel switching with larger customers, e.g. wood waste.

Successes and Setbacks

For the first time BC Hydro's REAP is now including a greenhouse gas (GHG) adjustor in least cost planning. This admission that GHG liability is not zero will help to drive DSM interest.

BC Hydro is concerned about the role of the RIM test (formerly non-participant test) because of a decision from BCUC last year as part of a revenue application. The decision was that any program with a RIM below 0.8 needs to be justified to the commission and get approval. BC Hydro believes that it deals with non-participants by offering a wide enough variety of programs to enable all customers to participate. The utility expects that it will need to propose new DSM programs in the IEP, many of which may not meet this criterion; many existing programs will also not meet the criteria.

Design, Implementation, and Evaluation

Responsibility

Electrical utilities are responsible to plan, design, implement, and evaluate the programs. TGI has its completed programs evaluated by a third party. The British Columbia Utilities Commission (BCUC) approves spending as part of revenue requirements during rate applications which are done every two years. Plans are not explicitly approved.

Benefit-Cost Tests

BC Hydro undertakes Utility Cost (UC), Total Resource Cost (TRC), and Rate Impact Measure (RIM) tests on all DSM programs, but relies primarily on the TRC test results to screen programs for cost-effectiveness. The UC test is done to look at costs to BC Hydro and customers. The company requires DSM to be cheaper than avoided costs of supply (currently about 4 cents/kWh). The regulator, BCUC, looks at the TRC and RIM tests.

Assessing Programs

BC Hydro determines the impact of its DSM programs in the following manner:

- A complete evaluation plan is prepared.
- The actual evaluations are conducted at major milestones or at program completion.

[6] British Columbia Hydro and Power Authority Research Expenditure and Acquisition Plan, March 7, 2005.

- 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.

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

[10] Terasen Revenue Requirement submission, 2005.

Resources for the Future

BC Hydro Resource Expenditure and Acquisition Plan.

http://www.bcuc.com/Documents/Proceedings/2005/DOC_7363_B-1_Resource%20Expenditure%20and%20Acquisition%20Plan.pdf

http://www.bcuc.com/Documents/Proceedings/2005/DOC_7536_C6-2_JIESC_IR-1.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

Stakeholder Process

Fortis has a formal DSM Technical Committee that participates in hearings and/or negotiated settlement conference. BC Hydro does not have a formal stakeholder process to develop DSM plans but does a lot of customer consultation during program development and will be setting up an external advisory panel for DSM within the next 3 to 4 months.

As part of the development of the Integrated Electricity Plan (IEP) BC Hydro has developed a First Nations and stakeholder engagement plan that outlines how interested parties can become involved and provide input into the 2005 IEP process.

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California DSM Summary[1]

DSM Background and Approaches

Background and Interest

California has over thirty years' experience with DSM, and has been a leader and innovator of DSM programs, beginning in 1974 when it adopted the nation's first energy codes and appliance standards. Interest in DSM has skyrocketed in recent years as state policy makers have placed efficiency at the forefront of state energy policy. In 2005, the CPUC established the most aggressive and comprehensive efficiency savings goals ever seen in the utility industry.

Prevailing attitudes toward DSM have evolved over time. In the 1980s, utilities were required to do integrated resource planning, and DSM was viewed as a means of resource acquisition. During the late 1990s, as California proceeded with deregulation, the premise was that the market would supply as much efficiency as necessary, and the amount of required efficiency declined. To offset the decline and as part of the restructuring legislation, a public goods charge (PGC) was established to fund efficiency, renewable, and low-income energy projects. Using these funds, the IOUs maintained some DSM programs during this time, but overall funding decreased, and programs were viewed in the context of market transformation rather than as reliable supply sources.

DSM became more prominent in the midst of the 2000-2001 energy crisis. In response to the summer 2000 blackouts, DSM spending was aggressively ramped up. Demand response was used to encourage customers to respond to price signals at critical peak times, and blackouts were successfully avoided in the summer of 2001.

Beginning in 2002, a new structure for the state's electricity system was developed, placing increasing emphasis on DSM. Restructuring was suspended and the IOUs were returned to the role of procurement. Integrated resource plans were required, and DSM was again to be viewed as a means of resource acquisition. In 2003 the California Public Utilities Commission (CPUC), the California Energy Commission (CEC), and the California Power Authority (CPA) jointly released the Energy Action Plan (EAP), a document that continues to serve as the blueprint for the state's electric procurement. The EAP established goals and targets for efficiency, demand response, distributed generation, and renewable energy. It also established a "loading order" which prioritizes among new energy sources, giving the greatest priority to efficiency and demand response. In its subsequent decisions, the CPUC has incorporated the EAP goals into a new long-term procurement planning (LTPP) process. In this process, the IOUs are required to exhaust all available, cost-effective efficiency and demand response programs before considering other supply sources. To adequately fund the new mandate, the CPUC in 2003 authorized funding from the IOUs' procurement funds ($245 million for 2004-2005) to be spent on efficiency, in addition to the existing PGC funds.[2] In 2004, specific annual savings targets were established for each of the four major utilities, based on an EAP goal of capturing 70% of economic potential efficiency and 90% of maximum achievable efficiency.[3] The new savings targets are set to

[1] This summary is based primarily on interviews completed during October 2005 with Zenaida Tappawan-Conway of the California Public Utilities Commission and Bill Miller of Pacific Gas & Electric. Interviews with Bruce Kaneshiro and Nilgun Atamturk of the CPUC were also used, as well as supporting information from CPUC decisions.

[2] See D. 0312060, online at http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/32828.htm.

[3] See D. 0409060, online at http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/40212.htm.

increase each year through 2013, and have been widely acclaimed as the most aggressive savings targets in the history of utility regulation.

Throughout the last few years, regulators, the Legislature, and the Governor's office have all made DSM a priority. The Legislature responded to the state's energy crisis with emergency funding for DSM programs, a mandated return to integrated resource planning, and a mandatory decoupling of utilities' profits from sales, effectively removing the IOUs' disincentive to procuring efficiency.[4] The CPUC has carefully followed the EAP and has made DSM a centerpiece throughout the process of rebuilding the state's electricity planning process. Recently, the Governor has also made efficiency a priority in issuing two initiatives, one on green buildings and the other on greenhouse gas emissions. The Governor also released an updated Energy Action Plan in 2005, which continues to emphasize efficiency while guiding the process going forward.

The state's experience with the crisis, the current high natural gas prices, the historic success with DSM, and the clear policy support from regulators and lawmakers have all contributed to the high interest in DSM. California's public also has a robust interest in efficiency, with over 100 intervenors a party to efficiency proceedings with the CPUC, many of them materially participating.

Efficiency is the major focus of the current interest in DSM. There is a general agreement among participants that efficiency has worked well in the past, helping California to maintain steady per-capita electricity usage over the last decade, while the rest of the nation's consumption has increased. Following the blackouts of 2000, it became clear to virtually all parties that efficiency must be a crucial component of California's long-term energy supply, and efficiency has received widespread support with very little opposition.

Interest in demand response (DR) is also high. IOUs have historically maintained interruptible contracts with large C&I customers. California IOUs also have long experience with air conditioning cycling programs. Ramping up these programs helped to avoid blackouts in 2001, and the 2000-2001 crisis spurred the development of a wider variety of programs.

Demand response is a current priority among California's governing bodies, and it was placed, along with efficiency, at the top of the EAP "loading order". There is general agreement that demand response is a valuable tool. However, the state has limited experience with the new demand response programs, and questions remain about how much DR can be done cost-effectively, particularly with smaller customers. DR approaches are being scrutinized carefully to develop accurate avoided cost methodologies and effective marketing strategies, and programs may evolve over time as the most successful strategies are developed.

In December 2004, the CPUC advanced an initiative designed to make enrollment in critical peak pricing programs mandatory for all customers larger than 200 kW during the summer of 2005. The initiative met with a tremendous amount of resistance from large customers and IOUs, and it was dropped in early 2005. Enrollment in programs has been modest, and the CPUC recognizes that more information and education is needed in order for the programs to receive broad public support.

Despite the relatively short track record with DR, however, it is still seen as an important DSM tool. One IOU, SCE, successfully petitioned the CPUC to authorize an additional $40 million in funding for

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[4] In 2001, legislation established Public Utilities Code 739.10, which states: "The commission shall ensure that errors in estimates of demand elasticity or sales do not result in material over or undercollections of the electrical corporations." Decoupling mechanisms were put in place for each individual utility, starting in 2002. Currently all three major electric IOUs and the one major gas IOU have decoupling mechanisms in place.

summer 2005 demand response programs, to meet anticipated increases in summer demand in accordance with the EAP. [5]

Approaches

Efficiency programs are approached in a variety of ways, including the use of rebate programs, education programs, business incentives, residential rebates, HVAC programs, etc. [6] In the 2006-2008 program cycle, IOUs are instructed to allocate programs equitably across customer sectors, gain savings from each sector in a manner consistent with potential studies, and balance the need to meet both short- and long-term goals. [7] One of the current challenges for IOUs is to increase participation levels of existing programs in order to maximize the amount of savings that can be gained from existing efficiency infrastructure in order to meet the aggressive targets. Also, for efficiency that is procured through PGC funds, the utilities must balance the need for maximum savings with the need for equity among ratepayers. The prevailing view is that larger commercial customers offer the most opportunity for overall savings, but that all customers who pay into the PGC fund must be eligible to participate in programs.

The IOUs have also engaged in a number of partnerships with municipalities. Some programs combine elements of conservation, efficiency, and load management, such as heating and air conditioning programs that involve the installation of efficient equipment, along with a programmable thermostat that the utility may reset at peak times. IOUs have expanded existing programs and developed new pilot programs. They are required to put at least 20% of their efficiency funding out to competitive bid, in order to encourage innovation by third parties.

PG&E's current approach to efficiency is geared toward meeting the new savings targets. The company is taking a market-based approach, in which the benefits of its programs are marketed comprehensively to customers. Their goal is to simplify the process while offering more customers more opportunities to increase efficiency. In this approach, the use of efficiency programs may be combined with conservation measures, demand response programs, or distributed generation options that best meet customers' needs and save energy. The company's current approach involves taking a sequence of actions to customers, beginning with low-cost/no-cost approaches and moving toward more significant investments, such as distributed generation plants. In this way, PGE offers customers a suite of integrated, comprehensive programs.

To a certain degree, efficiency and conservation are considered jointly in California. There is a distinction made between efficiency and conservation, with efficiency seen as technological changes that result in the same level of services with a reduced amount of electrical input. Conservation measures are seen as behavioural changes in which customers opt for a reduced level of services and a reduced amount of electrical input. In practice, however, efficiency and conservation are often promoted at the same time and are offered to customers as no-cost/low-cost ways to reduce energy bills. For example, California has a "20/20" program that offers customers a 20% discount on bills when they reduce their usage 20% compared to the previous year.

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[5] See D. 0505012, online at http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/46225.htm.

[6] For more information about specific programs, refer to CPUC D.0412048, adopting efficiency portfolio plans and funding levels for 2006-2008, online at http://www.cpuc.ca.gov/PUBLISHED/COMMENT_DECISION/48667.htm, and attachments describing program costs and savings at http://www.cpuc.ca.gov/PUBLISHED/Graphics/48668.PDF.

[7] D. 0509043, online at http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/49859.htm

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

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[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

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[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 (IU).

[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.

generation and heating applications. One result of this increased interest was passage of Public Act 05-01, the Energy Independence Act (EIA) during a special session in 2005.

According to DPUC staff, the EIA "is a multi-pronged effort to reduce energy costs in the state."[6] The EIA is likely to result in the expansion and some change in emphasis of both electric and gas C&LM activities. Here are just a few of the relevant changes resulting from the EIA:

- The ECMB must give preference to C&LM projects that maximize the reduction of "federally mandated congestion charges (FMCC).[7]
- Gas utility conservation efforts will now be guided by the ECMB (with membership expanded to reflect this new role). The ECMB will look for opportunities to offer joint C&LM programs that can save more than one fuel resource. The gas utilities have proposed increased funding for C&LM programs for 2006.
- C&LM savings in the industrial and commercial sector can contribute to the new demand-side portfolio standard created by the EIA.[8]
- Demand-side resources, such as conservation, demand response, and other distributed resources, can compete with supply-side solutions to reduce FMCC. The DPUC has opened Docket 05-07-14 to look at short- and intermediate-term approaches to mitigate these charges.
- The DPUC will report to the legislature in 2006 on the best way for utilities to decouple earnings from sales in order to support the state's energy policies.

The C&LM programs have received consistent support from utilities, regulators, many legislators, environmental and citizen advocates, vendors and others. The new governor and the legislature have strengthened support in the face of rising energy prices and impending congestion-related charges.

Approaches

As its name indicates, the electric C&LM programs have been designed to offer an integrated approach, producing both long-term energy and demand (kW and kWh) savings. For example, incentives for

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[6] See the EIA at: http://www.cga.ct.gov/2005/ACT/PA/2005PA-00001-R00HB-07501SS1-PA.htm

[7] The EIA defines federally mandated congestion charges as "any cost approved by the Federal Energy Regulatory Commission as part of New England Standard Market Design including, but not limited to, locational marginal pricing, locational installed capacity payments, any cost approved by the Department of Public Utility Control to reduce federally mandated congestion charges…and reliability must run contracts."

[8] Beginning in 2007, not less than 1% of electric supplies must be met by Class III resources. The required percentage increases for the following three years, becoming not less than 4% in 2010. Class III resources include electric output from certain customer-side combined heat and power installations, or electric savings in the commercial and industrial sector from new C&LM programs. Residential electricity savings are not included yet, but they are being considered in the docket established to develop processes needed to implement the Class III provision of the EIA (Docket 05-07-19). This docket is also examining how savings will be verified and how Class III credits will be traded or transferred.

This is somewhat similar to Pennsylvania's approach. The Alternative Energy Portfolio Standards Act of 2004 requires an increasing percentage of electricity sold in the state to come from a list of two "tiers" of eligible alternative sources. Tier II includes energy efficiency and other demand side measures (along with coal gasification, municipal solid waste, biomass and other alternative sources). See the bill that became law at http://www.legis.state.pa.us/WU01/LI/BI/ALL/2003/0/SB1030.HTM 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.

- C&LM savings in the industrial and commercial sector can contribute to the new demand-side portfolio standard created by the EIA.[10]
- Demand-side resources, such as conservation, demand response, and other distributed resources, will compete with supply-side solutions to reduce FMCC.[11]
- Large Commercial and Industrial (C&I) customers will have mandatory TOU rates, and other customers must be offered voluntary TOU rates, and all customers will have mandatory seasonal rates.

Vendors of new technology (primarily controls for C&I applications) are also driving interest in demand response/demand reduction.

The gas utilities presently implement low-income residential programs which include weatherization activities such as caulking, duct sealing, and insulation, as well as repair and tune-up of gas furnaces. These programs are done in cooperation with community agencies and complement federal weatherization programs. The DPUC recently approved a pilot program to pay the incremental cost of new efficient gas furnaces, and some hot water heaters, in low-income applications. The utilities also offer a small energy conservation loan program to low- and lower-income customers. The C&LM offerings of the gas utilities may expand in scope and size with the involvement of the ECMB and the new process laid out in the EIA.

Successes and Setbacks

The major setback to the C&LM programs has been the diversion of millions of dollars of ratepayer funds to the state treasury. For most months since 2002, $1 million per month has been set aside for state government expenses.[12] Although this taking is not scheduled for the first six months of 2006, it may resume in July. A more dramatic cut to the C&LM budget, reducing it by close to one third, was created by a securitization arrangement set in motion in 2003. This arrangement allowed a one-time deposit of funds from a non-C&LM fund to close a state budget gap. That fund will be paid back over seven years, using about one third of the C&LM funds each year. This legislative “taking” was not due to opposition to the C&LM programs. In fact, the securitization arrangement, as opposed to a complete taking, was the result of strong support for the C&LM programs by utilities, regulators, environmental and consumer advocates, vendors and others. Still, some programs lost momentum due to budgetary uncertainty, and others have had to be severely ramped down (e.g. RD&D projects) to accommodate the resulting budget reductions.

With so many parties impacting the C&LM programs (regulators, ECMB, legislators, others), timing can be off. For example, the C&LM programs were required to support a baseline study for new construction efficiency opportunities last year. However, the state had just changed building codes. Since practice lags behind codes, the study might have been more useful if it had been done later.

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[10] Beginning in 2007, an increasing percent of electric supplies must be met by Class III resources, becoming not less than 4% in 2010. Class III resources include electric output from certain customer-side combined heat and power installations, or electric savings in the commercial and industrial sector from new C&LM programs. See Docket 05-07-19.

[11] See Docket 05-07-14.

[12] This began with Public Act 01-9.

A conservation approach that did not experience success was the attempt to offer an alternative to the Standard Offer that would include C&LM approaches as part of the electric service (ATSO). The RFP to provide the ATSO had no respondents. The utility respondent's impression was that the likely service providers (ESCOs) would rather respond to smaller requests from the utilities through the C&LM program, than commit to procuring a large efficiency supply.

There have been many successes. The C&LM programs have acquired cost-effective energy and demand savings for five years, often exceeding expectations. Several programs have received national honors.[13] The C&LM programs have impacted new construction throughout CT, including SWCT.[14] There is widespread support for the programs from the Office of Consumer Counsel, the DPUC, the utilities, and a wide variety of consumer, energy service and environmental advocates. The legislature and the governor are very interested in the value of the programs for addressing current issues. According to CL&P, vendors have responded to C&LM opportunities with new technologies, especially relating to demand savings.

The CL&P respondent indicated that one reason programs are successful is because program managers look at what the customer's needs are and find cost-effective solutions. Programs fit together well; they don't compete with each other. The incentive remains the same no matter what program a customer uses to obtain the measure. This discourages "program shopping." Programs are targeted to the decision-maker, e.g. in new construction, target the engineer. Market barriers are identified, and they are not always funding. For example, the C&LM program offered incentives to cover the cost of an efficient exhaust system, but the engineer said comfort, not funds, was the issue. The installation needed extra dampers to convince the engineer that the comfort level was adequate. There may be code issues, or CO_2 level issues. Also, program managers analyze the project as a whole but may end up offering incentives in palatable pieces. The result of this approach may be lower savings at a slightly higher cost, but those savings will still be cost-effective, and the opportunity will not be lost. He indicated success comes with obtaining 80-90% of the available savings, instead of focusing on the missing 10-20%.

Regulatory staff sees the EIA as a good example of a comprehensive approach to energy policy. Electric and gas conservation approaches will be examined for opportunities to save more than one fuel. Demand-side measures can compete with supply-side measures to reduce capacity and congestion-related charges. Demand-side measures and other distributed resources (called Class III resources) are required to be obtained by electricity suppliers as an increasing percent of supply. As a result, Connecticut will be a leader in developing M&V protocols that allow energy and demand savings to be valued for their contribution to system benefits, and documented for tradable certificate programs.

Gas conservation programs have been modest compared to electric C&LM programs, and they have not experienced the same magnitude of success or setbacks. When gas conservation funds were available to commercial and industrial customers in the 1990s those customers did not take full advantage of the programs. That might change if similar programs were offered in today's high price environment. On the other hand, gas conservation programs for low-income customers created a variety of benefits and support.

There are some decisions unique to gas conservation programs that policymakers must address. One example would be, whether transportation and other non-firm gas customers should contribute to gas conservation programs. Also policymakers have to decide on the best approach in jurisdictions such as

[13] See ACEEE summary of exemplary efficiency programs at http://www.aceee.org/utility/bestpractoc.pdf.

[14] The "Dodge report" lists all major new construction projects that are out to bid. According to CL&P, the utility gets C&LM programs into most of them.

Connecticut, where gas competes with heating oil for space and water heating customers, but heating oil suppliers and/or customers do not fund oil conservation programs.[15]

Design, Implementation and Evaluation

Responsibility

Electric C&LM programs are planned and designed by the two DUs, with guidance from ECMB and its consultants. Once the ECMB approves the goals and the portfolio of programs, the joint annual plan with budgets is filed with the DPUC for review and approval or modification. This process may not be finalized until April even though the program year begins in January. Implementation is the responsibility of the DUs, who contract with third parties for many of the programs. For example, in new construction, the customer may pick the contractor, while for the small business retrofit program, the DU put out an RFP and chose one contractor. With C&I programs, the DUs do a lot of the "front" work (not measure installation) because they have a service relationship with the customer. ECMB consultants offer recommendations for evaluation procedures. Measurement and verification (M&V) is imbedded in program design, and third-party evaluators are utilized, sometimes piggybacking on regional efforts.

Prior to passage of the EIA, gas conservation plans were generally submitted by gas utilities for DPUC approval every even-numbered year, as part of their statutorily required biennial forecasts of natural gas demand and supply (with a five-year planning horizon).[16] Conservation collaborative groups provided input to the gas utilities on program designs and plans. Third-party contractors implemented the programs, which were primarily low-income weatherization efforts. Utilities reported estimates of savings, based on deemed measure savings and engineering calculations.

The EIA appears to establish a new process for gas conservation programs. It involves the ECMB (with expanded gas-related membership) in plan development and review prior to consideration of the plans by the DPUC. The ECMB will also be involved in gas program evaluation. It is not yet clear how this new process will play out, since the outcomes of the conservation programs still need to be considered in the demand forecast of the biennial demand and supply plans. The DPUC was already considering the biennial gas plans in Docket 04-10-02. That docket may include consideration of a joint conservation plan for 2005/2006 submitted by the three gas utilities to the ECMB in response to the EIA, if it is approved by the ECMB. The proposed new plan increases funding for conservation efforts.

Program Design Details

The two electric utilities design programs in consultation with the ECMB and its consultants to meet kW and kWh savings goals, while ensuring that various customer sectors and geographic areas have access to programs, and provide any other focus required by the DPUC (e.g. SWCT needs). Programs are modified based on experience, and may change if the baseline or other important factors change, but don't tend to change much from year to year. Goals have been budget-driven, due to limits on the C&LM funds and program budget direction from the ECMB. When ECMB consultants or other third parties think program goals are too low, it is incumbent upon the utilities to show the methodology for what is achievable. Program-specific goals are also based on outcomes of present activities, updated with input from evaluations. The various initiatives of the EIA may change the C&LM budget limits.

[15] In Connecticut, gas supplies about 29% of the market, heating oil, about 52%, according to DPUC staff.

[16] Section 16-32f of the General Statutes as amended by Public Act 94-1 requires the biennial forecast of natural gas demand and supply.

Gas conservation programs have generally supplemented the low-income weatherization efforts of community agencies. A few new programs have been proposed during the last few years, including a recent proposal to pay the full cost of high efficiency furnaces in low-income applications. To support more installations, the DPUC modified the program to fund only the incremental cost (i.e., the cost differential between a low-efficiency furnace and an Energy Star higher-efficiency furnace). New EIA initiatives are likely to result in the design of new programs. There may be joint endeavors or coordinated offerings with electric utilities. The gas programs will still be considered in the context of the supply and demand planning process, but they will also be held to new cost-effectiveness standards and may have new attributes. Gas savings will occur from gas efficiency measures, and those same customers may reduce the use of natural gas for electricity generation with electricity efficiency measures.

Screening Programs

To date, the primary screening tool for the C&LM programs has been the utility test, called the "electric system test." The total resource cost test, including consideraton of non-electric benefits, has been used by the ECMB as an additional screen for particular programs such as low-income, new construction, residential HVAC and appliances.[17]

Programs have also been screened to ensure reasonable geographic and customer sector diversity. The ECMB process involves a lot of stakeholder and consultant input into the final collection of programs proposed to the DPUC. As a result the most cost-effective programs are not necessarily the only ones funded. According to the CL&P respondent, C&I programs generally show a benefit-cost ratio close to three. Low- income programs are closer to one.

The total resource cost test includes all costs to the participant. Although these costs, and the resulting payback period to the customer, are not used as the primary screen for C&LM program offerings, they are important for several other reasons. First, from the utility perspective, the customer's payback period is useful to determine whether the measure qualifies as a retrofit or a lost opportunity measure. The incentives offered do vary with the application. The C&LM incentives for lost opportunity measures pay for 100% of incremental cost, while incentives pay for up to 50% of total costs in a retrofit application. In general, the payback period must be less than half the measure life for an application to count as a retrofit.

Total resource cost information is also useful to help find a good program fit for consumers. The utilities do tell customers if non-electric impacts can be quantified and affect other costs, or payback period. The overall impact may be negative or positive (e.g., reduced lighting wattage will impact heating and cooling costs). When non-electric benefits improve the payback it can help sell the program to customers.[18]

The recently enacted EIA added new dimensions to the screening tools for C&LM programs. "Programs included in the plan…shall be screened through cost-effectiveness testing which compares the value and payback period of program benefits to program costs to ensure that programs are designed to obtain energy savings *and system benefits, including mitigation of federally mandated congestion charges*, whose value is greater than the costs of the programs."[19] [Emphasis added.]

[17] See Docket 04-11-01 for some discussion of benefit-cost tests in context of the 2005 plan.

[18] According to the C&LP respondent, process improvement is a good example of a situation where C&LM measures can result in increased profitability for a business. Measures may increase electric load but decrease them per unit produced.

[19] See (d)(3) in Section 5 of The Energy Independence Act (Public Act 05-1)
http://www.cga.ct.gov/2005/ACT/PA/2005PA-00001-R00HB-07501SS1-PA.htm

In concert with these new goals, Connecticut is participating in a regional effort to update avoided costs due to energy and demand savings, with a new focus on benefits to the electric transmission system from reduced demand. Avoided cost determinations are an important component of the screening tools used for the C&LM programs. Here is a description of this effort:

> Recently, the Companies [C&LP and UI] participated in a New England region avoided cost study to update our avoided costs for energy. Approximately 11 New England gas and electric distribution companies, plus the states of Vermont and Maine, agreed to participate in the project management and funding of the study. The purpose of the study was to update the avoided cost values used for benefit-cost analysis given the evolutions in the market and market design being implemented by the Federal Energy Regulatory Commission and ISO-NE. Specifically, the study will help the Companies to understand and quantify all the electric benefits associated with energy efficiency including FMCC reductions, as well as to identify regional differences in energy efficiency benefits. As a result of the study, the Companies are currently screening programs based on three defined geographical areas: the Norwalk/Stamford region, the rest of SWCT (excluding the Norwalk/Stamford area), and the remainder of Connecticut. The vendor that was chosen to complete the work was ICF Consulting. The study is reaching its final stages, but is not quite finalized…
>
> In the study, ICF Consulting also quantified a price reduction benefit associated with energy efficiency. The DRIPE ("Demand Reduction Induced Price Effect") benefit is the "universal" savings that results from lower capacity prices in the market. Conservation efforts reduce the required capacity in the market. While the effects of reduced capacity requirements are very complex, the ICF study suggested that reductions in required capacity, specifically in the Norwalk/Stamford area, will generally place downward pressure on capacity prices and will result in significant reductions in FMCCs to all customers in that region. The study will allow accurate quantification of conservation benefits, including FMCCs and will allow the Companies to quantify the additional benefits that result from geographical targeting of measures.[20]

The joint gas programs recently proposed to the DPUC were screened by the companies and the ECMB using the total resource cost test. This whole area is in flux due to the EIA. There will be more definitive answers and practices regarding gas conservation in the coming year.

Assessing Programs

Until recently, the C&LM programs have been designed to meet three primary objectives:

- Advance the efficient use of energy.
- Reduce air pollution and negative environmental impacts.
- Promote economic development and energy security.

In response, the ECMB reports of preliminary program results to the legislature generally consider the following areas:

[20] From the 2006 C&LM plan (Docket Number 05-10-02).

- Annual and lifetime energy savings, peak demand savings, bill savings by customer class, customer sector equity/diversity, criteria pollutant reduction, job creation, improvements in C&I productivity, leveraging other funds.

Particular emphasis is given to balancing accomplishments in SWCT, which has serious reliability issues, and the rest of the state.[21] In addition, each utility must report on program results to the DPUC to be awarded performance incentives.

It is likely that passage of the EIA will change C&LM assessments, due to its emphasis on reducing charges associated with congestion on the grid.

The respondent from CL&P described the overall process of C&LM program assessment this way. The ECMB assures that C&LM programs are subject to process studies, impact studies, free ridership studies, and baseline studies. The ECMB, often with input from an evaluation consultant, puts out a RFP for third-party contractors to evaluate programs. The level of rigor requested may vary for a variety of reasons. Originally in Connecticut an intense evaluation was completed every other year for each program, but staggered so only half the programs would receive that rigorous evaluation in any one year. Budget cuts in recent years have led to a pared-down approach. Studies and evaluations take advantage of regional efforts with Massachusetts and other states, and share consultants at times. There are advantages and disadvantages when these are done regionally.

For example, a lighting hours study regarding small business measures was just completed for utilities all over the Northeast. A regional study of free riders was conducted recently, as well. Differences in codes or standards between states can make regional baseline studies less useful. These regional assessments are not necessarily as comprehensive or internally consistent as the past practices of CL&P. On the other hand, custom programs continue to be rigorously evaluated.

One purpose of evaluations is to assess progress toward goals. C&LM goals are based on outcomes of present activities, updated with input from evaluations. The overall goals are described in terms of the net present value of energy savings, including both kW and kWh, for the residential and commercial sectors. The performance incentive available to the electric utilities is based on goal attainment. In 2004, the two electric utilities collectively reached 130% of their 2004 target performance with reported lifetime savings of over 4,000,000 MWh and attained 124% of their 2004 targeted demand performance with demand savings of over 85 MW.[22]

Historically, when considering results of the biennial gas conservation plans, the DPUC looked at energy savings and the number of low-income customers served. There may be different indicators of success going forward under the EIA.

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[21] 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

[22] Ibid.

DSM Spending

Actual Spending

The electric C&LM programs are funded with a statutory surcharge set at 3 mills/kWh. This should bring in close to $90 million per year. However, only about two-thirds of these funds are actually available to the C&LM programs presently due to the two state government diversions described earlier.

This coming year will be the first year to experience the full impact of the budget reduction due to the securitization arrangement. The electric utilities' joint 2006 plan budget is $62.1 million. This includes $49.8 million in efficiency programs (primarily incentives) and $2.8 million in "load response" efforts. Other expenditures include RD&D, education, administration costs, ECMB expenses, and utility performance incentives.[23]

The three gas utilities proposed conservation spending of $569,000, $300,000 and $282,000 in 2005. The 2006 gas utility plans are the first to be developed with the guidance of the ECMB. Future spending is uncertain at this time.

Optimal Levels

The present spending on C&LM programs is determined by the statutory surcharge. The surcharge and resulting budget was not based on a study of potential efficiency available in Connecticut, or determined in a resource comparison process like Least-cost Planning. As a result, program goals are budget-driven, rather than the budget being goal-driven. However a 2004 efficiency potential study was done by GDS Associates, which may have an impact on policy and/or funding in the future.

The experience of CL&P, the state's largest electric utility, has been that the recent track record of C&LM programs, along with consideration of changes in codes and industry standards (e.g. ASHRAE), is a much more useful predictor of achievable savings than most potential or baseline studies.

Present spending on gas efficiency also has not been based on any studies or resource planning activities. Proposed budgets have been based primarily on low-income needs. In recent years the vast majority of gas conservation programs were focused on low-income residential customers. Community agencies would give gas companies data about potential program candidates and their needs, and that would lead to program plans and budgets. A small additional amount of funding was available for efficiency loan programs. Gas utility efficiency spending was tempered for several reasons, including the fact that gas companies compete with heating oil companies that do not offer conservation programs, and gas customers also pay for electric conservation programs. However, the EIA has increased the focus on gas conservation efforts, and brought them under the guidance of the ECMB. The gas utilities have already responded with higher proposed budgets for 2006. Additional changes are likely as all the EIA initiatives begin to take shape.

Cost Recovery and Incentives

Cost recovery

The electric utilities recover expenses through the C&LM surcharge. All costs are expensed. Presently gas utilities can recover costs and lost revenues associated with conservation programs. They expense costs

[23] The 2006 plan and budget were filed in Docket Number 05-10-02.

and recover costs through rates. Two of the gas utilities have a DPUC-approved monthly conservation adjustment mechanism (cam) which allows them to recover incurred program costs and any lower sales that result from conservation efforts. The third utility may request approval for a recovery mechanism due to its proposed higher level of conservation investment in 2006. All or a portion of these arrangements may change due to new policies set in motion by the EIA.

Incentives

Each year, the two electric utilities managing C&LM programs are eligible for "performance management fees," that is, incentives tied to performance goals approved by the ECMB and DPUC, including lifetime energy savings and demand savings, and other measures. Incentives are available for a range of outcomes from 70-130% of pre-determined goals. In 2004 the two utilities collectively reached 130% of their energy savings goals, and 124% of their demand savings goals. They received performance management fees totaling $5.27 million. The 2006 joint budget anticipates $2.9 million in performance incentives.

Gas and electric utilities may have new incentive and disincentive structures in the near future. Prior to enactment of the EIA, the DPUC was beginning to re-examine incentives and disincentives to DSM in a rate design docket (Docket Number 04-05-06). However, that proceeding has been folded into a new docket on decoupling, opened in response to the EIA (Docket Number 05-09-09). Section 21 of the EIA states: "The Department of Public Utility Control shall conduct an investigation on how best to decouple the earnings of natural gas companies and other public service companies from their sales to promote the state's energy policy." The DPUC must report back to the legislature by January 1, 2006. In order to make best use of time, the DPUC has asked parties to the present docket to look at a more lengthy 1991 proceeding on decoupling, and articulate what has changed and what may still be relevant from that time.

Resources for Future Reference

The Energy Independence Act (Public Act 05-1)

http://www.cga.ct.gov/2005/ACT/PA/2005PA-00001-R00HB-07501SS1-PA.htm

Public Act 98-28 (restructuring legislation that established the C&LM fund)

http://www.cga.ct.gov/ps98/Act/pa/1998PA-00028-R00HB-05005-PA.htm

Relevant dockets:

Active and inactive docket documents can be accessed at: http://www.state.ct.us/dpuc/database.htm

- Docket 04-10-02: Gas utility conservation plans.
- Docket 04-11-01: Included a C&LM-funded pilot supplemental price response program to be implemented in 2005 for certain high price events (see pp 20-21).
- Docket 05-07-14: In Phase I, the DPUC will identify short-term strategies to mitigate capacity-related and congestion-related charges ("federally-mandated congestion charges" or FMCC), including load response, conservation, distributed resources and other measures. Phase 2 will examine intermediate-term approaches to mitigate FMCC. Both supply and demand approaches will be allowed to compete.
- Docket 05-07-19: Examines the use of conservation and other DSM strategies as Class III resources to meet certain supply goals.

- 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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Illinois DSM Summary

DSM Background and Interest in DSM

Historically there has been modest interest in energy efficiency in Illinois, but considerable interest in load management. There are several reasons that interest in energy efficiency in Illinois has not been stronger in the past, as it was in the surrounding states of Iowa and Wisconsin:

- In the 1980s and early 1990s, Commonwealth Edison had excess nuclear generating capacity.

- Southern Illinois contains significant coal resources, and DSM was not thought to be in the interests of coal companies or coal miners.

- The Illinois Commerce Commission refused to grant Commonwealth Edison guaranteed DSM cost recovery in about 1990. Without such assurances, Commonwealth Edison was unwilling to commit significant resources to DSM programs.[1]

In February of 2005, Illinois Governor Blagojevich announced a Sustainable Energy Plan that he asked the Illinois Commerce Commission (ICC) to implement.[2] The two main elements of this plan include:

1. A renewable portfolio standard that requires Illinois' investor-owned electric utilities to provide 2% of the electricity they sell from renewable sources starting in 2006, and increasing 1% per year up to a maximum of 8% by 2012.

2. An energy efficiency portfolio standard that requires Illinois' investor-owned electric utilities to reduce electricity consumption by 10% of forecast consumption starting in 2006, increasing to 15% of consumption in 2009, increasing to 20% of consumption in 2012, and finally increasing to 25% of consumption in 2015 and future years.

According to a press release from the Governor's office announcing the plan, "consumer advocates and environmental groups alike strongly support the Governor's plan".[3] In addition, "both of Illinois' two largest utilities – Commonwealth Edison and Ameren Corporation have also endorsed the Governor's Sustainable Energy Plan".[4] Based on comments made during the ICC working group meetings on this topic, these comments appear accurate.[5] Governor Blagojevich asked the ICC to implement this plan instead of submitting the proposal to the Illinois legislature for enactment because his relations with legislative leaders were strained at the time, and he was uncertain whether they would pass enabling legislation.[6]

Illinois passed an electric restructuring law, the Illinois Electric Service Customer Choice and Rate Relief Law of 1997. Among its many provisions, this law repealed requirements for electric utilities to prepare

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[1] Howard Learner, Environmental Law and Policy Center, personal conversation, October 2005.

[2] See Illinois Commerce Commission web site: www.icc.Illinois.gov, "Sustainable Energy Plan".

[3] Office of the Governor, Press Release, February 14, 2005, p. 2.

[4] Ibid.

[5] Randy Gunn of Summit Blue is based in Chicago, and attended most of the ICC public hearings held on the Sustainable Energy Plan in the spring of 2005.

[6] Anonymous source, Illinois Commerce Commission, personal conversation, October 2005.

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.

Optimizing DSM Spending/Integrated Resource Planning

As noted previously, the 1997 Illinois restructuring law repealed requirements for Illinois utilities to develop integrated resource plans. How the state will ensure that the DSM plans developed by the utilities to comply with Sustainable Energy Plan requirements are appropriate is uncertain.

DSM Cost Recovery and Incentives

This matter is quite important to ComEd, but the details of how this will work have not yet been finalized. ComEd would prefer that DSM costs be expensed and recovered annually.[16]

Resources for Future Reference

The best source of information about the Sustainable Energy Plan is the ICC web site: www.icc.illinois.gov, Sustainable Energy Plan.

The contact information for the two main people interviewed for this jurisdiction is:

- Charles Budd, Director of Strategic Initiatives, ComEd, charles.budd@exeloncorp.com, and 312-394-7369.

- Michelle Mishoe, Senior Policy Advisor, Illinois Commerce Commission, mmishoe@icc.state.il.us, and 312-814-4088.

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

Iowa DSM Summary[1]

DSM Background and Approaches

Background and Interest

Interest in DSM in Iowa is high and growing. Iowa's electric and gas utilities have been required by statute to participate in Energy Efficiency Planning since 1990.[2] In addition to a state law that mandates energy efficiency, the Iowa Utilities Board (IUB) sees DSM as a means of ensuring reasonable rates, and utilities view it as a way to maintain a positive relationship with customers. In addition to efficiency, Iowa utilities offer a several load management programs with significant impacts on electric peak load. Funding is divided relatively equally between electric efficiency, natural gas efficiency, and electric load management, although efficiency has a higher profile in the state.

The approach to DSM has varied over the years. From 1990-1996, the Iowa Utilities Board (IUB) offered utilities financial incentives for delivering efficiency, as authorized by law. Cost recovery was approved by the IUB via "mini" rate cases that occurred once every few years. In 1996, the law was changed and the IUB and the utilities abandoned the incentives in exchange for concurrent cost recovery. Investment in DSM dropped off slightly after the regulatory change, but has been steadily increasing since 2000. 2003 and 2004 both saw large increases in DSM spending, both on efficiency and on load management.[3] Despite the increases, there is a growing sense that more could and should be done, and utilities are working to increase customer participation by examining programs and, in some cases, increasing rebates and incentives.

Integrated resource planning is not an official method of planning in Iowa. Under Energy Efficiency Planning, the four investor-owned utilities submit five-year energy efficiency plans to the Board (municipalities and coops also file efficiency plans, but these plans are not evaluated or approved by the IUB). In the plans, utilities compare the costs of various demand-side options to the avoided costs of supply options. Cost-effective DSM measures and programs are included in the plans, and five-year budgets and savings goals are established. The Board is authorized to conduct prudency reviews of utility programs and may disallow cost recovery for imprudent investments. The most recent energy efficiency plan filings were approved in 2003. Investment in efficiency has increased over time, and utilities are currently exceeding their established goals.

The current interest in efficiency is primarily driven by high natural gas prices. The Governor and the IUB are also supportive of efficiency. The IUB has placed increasing emphasis on efficiency in recent years, and the Governor has encouraged the public to become more involved in efficiency, which has increased public interest in the programs. In recent years, MidAmerican Energy and Alliant Energy have been nationally recognized for programs, which have helped to give efficiency a high profile as well.

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[1] This summary is based primarily on interviews completed in 2005 with Gordon Dunn of the Iowa Utilities Board and Dave McCammant of MidAmerican Energy.

[2] Statutory requirements can be found in Iowa Code 476.6(17), online at http://www.legis.state.ia.us/IACODE/2003/476/6.html. Regulatory rules can be found in Chapter 35 of the Iowa Administrative Code, online at http://www.legis.state.ia.us/Rules/Current/iac/199iac/19935/19935.pdf.

[3] Iowa Utility Board Energy Efficiency Team. September 2005. Energy Efficiency in Iowa: Investor-owned Utility (IOU) Results. Power Point Presentation, available online at http://www.state.ia.us/government/com/util/ee.html.

Approaches

Iowa's utilities approach efficiency from a customer relations standpoint. Programs are divided into broad customer classes: low-income, residential, and nonresidential. Low-income programs focus on weatherization. A range of programs are offered to residential customers, including rebates, home audits, and weatherization programs such as insulation and window rebates. Lighting, hot water heating, and window replacement programs draw the most customers. On the nonresidential side, utilities work with commercial and industrial customers to offer customized savings. MidAmerican offers large customers a bidding program, where a company can design its own efficiency programs and submit a bid to the utility. The most cost-effective bids will receive utility funding. There is also a focus on new construction, both residential and commercial, to avoid lost opportunities. Residential programs provide the greatest savings opportunities for gas, while nonresidential programs provide the greatest electrical savings opportunities.

While the focus is on efficiency, conservation education is also done. MidAmerican has targeted industrial customers and schools with conservation messages.

There are a small number of load management programs in the state, which produce significant impacts. MidAmerican Energy, the state's largest utility, offers load management programs for residential AC customers, and a curtailment program for industrial customers. As gas prices rise, there is increasing interest in load management by industrial customers. Overall, load management programs account for roughly half of electric DSM spending.

Because both MidAmerican and Alliant are dual-fuel, programs target both electric and natural gas efficiency, and both fuels are included in efficiency plans. Fuel-switching is not formally promoted, although rebates and incentives are offered for efficient equipment, regardless of fuel

Successes and Setbacks

One of MidAmerican's successes has been its new construction programs. In 2005, the utility won an Energy Star award for its residential new construction program and a Midwest Energy Efficiency Alliance award for commercial new construction. These programs have been effective at saving energy and capturing the lost opportunity in the building process.

One setback was MidAmerican's Early Exchange program, designed to encourage commercial customers to replace equipment before it broke. The program was dropped for lack of participation. Commercial and industrial customers' ROR goals for equipment and their cash flow concerns discouraged them from utilizing this approach. The current focus is on giving incentives for the most efficient equipment when timely replacements are necessary.

The IUB's shift from incentive-based regulation to annual cost recovery is also seen as a success by the utilities. Under the original rules, utilities waited for four to six years before recovering their investments in efficiency. This "cost of money" diminished the value of the efficiency incentives.

Design, Implementation and Evaluation

Responsibility

Utilities are responsible for planning, designing, implementing, and evaluating their programs. The IUB approves plans in contested case proceedings. Third party contractors bid directly with the utilities to perform evaluations.

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

Appropriate Levels

There is no specific appropriate level of spending. Utilities develop budgets based on forecasts, but actual spending reflects customer demand. Programs may be expanded or discontinued, based on customer response.

Cost Recovery and Incentives

Cost Recovery

There is a special charge built into customer rates on a per-unit basis. Residential customers fund residential programs, and non-residential customers fund non-residential programs. The budgets for each set of programs are determined in the energy efficiency plans. Rates are determined by actual spending and are trued up annually.

Incentives

There are no current regulatory incentives for utilities to deliver efficiency. In the past, utilities could receive incentives for meeting certain goals, but this provision was dropped in 1996 when a concurrent cost recovery system was adopted. (From 1990 to 1996, cost recovery and incentive awards were done once every few years, with the result that the utilities' incentive was diminished by the expense of waiting for cost recovery.)

Resources for the Future

Iowa Utilities Board Staff Energy Efficiency Team. 2005. "Energy Efficiency in Iowa: Investor-owned Utility (IOU) Results." Power Point Presentation, Iowa Utilities Board.

http://www.state.ia.us/government/com/util/ee.html (accessed November 10, 2005)

Stakeholder Process

The rules include a collaborative stakeholder process. Stakeholders meet with utilities to suggest programs and features during the plans' development. Typical respondents include large industrial customers, the Office of Consumer Advocate, trade unions, and trade allies. For more information on the stakeholder process, contact Gordon Dunn of the IUB or Dave McCammant of MidAmerican Energy (contact information below).

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Massachusetts DSM Summary[1]

DSM Background and Approaches

Background and Interest

There is long-standing interest in demand-side management (DSM) in Massachusetts. For a number of years prior to 1998, integrated electric utilities were responsible for DSM, under the oversight of the utility regulator (now known as Department of Telecommunications and Energy or DTE) in the context of utility resource planning. Gas distribution utilities were also required by DTE to invest in efficiency for many years, though to a lesser extent than electric utilities. As a result, every utility had a different level of DSM funding.

Electric sector restructuring legislation effective in 1998 created a system benefit charge (SBC) for electric energy efficiency (including low-income) and renewable energy activities. The legislation set the efficiency SBC initially at 3.3 mills/kWh of sales, ramping it down gradually to 2.5 mills in 2002. The Division of Energy Resources (DOER) has the authority to oversee and coordinate ratepayer-funded energy efficiency programs, certifying that program plans are consistent with specified goals, and is required to file annual reports with the DTE regarding proposed funding levels for programs, while the DTE provides other regulatory review, including review of cost-effectiveness and use of competitive procurement processes.[2] The legislature subsequently renewed the efficiency SBC for five years at 2.5mills/kWh. Funding was set to expire at the end of 2007, but the legislature took it up ahead of schedule, and in November 2005 extended the SBC for an additional five years. The goals of the legislature when establishing the SBC funds included reducing customer bills, achieving environmental goals, providing other economic benefits, such as job creation and development of a competitive sector of energy service providers. Funding for gas efficiency programs continues to be determined by regulators on a case-by-case basis.

There is increased interest in DSM among many parties right now because of high energy prices and potential energy shortages this winter. The ISO-NE forecast worst-case scenario for this winter of a prolonged period of cold weather with freezing in Boston Harbor could result in rolling blackouts. Massachusetts relies heavily on natural gas for both electricity generation (30%) and space/water heating (60%). Although it is not likely to be a true shortage situation, natural gas may be less available for generation since generators do not have the obligation to serve that vertically integrated utilities had under full regulation.

Many parties have been supportive of ratepayer funded DSM programs: the legislature, advocates, utilities and regulators. At first, some large customers were negative, with the attitude, "we can do it better ourselves." The industry trade associations now see that these programs do provide value to their constituents. They supported extension of program in 2002.

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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 November 2005 with Lawrence Masland and Michael Sherman of the Massachusetts Division of Energy Resources, Carol White of National Grid, and Robert Harrold of the Massachusetts Department of Telecommunications and Energy.

[2] 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

The legislature, governor, DOER, DTE, utilities and other parties are all looking at DSM strategies to improve the energy outlook this winter, both in terms of prices and reliability. The legislature enacted emergency legislation in November 2005 that extended the SBC funding through 2012. This legislation provided a number of efficiency incentives such as tax credits and no or low interest loans for efficiency measures, as well as funds for heating assistance.[3] There has not been a similar push to legislate increased gas efficiency efforts; however, some gas utilities may be increasing their efficiency budgets this year.

The electric distribution utilities are the default providers in their service territories. A very high percentage of customers, particularly residential, are still on default. Half of default goes to bid every six months, so there are big swings in prices. There are some discussions about allowing default providers to go out for longer-term contracts or other mitigation strategies. However there has been no public discussion of a return to any kind of least-cost planning approach in the context of resource adequacy.

Approaches

The electric efficiency programs tend to make market transformation a key component of every approach, although the focus may be retrofit or intervening in lost opportunity situations (e.g. new construction, major process upgrades). Program administrators use multiple strategies to improve overall building and process efficiency. They use incentives to get efficient products in the market, improve market share, and provide needed training. With market transformation initiatives, program administrators often coordinate with key trade allies, the Northeast Energy Efficiency Partnership (NEEP), the Consortium for Energy Efficiency (CEE), and the EPA's and DOE's Energy Star on a regional or national basis. NEEP has been important in bringing regional economies of scale to market transformation efforts.

The focus of approaches varies. For example, to improve the market share of Energy Star fixtures and appliances, the focus might be on national and regional distributors and retailers, as well as customers. Cooperative agreements with lighting distributors can give consumers a lower price in the store instead of, or in addition to, a rebate. When this works, the result is businesses naturally promoting efficiency, and efficiency measures are widely and readily available. In addition to the electric efficiency programs funded by the SBC, new appliance standards and building codes are being supported by the legislature, which will complement these efforts.

Most gas efficiency programs are also market transformation programs, providing incentives for the incremental costs (above code or standard) for space conditioning (weatherization) and high efficiency units for heating, hot water, and other appliances. The gas utilities work together in a group (Gas Networks); they offer standard rebate forms, and training to contractors for installing high efficiency units.

Very few ratepayer funds are used for any load management or demand response efforts. According to the DOER, in 2002 11% of demand savings were due to interruptible contracts, primarily residential contracts (radio controlled hot water heaters). The technology became outdated and programs were no longer cost-effective, so they were ended.

The ISO-NE does offer customers some demand response options. Some efficiency program administrators use a modest amount of the SBC funds to support Demand Response audits with large customers, while also searching for efficiency opportunities. The Demand Audits can reveal ways for large customers to respond to NE-ISO DR opportunities with confidence.

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[3] See Chapter 140 of the Acts of 2005 at http://www.mass.gov/legis/laws/seslaw05/sl050140.htm

Efficiency has not been used directly for distribution system optimization yet. Some utilities are interested in using demand response and price responsive rates to defer the need for new infrastructure, curtail demand while building new infrastructure, or pay incentives for demand-rich efficiency opportunities. It was not clear from research done for this paper whether any SBC funds were being used for advanced metering needed for price-responsive rates. The ISO-NE may be paying for it.

There are other trends regarding demand response. There is talk that TOU or other price responsive rates might get more results than demand response. There has been some discussion about requiring that any funding for technologies that reduces demand by shifting peak must also produce energy savings. This is an ongoing conversation with utilities and the non-utility parties (NUPs). It seems likely that efficiency measures that produce larger demand reductions will be emphasized more in the future due to capacity issues and constraints.

The Cape Light Compact, a municipal aggregator that purchases energy supplies and manages efficiency programs for a group of towns and their residents, is using ratepayer funds to support some fuel switching away from electric heat.

There is a small program called the Residential Conservation Service that provides some funds for residential retrofit efforts under a separate statute (Chapter 465). This has been the only state program that provides any assistance for oil heating customers, although the recently passed emergency legislation provides some tax credits and loans. Regarding other oil efficiency concerns, there is some thinking that if funds for efficiency result from the Regional Greenhouse Gas Initiative (RGGI) program, they might be used to address the state's own building efficiency problems. State buildings and public housing, often using heating oil, are in need of efficiency funding.

Successes and Setbacks

The electric efficiency programs in Massachusetts have matured over the last eight years, and learned some useful lessons.

- Efficiency programs are most effective if funding and implementation is ongoing and stable.
- It has been important to develop mutually beneficial alliances with key contractors, architects, engineers, and distributors.
- By assigning programs to utilities, which are pretty strong politically and want the programs, we have avoided problems seen in some other states.
- DSM administrators should require sufficient cost-share so customers have ownership with measures, while being realistic about customers' access to capital.
- Allow for flexibility and creativity. With five program administrators, some are more creative and find new approaches. Feedback from DOER allows them to reflect on how well they are doing and compare approaches and outcomes. The opportunity for municipal aggregators, not just utilities, to be program administrators provides healthy competition.
- All parties involved have worked to make data and communication more transparent. The result is good information systems to measure performance over time and to use for planning forward.
- Collaborative arrangements, like the ones involving the program administrators, NUPs, contractors and DOER, require building trust and credibility. That takes time, but experience in Massachusetts is that everyone wants to make it work.

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.

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[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 their consultants, as well as the DOER, also provide input. Program administrators may also combine forces with other utilities for joint studies that are statewide or regional.

Program administrators may engage in impact and process studies, baseline studies, free ridership determinations, avoided cost studies, market penetration studies, etc. Here is an excerpt from National Grid's proposed 2005 Efficiency Plan which describes some of the decision-making around evaluations:

> In planning evaluation activities for the coming year, the Company considers several factors, including the length of time since a program or end-use was evaluated, the maturity of the program (particularly for process evaluation issues), the significance of expected savings for the end-use or project in the recently completed program year, the stability of prior evaluation results for the program aspect under consideration, and expected opportunities to participate in joint-utility studies, including market assessments, in the coming year. In addition, the Company seeks input from interested stakeholders about its evaluation plans as those plans are developed so that significant issues are addressed through the studies that the Company sponsors.[7]

Electric program administrators hire evaluators. An entirely independent audit of the whole SBC program has not yet occurred.

The DOER prepares annual reports to the Legislature on the use of the SBC funds, including the most recent statewide results. Recent reports have focused on the following statutory and regulatory priorities:

- Program cost-effectiveness,
- Equitable allocation of funds between customer classes,
- Balancing of short-term and long-term saving objectives, and;
- The development of a competitive market for energy efficiency services.

The most recent report attempted to quantify or describe the following outcomes:

- Program participant savings: annual and lifetime energy savings, demand savings, average annual and long-term bill savings, customer participation.
- Electric system benefits: reducing wholesale energy clearing prices, increasing system reliability, increasing reliability of local T&D networks.
- Economic development impacts: short-term job creation, long-term job creation, and increases in gross state product and disposable income.
- Environmental Protection: emission reduction impacts, other resource savings.

Some of the 2002 results were:

- 241 GWh annual and 3,428 GWh lifetime savings.
- 48 MW of demand savings (at the customer level).
- Average cost of 4cents/kWh (including participant costs).
- Total participant lifetime energy savings of about $249 million.
- Average annual bill savings ranged from 5-16% of average annual bills.
- Savings due to lower wholesale energy clearing prices were about $19.4 million.

[7] National Grid "2005 Energy Efficiency Plan," page 106.

- Over 2000 new jobs were created.
- Efficiency measures installed in 2002 are credited with reducing emissions in 2002 alone as follows: 135 tons NO_x, 394 tons SO_2, 161,205 tons CO_2. Lifetime reductions are significantly larger.

DTE reviews program evaluations after the fact for savings, verified by statistical sampling. The M&E (monitoring and evaluation) filings are complicated, and highly technical in terms of data and statistics. From the DTE's point of view, the evaluations are undertaken by knowledgeable consultants, subject to review by Jeff Schlegel and similarly experienced people, as well as company staff, so to the DTE there is not a lot of value to second-guessing. DTE approval of evaluations is required before shareholder incentives can be finalized. DTE staff also looks at cost-effectiveness of programs as revealed by evaluations. If this stage shows slippage, DTE feeds this information back to program administrators for the next proposal stage. DTE presently has a backlog of evaluations. Both utilities and the DTE hope to reduce the backlog significantly in the near future.

Gas programs are evaluated differently, although third-party contractors are often used to verify program performance. Engineering studies and deemed measures are used to estimate savings. In the early 1990s, gas utilities got both performance incentives and lost base revenue. DTE wanted more confidence in savings, so it did a massive evaluation study, the Gas Evaluation and Monitoring (GEM) study, and decided they could show statistically that certain measures saved a certain percent of bill, when looking at unit energy consumption (e.g. wall insulation would save 18% on heating bill). These figures continue to be used. Preliminary results from a recent University of Massachusetts study appear to support these findings, but it is not completed yet.

DSM Spending

Actual Spending

The statute requires electric DSM funding of 2.5 mills/kWh. This is augmented in small part by interest accrued on the DSM fund balance (due to the timing difference between when revenues are received by utilities and when expenses are incurred). There is a formula for the minimum that must be spent on low-income programs.[8]

The statewide total annual electric efficiency budget is about $120 million, not counting participant costs. In 2003 electric efficiency participant costs were about $50 million.

The 2005 Efficiency Plan submitted by National Grid anticipated total program costs of $69.1 million. That included $14.3 million in participant and spillover customer costs. The utility budget is $54.8 million, with $8.3 million for low income (significantly exceeding the 0.25mills/kWh required to be set aside for LI. That would only be $5.6 million.). Customer incentives account for about $37 million in the 2005 budget.

Gas spending is negotiated with each LDC in annual regulatory hearings. Statewide, gas utility efficiency expenditures total about $20-25 million.

[8] From Chapter 25, Section 19 of the General Laws of Massachusetts "At least 20 per cent of the amount expended for residential demand-side management programs by each distribution company in any year, and in no event less than the amount funded by a charge of 0.25 mills per kilowatt-hour… shall be spent on comprehensive low-income residential demand-side management and education programs."

Optimal Levels

In Massachusetts the system benefit charge funding available for electric efficiency was established by the 1997 restructuring legislation. That statute also prohibited utilities from charging ratepayers for efficiency expenses exceeding the statutory levels. As a result, efficiency goals are budget-driven, rather than related to what is cost-effective and available. Regulators see Massachusetts utilities doing a good job of obtaining efficiency, but they see efficiency outcomes being constrained by the SBC budget limits.

A report was prepared for the DOER and efficiency program administrators in 2001 estimating the amount of economic potential savings that would be achieved with continued SBC funding from 2003-2007.[9] This report found that the efficiency savings likely to be obtained in the scenario that included continued SBC funding represented only about 20% of the potential available savings.[10] This report estimated the remaining economic potential savings available during 2003-2007. Economic potential savings are those energy savings that are societally cost-effective to install.

The DOER is thinking about conducting an electric efficiency market potential study this spring. The respondents in this study were not sure that any gas efficiency potential study has been done.

Cost Recovery and Incentives

Cost recovery

All electric DSM expenditures, other than demand response activities, are expensed and paid for with the statutory SBC funds. Interest may be accrued on the monthly fund balance, taking into account the timing difference between when SBC revenues come in and when expenses are incurred. Gas utilities recover expenses in rates, and have access to lost revenue recovery. One gas utility receives a performance incentive.

Incentives

Shareholder performance incentives are available to the electric utilities administering efficiency programs. The calculation of the incentive has evolved over the years, with the DTE having the final say after considering modifications suggested by utilities and the NUPs. The 1998 DTE Order establishing incentives initially pegged them to the US Treasury bill rate, but in recent years, as that rate has gone down, the target design level after-tax incentive has been set at 5% of spending.[11] The balancing act remains the same. The incentive must be large enough to promote effective programs but small enough that the interests of ratepayers are protected.

The calculation of the shareholder incentive has become increasingly sophisticated to capture and reward certain outcomes. In the most recent efficiency plan proposed by National Grid, the final net after-tax incentive would be the product of the 5% incentive factor, the actual efficiency spending, and the level of performance (the reward starts at 75% for threshold level performance to 110% for exemplary performance). Since exemplary performance of 110% of goals can be rewarded, the maximum after-tax pay-out to shareholders could actually be 5.5%.

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[9] "Economic potential" was defined as the "portion of the energy savings available that is societally cost-effective to install."

[10] RLW Analytics, Inc. and Shel Feldman Management Consulting. June, 2001. "The Remaining Electric Energy Efficiency Opportunities in Massachusetts: Final Report." http://www.mass.gov/doer/pub_info/e3o.pdf

[11] For recent regulatory thinking on incentives, see Docket 04-11 at: http://www.mass.gov/dte/electric/04-11/819order.pdf.

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

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[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.

- Large industrial customers are generally opposed to CIP requirements, as they increase electric bills in the short term. However, the largest industrial customers are given a way to “opt-out” of funding CIP, as will be discussed further in the DSM Spending section.

Minnesota has never passed an electric restructuring law, and generally regulates its electric utilities in the traditional manner. One exception to this is that the state’s electric customers with demands of two megawatts or more can petition the MPUC to change electric suppliers. Also, medium to large natural gas customers can purchase gas on the open market.

DSM Approach/Xcel Energy’s DSM Portfolio Summary

Xcel Energy’s DSM approach focuses on energy efficiency and load management. Virtually none of their DSM programs are “energy conservation” programs, defined as encouraging customers to just restrict energy use, such as through reducing thermostat temperatures. (However, the term “energy conservation” is often used instead of “energy efficiency” there.) Demand response programs such as real-time pricing are not considered DSM programs in Minnesota, as will be discussed further in the DSM Spending section. Fuel switching programs do not qualify as CIP programs by administrative CIP implementation rules.

Xcel Energy’s proposed total electric DSM goals and budgets for 2005 include 86 MW of peak demand reduction and 180 GWh of energy conservation, at a cost of $36.7 million for electric programs.[4] This proposed spending represents 2.04% of its electric GOR.[5] For its smaller gas utility, Xcel proposed 404 million cu.ft. of natural gas savings at a cost of $3.6 million.[6] This represents 0.61% of its gas GOR.[7]

Xcel Energy conducts a variety of different types of DSM programs. The Company spends most of its DSM funds on energy efficiency programs, which are budgeted for $28.5 million for 2005.[8] Its total demand reduction goals for all of its efficiency programs for 2005 are 41 MW of peak demand reduction, and its total energy savings goal for these programs is 178 GWh of (generator) energy savings.

Xcel Energy’s largest efficiency programs include:

- The ENERGY STAR program for residential customers, which offers customers rebates for purchasing energy-efficient air conditioners and heat pumps, as well as gas furnaces and boilers. This program has a proposed 2005 electric budget of $5.7 million, and a gas budget of $0.6 million. Its 2005 proposed conservation goals are 6.5 MW of peak demand reduction, 4 GWh of energy savings, and 71 million cu.ft. of gas savings.

- Energy Design Assistance, a commercial new construction program, which offers design assistance to commercial and industrial customers constructing new buildings and rebates for purchasing energy-efficient equipment. The proposed 2005 electric budget for this program is $5 million, and its corresponding proposed electric DSM goals are 7.8 MW of peak demand reduction and 27 GWh of energy savings.

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[4] Xcel Energy, “2005/2006 Biennial Plan, Minnesota Natural Gas and Electric Conservation Improvement Program” p. xx (Xcel Energy, Minneapolis, MN, June 2004).

[5] Ibid, p. 1.

[6] Ibid, p. xx.

[7] Ibid, p.2.

[8] Ibid, p. xiv. All other statistics in the section are also drawn from the Executive Summary section of this document.

- Custom Efficiency, which offers rebates to commercial and industrial customers for installing somewhat unique industrial process and other types of conservation measures. This program has a proposed 2005 electric budget of $3 million, and proposed goals of 6 MW of peak demand reduction and 50 GWh of energy savings.

- Commercial Lighting Efficiency, which offers rebates to commercial and industrial customers for purchasing efficient commercial lighting equipment. The proposed 2005 budget for this program is $2.9 million, and has proposed goals of 8 MW of peak demand reduction and 43 GWh of energy savings.

- The Boiler Efficiency program, which offers rebates to commercial and industrial customers for purchasing efficient natural gas boilers and boiler retrofit energy efficiency measures. This is the Company's largest natural gas DSM program as measured by energy savings. The total proposed 2005 energy savings goal for this program is 171 million cu.ft. of savings, about 40% of the Company's total gas DSM goal. The total proposed 2005 program budget is $0.6 million.

In addition, the Company offers financing programs for energy efficiency measures that allow customers to finance the cost of DSM measures through their utility bills. The Company also offers energy information programs, such as subsidized energy audits, for all customer classes.

Xcel Energy's two main load management programs are Saver's Switch, a direct load control program for central air conditioners for residential and small business customers, and Energy Reduction Savings, an interruptible rate program for commercial and industrial customers. Xcel Energy regularly uses both of these programs, and achieves significant peak demand reductions from them. The Company's proposed total 2005 load management program CIP budget is $8.1 million, and its total proposed 2005 load management DSM goals are 45 MW of (incremental) peak demand reduction and 2 GWh of energy savings.

Successes and Setbacks

The Company has realized significant energy savings from its commercial lighting programs over time. In 2004, the Company achieved more energy savings from its Lighting Efficiency Program than any other DSM program.[9] This project was selected by ACEEE for "honorable mention" status in 2003. ACEEE also selected the company's Energy Design Assistance as an "exemplary" energy efficiency program in 2003.[10] The Company's load management programs are also leaders in the industry in terms of their demand reduction impacts.

One program area that the Company has been working on has been its low income programs. The Company's programs in this area have not been cost-effective as measured by the societal test, as is often the case with programs for this customer group. However, there is interest in improving this program area.

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[9] Xcel Energy, "2004 Status Report & Associated Compliance Filings, Minnesota Natural Gas and Electric Conservation Improvement Program" p. 5 (Xcel Energy, Minneapolis, MN, April 2005).

[10] ACEEE, "America's Best: Profiles of America's Leading Energy Efficiency Programs" (ACEEE, Washington, DC, March 2003). Available at www.aceee.org.

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

Xcel Energy and other Minnesota utilities are responsible for DSM program planning, design, implementation, and evaluation. The MDOC must approve new or substantially modified DSM programs. The general CIP process for Xcel Energy is that the Company files proposed plans, goals, and budgets for its CIP programs on June 1st every other year. These biennial CIP filings cover the forthcoming two year period. The MDOC reviews these filings and solicits comments from interested parties. The MDOC staff first assesses the filings to determine whether they are complete, in terms of meeting statutory and regulatory requirements. Then the MDOC staff analyzes the filings to determine whether the Company's proposed program mix, goals, and budgets are appropriate. At the conclusion of the MDOC staff's analysis of Xcel Energy's proposed CIP filing, they issue a proposed decision for their Commissioner. The MDOC Commissioners generally largely follow the staff's proposed decisions, but generally add some of their own ideas to the final CIP orders. Xcel Energy either proposes new DSM programs as part of their major biennial CIP filings, or through miscellaneous filings that they can submit at any time to the MDOC.

The MDOC staff often propose increases in Xcel Energy's proposed DSM goals while maintaining the Company's proposed DSM program budgets, particularly when they believe that the proposed goals are too low relative to the past performance of the utility's DSM programs. However, the MDOC Commissioner often does not order such higher goals, although the Company often exceeds its proposed CIP goals.[11] MDOC staff proposals in this regard are made primarily to ensure that customers are getting a good value from the utilities' CIP expenditures, and for purposes of setting reasonable baselines for calculating utilities' DSM financial incentives, as will be discussed in the last section.

Xcel Energy set up a collaborative group, the CIP Advisory Board, which is composed of regulatory staff, energy efficiency advocates, and service providers. The Company agreed to meet regularly with this group as part of a 2001 merger agreement. The group advises the Company on program evaluations and market studies, as well as opportunities to improve existing programs and start new programs. The group meets approximately quarterly, and meetings are generally cordial and productive.

Utilities are not obligated to evaluate their DSM programs on a regular cycle. The main legislative requirement regarding DSM program evaluations is that utilities are prohibited from spending more than 3% of their DSM program funds on program evaluations. Xcel Energy generally subcontracts DSM program evaluations to energy consulting firms like Summit Blue, except for impact evaluations for its load management programs, which it conducts internally.

DSM Benefit-Cost Analysis

Xcel Energy conducts DSM program benefit-cost analyses using the California standard practice manual approach[12]. This general framework is widely used in the U.S. The California approach uses five "stakeholder" tests to assess the benefits and costs of DSM programs from different perspectives:

- Participant customers in DSM programs.
- The utility.

[11] Chris Davis, MDOC, personal conversation, October 2005.

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

- The impact on rates (formerly called the non-participant customer test).

- The total resource cost (TRC) test, which is essentially the perspective of all utility customers combined.

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

In addition to avoided generation and fuel costs due to DSM, Xcel Energy includes avoided transmission and distribution costs due to DSM programs in its benefit-cost analyses. [13]

The MDOC considers the societal test to be the most important test of the five California tests, but also considers the participant test to be important, as well as the utility test, as will be discussed further below. The MDOC considers DSM programs with societal benefit-cost ratios of 1.0 or greater to be cost-effective. The benefit-cost analyses conducted as part of the CIP process are generally used primarily to determine whether specific DSM programs are cost-effective or not. The MDOC has regularly required utilities to cease conducting DSM programs that do not pass the societal cost-effectiveness test.

Xcel Energy uses the DSManager model to conduct its electric DSM benefit-cost analyses. DSManager is a 1990s vintage model that conducts static analyses of the benefits of DSM programs using one set of projected avoided costs, one set of projected electric rates, and one set of DSM "loads shapes" that show the hourly distribution of conserved energy over a year. Xcel Energy conducts program-by-program DSM benefit-cost analyses, and then totals the results for each customer class, and for conservation programs separately from load management programs. Xcel Energy uses a much simpler spreadsheet benefit-cost analysis tool ("BENCOST") that was developed for the MDOC for natural gas DSM benefit-cost analyses.[14]

DSM Spending Requirements

Minnesota's DSM requirements for utilities have become more specific over time. In the early and mid-1990s, the Legislature amended the CIP statute to require the state's utilities to spend the following percentages of their gross operating revenues (GOR) on DSM:

- Electric utilities with nuclear facilities must spend 2% of their electric GOR on DSM. (This provision only applies to Xcel Energy.)

- Other electric utilities must spend 1.5% of their GOR on DSM.

- Gas utilities must spend 0.5% of their GOR on DSM.

Other notable aspects of Minnesota's DSM requirements include:

- Customers with peak demands of 20 MW or more can petition the MDOC Commissioner to be exempted from funding CIP programs. To be exempted, they must provide evidence that they have their own self-funded energy conservation activities underway.

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[13] Xcel Energy, 2004, op.cit., p. 253.

[14] Xcel Energy retained Summit Blue Consulting to conduct its electric and gas DSM benefit-cost analyses for their 2002 and 2004 CIP filings.

- Load management programs are considered DSM programs so long as they result in demonstrable energy conservation. However, demand response (DR) programs such as real-time pricing or time-of-day (TOD) rates are not considered CIP programs in Minnesota. This policy was enacted several years ago by the MDOC, who were concerned that treating the cost of DR programs as CIP programs would significantly reduce Xcel Energy's energy efficiency program funding. [15] This policy has some historical precedent, as Xcel Energy's predecessor company NSP discussed the possibility of treating rate discounts from TOD rates as contributing to CIP funding requirements with Minnesota regulators in the mid-1980s, but this proposal was rebuffed.

- Utilities are required to conduct DSM programs for low-income customers.

- Xcel Energy must contribute 5% of its required CIP funds to the University of Minnesota's Renewable Energy and the Environment initiative. This requirement was imposed by the Legislature in 2002.

- Distributed generation programs can qualify as CIP programs, but spending on such programs cannot exceed 5% of the total minimum CIP spending requirements.

Optimizing DSM Spending/Integrated Resource Planning

In about 1990, the MPUC started requiring the state's larger electric utilities to submit integrated resource plans (IRPs) every two years that cover a 15-year forecast period. Xcel Energy's predecessor company Northern States Power Company submitted their first IRP in 1991, and their most recent IRP in 2004. The MPUC has used the IRP process to optimize the utilities' DSM plans. IRP requirements do not apply to gas utilities in Minnesota.

For the IRP process, NSP develops several DSM scenarios (in addition to several types of generation and power purchase scenarios). The DSM scenarios that Xcel Energy develops vary by DSM impacts and costs, and are usually modeled by estimating the amount of DSM that the company would realize by varying its rebate amounts that the Company offers customers. [16] Xcel Energy conducts DSM potential studies about every five years to develop up-to-date DSM scenarios for IRP purposes. The Company uses integrated planning models such as Strategist (most recently) to select the lowest cost expansion plan combining the appropriate DSM and generation scenarios.

The IRP process in Minnesota has resulted in significant changes to Xcel Energy's DSM portfolio over time. Most recently, the MPUC is in the process of finalizing its 2004 IRP order that will (likely) increase Xcel Energy's long-term DSM goals by approximately 25% compared to its previously ordered DSM goals. [17] A higher level of DSM was found to result in lower long-term system costs due to higher gas prices projected by Xcel Energy than previously estimated, as well as due to expanded DSM impacts from industrial DSM programs than previously projected[18].

Utilities' DSM goals proposed through the CIP process must be consistent with the MPUC's latest DSM goals ordered in the most recent IRP proceeding. The MDOC Commissioner has statutory authority to

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[15] Personal conversation with Chris Davis, MDOC, October 2005.

[16] Randy Gunn and others at Summit Blue have assisted Xcel Energy in developing the DSM scenarios for its last several resources plans, working with another consulting firm (RER, now part of Itron) and their ASSET DSM forecasting model.

[17] Personal conversation with Chris Davis, MDOC, October 2005.

[18] See www.xcelenergy.com, "About Energy and Rates, Resource Plan (MN)". Chapter 6 covers DSM.

increase CIP spending requirements for utilities proposing new generating facilities in the period covered by their most recent IRP.

DSM Cost Recovery and Incentives

Xcel Energy uses MPUC-approved deferred accounts ("CIP Trackers") for its CIP expenditures. The Company collects these CIP expenses through a "CIP Adjustment Rate", which the MPUC approved in 1995. This rate is part of the Company's fuel-clause adjustment mechanism. The CIP Adjustment Rate is updated annually based on the balances in the CIP Tracker accounts. Administratively, this is done as part of the Company's annual CIP Status Report, which is filed with the MDOC and MPUC each April 1st.

Up until 1999, Xcel Energy and other Minnesota utilities were allowed to recover the "lost margins" or lost profits from its CIP programs between rate cases. Minnesota utilities are not required to file annual rate cases, and rate cases are often filed 3-10 years apart. Since Minnesota utilities' rates are based on anticipated sales in a forward-looking test year in rate cases, lower sales caused by a utility's DSM programs in the years between rate cases result in lower sales and profits than they would have realized if they were not conducting DSM programs. These lost margins are a significant disincentive for utilities to conduct DSM programs, as was widely recognized in the U.S. in the early 1990s.

Minnesota decided to address this issue by granting utilities recovery of these lost margins in the early to mid-1990s. These lost margins were directly estimated by utilities based on their DSM program impacts. However, Xcel Energy did not file a rate case for over five years in the mid to late 1990s, and by 1999 their estimated lost margins totalled about $30 million annually. This amount was similar in magnitude to the Company's annual direct CIP program costs, so MDOC staff began to advocate cancelling lost margin recovery, since it essentially doubled the cost of CIP. [19]

The MPUC eventually approved the MDOC staff's proposal, and developed a new DSM incentive mechanism in 1999. [20] "The Company earns an incentive for achievement greater than 91 percent of its minimum spending equivalent energy savings goal. The 'goal' is equal to the number of kilowatt-hours that the Company is expected to save when it meets its minimum spending requirement. The financial incentive is capped at the lesser of 30 percent of the DOC Commissioner-approved or actual CIP spending". [21]

Resources for Future Reference

Xcel Energy's Biennial CIP Filing (Docket # 04-820, filed 6/1/04) and CIP Status report (Docket 02-854.19, filed 4/1/05) are available online on part of the MDOC's web site: edockets.state.mn.us. Xcel Energy's 2004 Resource Plan is available on their web site [www.xcelenergy.com, "About Energy and Rates, Resource Plan (MN)"]

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

- Bridget McLaughlin, Regulatory Analyst, Xcel Energy: bridget.mclaughlin@xcelenergy.com, and 612-330-6791.

- Chris Davis, Rates Analyst, MDOC: Christopher.davis@state.mn.us, and 651-296-7130.

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[19] Personal conversation with Chris Davis, MDOC, October 2005.

[20] Xcel Energy, 2005, op.cit, p. 18.

[21] Ibid.

New Jersey DSM Summary[1]

DSM Background and Approaches

Background and Interest

New Jersey's seven natural gas and electric utilities have been running demand-side management programs since the early 1980s. In 1999, when New Jersey opened its electric market to competition, there was concern about the future of these programs. Restructuring legislation, passed in February 1999, provided for a systems benefit charge to continue to fund utility programs. The original mandate for spending on Energy Efficiency (EE) and Renewable Energy (RE) was for eight years at a minimum funding level of about $107 million per year, about double what was being spent. Annual spending has steadily increased over the years with $143 million spent on EE/RE in 2004.[2] Unlike most other jurisdictions, with separate funds for energy efficiency and renewable energy, in New Jersey, money is collected for both, and it is up to the Board of Public Utilities (BPU) to manage the two purposes and divide the funds accordingly. The budget will increase to $235 million in 2008 with the incremental increase in spending approximately equivalent to a 1 per cent increase in customer rates. About 75% of the funds are spent on EE.

The level of interest in demand response (DR) is increasing, but there is long way to go, especially in terms of education of stakeholders. The key reason for the stakeholder interest in DR is that fuel costs are affecting energy bills and there is a need to manage costs. Word of mouth is beginning to generate interests among larger customers. Functional wholesale markets are still a big priority for PJM and demand response is an essential way to get there. There are some real peak load concerns, especially in eastern PJM that demand response can help to manage, especially where it is hard to build new generation.

In the past two months the BPU has been looking at mitigating the impact of higher gas prices such as increasing rebates, using education and audits, and spending more on low income consumers. The BPU is in the midst of supervising the transfer of administrative responsibility over energy efficiency programs from the utilities to itself.

Reason for interest

There are a number of reasons for the interest in DSM. The key one is environmental; New Jersey is downwind from the midwest coal plants and even if the state elimated all emissions they still would not be in compliance with environmental regulatations. Another key issue is transmission contraints, particularly critical to New Jersey with the Atlantic Ocean as a large fraction of its perimeter and much of its coastline isolated by the environmentally sensitive Pine Barrens. And the state has many aging power plants, boasting the oldest operating nuclear plant in the nation.

The government drives the interest in DSM and the expectation is that the new administration will be very supportive of funding. New Jersy believes in energy efficiency—"it's the right way to go." Efficiency has been very effective over the last 20 years, it is good for consumers and for the environoment. However,

[1] This summary is based primarily on interviews completed during November 2005 with Michael Ambrosio, a consultant to BPU, and Susan Covins of PJM.

[2] 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

there has to be a balance between how much DSM is implemented and the impact on non-participating customers. They could have done even more last year to get all cost-effective DSM but the state is only willing to accept a 1% incremental increase in rates.

FERC influence continues to encourage market development of demand response in PJM. The interest in DR is also driven by stakeholders and state regulators.

Approaches

In the past DSM was done by the seven natural gas and electric utilities, collecting the money from rates and using a deferred account. Now the BPU will take over all administrative responsibility and will outsource all responsibility for EE/RE to three firms - Residential, C&I, and RE. In the interim, the utilities are deducting DSM expenses from a fixed monthly amount allowed for EE/RE and sending the difference to a new fiscal agent. There is $100 million in a bank account now but $150 million committed to solar projects.

The following are the five key EE programs:

- Residential HVAC electric/gas
- Residential new construction
- ES Products
- Residential Low Income
- C/I Construction.

Demand Response

For DR, reliability and markets are addressed through two different types of programs organized by PJM. Emergency programs pay participants to be available, and penalize them if they do not perform. This resource is driven by reliability concerns and counts in reliability assessments. Economic programs are bid-driven -- participants are paid a floor price or more depending on the bid and market conditions. Customers are assisted by their utility or curtailment service providers.

FERC approved PJM's multiyear Economic Load-Response Program in 2002, with a sunset provision. FERC has since extended the program until December 31, 2007. The Program provides a PJM-managed accounting mechanism that requires payment of the real savings to the load-reducing customer that result from load reductions. Such a mechanism is required because of the complex interaction between the wholesale market and the incentive and regulatory structures faced by both load-serving entities and customers. The broader goal of the Economic Program is a transition to a structure whereby customers do not require mandated payments but where customers see and react to market signals or where customers enter into contracts with intermediaries who see and react to market signals on their behalf. Even as currently structured, however, the Economic Program represents a minimal and relatively efficient intervention into the market. Also in 2002 FERC approved PJM's Emergency Load-Response Program which FERC also extended to 2007, making it coterminous with the Economic Program.[3]

Successes and Setbacks

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[3] 2004 State of the Market, March 8, 2005. http://www.pjm.com/markets/market-monitor/downloads/mmu-reports/pjm-som-2004.pdf

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

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[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

managers to file program descriptions for each program by February 2005. A revised exhibit outlining programs and budgets was filed in June 2005[9].

Program Design: Demand Response

For DR, there is a PJM Demand Response working group, and PJM staff supports their efforts. Change is driven by the PJM stakeholders' process. High levels (management committee) give direction, while the working group implements. A management directive is that demand response is not a "program," but, rather, it should be integrated into PJM markets. This is an iterative process so change over time is incremental from year to year, but regular; PJM staff develops actual market initiatives in steps responding to results and next clear opportunities. Wholesale market participants are selling PJM DR programs to their customers.

In a Dec 22, 2004 Order the BPU adopted Clean Energy Program protocols to measure energy savings from the EE program and energy generation from the RE program.[10] These protocols are to be updated on a continuous basis to remain current with new Federal or State guidelines and laws, as well as technology improvements made by industry and changes in the market. The Order directed the establishment of a Protocols Oversight Group comprised of representative of the Ratepayer Advocate, the Department of Environmental Protection and other interested parties. This group will recommend changes and updates to the Protocols as required and propose a Protocol for any existing program without one, and any new program proposal must have a measurement and verification protocol in place prior to its acceptance for implementation. The Protocols focus on the determination of the per unit savings for the EE measures—electricity (kW, kWh), gas (therms), and other (oil, propane, water, maintenance). These resource savings are used to calculate avoided environmental emissions.

Assessing Programs

Rutgers University's Center for Energy, Economic and Environmental Policy (CEEEP) has been engaged by the OCE to manage evaluation and related research activities. CEEEP develops evaluation and related research plans, with input on the plans from the OCE, the Clean Energy Council, program managers and others. Once plans are approved by the OCE, CEEEP either perform the evaluation and research activities or engages third-party contractors through RFPs. CEEEP coordinates with the OCE and the Clean Energy Council to implement recommendations from the evaluations and related research. The approved 2005 Evaluation and Related Research Plan includes:

- *Market Assessment:* The market assessment planned for 2005 is intended to gather information regarding the state of the energy efficiency marketplace in New Jersey to help inform program designs and incentive levels.
- *Impact Evaluation:* Protocols are used to estimate the savings from energy efficiency measures and generation from renewable energy facilities. An impact evaluation contractor has been engaged to measure actual savings or generation which will be used to update protocols.

In addition to implementing the evaluation activities noted above, OCE coordinates with regional and national energy efficiency and renewable energy groups such as the US EPA Energy Star program, the Northeast Energy Efficiency Partnership (NEEP), the Consortium for Energy Efficiency (CEE), National

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

[10] 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

Association of State Energy offices, NARUC, the Clean Energy states Alliance and others. Coordination with these groups assists with the development and evaluation of programs.

Benefit-Cost Tests

Cost-effectiveness analysis counts all resource costs and savings, which in practice is the Total Resource Cost (TRC) test plus externalities. This is the primary test to assess the relative economic value of the New Jersey Clean Energy Programs.

DSM Spending

Actual Spending

In 2004 $93 million was spent on DSM in New Jersey. The 2005 budget for gas and electric EE is $102 million.[11] The following table shows how the SBC cost translates into % of customer bill.

	SBC cost as a % of electric bill	SBC cost as a % of gas bill
Residential	2.0	1.1
Commercial	2.2	1.6
Industrial	2.5	2.1

DR spending for the Economic Program is shown in the table below[12].

Table 2-40 - Performance of PJM Economic Program participants

	Total MWh	Total Payments	$/MWh	Total MWh per Cumulative Total MW
2001	50	$13,994	$283	N/A
2002	6,462	$761,977	$118	21
2003	19,290	$827,179	$43	33
2004	48,622	$1,487,848	$31	67

Appropriate Levels

The ultimate decision on how much to spend on energy efficiency programs and how to spend it is not an output of any one of the cost-benefit tests. Rather, budgeting decisions are informed by policy, political and practical considerations (e.g. incremental rate impacts; the distribution of program benefits among customers and customer classes); the recent legislative directives to increase energy efficiency by

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

[12] PJM State of the Market Report, 2004. http://www.pjm.com/markets/market-monitor/som.html

transforming markets, serving low-income customers and capturing lost opportunities for savings; and the existence of relevant regional and national programs.[13]

Two market potential studies were done 1999 for each of EE and RE to help balance implementing cost-effective EE and RE with increased rates[14]. The guideline is that incremental funding for such activities cannot exceed a 1% increase in rates. The market assessment for EE concluded that increasing funding for EE from currents level would increase benefits to society from $1.8 billion to $2.6 billion. The table below shows final funding for 2005 through 2008.

Year	Total ($ million)	Energy Efficiency	% of Total	Renewable Energy	% of Total
2005	$140	$103	74%	$37	26%
2006	$165	$113	68%	$52	32%
2007	$205	$123	60%	$82	40%
2008	$235	$133	56%	$102	44%
Total	$745	$472	63%	$273	37%

New Jersey is not currently using a least-cost approach to regulation; however, recently the BPU board authorized a task force to look at setting up a process to do portfolio management, the latest iteration of least cost planning, Rutgers, which does a lot of evaluation work recommended portfolio management, noting that with a competitive market there is a need to balance different interests.

Cost Recovery and Incentives

Cost recovery

Costs are recovered through a systems benefit charge collected through a fuel adjustment clause. Costs are expensed and deferred accounting with pass through is to be used until 2006.

Incentives – LRAM Mechanism

New Jersey currently has no incentives for utilities to participate in DSM. They used to have a lost revenue adjustment mechanism (LRAM) until 2003. The Board originally approved lost revenue recovery for utilities as part of its DSM incentive regulations adopted in 1991. The regulation provided utilities with incentives to invest in DSM as an alternative to invest in generation by providing an opportunity to earn profits on investments in EE. The regulations also removed a disincentive by allowing a utility to recover fixed costs they otherwise would have collected if the saved kWh was sold instead. Since that time the electric power industry in New Jersey has been restructured such that the utilities now are wires companies only and no longer build, own or operate electric generation. Also the Board has transferred responsibility for program administration to the OCE and will hire program mangers to deliver most of the programs. It is anticipated that the entities engaged to serve as program managers will be provided with financial incentives to deliver certain levels of energy savings. "*Therefore lost revenue recovery is no longer needed as an incentive for a utility to invest in energy efficiency and renewable energy…*"[15]

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

[14] New Jersey Statewide Market Assessment, Xenergy 1999. http://www.njcleanenergy.com/html/5library/nj_baseline_studies_cost.html

[15] BPU Dec. 22, 2004 Order.

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.

Interview Contacts

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New York DSM Summary[1]

DSM Background and Approaches

Background and Interest

In 1996, the New York State Public Service Commission (PSC) established a System Benefits Charge (SBC) to fund public policy initiatives not expected to be adequately addressed by New York's competitive electricity markets[2]. The underserved areas were identified as energy efficiency, energy related research and development programs, and initiatives designed to reduce the financial burden of energy costs on low-income consumers. In 1998, the PSC specified SBC funding levels for three years and the framework for energy programs targeting efficiency measures (EE), research and development (R&D) and the low-income sector (LI). The SBC was renewed for a five-year period in January 2001 (July 1, 2001 to June 30, 2006) with increased funding and additional focus on programs designed to achieve peak load reductions[3]. The current SBC funding level is approximately $150 million annually. The Commission also ordered that the New York State Energy Research and Development Authority (NYSERDA) complete "detailed evaluations" of the SBC and its funded programs for the calendar years 2002 and 2004, with "interim status reports" for the remaining program years.

The New York State Department of Public Service (DPS-staff to the PSC) recently completed a major SBC program review with the objective of advising the PSC regarding the future of the SBC beyond its funding expiration on June 30, 2006. On December 14 2005, a PSC Order[4] extended SBC funding for another five years (2006-2011) and increased the level to $175 million annually; PSC staff had recommended $150 million but many intervenors argued to increase funding. Proponents of an increase argue that it is needed for the following reasons:

- *to keep pace with the effect of inflation on the costs of the programs,*
- *as an offset to the current high and rapidly escalating energy prices (particularly for low-income programs),*
- *to provide more public benefits,*
- *to provide more net environmental and cost benefits,*
- *to better align New York's expenditures with the level of spending on similar programs in other states in the Northeast and with California,*
- *to match the growth in kilowatt-hour sales,*
- *to have a greater near-term impact on market transformation programs,*
- *to restore funding on a per-capita basis nearer to expenditure levels in the 1990s,*
- *to reduce energy costs to make New York competitive with other regions, and*

[1] This summary is based primarily on an interview completed during December 2005 with Bill Saxonis of the Dept. of Public Service of New York, supplemented by information sources provided by Mr. Saxonis.

[2] Case 94-E-0952, et al., In the Matter of Competitive Opportunities Regarding Electric Service, Opinion 96-12 (issued May 20, 1996).

[3] Case 94-E-0952, et al., In the Matter of Competitive Opportunities Regarding Electric Service, Order Continuing and Expanding the System Benefits Charge for Public Benefit Programs (issued January 26, 2001).

[4] Order Continuing the System Benefits Charge (SBC) and The SBC-Funded Public Benefit Programs, December 14, 2005 http://www3.dps.state.ny.us/pscweb/WebFileRoom.nsf/Web/5375707FAF2225B2852570D600700767/$File/05m0090_12_21_05.pdf?OpenElement

- *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

> 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.

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 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 $mart^{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

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[6] 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

coupled with a multi-media marketing campaign encouraging consumers to follow three specific energy tips during the summer months: (1) buy ENERGY STAR® products, (2) shift appliance use to non-peak periods, and (3) use timers or programmable thermostats on air conditioners. Due to the success of the program, the bounty program ceased after 2003. The marketing component was continued in 2004 and the program was renamed Stay Cool!.

- **New York ENERGY STAR® Labeled Homes (NYESLH) Program**. This program is an enhanced version of the EPA's ENERGY STAR® Labeled Homes Program, providing technical assistance and financial incentives to one- to four-family home builders and Home Energy Rating System (HERS) raters. The program encourages the adoption of energy-efficient design features and the selection and installation of more energy-efficient equipment in new construction and substantial renovation projects.

- **Home Performance with ENERGY STAR® (HPwES) Program**. This program is designed to enhance the capacity for delivering energy efficiency services to existing one-to four-family residences. Energy efficiency improvements supported by the program include building shell measures; electric measures, such as refrigerators and lighting fixtures; heating and cooling measures, such as boilers and central air conditioning; and renewable energy technologies, such as photovoltaics.

- **ENERGY STAR® Products Bulk Purchase Program.** This program provides purchase assistance for early replacement of inefficient appliances through education, bulk procurement, and incentives in order to influence market transformation in the multifamily sector. Bulk purchase activities were originally part of the Appliances and Lighting Program, but became a separate program in 2002. Incentives were discontinued in 2003.

- **Residential Comprehensive Energy Management Program**. This program promotes the acquisition and installation of sophisticated energy management and advanced metering systems. This program helps position residential customers to take advantage of retail competition, while enabling program implementers access to customers' energy-use data.

- **Residential Technical Assistance Program.** This program improves the operation of multifamily housing by identifying and encouraging the implementation of cost-effective energy efficiency measures that also enhance health, safety, and comfort. Activities supported include: feasibility studies, computer-assisted building modeling; energy efficiency technical training, and commissioning.

- **Website Hosting and Re-Design.** The purpose of the www.GetEnergySmart.org website is to inform the public of **New York Energy $mart**SM programs and to provide details on the benefits of energy-efficient and/or ENERGY STAR® products and methods over conventional products and building methods. The new hosting platform and website re-design have been employed to improve visitors' experience on the website and to encourage their participation in the program that best addresses their energy efficiency needs. The website also serves as a communication tool with program partners.

- **Energy $mart Communities Program**. The program was developed to complement the Department of Energy **Rebuild America** Program. Energy $mart Communities targets regional needs by bringing together organizations and agencies that contribute to local "model" projects demonstrating how energy efficiency and energy resource approaches can be used to create economic, social and environmental benefits. To transfer the success of these model projects to the rest of the region, this program provides information and support at the local level to 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 wherever practicable to maximize the use of public funds for the programs and to ensure a coordinated statewide effort to meet public policy goals.

Demand Response

With rising electricity demand, interest in demand response (DR) has been increasing as well. DR is delivered in a coordinated fashion in New York, both through NYSERDA and the independent system operator, the NYISO. NYSERDA supports participation in NYISO programs by providing services such as incentives for interval meters and education and outreach. In addition, NYSERDA offers programs that target reducing electricity use during periods of peak demand, such as the Keep Cool program. This program provided financial incentives for over 141,000 units for the replacement of inefficient room air conditioners with energy-efficient Energy Star® replacements.

NYISO programs include both Reliability DR programs and a Day-Ahead DR program. The Reliability Demand Response programs—the Emergency Demand Response Program and ICAP Special Case Resources program— provide the NYISO with additional resources to deploy in the event of energy shortages to maintain system reliability. The Day-Ahead Demand Response Program (DADRP) allows energy users to bid their load reductions, or "negawatts," into the day-ahead energy market just as generators do. Offers that are determined to be economic are paid the market clearing price. DADRP allows flexible loads to effectively increase the amount of supply in the market and thereby moderate prices.[7]

Successes and Setbacks

SBC funded programs have generally been pretty successful, e.g. sales of Energy Star® appliances have increased in New York. The overall portfolio benefit-cost ratio is 2:1 with the strict TRC (TMET1) and is much higher with externalities included (TMET4). Demand response programs have also been successful; they had to called several times over the last few years to enhance system reliability and avoid potential supply disruptions.

On the negative side, a few intervener groups argue that DSM is a fee on ratepayers in a state that already has high rates and argue that efficiency will happen naturally.

Design, Implementation and Evaluation

Responsibility

With few exceptions, NYSERDA projects are competitively selected. NYSERDA has instituted numerous policies to ensure that the Program is administered in an open, fair, and equitable manner. Ninety-seven percent (97%) of projects are competitively selected. The remaining 3% of projects involve contracts less than $15,000 each, unsolicited proposals that are deemed to support the Program's goals and sole-source contracts with unique, specially-skilled contractors.

NYSERDA works with the SBC Advisory Group of about 24 electric utility experts, energy consultants, for both design and implementation of programs, to establish program priorities and evaluate progress in achieving those objectives.

[7]NYISO web site http://www.nyiso.com/public/products/demand_response/index.jsp

Screening Programs

For deployment and market transformation programs for which energy and demand savings can be estimated, an economic benefit/cost (B/C) analysis is used. One variation of the total market effects test (TMET1), which is similar to the Total Resource Cost test, compares the benefits to both the program and customer costs. Another variation—TMET4—includes several non-energy benefits, including, job creation, health, and safety. Another test, the program efficiency test (PET), compares the benefits to just program costs. NYSERDA includes B/C ratios as one element among numerous decision criteria for this purpose. Programs are continually reviewed and revised by NYSERDA in response to customer feedback and evaluation findings.

For some R&D programs, the economic benefit/cost methodology is inappropriate because these programs are designed to accomplish a range of objectives, many of which cannot be monetized in the early years. For these programs, the value/cost analysis was developed to assess the benefits qualitatively and to monitor progress toward measurable energy, economic, and environmental benefits.

Assessing Programs

An order of the PSC created an Advisory Group from utility companies, business and environmental groups, community organizations, professional and trade associations, other State agencies, and national energy efficiency and R&D experts. The Advisory Group serves as the Independent Program Evaluator and provides guidance and feedback on program administration. The Advisory Group usually meets three or four times each year. The Advisory Group is independent of NYSERDA. Members of the group participate in selection of evaluation contractors, receive evaluation reports for review, and have independent access to the evaluation contractors. The evaluation budget is two per cent of program funding.

NYSERDA's evaluation function is conducted primarily by a team of independent evaluation contractors. All contractors were selected through competitive solicitation with a member of the Advisory Group and DPS staff serving on each review panel. The Advisory Group and DPS staff help allocate the evaluation budget, identify evaluation activities to be conducted, and establish timelines for evaluation activities.

NYSERDA has a performance measurement plan for its programs individually and as a portfolio to evaluate their effects on New York's economy, businesses, and residents. NYSERDA integrates performance measurement into its program planning from the outset, starting with the development phase, continuing to completion, and ending in post-implementation follow-up and reporting. Some of the effects measured include:

- Promoting energy savings, energy demand reductions, improved affordability of energy, and lowered energy bills for New Yorkers;
- Reducing non-energy business expenses, including reduced operation and maintenance, processing, regulatory, and administrative costs;
- Enhancing product development and economic growth and transformation of market processes and behavior to support an energy efficiency ethic in decision making;
- Increasing product sales and jobs created and retained by New York companies;
- Reducing harmful air and water emissions; and,

- 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.

Table 3-2. Financial Status of the New York Energy Smart[SM] Program as of December 31, 2004

Program Area	8-year Budget (millions)	Funds Committed (millions)	% of 8-year Budget Committed	Funds Encumbered (millions)	% of 8-year Budget Encumbered
Business/Institutional	$359.1	$328.5	91.5%	$299.6	83.4%
Residential	$170.7	$157.2	92.1%	$154.3	90.4%
Low-Income	$128.4	$111.3	86.7%	$86.1	67.1%
Research and Development	$210.8	$160.7	76.2%	$137.2	65.1%
Environmental Disclosure	$2.9	$1.1	35.9%	$0.7	22.2%
Evaluation	$16.2	$10.8	66.5%	$10.3	63.4%
Administration	$64.6	$43.2	67.0%	$43.2	67.0%
NYS Cost Recovery Fee	$9.0	$4.1	45.1%	$4.1	45.1%
Total[a]	**$961.8**	**$816.9**	**84.9%**	**$735.5**	**76.5%**

a. Totals may not sum due to rounding.

Source: New York Energy Smart[SM] Program - Financial Status Report, as of December 31, 2004.

Optimal Levels

New York's expenditure level on the SBC program is less than the peak year of spending on the utility energy efficiency programs before competition due to many factors.[10] The following chart shows the impact of the new SBC allocation formula using 2004 actual utility electric operating revenues to determine the allocation by utility for a five-year period. The annual amount to be collected by each utility is shown in the table below.

Annual Collection Shares

SBC Utility	2004 Electric Revenues	Percentage of Total	Annual Collection Amount	Collection as a % of Rev
Central Hudson	$430,586,411	3.49%	$6,110,295	1.42%
Con Edison	6,164,406,553	49.99%	$87,476,852	1.42%
NYSEG	1,529,822,159	12.41%	$21,709,150	1.42%
National Grid	3,175,168,934	25.75%	$45,057,668	1.42%
O&R	368,129,383	2.99%	$5,223,990	1.42%
RG&E	663,962,122	5.38%	$9,422,045	1.42%
TOTALS	$12,332,075,562	100.00%	$175,000,000	1.42%

[11]

A study was done of the technical potential for electricity DSM in 2003[12]. In addition, NYSERDA is conducting a study of the potential for natural gas efficiency improvements in Con Edison Gas' service area as part of a Sept 27, 2004 Order and has expanded this study state wide.

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[10] Order Continuing the System Benefits Charge (SBC) and The SBC-Funded Public Benefit Programs, December 14, 2005 http://www3.dps.state.ny.us/pscweb/WebFileRoom.nsf/Web/5375707FAF2225B2852570D600700767/$File/05m0090_12_21_05.pdf?OpenElement

[11] Appendix A, PSC Dec. 14, 2005 Order.

[12] Energy Efficiency and Renewable Energy Resource Development Potential in New York State - Final Report, Volume One: Summary Report August 2003 http://www.nyserda.org/publications/EE&ERpotentialVolume1.pdf

Cost Recovery and Incentives

Cost recovery

Costs are recovered through a system benefits charge and expensed. Utilities collect the funds from customers through rates and remit them to NYSERDA. Sometimes utilities keep some of the funds, for example, Rochester G&E had a lot of ESCO contract obligations so the utility keeps some of the funds to pay for these.

Least cost planning can be used in specific rate cases, e.g. Con Ed - targeted DSM program for MW relief- system wide program that can be funded with incremental dollars to the SBC charge - 25% of power to come from renewable resources (now at about 18 % from water).

Resources for Future Reference

Public Service Commission, System Benefits Charge, 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

Order Continuing the System Benefits Charge (SBC) and The SBC-Funded Public Benefit Programs, December 14, 2005
http://www3.dps.state.ny.us/pscweb/WebFileRoom.nsf/Web/5375707FAF2225B2852570D600700767/$File/05m0090_12_21_05.pdf?OpenElement

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Ontario DSM Summary

DSM Background and Approaches[1]

Background and Interest

Since 2003, the level of interest in DSM for electricity use in Ontario has risen dramatically. With Ontario now facing increasing demand for electricity and supply shortages due to difficulties with nuclear, phase-out of coal generation, and aging plants, interest in DSM for electricity is very high. The Ontario Energy Board (OEB) regulates aspects of the gas and electricity industry in Ontario. Notably, one of the OEB mandates in the gas sector is to "Promote energy conservation and energy efficiency in a manner consistent with the policies of the Government of Ontario." As such, the OEB has encouraged DSM in the natural gas sector for over 10 years, approving considerable funding for energy conservation and efficiency. While commitment to DSM from the large gas utilities (Enbridge and Union Gas) has varied, investments have generally been sustained. Recent events have not significantly altered the level of interest or desirability in gas DSM from the OEB's perspective. However, Enbridge and Union Gas are more actively and aggressively pursuing DSM.

Unlike in the gas sector, the OEB has not had a sustained legislative mandate to pursue DSM in the electricity sector. The OEB did, however, oversee some significant investments in DSM by Ontario Hydro in the early 1990s. The current level of interest in DSM in this sector is elevated. Since 2003, the issue of DSM has been the subject of one generic hearing and a portion of several others. Recently, the OEB approved significant funding, recovered in 2005 distribution rates, for distributors to invest in energy efficiency, conservation, load management, demand response, and other DSM or system benefiting type of initiatives

Ontario opened electricity markets to competition in May 2002. The over 90 electricity LDCs were allowed to increase distribution rates in three instalments (tranches) to cover costs to change systems. In November, after a hot summer with high volatile prices, the Conservative government froze distribution rates and capped commodity rates for about half the market (in terms of load), halting private investment in power generation in Ontario. The LDCs had not yet implemented the 3rd tranche. In spring 2003, the Liberals were elected and began to push DSM and clean energy supply. In summer the government established an Electricity Conservation and Supply Task Force (ECSTF) to develop an action plan to attract new generation, promote conservation, and enhance reliability of the transmission grid, and the Ministry of Energy directed the OEB to consult with stakeholders to identify and review options to deliver DSM and demand response activities within the electricity sector.

The ECSTF report released in January 2004 recommended, among other things, creating a conservation culture in Ontario. And in spring 2004 the OEB report to the Minister of Energy on Demand-side Management and Demand Response in the Ontario Electricity Sector recommended the following:

- a conservation agency be set up to oversee DSM/DR activities;
- conservation efforts and programs be funded by a charge on electricity consumption levied on all consumers, but not on self-generated electricity;

[1] This summary is based primarily on the knowledge of Gay Cook of Summit Blue based on 25 years of experience in the Ontario energy market, supplemented by interviews with Ontario Energy Board staff.

- LDCs be eligible to develop and deliver DSM/DR activities beyond LCP and/or distribution system optimization with the Board regulating distributor activities funded out of distribution revenues;

- the Independent Electricity System Operator (IESO), in consultation with stakeholders, design and develop economic DR as a transitional measure; and,

- education of consumers.

The LDCs could implement the third tranche if they spent the first year's revenue on conservation and demand management (CDM) programs. In May, the Minister of Energy sent a letter to LDCs allowing them to apply to the OEB for deferral accounts to track expenditures on CDM initiatives in advance of normal recovery of costs in March 2005. In August 2004, the OEB issued an issued information bulletin to LDCs on distributor CDM activities and on the process to apply for deferral accounts and two procedural orders in Oct. and Nov. Over 60 LDCs submitted plans for approval and by spring 2005 the OEB had approved $160 million for LDCs to spend on CDM activities by the end of the year 2007. They are required to file quarterly reports and annual reports with the OEB.

In summer the government tabled legislation – the Ontario Electricity Restructuring Act 2004 (Bill 100), which included establishing a new Ontario Power Authority (OPA) to ensure long-term electricity supply in Ontario. Its mandate included forecasting future demand and the potential for conservation and renewable energy, preparing an integrated system plan for generation, transmission, and conservation, and establishing a Conservation Bureau, headed by a Chief Energy Conservation Officer, to provide leadership in planning and coordination of electricity CDM. The government set targets which the OPA is charged with achieving: 5% of Ontario's capacity from new renewable sources by 2007, 10% by 2010; and electricity demand reduced by 5% by 2007 through conservation. After extensive consultations over the summer and fall, Bill 100 received Royal Assent on Dec. 9, 2004.

The OPA was established in January and a Chief Conservation Officer appointed in April 2005. In the summer the Minister asked the OPA to begin work on a twenty-year Integrated Power System Plan and the OPA hired consultants to develop electricity supply mix recommendations for the OPA to deliver to the Ministry of Energy by December 1, 2005. As part of this mix, the OPA must identify and develop strategies to accelerate the implementation of conservation, energy efficiency, and demand management. The previous plan for supply in Ontario was last done by Ontario Hydro in 1989. Natural gas distributors plan DSM and their system in the context of least cost planning.

On November 3, the Energy Minister proposed Bill 21 introducing the Energy Conservation Responsibility Act, 2005. The proposed legislation provides the framework to install 800,000 smart meters in Ontario by 2007 and in all homes and businesses by 2010. It sets the framework for an entity to oversee smart metering communications systems and technologies, giving the government flexibility to determine the best options for the governance, ownership, and regulatory structures of the smart metering initiative. These options will be the subject of consultations over the next two months. The government also directed the OPA to produce three programs, expected to reduce electricity use by up to 200 MW: 1) a low-income and social housing program; 2) an appliance exchange program; and 3) a conservation outreach and education program targeting residential and small and medium-sized enterprises that would promote energy-efficient lighting technologies and efficient lighting design.

Approaches

Ontario is implementing DSM in several ways: 1) through natural gas and electricity LDCs regulated by the OEB; 2) through an OPA bidding process for demand response projects; 3) other OPA initiatives including recent directives; and 4) the Conservation Action Team established by the Energy Minister in January 2004. This team, chaired by Donna Cansfield, (now Minister of Energy), developed an action plan to help the government meet its electricity conservation target of 5% by 2007, identified and removed barriers to conservation in existing government policies/programs, and explored ways for new government policies/programs to incorporate conservation principles. The first report was done May 18, 2005.

Going forward, it expected that the Ontario Energy Board will focus on conservation and demand management activities that can only be achieved by the distributors.

Types of Programs

Natural gas distributors focus on energy efficiency and conservation. Electric LDCs, with the approval given to distributors in 2005, all of the following list of programs are supported including others relating to distributed generation.

- Energy efficiency
- Energy conservation
- Load management
- Demand response
- Distribution system optimization
- Fuel switching

Successes/Setbacks

One key issue is high regulatory costs for natural gas DSM. The OEB treats DSM differently for electricity than it has done for natural gas; however, there is no substantial experience with electricity yet. DSM for gas is done through evaluations that are filed during rate hearings and scrutinized by intervenors. Although gas savings have been very cost-effective, lots of hearing time is devoted to DSM and regulatory costs are very high. The last evaluation from Enbridge took three years, for example, dramatically increasing regulatory costs. The two large gas distributors have quite different estimates and savings, free riders, etc., leading many issues with estimates of impacts. The distributors are also concerned about retroactive changes to estimates of savings as a result of audits of impacts of measures. The electricity model, on the other hand, involves developing pre-approved estimates (savings, free riders, costs, etc.) for various measures; however, some stakeholders are pushing to adapt the gas model to electricity. The gas model provides much more uncertainty than does the electricity model.

Demand Response

Demand response (DR) is becoming more important since the very hot summer of 2005, which saw the 2006 normal weather summer peak forecast value of 24,234 MW on 18 days, setting a new record for summer demand of 26,160 MW.

The IESO has implemented some DR initiatives for the wholesale market participants, which include both reliability and real-time price DR programs. Hour-ahead Dispatchable Load and Transitional Demand

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

In 2005 DSM spending in the gas sector will be $25 million and electricity distributors will spend $163 million in DSM activities over three years. In 2006 distributors have applied for an incremental $3.5 million and the OPA's Conservation Bureau is expected to spend about $4 million. There is no prescribed percentage of revenue to spend on DSM. Enbridge spends 0.7% of revenue; Union spends 0.8% of revenue, and electric LDCs about 5% of revenue.

Appropriate Level

The OEB considered the issue of the appropriate level of spending on DSM by electricity LDCs during EDR 2006 but the Board decided that there should be no preset level of spending. However, it was found that the desirable level of spending was more than the current level.

In the gas sector, Union Gas did a technical potential study in November 2004 and Enbridge will have a study completed in 2005. In the electricity sector, no formal studies have been done, however, the Report of the Board on DSM and DR addresses the issues of market potential. It was also addressed in the context of distribution rates for 2006 and the subsequent Report of the Board.

Cost Recovery and Incentives

Cost Recovery

DSM spending in the gas sector is typically expensed. DSM costs in the electricity sector are either expensed or capitalized depending on the nature of the spending. With respect to utilities, the Board approves funds for DSM to be recovered in distributions rates. The Board also approves the budget of the Conservation Bureau; this funding will be recovered from a charge on the market (system benefit charge).

Special Case 2005: In 2005, the Board approved fund for electric distributors to be invested over 3 years, expenditures of these funds are being tracked in a deferral or tracking account for regulatory purposes.

Incentives

The gas sector is held harmless from the loss of revenue through a revenue protection mechanism. An incentive mechanism is also put in place based on a percentage value of the net TRC savings. Accessing the incentive is contingent on the utility achieving a stretch target. The revenue protection for electricity is similar to the gas model. The incentive mechanism is a simple 5% of net TRC benefits**.**

Resources for the Future

Minister's Directive to the OEB. http://www.oeb.gov.on.ca/documents/directive_dsm_070703.pdf.

Electricity Conservation & Supply Force Task Report, January 2004. http://www.energy.gov.on.ca/english/pdf/electricity/TaskForceReport.pdf

OEB Report: Demand-side management and Demand Response in the Ontario Electricity Sector, March 1, 2004. http://www.oeb.gov.on.ca/documents/cases/RP-2003-0144/pressrelease_report_finalwithappendices_030304.pdf

OEB Information Bulletins and Procedural Orders.

http://www.oeb.gov.on.ca/documents/dcdm_informationbulletin_310804.pdf

http://www.oeb.gov.on.ca/documents/dcdm_po_051004.pdf

http://www.oeb.gov.on.ca/documents/dcdm_amend_proc_order2_041104.pdf

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

Bill 100, Dec. 9, 2004 http://www.ontla.on.ca/documents/Bills/38_Parliament/Session1/b100_e.htm

Bill 21, introduced Nov. 3, 2005
http://www.ontla.on.ca/documents/Bills/38_Parliament/session2/b021_e.htm

Conservation Action Team Report
http://www.energy.gov.on.ca/english/pdf/conservation/CAT_Report.pdf

Report of the OEB on EDR 2006
http://www.oeb.gov.on.ca/html/en/industryrelations/ongoingprojects_EDR.htm

TRC Guidelines http://www.oeb.gov.on.ca/documents/cdm_trcguide_141005.pdf.

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Oregon DSM Summary[1]

DSM Background and Approaches

Background and Interest

Demand-side management (DSM) has a long tradition in Oregon, as in the rest of the Pacific Northwest. The 1980 Northwest Power Act requires that energy conservation be the first supply acquired to meet new power needs. The 1989 Order (89-507) of the Oregon Public Utilities Commission (OPUC) that established the requirement for Least Cost Planning (LCP) by investor-owned gas and electric utilities (IOUs) also required that all resources, supply and demand, be evaluated in a consistent and comparable manner. In Oregon, energy efficiency is understood as a legitimate resource that lowers overall utility costs.

After 1989, DSM measures were acquired according to LCPs developed by the electric and gas utilities with public input, and acknowledged by the OPUC. Although not all cost-effective DSM was acquired for a variety of reasons, the utilities always had to include DSM, and investments were higher than in many parts of the country. The DSM landscape began to change in the late 1990s, with major changes in Oregon prompted by the passage in 1999 of SB 1149, the Restructuring Act.[2]

Anticipating the loss of public benefits that can come with restructuring, the legislature also created a public purpose charge (PPC) of 3% of revenues from the state's two largest electric utilities, PacifiCorp (aka Pacific Power), and Portland General Electric (PGE). By statute the PPC funds are to support programs in the following proportions:

56.7% New cost-effective energy conservation and market transformation.

17.1% Above-market costs of new renewable energy.

11.7% New low-income weatherization.

10.0% Energy conservation in schools.

4.5% Low-income housing.

A new non-profit organization, the Energy Trust of Oregon (ETO), was created to administer the first two program areas under contract with the OPUC. Load management and demand response (DR) programs would still be the responsibility of the utilities. By 2004, the OPUC and the state's largest natural gas utility (80% of customers), NW Natural, had agreed to a PPC of 1.25% of the utility's revenues to be administered by the ETO, along with a formula that decoupled the gas utility's revenues from sales.

[1] This summary is based primarily on interviews completed during October 2005 with Lynn Kittilson and Lisa Schwartz of the Oregon Public Utilities Commission, and Fred Gordon of the Energy Trust of Oregon.

[2] The electric restructuring statute provided that residential customers of PGE and Pacific Power have access to a standard cost-of-service rate, at least one renewable resource option, and a market-based option, all provided by their utility. Small businesses (30 kW demand) have direct access to alternative suppliers or can choose from the renewable resource and market-based options offered to residential customers. Large commercial and industrial customers can choose an alternative supplier or a standard offer tied to market prices, in addition to the cost-of-service option. About 86% of business load is still using the traditional cost-of-service option.

Presently the ETO administers energy efficiency programs using over $50 million in PPC funds for the benefit of the customers of Pacific Power, PGE, and NW Natural; renewable energy programs benefit customers of the two electric utilities only. When possible, the ETO programs are designed to achieve synergies with the Oregon Department of Energy's highly successful residential and business energy tax credit programs and State Energy Loan Program.

The remaining electric IOU, Idaho Power, and two gas IOUs, Avista and Cascade, conduct DSM programs in the context of their LCPs.[3] These utilities get both cost recovery and lost revenue adjustments, but that has not been enough to heighten interest in DSM. However, Cascade has proposed a decoupling arrangement that would also move its DSM programs to the ETO. This is likely to result in an upward trend in gas DSM investment and savings.

Present interest in DSM in Oregon is very high among many sectors. The Oregon Department of Energy runs the state's highly successful residential and business energy tax credit programs and State Energy Loan Program. ETO program participation levels are skyrocketing, due to good programs, concern about rates, and the new availability of gas efficiency programs. Gas utilities have been showing some interest in DSM that might relieve pipeline congestion. Interest in many ETO programs has been so high that incentives have been lowered and programs have been capped to stay within budget. A recently commissioned study of efficiency potential is expected to show that more cost-effective efficiency exists than can be acquired by the capped PPC.

The OPUC is very interested in Demand Response due to increasing summer peak, increasing market volatility, and recognition that DR works and can be very cost-effective. The 2000-2001 energy crisis in the West reinforced the value of DR to the region. Demand and energy buyback programs for industrial loads significantly reduced excess power costs and helped avoid outages throughout the region. "However, the long-term agreements appear to have increased utility costs. They locked-in rates for customer credits for several months based on high forecasted market rates, just before FERC set a price cap in the Western wholesale market and prices fell. On the other hand, we do not know to what extent the long-term buybacks reduced market prices and therefore provided ratepayer benefits."[4] At the same time, OPUC staff concluded that Oregon did not capture all of the benefits of DR because strategies were not in place before the crisis hit. Interest in DR had not been as urgent as in other states because of the historic lack of a summer peak when prices in the West are highest, and the seasonal sharing of excess power between Oregon and California.

Interest in efficiency investments has been driven by strong, broad-based citizen action groups and supported by industry, regulators, and the legislature. There is some concern that capping funds available for industries may cut into their support.

Interest in DR is being driven on several fronts. One outcome of OPUC staff reports and recommendations after the energy crisis was Order 03-408, which required utilities to include DR in LCPs, to assess potential and barriers, and to adopt new pilot programs. The OPUC has opened an investigation (UM 1188) into policies to facilitate advanced metering, and its LCP investigation (UM 1056) includes an examination of how DR can be addressed in the context of LCP. These state-level efforts coincide with national requirements and recommendations in the 2005 EPAct.

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[3] A docket, UM 1056, was recently opened to update the LCP process in Oregon. A new Order is expected soon which will give guidance to the process.

[4] OPUC Staff report. May 2003. "Demand Response Programs for Oregon Utilities." http://www.puc.state.or.us/elecnat/demand/default.htm

Approaches

The ETO acquires efficiency resources directly using vendor-driven rebates and other incentives, but also funds and cooperates with the Northwest Energy Efficiency Alliance (NW Alliance) to support market transformation. The ETO does joint marketing and co-branding with all 3 utilities. ETO works with hundreds of vendors to implement residential and commercial projects. Programs address lighting, heating, building operation, appliances, industrial process design, and more. Although absolute equity is not required, ETO does attempt to reach all customer sectors, including hard-to-reach customers. The NW Alliance works with industry executives to make the business case of efficiency as a profit center. The ETO provides examples to show it's possible. The ETO and NW Alliance may co-fund pilots, such as commercial building tune-ups, to get people interested and refine program delivery. Large customers (over 1 MW demand) can self-direct funds to their own DSM programs. Recent trends show more large customers using ETO services, perhaps due to the success of its custom industrial programs.

The ETO would like to contribute to distribution system optimization, but serious conversation with utilities on this is not happening yet. The ETO is planning a pilot project to concentrate energy efficiency and renewable program investments in a particular neighbourhood or community. These efforts have potential benefits to the system grid, deferring T&D investment, increasing reliability, and relieving congestion. The OPUC held a workshop on non-wires alternatives to utility T&D investments in 2004 and plans to open an investigation in 2006.

Most non-ETO gas utility DSM programs have been in existence and unchanged for some time. They include small rebate programs for furnaces, hot water heaters, etc., implemented by third-party contractors. They do energy audits if requested, but do not promote them. State-mandated weatherization programs are available but the incentives haven't changed for years. Questionable assumptions about avoided costs and other factors have resulted in relatively low levels of DSM investment. Avista and Cascade each have less than one full-time-equivalent dedicated to DSM in Oregon. Large gas consumers generally have their own non-utility contracts for supply, storage, and transport. As a result their needs are not reflected in LCPs and no utility DSM is directed at these consumers.

Gas utilities and the OPUC are beginning to discuss distribution system optimization and DSM. For example, Cascade has constraints in Washington State, due primarily to transporter customers. They can't use the rate base to pay for capital improvements, so they are interested in DSM that might defer or remove the need for those investments. Once a model for this starts developing and value is proven, there will be more interest.[5]

Demand response efforts were most robust in response to the 2000-2001 Western energy crisis. PGE has about 30 MW of dispatchable customer standby generation contracts. Demand buyback programs are inactive right now. PGE conducted direct load control pilots of water and space heating but found that it was not cost-effective at the time. However, higher energy prices and summer peaks are developing new opportunities for water heating, air-conditioning and lighting load control. PGE and PacifiCorp are

[5] Note that the LCPs, including DSM plans, of gas distribution utilities only address the needs of their firm distribution or "core" customers. The gas utilities buy the commodity from a variety of suppliers and transport it through pipeline, storage, and distribution systems to meet the needs of these firm sales customers (primarily residential and small commercial and industrial customers). They generally own their distribution systems and some storage, and contract for the commodity and pipeline transport. Large gas consumers are likely to have their own non-utility contracts for supply, storage, and transport. If needed, they may have a contract with a utility for distribution only. As a result, the needs of most large consumers are not reflected in utility LCPs, and no utility DSM is directed at these consumers. So when they do LCP now, the gas companies plan for firm core customers; they plan to buy supply and have pipeline capacity for them, plus they report throughput expected from large customers. Only plan DSM for core customers. They are the only ones where all costs covered in rates.

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 customers involved in daily pricing. There are no interruptible electric contracts; there are interruptible gas customers.

Design, Implementation and Evaluation

Responsibility

The ETO is responsible for the planning and design of the DSM programs they administer. The ETO's Board of Directors approves programs. The multi-year contract between ETO and the OPUC gives the ETO a fair amount of freedom to reach goals. Efficiency programs are primarily implemented by third-party contractors, who also provide feedback to the ETO about program design. Renewable energy programs are mostly managed in-house, because they are evolving very rapidly. Programs are evaluated by different third party contractors, although evaluation plans and tracking systems must be designed into every program from the start.

The few Oregon investor-owned utilities (and all consumer owned utilities) not providing funds to the ETO are responsible for the planning and design of the DSM programs they administer. Investor-owned utility programs must be approved by the OPUC if the utilities expect to receive cost recovery and lost revenue adjustments. The non-ETO gas DSM programs are so small that thorough evaluation would not be cost-effective. Cascade often uses incremental savings figures from ETO program results. Avista uses engineering estimates for its custom savings programs for small customers. The OPUC "deems" the savings for programs using savings results from similar, credible programs in the region. One of the reasons the OPUC staff is interested in ETO administration of DSM programs is to capture economies of scale.

Demand response strategies are generally planned and designed by utilities. OPUC staff evaluates the proposed tariffs needed to cover pilot program expenses. Demand response programs must be approved by the OPUC. They are implemented by the utilities.

Program Design Details

At the ETO, program managers pick a mix of strategies that pass cost-effectiveness tests and meet energy savings goals, as well as addressing customer diversity and other issues.

Ideally non-ETO utility-based DSM programs and demand response programs are proposed in the context of utilities' LCP plans, so they can be compared against all other strategies in various scenarios. There are several ways programs may be designed outside of the LCP process. Utilities can propose programs at any time. The OPUC can open an investigation that might result in pilot or new demand response programs (e.g., industrial customers asked the OPUC to respond to the energy crisis with new programs). The basic design can be the result of legislation (e.g., the 2005 EPAct requires investigation of a market rate option or load reduction credits for all customers).

Screening Programs

Gas and electric utility DSM and demand response programs are screened for cost-effectiveness using the Utility test and Total Resource test for cost-effectiveness. Some societal adders are used as described below. System benefits are not considered at this time for gas DSM. When considered in the LCP process, DSM programs are approved when they are identified as more cost-effective than supply options in the LCP model.

Utility DSM screening in Oregon does consider societal impacts. The OPUC's Order re: cost-effectiveness requires energy conservation to have a 10% advantage in cost-effectiveness calculations. When considering avoided costs, T&D line construction savings are considered in addition to energy and demand savings. Utilities must analyze a variety of external environmental costs for the LCP, but aren't required to use them in cost/benefit calculations. Traditionally, in the LCP process, to the extent utilities foresee external costs are going to become internal costs, utilities ought to include them in cost/benefit analyses of supply and demand strategies. As a result, mercury and carbon costs are beginning to be included.

The ETO uses the Utility System test (same as the utility test, but the name acknowledges that ETO is not a utility) and the Societal test to screen efficiency programs. The Societal test expands on the Total Resource test to include a factor for carbon reductions, as calculated by the Northwest Power and Conservation Council (NWPCC). Avoided costs include T&D line and construction savings. The ETO is working with the NWPCC to use Monte Carlo simulations to articulate the hedge value of efficiency. The ETO also considers customer-specific non-energy benefits in the societal test, where these can be estimated. Although the ETO has a goal of reaching under-served customers, they try to do so with cost-effective measures and initiatives.

The Total Resource test has also been used to screen some demand response programs, but when DR is considered outside the LCP process this doesn't address fuel price risks and market price risks and it is difficult to account for its impact on risk reduction. The NWPCC is evaluating the cost-effectiveness of demand response strategies. The Demand Response Center in California may also be helpful in this area. The system benefits of DR are typically not included in program screening. (They were included in some of PGE's Time of Use program analyses.) The planned OPUC investigation into non-wires solutions may change this.

Assessing Programs

The success of electric utility DSM programs is measured using energy and capacity cost savings. T&D savings are also considered when assessing electric *efficiency* DSM programs, but they are not routinely considered in the context of DR programs yet. [See comment above.] Gas DSM success is measured by energy savings.

The ETO uses energy and capacity cost savings and sometimes market development indicators to gauge success. Their progress is also measured against ambitious goals set by the ETO Board for the year 2012 (300 average MW and 19 million annual therms), as well as performance measures established by the OPUC (therm and aMW targets, percent used for administration, levelized cost of savings). They see weekly and hourly cost benefits as a measure in the future. The measurement of market transformation and amount of credit due to the ETO is an inexact science. The ETO is not assessed by emission reductions other than carbon. They have analyzed jobs created and economic benefits, but do not formally include them in cost/benefit analysis.

The ETO has a many-layered evaluation system for both process and program impacts. Evaluation plans and tracking systems are designed into every program, including spot checks for quality control and assurance, and statistical samples for impact evaluation. They intend to do persistence studies. ETO has complex arrangements with utilities for access to bills for all customers under 1 MW, as well as the bigger customers if they participate. This allows pre- and post-evaluation. Process evaluation is valued for feedback to improve effectiveness.

DSM Spending

Actual Spending

A public purpose charge of 3% of revenues is assessed on the two largest electric utilities in Oregon for energy efficiency and renewable energy DSM. Almost three-quarters of this is administered by the ETO, with the remainder going to energy conservation in schools and low-income programs administered by other entities. The largest natural gas utility has a public purpose charge of 1.5% of revenues for energy efficiency DSM, with 1.25% of revenues going to the ETO for energy efficiency DSM, and 0.25% to low-income programs administered by the utility. (They have a separate fund for low income billpayer assistance.)

The ETO's 2005 budget for electric and gas efficiency programs is $59.9 million, with about $18 million coming from carryover funds. Close to $36 million in this budget is dedicated to rebate incentives (e.g., cash to customers, vendor incentives for selling equipment, etc.). Administrative costs are less than 10% of the budget. According to a report to the legislature by ECONorthwest, ETO programs in 2004, using the electricity PPC only, will save at least 339 GWh of electricity (not counting T&D savings) and over 1 million mmBTUs at a levelized cost of about 2 cents/kWh and less than $6/therm. Carryover funds are estimated to be modest in the future now that programs are ramped up. Reports, plans, and budgets are available at http://www.energytrust.org.

The two natural gas utilities not using the ETO to deliver DSM acquire the amount of efficiency resulting from their LCPs. Avista spends around $250,000; Cascade spends around $100,000. Cascade may bump it up to $500,000 if new arrangements are made for decoupling revenues, etc. The present level of spending is less than half of a percent of revenue. Most of these funds are spent on high efficiency furnace rebates. These utilities spend very little money on administration. These utilities submit annual conservation reports to the OPUC each year, but they are not available electronically.

In August 2005, Idaho Power, the only electric IOU that administers its own DSM programs, proposed a rider of 1.5% of base revenues to fund efficiency and DR programs.

Demand response costs per strategy anticipated by the two major electric utilities were reported in the economic potential section of the January 2004 report "Assessment of Demand Response Resource Potentials for PGE and Pacific Power." At that time the costs varied so widely depending on the strategy and customer sector that the reader is referred to that publication for details.

Appropriate Levels

The funds available from the two electric utilities to the ETO for efficiency DSM are statutorily capped for the present. The funds available from the gas utility resulted from a regulatory decision and could change. The ETO must present a major progress report to the legislature in 2007, which may result in changes to the 3% PPC. It is evident that there is more cost-effective efficiency available than the ETO can acquire with present funding. (Evidence includes: just beginning to tap into gas efficiency, need to cap electric program participation due to funding limits even after reducing what were already very cost-effective incentive levels, new efficiency measures exist and some nearing commercial availability, issues with power availability, and CO_2 impacts.)

The ETO has contracted with Stellar Processes and Ecotope to complete an efficiency potential study by April 2006. This will cover at least the footprint of PacifiCorp, PGE, and Northwest Natural, and may cover Cascade as well. Avista will present its potential study to the OPUC in November. The ETO study will be used by the legislature and the OPUC to determine whether the present PPCs are adequate to acquire all cost-effective efficiency.

Theoretically the utilities without a PPC should obtain all the energy efficiency that is cost-effective as revealed in the IRP process. In practice this has not happened. The OPUC has recently questioned the assumptions and calculations used by the utilities regarding avoided costs, including the incremental cost of supply, and incremental pipeline capacity costs. The ETO efficiency study will inform the IRP process for these utilities as well.

Regarding demand response, in January 2004 the two major electric utilities filed a joint report with the OPUC identifying the technical and economic potential of demand response by market segment.[6] The utilities identified 4 cost-effective DR strategies: dispatchable standby generation, irrigation load control, non-residential time varying prices, and very low-cost demand buyback.

Cost Recovery and Incentives

Cost recovery

The DSM programs administered by the ETO are handled differently than those run by utilities. The funds come directly out of rates, via public purpose charges, to the ETO, and are spent almost immediately. The ETO uses a line of credit or other month-to-month levelling device, when necessary.

The few utilities, which are still doing DSM in the context of their LCPs, recover their costs in rates. A special tariff allows cost recovery and lost revenue adjustments for those DSM programs that have been approved by the OPUC. The utilities are allowed to capitalize expenses and earn a rate of return. The electric utility, Idaho Power, moved back to expensing because it didn't want to carry DSM expenses on its books. One gas utility, Cascade, defers expenses during the year, earning a rate of return for that year only, and recovers them all during the next year, upon OPUC determination of prudency. Only one gas utility, Avista, is still capitalizing DSM costs. Expenditures are amortized over the life of the measures installed. Avista would rather expense costs now, but it doesn't want to create a quick rate hike to recover all past costs at once, so continues to capitalize.

Demand response costs appear to be expensed. The utilities have not requested deferred accounting for them from the OPUC.

Incentives

The ETO is under contract to the OPUC to acquire energy efficiency and renewable energy resources. There are no structural disincentives to these goals, and the organization may lose its contract if it doesn't meet performance measures established by the OPUC. There are no direct performance incentives for the ETO or for the three utilities that are now relieved of the energy efficiency portion of their DSM responsibilities. However, there are indirect incentives for the utilities. Utilities are rewarded for customer satisfaction by the OPUC. After ETO started investing in electric efficiency, electric customer satisfaction went up. Utilities are now interested in co-marketing ETO programs. Some would say that disincentives to DSM have been removed for NW Natural, since its revenues have been decoupled from sales as its DSM programs have been moved to ETO.

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[6] H. Haeri, L. Miller and M. Perussi. January, 2004. "Assessment of Demand Response Resource Potentials for PGE and Pacific Power." http://www.nwcouncil.org/energy/dr/library/dr_assessment.pdf

A previous Order from the OPUC allowed utilities to propose incentive mechanisms. The two major electric utilities had them, but became less interested in them when it became evident that utilities could be penalized for not meeting targets. Those incentives no longer apply since those two utilities are no longer responsible for DSM.

As mentioned above, the utilities conducting their own DSM programs recover their costs and lost revenue adjustments through rates. OPUC staff receives quarterly reports from the utilities recovering costs to track DSM investments. Only a few expenses have been questioned regarding advertising expenses.

In the bigger picture, OPUC staff would say that utilities have every incentive to get supply and hardly any to do DSM. OPUC is opening a docket on performance-based ratemaking to investigate options. Also ratemaking treatment and risk creates incentives/disincentives. Oregon utilities don't have automatic fuel adjustments, so there is a regulatory lag between rate cases. As a result, during the energy crisis, utilities were exposed to risk and didn't know if they would be able to recover excess fuel charges that showed up in the crisis. The present rate-setting methods create incentives to build plants. Utilities are more interested in demand response that behaves like a power plant (e.g., direct load control) than in other forms of demand response like pricing and efficiency.

Resources for Future Reference

Re: DSM by the Energy Trust of Oregon

The Energy Trust of Oregon 2005-2006 Final Action Plan
http://www.energytrust.org/Pages/about/library/plans/0506_action_plan.pdf

Energy Efficiency Approved 2005 Budget
http://www.energytrust.org/Pages/about/library/financial/05_Budget/EE.pdf

ECONorthwest. March, 2005. "Report to Legislative Assembly on Public Purpose Expenditures: Final Report."http://www.puc.state.or.us/erestruc/public_purpose_report_030305.pdf

Re: Demand Response:

H. Haeri, L. Miller and M. Perussi. January, 2004. "Assessment of Demand Response Resource Potentials for PGE and Pacific Power." http://www.nwcouncil.org/energy/dr/library/dr_assessment.pdf

OPUC Order on demand response, opening investigation
http://apps.puc.state.or.us/orders/2003ords/03%2D408.pdf

OPUC Staff report. May 2003. "Demand Response Programs for Oregon Utilities."
http://www.puc.state.or.us/elecnat/demand/default.htm

LBNL. August 2005. "Real Time Pricing as a Default or Optional Service for C&I Customers: A Comparative Analysis of Eight Case Studies." LBNL Report No. 57661.

http://drrc.lbl.gov/drrc-pubs2abs.html

Re: State of Oregon Energy Programs:

http://oregon.gov/ENERGY/programs.shtml

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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Texas DSM Summary[1]

DSM Background and Approaches

Background and Interest

As a result of the Texas Electric Choice Act, enacted in 1999 (SB7), the electric sector was deregulated and investor-owned utilities were unbundled. Part of this comprehensive bill required the new transmission and distribution utilities (TDUs) within the footprint of the Electric Reliability Council of Texas (ERCOT) to acquire efficiency savings equivalent to at least 10% percent of forecasted growth in demand, each year beginning January 2004. They had to achieve a 5% reduction by January 2003.[2]

This statutory requirement was an outcome of negotiations around this very comprehensive piece of legislation. There were a variety of policy drivers, including the Clean Air Act (reducing emissions in non-attainment and near non-attainment areas). Reserve margin concerns due to load growth and plant retirement were also factors. Prior to deregulation, ratepayer funds were used to obtain efficiency-related public benefits, such as lower bills. Many parties were interested in seeing these benefits continue in some form in the new competitive environment.

There were many stakeholders driving interest in efficiency programs: energy service companies (ESCOs), TDUs, consumer and low-income advocates, the Public Utility Commission of Texas (PUCT), other public interest groups, and the Texas Commission on Environmental Quality (TCEQ). The Office of Public Utility Council, with its focus on rates, provides a different perspective on efficiency spending from time to time. Large industrial customers have provided some pushback. Their specific circumstances require custom efficiency measures that are not always available through the TDU efficiency offerings. However, they are not necessarily subsidizing other customers, due to the rate structure.

Approaches

Texas has a somewhat unique approach because efficiency approaches are used to meet demand reduction goals. Programs focus primarily on efficiency gains, but since the ultimate measure is demand reduction all programs have a demand reduction component. Some utilities in state have negative demand, but still set efficiency goals. (e.g. one small DU lost a large industrial customer). TDUs must administer the programs in a non-discriminatory, neutral fashion, reaching all customer sectors.

The specific enacting legislation gave TDUs two program options: Standard Offer Programs (SOP) and market transformation (MT) approaches. MT programs attempt to increase market penetration of technologies/measures that reduce summer peak (e.g. high efficiency air conditioners, Energy Star Homes, and high-efficiency gas water heaters in multi-family settings). The variety of measures available through SOPs allows all customer classes the opportunity to participate (e.g. large C&I, small commercial and residential). The focus for low-income is often weatherization. All efficiency measures installed must be long-lived and have at least a 10-year measure life (there is an exception allowing shorter-lived compact fluorescent bulbs in low-income programs). TDUs can choose the mix of approved programs

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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 October and November 2005 with Theresa Gross at the Public Utility Commission of Texas and Mike Stockard at TXU Electric Delivery. TXU-ED is the distribution utility (TDU) for about 2.5 million customers in the Dallas Fort Worth area.

[2] See the statute, PURA 39.905 (1999, 76th Legislative Session) (aka SB 7) at http://www.capitol.state.tx.us/statutes/ut.toc.htm

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 permanent changes to the energy efficiency of buildings, processes and appliances. The results should be quantifiable and verifiable demand and energy savings. Program approval does not sunset, but they may be updated or end with reason (e.g. present program providing incentives to air conditioning distributors will have to be updated or end due to new appliance standards).

The TDUs pay incentives to third parties ("project sponsors") who actually implement program measures. The project sponsors may be HVAC or lighting contractors, retail electric providers, ESCOs, community action agencies, etc. Generally MT payments will go to an implementer for upstream work; SOP payments go directly to contractors or others installing measures. The project sponsors may keep the incentives or pass them along at whatever level and in whatever manner they believe will accomplish the savings goals.

The project sponsors calculate energy savings, subject to measurement and verification (M&V) standards, and report them to the TDUs. The TDUs conduct additional verification, and report the savings to the PUCT. Incentive payments are not made to project sponsors without some level of M&V. The TDUs may do a statistically significant sample of on-site inspections or interview the end use customer to verify results.

Under the rules, the PUCT must hire an independent third party to evaluate the overall approach of efficiency programs statewide. It recently issued a RFP (Project Number 30170) for independent investigation into how the TDUs are using deemed savings and other M&V approaches.

The PUCT is also required to report to the Texas Commission on Environmental Quality (TCEQ) on the emissions reduction achievements by county from the energy efficiency programs, due to concerns about non-attainment areas.[4]

Program Design Details

The TDUs offer a mix of programs chosen from the Standard Offer and Market Transformation program offerings approved by the PUCT, which are described in Rule 25.184. These approved offerings are very similar to programs offered by TDUs before the passage of SB7, since their effectiveness was known. Programs are required to have at least a 10-year measure life. They are generally designed to cost-effectively produce both kW and kWh savings. The mix of offerings from each TDU should allow all customer classes to participate.

New ideas for Texas's efficiency programs are considered by the Energy Efficiency Implementation Project, which meets 2-3 times per year at the PUCT. It is open to all stakeholders. Present participants include TDUs, ESCOs, trade allies, technology developers, and others. This is presently a group of over 100 stakeholders facilitated by PUCT staff. New approaches can be proposed by any party. All stakeholders are notified of any proposed changes, deletions, suggestions. When drafting new rules, all proposals are filed on the PUCT web-based "interchange" and informal meetings are held. After this informal process, draft rules go to the PUCT for formal adoption. New legislation has been introduced (SB12), which may require new programs to be added, such as efficiency through landscaping, efficiency for schools, and appliance recycling. All interested stakeholders will be invited to the table to discuss how to make new programs fit.

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[4] See Health and Safety Code subchapter 386.201-386.205 (2001, 77thLegislature) (aka SB 5) http://www.capitol.state.tx.us/statutes/hs.toc.htm, and related rules at http://www.puc.state.tx.us/rules/subrules/electric/25.183/25.183.pdf

Screening Programs

The Utility Cost Test is used to determine the cost-effectiveness of proposed projects. This is defined in Rule 25.181(e)(1): "An energy efficiency project is deemed to be cost-effective if the cost of the project to the utility is less than or equal to the benefits of the project. The cost of a project includes the cost of incentives, the measurement and verification costs, and program administrative costs. The benefits of the project include the value of the purchased electrical energy saved, the value of the corresponding generating capacity requirements, and associated reserves displaced or deferred by the project. The present value of the project benefits shall be calculated over the projected life of the measure, not to exceed ten years."[5]

Certain environmental benefits can be factored into the screening calculation. "The utility may apply an environmental adder of up to 20% above the cost-effectiveness standard prescribed [above] for targeted projects conducted in an area that is not in attainment for air emission that is subject to the regulations of the TCEQ. The environmental adder is available only for targeted energy efficiency projects that would not be implemented without the adder."[6]

Assessing Programs

The major program effectiveness measures are energy and demand savings. Also important are emissions reductions in non-attainment areas, bill savings, market penetration for some programs, and participation of all customer classes. Administrative costs are capped at 10% of total spending. According to the rules, at least 5% of the reduction in demand has to come from hard to reach customers, and no more than 30% can come from load management programs.

Some results from the PUCT's January 2005 "Report to the 79th Texas Legislature: Scope of Competition in Electric Markets in Texas"[7] noted these outcomes from the 2003 efficiency programs (which had to meet a goal of 5% reduction in demand growth):

- "The demand reduction goal for 2003 was 135 megawatts. The utilities exceeded this goal by 11% with an actual reduction of 151 megawatts.
- The programs resulted in 370,000 megawatt-hours of savings for customers.
- The Hard-to-Reach and Residential/Small Commercial Standard Offer Programs performed very well, with demand savings exceeding savings that the utilities had projected in 2002.
- Most program activity is in areas of the state that experience air quality problems: 86% of demand savings and 78% of energy savings were achieved in the non-attainment and near-non-attainment counties.
- Overall administrative costs were 8%, well below the ceiling of 10% of total program costs that the Commission included in the rules."

Texas uses layers of review to validate claimed energy savings. Substantive Rule §25.181 governs TDU reporting and independent measurement and verification (M&V) of program savings. In practice, the

[5] http://www.puc.state.tx.us/rules/subrules/electric/25.181/25.181.pdf

[6] Rule 25.181 (e)(3)(B).

[7] http://www.puc.state.tx.us/electric/reports/scope/index.cfm

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.

specific to a TDU's particular service territory. Presently the avoided cost of capacity savings is set at $78.5/kW "saved annually at the customer's meter" and at 2.68 cents/kWh "saved annually at the customer's meter." Incentives range from 35-100% of avoided cost for different customer sectors.[10]

Higher incentives are available for targeted load management projects where transmission and/or distribution system enhancements could be avoided or deferred or congestion management costs could be reduced, when the load management project would not occur without the higher incentive.

Optimal Levels

No efficiency potential studies have been conducted to determine the amount of cost-effective efficiency available to Texas consumers. Decisions are not made in the context of any long-range planning processes. In Texas, the market is expected to solve the problem of resource adequacy. The TDUs propose spending they expect will be adequate to meet the goal of reducing anticipated load growth by 10% each year.

The PUCT is contracting in Project Number 30170 to have the effectiveness and accuracy of the current programs evaluated. This may lead to changes in spending and/or programs.

Cost Recovery and Incentives

Cost recovery

TDUs are allowed to recover the cost of the DSM programs in rates. All spending is expensed. The amount recovered, and the impact on rates, varies depending on the size of the utility and its efficiency goals. Administrative costs are capped at 10% of the budget. In Docket 22350, the PUCT approved a three-year average funding mechanism for cost recovery for TXU-ED, the utility interviewed for this project. This resulted in cost recovery capped at $43 million per year; any expenses beyond the cap, over the three-year period, would come from shareholder funds. However, unexpended funds are rolled forward from year to year. This allowed the utility to ramp up programs and spend more, as planned, further into the three-year period. The utility can request a new budget during the next rate case.

Incentives

Utilities don't receive specific financial incentives for DSM performance. Prior to deregulation, some utilities got some basis points in rate of return for excellent performance. Presently there is the possibility of administrative fines, or reduced rate of return if not performing, but that hasn't happened since utilities are presently exceeding their goals. TDU revenues are dependent on energy and demand consumption, so a utility with little or no growth might experience some disincentives to DSM.

Resources for Future Reference

Documents on this topic for all distribution utilities in Texas can be accessed using the PUCT Interchange page at

http://interchange.puc.state.tx.us/WebApp/Interchange/application/dbapps/login/pgLogin.asp.

[10] See Rule 25.181 at http://www.puc.state.tx.us/rules/subrules/electric/25.181/25.181.pdf. In 2004 incentives paid out by TXU-ED ranged from 9.25 to 16.65 cents/kWh (first year savings) and $270-486/kW (the highest figures are for low-income weatherization). These figures do not include administration, which is capped at 10%. Market transformation incentives generally come in at the lower end of these figures.

- 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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Vertmont DSM Summary[1]

DSM Background and Approaches

Background and Interest

DSM has been an important regulatory tool in Vermont for over 15 years. Interest in DSM, particularly energy efficiency (EE), has grown over time. Historically, utilities have been asked to acquire all cost-effective energy efficiency as part of the Integrated Resource Planning (IRP) process.[2] In 2000, an "energy efficiency utility" (EEU) was established to deliver efficiency within the state, and to satisfy the utilities' basic requirement to deliver efficiency within their jurisdictions.[3] As the EEU has established a track record of procuring cost-effective efficiency, its annual budgets and scope of activity has increased. 2005 was a year of record interest in DSM, with renewed interest coming from the Legislature and the Public Service Board (PSB).

The EEU was concept was developed in 1996-1997 as part of a discussion about electricity restructuring. While the state chose not to restructure, the Department of Public Service (DPS) performed a study in 1997 which showed that the EEU approach to efficiency offered a number of benefits to the state, including increased statewide availability and consistency; reduced regulatory costs; increased efficiency spending; and greater effectiveness.[4] In 1999, the Vermont Legislature authorized the formation of an EEU, and a settlement agreement subsequently established the EEU's initial structure and funding levels. The PSB solicited bids from entities proposing to run the EEU, and the Vermont Energy Efficiency Investment Corporation (VEIC) was chosen to administer the EEU.

Energy efficiency delivered by the EEU makes up the lion's share of DSM in Vermont. A small amount of efficiency is implemented outside the EEU's jurisdiction, however. One utility, Burlington Electric, plans and delivers its own efficiency as part of its IRP. IOUs participate in a Distributed Utility Planning (DUP) process that requires IOU-administered efficiency in certain circumstances. The IOUs also utilize some load management and demand response programs. For natural gas, Vermont has one local distribution company, Vermont Gas Systems, Inc., (VGS) that delivers a range of DSM programs.

The EEU, also known as Efficiency Vermont (EVT), is funded by a nonbypassable wires charge (known as the Energy Efficiency Charge, or EEC), initially capped by the Legislature at $17.5 million annually, or about 3% of customers' bills. The $17.5 million roughly corresponds with efficiency funding levels at the time that the EEU was formed, and funds not only EVT's budget but also evaluation and administrative costs, as well as Burlington Electric's programs. The cap on EVT's funding levels has caused some to question whether EVT can adequately satisfy the IOUs' statutory obligation to procure all cost-effective energy efficiency. Historically, the cap on spending has "trumped" the IOUs' obligation. The cap was lifted in 2005, and new funding levels have not yet been established. EVT's budget is expected to increase, although the PSB will continue to consider rate impacts when determining budgets.

Most market participants are supportive of efficiency, which is widely seen as a cost-effective energy resource. Vermont's public is generally energy-conscious and inclined to support efficiency over existing

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[1] This summary is based primarily on interviews completed during August 2005 with Ann Bishop of the Vermont Public Service Board and in November 2005 with Blair Hamilton of Efficiency Vermont.

[2] VSA 30, section 218

[3] VSA 30, section 209c

[4] Vermont Department of Public Service, 1997.

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

Approaches

Efficiency Vermont

EVT's approach to efficiency has evolved over time. Initially, a program-based approach was used, establishing seven different programs (C&I New Construction, Residential Low Income, Dairy Farms, etc.). In 2003, EVT began to adopt a more service-oriented approach that focuses on building customer relationships and providing services to targeted market segments. For 2006-2008, EVT is using a market-based approach that seeks to influence individual decisions by removing market barriers. [6] Removal of market barriers may include offering rebates to customers, incentives to manufacturers, or education to store owners, among other strategies. One of the explicit goals of EVT's work is to transform the marketplace so that efficient products are widely understood and available to consumers, regardless of customer class. There is an understanding in Vermont that, as businesses evolve and technologies change, the work of procuring efficiency is continuous and requires developing long-term relationships with customers. Vermont uses relatively little electric heating and cooling, and has few large C&I customers, so there is relatively little savings to be found in single, large amounts. The focus is on achieving efficiency through a wide variety of small measures and capturing lost opportunities.

To implement the market-based approach, EVT's efforts are organized around core and targeted markets, grouped by similar needs and market barriers. Core markets are Business New Construction, Existing Business, Customer Credit, Residential New Homes, Existing Homes, and Retail Efficient Products. Targeted markets are Colleges & Universities, Dairy Farms, Industrial, K-12 Schools, Multi-Family Buildings, Ski Areas, State Buildings, and Water & Wastewater Treatment Facilities. In each area, EVT works to build relationships with market players, educate customers about efficiency, and remove or reduce market barriers such as product cost and availability. Outreach is also done with service providers (manufacturers, architects, contractors) to encourage a marketplace in which efficiency is valued and available. EVT works to create demand for efficient products by educating customers, and to ensure a supply of efficiency products and services to meet that demand. Technical assistance, training, and financial incentives are specific tools used with customers. EVT also conducts activities in partnership with local organizations and regional organizations.

Vermont is somewhat unique in that it encourages fuel-switching, when cost-effective, as a method to promote efficiency. Fuel-switching is done on an individual basis when analysis shows that a customer's switch provides a net benefit to the state as a whole.

IOUs

In addition to EVT's activities, Vermont's IOUs implement some DSM. Load management is done by the IOUs, most of which have long-established interruptible contracts with large customers (generally ski areas). Some utilities have encouraged the use of demand rates, combined with load limiters to help customers manage their load. The demand rates are used with larger customers, including residential customers, and establish a threshold level of energy use. Any use beyond that threshold is subject to a higher rate. Load limiters prevent electricity use from exceeding threshold levels.

There is some interest in demand response projects, but this area is not currently a robust part of the state's DSM efforts. IOUs can establish contracts with customers who want to participate in ISO demand response programs, but there have been concerns about the programs and participation has been limited.

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[6] A detailed description of the current market-based approach can be found in EVT's recently accepted response to the Board's RFP for an energy efficiency utility. Available online at http://www.state.vt.us/psb/vol1eeuprop.pdf

DSM solutions are recognized as viable alternatives to wires problems in Vermont, and IOUs actively participate in DSM efforts in their transmission and distribution planning. In 1999, the PSB identified ten constrained areas within the state, and established a Distribution Utility Planning (DUP) process for handling wires constraints that requires utilities to meet with stakeholders and consider all potential alternatives to problems. [7] Once all options have been considered, including DSM options, the most cost-effective solution must be implemented. When DSM solutions are implemented as part of the DUP process, it is the responsibility of the IOU, rather than EVT, to implement the program. (EVT may contract with the IOUs as a third-party implementer in this process, but responsibility rests with the IOU involved.)

There are also new efforts to improve Vermont's transmission planning process. In response to the controversial transmission siting case in early 2005, the Legislature has required utilities to submit transmission plans every three years, beginning in 2006. The PSB has also opened a docket to review transmission planning, and plans to develop new rules designed to ensure a robust planning process. One of the focuses of the new rules will be ensuring that needs are identified in a timely fashion so that DSM alternatives can receive full consideration by all parties, and be implemented to meet needs when cost-effective.

Vermont Gas Services, Inc.

VGS has been required by the PSB to implement efficiency measures since the early 1990s. VGS, the PSB, and the DPS worked together to develop VGS' initial program offerings. Initially, the VGS' focus was on regulatory compliance, but DSM has since evolved into a key component of the utility's customer service efforts.[8] Programs include: HomeBase Retrofit Program, HomeBase Equipment Replacement Program, Vermont Energy Star Homes, Workplace Retrofit Program, Workplace Equipment Retrofit Program, and Workplace New Construction Program. Programs are allocated across all customer segments and are designed to address all opportunities (i.e., new construction, building retrofits, and equipment replacement). [9] VGS also performs audits and provides technical advice. Rebates and financing are used. For low-income customers, programs are available at no cost in conjunction with Champlain Valley Weatherization Service. VGS also maintains interruptible contracts with about 30% of its customers.

Successes and Setbacks

One of Vermont's biggest successes has been achieving a high level of cost-effective savings and demonstrating that efficiency is a viable energy resource. With 3% of rates going to efficiency, EVT's activities have reduced usage by approximately 1% annually. If this trend continues, efficiency will have reduced cumulative energy usage 10% by 2012.

One approach that has been successful has been the switch from program-based services to market-based services. The change has allowed EVT to be more flexible, and has organized offerings in ways that are more closely aligned with customers' perspectives and needs.

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[7] Docket 6290, establishing the DUP process, can be found at http://www.state.vt.us/psb/orders/2003/files/6290irpextord.pdf

[8] ACEEE's Special Case Study of VGS' comprehensive programs can be found at: http://aceee.org/utility/ngbestprac/vgsprtflio.pdf

[9] See ACEEE's study of Exemplary Natural Gas Efficiency Programs at http://www.aceee.org/utility/ngbestprac/ngbestpractoc.pdf

Vermont's demonstrated savings have helped efficiency to gain widespread public and political support. Political activities have compromised funding in the past, but current political activities have tended to support the increased use of efficiency.

One area that could be improved would be to remove the EEC listing on customers' bills. The EEC has attracted attention out of proportion to its portion of the bill. The requirement to list the EEC separately is part of the statute that formed the EEU. The PSB has found it challenging to explain to people that what they thought was a new charge was something they had been paying in rates all along, and the resultant level of attention contributed to the politicizing of funding in past years.

There is also a need to educate customers about system benefits. The public typically understands how EE programs benefit participants, but may not understand how the entire system benefits from programs. The Board doesn't engage in public education, and EVT's education messages haven't focused on this subject, but a greater level of public awareness could be helpful.

There have been, and continue to be, missed opportunities. Lack of appliance and equipment efficiency standards is a missed opportunity. It was considered recently by Legislature and failed to pass. At its initial funding levels, EVT has not been able to capture all cost-effective efficiency. When the EEU was initially created by settlement, its funding level was based on existing utility spending, rather than on procuring all cost-effective efficiency, as required by the IRP statute. This was done so that rates wouldn't go up during the transition of efficiency services. A 2002 study showed that cost-effective EE potential was much greater than EVT's ability to capture efficiency, given its funding levels. While EVT's budget is expected to increase, it is likely that increases will be balanced with rate impacts in the foreseeable future.

Another challenge has been the balancing of multiple objectives, e.g., overall energy savings vs. geographic equity. While this issue has been addressed by the use of weighted performance incentives, it has been and remains a concern.

Design, Implementation and Evaluation

Responsibility

DSM planning is done by both EVT and the IOUs. In their IRPs, IOUs are required to address the role that DSM will play in meeting supply needs, whether from IOU-administered load management or from EVT-administered efficiency. Planning, design, and implementation of most efficiency services and programs is done by EVT, with exceptions as noted previously: Burlington Electric implements its own programs, and IOUs may implement distribution-related efficiency programs. EVT makes limited use of competitive solicitations and third-party implementation of its efficiency services.

The PSB reviews and approves IOUs' IRPs. The Board does not explicitly oversee the DUP process, but can choose whether or not to issue siting permits for wires projects based on whether or not the DUP process leading to the chosen project was robust.

EVT has a performance-based contract with the PSB. EVT is reimbursed for expenses, and is able to earn performance incentives based on its performance in a number of categories. Currently, about 75% of performance incentives are tied directly to energy savings (including net system benefits, annual kWh savings, and peak energy savings). Another 20% of incentives are tied to equity, both geographically and among customer classes. 5% of incentives are tied to the existence of projects in development. The number of performance incentive categories has decreased over time, as EVT has consistently shown an ability to meet its minimum goals (and often its "stretch" goals as well).

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

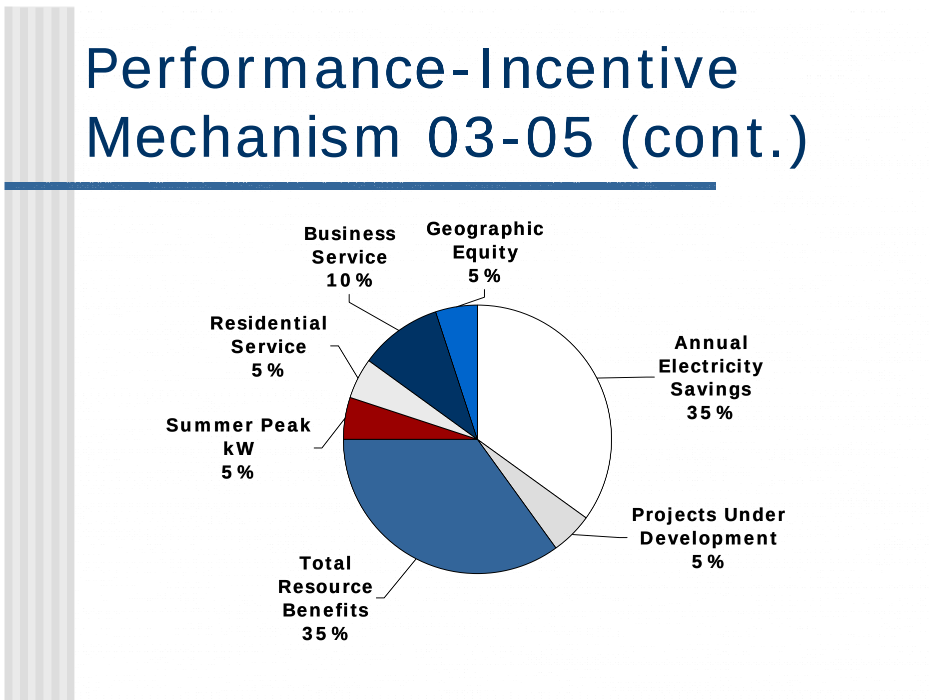
[12] http://aceee.org/utility/ngbestprac/vgsprtflio.pdf

[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

VGS defers and amortizes its DSM expenses, recovering costs in rates over a three-year period. VGS can also request lost revenue recovery from the Board.

Incentives

EVT receives performance incentives based on its performance in categories such as total electricity savings, total resource benefits, peak summer savings, geographic equity, etc. (see below). Incentive awards are scaled. EVT must meet minimum targets in order to receive any award. Meeting 100% of the target results in receiving 100% of the award for that category. Targets are designed to be "stretch targets" to encourage EVT to pursue ambitious goals. Higher performance in a given category can result in higher levels of incentives, but the total incentive is capped at pre-determined levels ($1.25 million in 2004).



Source: Efficiency Vermont: Vermont's Energy Efficiency Utility

Power Point Presentation by Ann Bishop, Vermont Public Utilities Board

Resources for the Future

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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.

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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.

[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.

Approaches

All three utilities conduct Least-Cost Planning, implement efficiency programs, and submit annual DSM reports to the WUTC. The utilities vary in their approach to DSM. Puget Sound Energy (PSE) has the largest customer base in Washington, and is experiencing rapid growth. It has also historically relied on purchased power to meet demand. This combination of rapid growth and purchased power has motivated PSE to aggressively pursue efficiency resources, and PSE offers its customers the most comprehensive set of programs in the state.

All three utilities allocate programs among customer classes (residential, commercial, industrial) to ensure that all ratepayers are eligible to participate in programs. A variety of programs are used, including incentives, rebates, home audits, new building programs, new construction, retrofits, lighting programs, process improvement, and education programs. PSE utilizes different approaches with residential and commercial customers. Residential efficiency, which depends on reaching a mass market and which offers savings in small increments, is reached mainly via rebates for efficient products, with an emphasis on lighting. Commercial and industrial customers are offered a more customized approach designed to meet customers' needs comprehensively. New buildings, retrofits, HVAC, and lighting programs are all utilized. The largest industrial customers are eligible to directly apply their wires charges to efficiency programs in their own facilities. In order to do so, the customer must develop a proposal and bid on four years' worth of wires charge funds. Funded projects must be cost-effective and overseen by PSE. [2]

Distribution system optimization is currently under investigation, and utilities are working with the Northwest Energy Efficiency Alliance (NWEEA) on pilot programs to determine if voltage controls are an effective way to realize significant energy savings without reducing services. PSE has entered a 2-year pilot program in which circuits will alternate between 24-hour periods of reduced voltage and 24-hour periods of normal voltage. An additional pilot places similar controls directly at residences.

Single family fuel switching (electric to gas) is a program at Avista. In Washington, a large percentage of multi-family housing is heated electrically. Avista has a fuel-switching program targeted at low income households, and PSE is conducting a pilot to find market barriers to the use of gas-powered heating equipment in multifamily housing. PSE has also conducted a fuel switching pilot as a means of delaying upgrades to targeted electric distribution circuits.

Successes and Setbacks

In recent years, the state's utilities invested heavily in advanced meters and billing systems to support the development of time-of-use (TOU) programs. The programs failed to deliver the anticipated amount of savings, due to a limited differential between peak and off-peak prices authorized by the WUTC. Because of the state's dependence on hydro, the WUTC is unconvinced that the cost difference between peak and non-peak hours will ever be large enough to support viable TOU programs, although Critical Peak Pricing may be implemented in the next few years. PSE has seen some efficiency improvements among metered customers, attributable to customers' ability to monitor their electricity use more closely.

Incentives and rebates for energy efficiency have been successful. Gas DSM programs have also been successful, although their potential was initially underestimated by the WUTC. The state's advisory process is strong, and works in the favour of successful programs by including participants in the process and providing adequate, timely information.

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[2] 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

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.

A portion of M&V is contracted out to third parties. Tracking is for the most part done internally. Most evaluation is contracted.

DSM Spending

Actual Spending

Total efficiency spending by regulated IOUs in 2004 was approximately $33 million. Of that, about $28.5 million was spent on electricity, and about $4.5 million was spent on natural gas. Resultant energy savings were 191,000 MWhs and 4 million therms. Percentage of funds spent on efficiency varied by utility, from 0.8% at Avista to 2.14% at Pacific Power.

2004 DSM Spending By Washington's Major IOUs

	Expenditures			Savings	
	Electric	Natural Gas	Total	Electric (kWh)	Natural Gas (therm)
Avista	$ 2,692,040	$ 757,166	$ 3,449,206	24,282,721	788,712
Pacific Power	$ 4,842,019	n/a	$ 4,842,019	28,345,994	n/a
Puget Sound Energy	$20,869,462	$3,781,810	$24,651,272	138,288,307	3,189,819
TOTAL	$28,403,521	$4,538,976	$32,942,497	190,917,022	3,978,531

Expenditures as % of Operating Revenue

	Electric	Natural Gas
Avista	0.80%	0.46%
Pacific Power	2.14%	n/a
Puget Sound Energy	1.41%	0.49%

Source: Joelle Steward, WUTC

Appropriate Levels

Cost-effective EE potential over a 20-year time period is assessed in the LCP. (These forecasts are based using methodology similar to, if not the same as, region-wide LCPs developed by the NWPPC.) In their LCPs, utilities develop savings goals, based on the level of achievable, cost-effective potential in their jurisdiction. Advisory groups provide guidance on the mix of programs that make up a balanced portfolio. In this process, all cost-effective DSM is not necessarily procured. The LCPs show EE potential over a number of years, and the utilities develop a plan for procuring that potential over a number of years. The preference is to sustain fairly consistent levels of acquisition, avoiding major increases or decreases in spending year to year. PSE's current goal involves accelerating procurement of 20 years' worth of efficiency potential in the next 10 years, while recognizing that cost-effective EE is a moving target that tends to change over time, and will be reassessed every two years. An effort is also made to allocate programs among all customer groups and end uses, which does not optimize cost-effectiveness of the portfolio, but ensures greater equity for all classes of customers.

Cost Recovery and Incentives

Cost recovery

Costs for most programs are expensed and recovered in rates. (Initially, for more than ten years, costs were capitalized, but by the early 1990s most utilities in Washington switched to expensing.) Riders/trackers are added to both electric and gas tariffs. The charge appears as a specific line item (per kWh or therm) on customers' bills. Conservation tariffs can be adjusted outside of rate cases, and are trued up to actual spending yearly. Electric rider funds are deposited into current accounts and spent on efficiency programs as needed. Gas tracker funds are deposited into deferral accounts, and utilities' cost recovery is delayed by a year.

BPA also offers utilities a Conservation and Renewable Discount (C&RD). Utilities throughout the region purchase a portion of their energy BPA's hydro system, which is federally owned. Bonneville has federal obligations to perform a certain amount of conservation. This is done through the utilities, which receive discounts on purchased power rates through BPA for delivering certain amounts of conservation above and beyond the base amounts authorized by the WUTC.

Incentives

PSE is subject to penalties if it fails to meet certain efficiency targets. There are currently no shareholder incentives for any of the utilities although there have been some in the past.

Resources for the Future

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

Stakeholder Process

Advisory groups meet with utilities on their DSM plans as need warrants (generally at least twice a year).

Interview Contacts

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Wisconsin Focus on Energy DSM Summary

DSM Background and Interest in DSM

The Wisconsin state legislature is the policy making body regarding DSM in Wisconsin. The Legislature started requiring the state's electric and gas utilities to operate DSM programs in the mid-1980s. In 1999, the legislature shifted to a "public benefits" approach for managing DSM programs in the state. The "Reliability 2000" legislation that established this new approach to implementing DSM programs in the state covered a wide range of topics relating to electric utilities, including:

1. Providing public utilities with partial relief from limits on nonutility assets they may own.

2. Establishing programs and policies intended to improve the electric transmission system in Wisconsin, and between Wisconsin and other states.

3. The public benefits program provisions.

4. Limiting utilities' real estate activities.

5. Creating protections for utility employees.

6. Addressing future requirements that may be placed on utilities and cooperatives regarding control of nitrogen oxide emissions. [1]

The way this public benefits approach is implemented in Wisconsin is that the Wisconsin Department of Administration (WDOA) is the overall administrator for the state's public benefits programs. The WDOA subcontracts with third party "implementation contractors" to implement various parts of the Focus on Energy program portfolio:

- The Wisconsin Energy Conservation Corporation (WECC) implements the residential and business DSM programs, and the renewable energy programs.

- The Energy Center of Wisconsin implements the Environmental Research Program.

- PA Consulting Government Services leads a team of consultants to evaluate the Focus programs.

In addition to the Focus on Energy programs, the WDOA administers the Home Energy Plus program for lower income Wisconsin residents. This programs accounts for almost half of the state's energy public benefits expenditures. The WDOA subcontracts implementation of this program to county health and social service agencies, community action agencies, tribal governments, and other non-profit organizations. [2]

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[1] 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", p.1 (Wisconsin Legislative Council Staff, Madison, WI, December 2, 1999).

[2] Wisconsin Department of Administration, Division of Energy, "Wisconsin Public Benefits Program: 2005 Annual Report", p. 3 (Wisconsin Department of Administration, Madison, WI, 2005).

Other key interest groups that are actively involved with DSM programs in Wisconsin include[3]:

- The Public Service Commission of Wisconsin (PSCW). The PSCW is the lead agency for administering the Wisconsin Energy Priorities Law. [4] This statute "establishes a flexible hierarchy for pursuing various energy resource options, with technically feasible cost-effective energy efficiency and renewables as the first and second priorities". [5]

- Environmental NGOs strongly support the Focus on Energy programs.

- The Citizens Utilities Board, an NGO that intervenes in utility rate cases and other utility proceedings on behalf of residential customers, also supports the Focus on Energy programs.

- Wisconsin's utilities generally support the Focus DSM programs, and actively supported the Reliability 2000 legislation that started this approach to implementing DSM programs in the state. However, some utilities would have preferred to continue to implement DSM program for their customers themselves.

- Trade associations whose members benefit from Focus on Energy programs actively support the Focus effort. The Wisconsin Retailers Association and the Wisconsin Builders Association are among the most active of such organizations in this regard.

- Some large industrial customers support the Focus programs, as they believe that such program benefit them, while other large industrial customers oppose the Focus programs, as they increase energy bills in the short term.

- Wisconsin's energy customers are also significantly interested in Focus programs, as over 220,000 customers participated in at least one Focus program in FY 2005. [6]

Wisconsin has never passed an electric restructuring law, and generally regulates its electric utilities in the traditional manner. In the late 1990s, the state started a long process to restructure the electric utility industry, but that effort was abandoned in the wake of the California energy crisis.

DSM Approach/Focus on Energy Portfolio Summary

The Wisconsin Focus on Energy's approach to DSM emphasizes energy efficiency programs. Virtually none of their DSM programs are "energy conservation" programs, defined as encouraging customers to just restrict energy use, such as through reducing thermostat temperatures. The Focus on Energy programs also include a renewable energy component, as previously mentioned. However, since renewable programs are not part of the scope of work for this CAMPUT project, they will not be discussed further in this report. [7]

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[3] Most of the information in this section was provided by Kathy Kuntz, WECC's Director of Operations, in a telephone conversation in November 2005. Exceptions are separately footnoted.

[4] Wisconsin statute 196.025(1).

[5] 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).

[6] Wisconsin DOA, 2005, op. cit., p. 2.

[7] Additional information about the Focus on Energy Programs, including their renewable energy programs, is available at www.focusonenergy.com.

Load management and demand response programs are not covered by the Focus on Energy, and are conducted by individual utilities in the state. The Focus on Energy also does not include any fuel switching programs.

For the fiscal year 2006, the Focus on Energy is conducting three main types of residential DSM programs. [8] These are:

1. Product/Market Specific Programs
    a. ENERGY STAR Products
    b. Efficient Heating and Cooling Initiative
2. Whole House Programs
    a. Home performance with ENERGY STAR
    b. Wisconsin Energy Star Homes
    c. Apartment and Condo Efficiency Services
    d. Targeted Home Performance with Energy Star
3. Information and Education Initiatives

For FY 2006, the total residential Focus budget is $21.6 million. The largest residential program is the ENERGY STAR Products program, which is budgeted for 24% of the total residential budget. This program offers information and rebates for the following types of energy-efficient products:

- Compact fluorescent lamps.
- Clothes washers and dishwashers.
- Refrigerators.
- Dehumidifiers.

Focus on Energy programs for the business sector are market segment focused, instead of technology-focused or focused on new construction. [9] The main business market segments that Focus programs are targeted towards are:

- Commercial
- Industrial
- Agricultural
- Schools/Government

For FY 2006, the total business Focus budget is $21.1 million. The industrial market segment has the largest budget allocation at 33% of the total business budget, followed by schools and government at 22%. In each overall market segment, specific sub-markets are targeted. For example, in the industrial market segment, the four largest sub-segments are forest products, food processing, metal casting, and chemicals/plastics.

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[8] Information on residential DSM programs comes from two sources, a telephone seminar presentation by WECC's Kathy Kuntz on 9/28/05, and the Focus on Energy web site.

[9] Information on business DSM programs comes from two sources, a telephone seminar presentation by WECC's Ed Carroll on 9/28/05, and the Focus on Energy web site.

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.

[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:

- Kathy Kuntz, Director of Operations for Wisconsin Energy Conservation Corporation, kkuntz@weccusa.org, 608-249-9322.

- 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.