PART TWO: STATE SURVEYS

1. COLORADO

(1999 Utility statistics from www.eia.doe.gov)

Population (2001 Census Estimate)	4,417,714
Net Summer Capability (MW)	8,034
Electricity Consumption (MWh) (excludes line losses)	40,955,315

	Investor-Owned	Public	Federal	Coop-erative	Total
Number of Utilities	2	29	1	28	60
Percentage of Retail Sales	61.3	17.8	0.2	20.7	100.0

Mechanism:	Tariff riders
Creation:	Regulatory
Duration:	5 year planning period
Administration:	Utilities
Budget:	Largest current program is $75million total for five-year period
Program Name:	None
Benefit Measure:	Recently changed to Net Present Value of Rate Impact
Incentives:	Cost recovery

Survey Questions

1. Process and timeline

   Regulated electric investor-owned utilities (IOUs) have been acquiring demand-side resources as part of the Integrated Resource Planning process for many years. In December 2002 the Colorado Public Utilities Commission (PUC) amended Rules 3600-3615 changing the process to Least-cost Resource Planning.

2. Organizational structure

   The IOUs administer energy conservation and efficiency programs resulting from resource acquisition plans approved by the PUC. The IOUs utilize Requests for Proposals (RFPs) to competitively acquire the needed resources. Programs are generally implemented by third party contractors.

   Xcel, the largest IOU with 60% of the Colorado market, has a Roundtable of public participants who provide input and informal review of program planning.

3. Funding mechanisms

   The PUC approves the IOUs' proposed resource acquisition costs. IOUs file annually for adjustments to existing tariff riders to recover costs. Tariff riders are paying for current expenditures as well as 5-year capitalization costs. Xcel's current program budget is $75million for the period 2001-2005.

4. Degree of association with a long run resources plan

   The major IOU energy efficiency program in effect now, which is Xcel's, was the result of a 1999 Integrated Resource Plan (IRP) stipulation. The IRP process was typically the stimulus for IOU energy conservation/efficiency programs. However, effective December 2002, the PUC and IOUs will use new Least-Cost Resource Planning rules, which may be less likely to result in energy conservation and efficiency programs.

   The Colorado legislature passed SB144, effective June 2001, which gives direction to the PUC to consider utility investments in energy efficiency to be an acceptable use of ratepayer moneys. This statute also directs the PUC to "give the fullest possible consideration to the cost-effective implementation of new clean energy and energy-efficient technologies in its consideration of generation acquisition for electric utilities."

5. Guidelines for program effectiveness and success

   The RFPs will detail measures of success. Programs must meet demand or savings goals, as well as cost goals. Xcel's five-year goals from the 1999 IRP process are to acquire 124 MW through efficiency and conservation, and to distribute benefits to all customer classes. They anticipate acquiring 200,000 MWh in savings as well, over the five year period. Under the new rules, the way RFPs are written will encourage or dissuade energy efficiency or conservation respondents.

6. Pre-implementation program evaluation guidance

   Under the new Least-Cost Planning rules, resource acquisition has to be cost-effective using the "Net present value of rate impact" as the measure. The Total Resource Cost test had been used in the past, and is still in use for programs approved prior to the new rules.

7. Results of program evaluation

   Xcel files measurement and evaluation reports annually with the PUC. Measurement and evaluation criteria are written into the program contracts. Programs are implemented by third party contractors, then evaluated by either the IOU or a different third party.

   From 2001 through 2002 Xcel has acquired 23 MW and 42,000 MWh in savings. They anticipate the program will cost less than $60million, rather than the $75million originally proposed.

8. Financial and performance incentives

   IOUs file for cost recovery through tariff rider adjustments annually. No lost revenue recovery or other incentives. Xcel does business in Minnesota, which does provide performance incentives and that is perceived as a more favorable arrangement for energy efficiency programs.

Resources

Department of Regulatory Agencies, Public Utilities Commission
www.dora.state.co.us/puc
Wendell Winger, 303-894-2874

Aquila (Western Plains Energy)
816-467-3753

Xcel (Public Service of Colorado)
Grey Staples, Manager, Retail Restructuring and Regulatory Strategy
Grey.s.staples@xcelenergy.com
612-330-5589

Land and Water Fund of the Rockies
303-444-1188
John Nielsen, Energy Project Director, x232
Jnielsen@lawfund.org
Eric Guidry, Staff Attorney, x226
Eguidry@lawfund.org

Colorado Office of Consumer Counsel
303-894-2121
www.dora.state.co.us/occ

2. CONNECTICUT

(1999 Utility Statistics from www.eia.doe.gov)

Population (2001 Census Estimate):	3,425,074
Net Summer Capability (MW)	7,077
Electricity Consumption (MWh)	30,664,200

	Investor-Owned	Public	Federal	Coop-erative	Total
Number of Utilities	3	7	0	0	10
Percentage of Retail Sales	93.9	6.1	0	0	100.0

Mechanism:	3mills/kWh surcharge on retail electric sales for Energy Efficiency Separate renewable and Societal Benefits charges for other purposes
Creation:	Legislative
Duration:	No sunset
Administration:	Utilities, with substantial direction and oversight from the Energy Conservation Management Board. Plan approval by DPUC.
Budget:	2002: $86.45million
Program Name:	Conservation and Load Management (C&LM) Programs "Energy Efficiency--Saving without Sacrifice"
Benefit Measure:	Electric System (Utility) Test and Total Resource Test
Incentives:	Utilities may receive performance incentives; No lost revenue recovery.

Survey Questions

1. Process and timeline

In July 1998 Public Act 98-28 became effective, establishing the surcharge on electric sales. Initial Conservation and Load Management (C&LM) plans were filed in 1999 and approved in 2000.

2. Organizational Structure

The Distribution Utilities (DUs) administer the C&LM programs. The two regulated electric utilities involved serve 95% of the CT market. The DUs prepare cost-effective program implementation plans and budgets with the assistance of the volunteer Energy Conservation Management Board (ECMB) and consultants, subject to approval by the Department of Public Utility Control (DPUC).

2002 Proposed Administrative Costs

Utility	Admin. Costs*	Total C&LM Costs	Percent*
CT Light and Power Co.	$1million	$69.47million	1.4%
United Illuminating Co.	$404,000	$16.98million	2.4%
Total	$1.4million	$86.45million	1.6%

*NOTE: These figures for administration do not include planning, analysis and evaluation activities or the ECMB costs. Some managers' costs that had previously been considered administrative were reallocated to specific programs.

According to statute, administrative costs may not exceed 5% of revenue collected for the fund.

DPUC staff provide about 0.5 FTE effort from 7 individuals to the C&LM plans.

Energy Conservation Management Board (ECMB)

The Act created the ECMB and requires it to advise and assist the utilities in the development and implementation of their comprehensive C&LM plans as well as market transformation plans. In practice, the ECMB attempts to reach consensus on plans and budgets, and presents them to the DPUC for approval.

The DPUC appoints members of this all-volunteer board. By statute it is composed of representatives of an environmental group, the Office of Consumer Counsel, the Office of the Attorney General, the Department of Environmental Protection, the two utilities, a statewide manufacturing association, a chamber of commerce, a statewide business association, a statewide retail association, and residential customers.

The ECMB is required to submit annual reports to the legislature covering C&LM program expenditures, fund balances and benefit cost analyses.

The ECMB uses C&LM funds to retain expert, independent consultants to assist the ECMB in reviewing and analyzing C&LM plans, programmatic design, goal setting and performance and incentive structures. The ECMB is presently contracting for a study of total energy efficiency potential in Connecticut.

In September 2001, the DPUC accepted the ECMB's three stage "Roadmap" to formalize a process for public input.

The budget for the ECMB is paid with C&LM funds, and varies from year to year. CL&P proposed $221,000 for its contribution in 2002 and UI proposed $135,000 for its contribution, for a total of $356,000, or less than 0.5% of the total C&LM budget.

3. Funding mechanisms

Beginning January 1, 2000, the Act created a 3mills/kWh charge to be assessed on each kWh of electricity sold in the service territories of the two DUs. The DUs must each establish a C&LM Fund, held separate from other funds and accounts of the DU, to hold the funds collected from the three mill charge.

4. Degree of association with a long run resources plan.

The C&LM plan is incorporated in the State's comprehensive energy plan. There is no IRP planning.

5. Guidelines for program effectiveness and success

The Act requires that C&LM programs be cost-effective.
The 2003-2004 C&LM Plan describes the following program goals:

Advance the efficient use of energy;

Reduce air pollution and the negative environmental impacts from generating electricity; and

Promote economic development and energy security in Connecticut.

There are many other goals described in the DU plans, including:

- Lower energy costs and increase aggregate productivity.
- Create an energy efficiency "ethic".
- Increase measurable energy efficiency for business success in the global economy.
- Transform markets and capture lost opportunities.
- Address market barriers to energy efficiency, especially for special needs groups.
- Sponsor RD&D of new energy efficient technologies, products, or processes.
- Allocate C&LM resources in an equitable manner across all customer sectors.
- Pursue uniform statewide programs between the two utilities.
- Pursue increased use of third-party planning and delivery of programs.
- Demonstrate measurable success in terms of environmental and economic betterment.

Equity: Historically, geographic and customer equity has been a goal of the C&LM programs. Serious demand and peak issues in southwestern Connecticut have resulted in a disproportionate focus of resources in that area. However, in their most recent resolutions filed with the DPUC, the ECMB has reaffirmed its commitment to equity over time.

6. Pre-implementation program evaluation guidance

The consultants to the ECMB work with utility staff to evaluate the savings that can be <u>expected</u> from specific program designs, including benefit:cost ratios. The consultants also help utility staff design measurement and evaluation into the programs. They propose to use industry-accepted protocols when possible including:

1997 International Performance Measurement and Verification Protocol;

1996 Federal Energy Management Program's Measurement Verification Guidelines; and draft ASHRAE 14-P Measurement of Energy and Demand Savings Guidelines.

The utilities' planning and evaluation staffs conduct program evaluation. The utilities also issue RFP's for third party evaluation of some programs. The ECMB consultants review the utility and third party evaluations. This year's docket (03-01-01) has become a venue for parties to examine the issue of program evaluation.

The DPUC uses the Electric Systems (aka Utility) test to screen for cost-effectiveness. The 2003-2004 C&LM plans proposed in Docket 03-01-01 are the first to incorporate the same screening tools and similar assumptions for key variables for both utilities' programs. Both utilities use the Electric Systems test and the Total Resource test to screen programs for cost-effectiveness.

Evaluation of regional market transformation activities will be commissioned and jointly funded by all participating utilities.

The DUs have been instructed by DPUC to develop specific goals and targets to use to evaluate their R&D efforts. The ECMB has directed the DUs to track expenditures for programs by class and geographic area so information is available in the future to ensure parity.

7. Results of program evaluation

Evaluation of Expected Outcomes

In Docket 01-01-14, September 2001, the DPUC made the following program screening determinations about the projected cost-effectiveness of programs offered by the two utilities:

The CL&P programs were expected to produce benefits of $62million, approximately twice the value of expenditures. The benefit:cost ratio of the Total Resource test was reported to be 2.1 and the Electric Systems test was reported to be 1.9.

UI's total savings were projected to be $25.4million, approximately 50% more than the value of expenditures. The overall Electric System benefit:cost ratio was reported to be 1.47.

Evaluation of Program Results

The ECMB reported the following 2001 C&LM program results, from a variety of utility and third-party evaluators, in its report to the legislature:

- Measures installed in 2001 resulted in 314million annual kWh savings and 4,735million kWh over the lifetime of the measures;
- Peak demand savings in 2001 were 65,605 kW;

- $86million customer contribution resulted in energy savings of $473million over the lifetime of the measures (4,735million kWh at 10 cents/kWh);
- More than 400,000 customers participated, representing all areas of the state.
- 75% of the lifetime savings were in the C&I sector;
- 21% were in the non-low income residential sector;
- 4% were in the low income residential sector;
- The measures taken in 2001 resulted in the following emissions reductions (in tons):

SOx	972 year 2001	14,679 lifetime
NOx	329 year 2001	4,972 lifetime
CO2	238,260 year 2001	3,598,600 lifetime

8. Financial or performance incentives

Each year the DUs propose energy savings goals and other performance metrics eligible for performance incentive payments. Within the range of 70-130% achievement, the DUs can earn pre-tax incentives of 2-8% of C&LM expenditures. Anticipated incentives are built into the annual budgets.

The Attorney General's office has argued against any performance incentive and its calculation. Over the course of several dockets, the DPUC has affirmed the value of the incentive, and that the expenditures used to calculate the incentive may include administrative and overhead costs, but not ECMB costs and the incentive costs.

Due to problems in southwestern Connecticut, in 2002 the DPUC agreed to utility incentives for MW savings from load response programs (LRP). In the 2003-2004 proposal [Docket 03-01-01] some demand goals are folded into a new performance incentive metric, the "Electric System Benefit", with reductions in SWCT resulting in higher incentives than reductions in other parts of Connecticut.

In Docket 01-01-14, September 19, 2001, the DPUC agreed on a reasonable rate of return when DUs market and sell their C&LM programs.

Issues and Special Situations

Consumer Awareness/Branding

The Consumer Education Outreach Program Unit of the DPUC is funded by the Systems Benefit Charge, not C&LM funds. All eleven staff members provide outreach that improves consumer awareness of C&LM programs.

In docket 01-01-14, the DPUC asked the DUs and the ECMB to find a way to incorporate customer awareness as a performance metric. The utilities surveyed and tracked customer awareness in 2001 to provide a baseline. DPUC required DUs to develop a common slogan for the C&LM programs. The DUs acquired trademark status for their Smart Living Catalog.

Legislative/Executive Diversion of Funds

Public Act 01-9 diverted $12million from the 2002 C&LM budgets for state building conservation. The present legislative session has already authorized another $12million diversion from the C&LM programs to pay for State utility bills or conservation. In a recent speech, the governor indicated he might direct that all C&LM funds for the next two years be utilized to reduce the deficit. There are state agencies and third parties considering a legal challenge to this legislative action.

Performance Incentives

There have been unforeseen consequences to the incentive structure that have surprised the parties. For example, in Docket 03-01-01, DPUC staff questioned whether a utility's massive give-away of lighting materials at year's end was, in part, the logical outcome of the incentive structure. The parties will be discussing incentives and disincentives during the course of this docket.

Societal Benefits fee

There is a separate Societal Benefits fee established by the PUC, that supports consumer education (about retail choice), dislocated electrical worker programs, low-income energy conservation, hardship protection for qualifying customers, post-retirement safe shutdown of plants/sites, nuclear plant decommissioning, spent fuel and nuclear storage costs; and other required payments to municipalities and resource recovery facilities. Connecticut also has a separate renewable energy charge, presently 0.75mills/kwh.

Programs

Sample programs from this year's plan include, but are not limited to:

Residential: SmartLiving Catalog, Energy Star Appliances, Retail Lighting, Residential Heating and Cooling, Refrigerator Early Retirement, Low Income, Community Based Program and the state-mandated Energy Conservation Loan Program.
Commercial and Industrial: Small Business Energy Advantage, C&I New Construction/Energy Blueprint, State Buildings, Municipal programs, C&I RFP, and Operations and Maintenance RFP.
Load Management: ISO-NE Program Support and utility-specific load management programs. DPUC staff are excited about some of the new efficiency possibilities using radio control of non-intrusive load.

The C&LM funds also support an endowed chair at Eastern Connecticut State University and the Sustainable Energy Institute at the same institution.

Resources

Connecticut Department of Public Utility Control
www.state.ct.us/dpuc
860-827-1553
At this website one may access:
Docket decisions, utility plans and the legislative report
Cindy Jacobs, Principal Utilities Finance Specialist, 860-827-2853 cindy.jacobs@po.state.ct.us
Arthur Marcylenas, Lead Rate Specialist, 860-827-2887 arthur.marcylenas@po.state.ct.us
Mark Quinlan, Public Utilities Supervisor of Technical Analysis, Electric 860-827-2691
mark.quinlan@po.state.ct.us
Michael Zawrotny, Utilities Examiner, 860-827-2785 michael.zawrotny@po.state.ct.us

Connecticut Energy Conservation Management Board
www.state.ct.us/dpuc/ecmb/index.html
Daniel Soslund, Chair 207-236-6470 dsoslund@env-ne.org

Consumer Education Outreach Program Unit of the DPUC
www.dpuc-electric-choice.com
Robert Granquist, Director
860-827-2635 robert.granquist@po.state.ct.us

Connecticut Light and Power
www.cl-p.com/

United Illuminating Company
www.uinet.com

To access the *Year 2001 ECMB Report to the Legislature* do the following:
Go to: www.state.ct.us/dpuc
Choose "General Info"; choose "ECMB" on the sidebar; choose "Misc. Documents"; then choose 2001 ECMB Legislative Report

Conservation and Load Management Plan: Years 2003-2004
Go to: www.state.ct.us/dpuc/database.htm
Choose: "Active Docket Database"; Choose: "Go to a specific docket number"
Choose: "Electric" ; Scroll down and select "03-01-01"
Choose: "Corres 01/13/2003[03-01-01] (CL&P & UI) DPUC Review…Plan for Years 2003-2004"; Choose: "Exhibit CLPUI 1 (plan)filed.doc"

3. FLORIDA

(1999 Utility Statistics from www.eia.doe.gov)

Population (2001 Census Estimate):	16,396,515
Net Summer Capability (MW)	40,940
Electricity Consumption (MWh)	193,394,452

	Investor Owned	Public	Federal	Coop-erative	Total
Number of Utilities	5	32	0	16	53
Percentage of Retail Sales	76.9	16.1	0	7.0	100.0

Program Name:	Demand Side Management (DSM) programs
Mechanism:	Conservation program costs recovered in rates.
Creation:	1980 Florida Energy Efficiency and Conservation Act (FEECA)
Administration:	Electric Utilities with sales of 2000 GWh or more
Duration:	New goals and plans every 5 years; no sunset
Budget:	$245-250million/year
Benefit Cost Test:	Rate Impact Measurement Test
Incentives:	Lost Revenue Recovery and other incentives on a case-by-case basis for specific measures. Cost Recovery.

Survey Questions

1. Process and timeline

   In 1980 the Florida Energy Efficiency and Conservation Act (FEECA) was enacted requiring many electric utilities to adopt cost-effective conservation programs. The law has undergone minor modifications regarding utility size and goal-setting.

2. Organizational structure

   Currently seven of Florida's integrated electric utilities are required to meet the FEECA standards. This includes 5 IOUs and 2 municipal utilities, which together are responsible for 87% of the state's total electric sales. The Florida Public Service Commission (PSC) sets DSM goals every five years for each utility, after reviewing utility goals and plans. The utilities develop, administer and implement DSM programs to meet goals set by the PSC. The utilities report DSM activities annually to the PSC. The PSC determines annually which programs will be eligible for cost recovery. The PSC must prepare an annual report to the legislature summarizing FEECA activities.

3. Funding mechanism

   The utilities propose programs to meet the MW and MWh goals set by the PSC. The PSC approves cost-effective programs and allows costs to be recovered, in a manner similar to a fuel adjustment clause. Once programs are approved, utilities "true up" the program costs annually.

   $245million in DSM expenditures was approved for cost recovery in 2000. There are no set limits or budget amounts for administration.

4. Degree of association with a long run resources plan

   The five-year MW and MWh goals determined by the PSC are set in the context of other statutory PSC responsibilities, such as determining the suitability of electric utility Ten-Year Site Plans. These plans provide forecasts of future electric load requirements and the resource mix planned to meet those needs.

5. Guidelines for program effectiveness and success

   FEECA emphasizes cost-effective programs that:
   - Reduce the growth rates of weather-sensitive peak demand;
   - Reduce and control the growth rates of electricity consumption; and
   - Reduce the consumption of expensive resources such as petroleum fuels.

   According to the PSC, cost-effective DSM programs will reduce current production cost, defer the need for future power plant construction and improve reliability.

   The PSC sets specific numeric goals for each utility in both the residential and the commercial/industrial sectors in the following areas:
   - Winter MW reduction goals;
   - Summer MW reduction goals, and
   - Annual GWh reduction goals.

6. Pre-implementation program evaluation guidance

   The PSC requires utilities to show that DSM programs meet the Rate Impact Measurement test for cost-effectiveness. All utility ratepayers must benefit from the programs, not just the ratepayers participating in the programs.

   Due to the cost-effectiveness test used, load management programs are favored over energy efficiency expenditures. In recent years, about 70% of expenditures went towards load management and 30% to energy efficiency.

7. Results of program evaluation

   The utilities self-report their results to the PSC. There is no independent auditing. The five utilities with goals in 2000 reported the following goals vs achievements:

	Goals	Achievements
Winter MW Reductions:	226.8 MW	172.7 MW
Summer MW Reductions:	213.6 MW	197.0 MW
GWh Reductions	219.6 GWh	258.6 GWh

   One utility met all its goals. The primary reasons given for unmet goals were programs needing more time than expected, or participation being less than expected. Some utilities requested PSC approval for program modification, others improved marketing. Most expected to meet goals in 2001.

8. Financial or performance incentives

   IOUs are allowed to recover "prudent and reasonable expenses" for PSC-approved DSM programs through the Energy Conservation Cost Recovery clause. To recover costs, utilities must present evidence that the programs are cost-effective. Since 1981, IOUs have recovered over $3.2billion of DSM program expenditures. In 2000, the five IOUs recovered total expenditures of $245.2million.

   According to the 2001 Annual Report, in 1994, the PSC "voted to allow for case-by-case consideration of lost revenue recovery and incentives through the Energy Conservation Cost Recovery Clause for a specific group of DSM measures. These measures include solar, renewables, natural gas substitution, high efficiency cogeneration, and other DSM programs that have significant savings but exert negligible upward pressure on rates."

Issues and Special Situations

<u>Consumer Awareness/Branding</u>

The PSC's Bureau of Consumer Outreach supplies consumers with comprehensive information about energy conservation and the conservation efforts of Florida's electric and gas utilities. The PSC website is utilized for this purpose.

<u>DSM Goals Decreasing</u>

In the most recent goal-setting proceedings (1999-2000), the utilities' numeric goals decreased substantially. According to the Annual Report there were several reasons for this. The primary reason was that the cost of new generating units had dropped substantially in the previous five years. This reduced the value to all ratepayers of programs deferring generating capacity. In addition, some DSM programs had reached a saturation level, which reduced the future market potential of those measures, again reducing their cost-effectiveness.

In 2000 the PSC set the DSM goals for the two municipal utilities at zero because the utilities could not identify any additional cost-effective DSM programs to offer.

Utilities can file a petition before the PSC requesting changes to their DSM programs. In the Annual Report, the PSC noted several petitions had been received from the IOUs to change or discontinue programs due primarily to reduced generating costs.

Programs

A detailed listing of programs can be seen at the PSC website. Here is a summary list:

- Energy education and audits: Florida Statutes require that energy audits be available to all residential customers.
- Efficient Equipment Replacement Programs: rebates or low interest loans for high efficiency equipment purchases.
- Building Envelope Programs: rebates or low interest loans for improvements that decrease the load on heating or air conditioning equipment.
- Load Management and Interruptible Service: customers receive a reduced rate or a monthly incentive in exchange for allowing the utility to control when certain electric appliances are available for use. PSC staff think Florida may be the leader nationally in both percent of load and actual MW under direct utility control.

Resources

Florida Public Service Commission
850-413-6344
www.floridapsc.com
Jim Dean, 850-413-6058
JDean@psc.state.fl.us

Division of Economic Regulation, Florida Public Service Commission, *Annual Report on Activities Pursuant to the Florida Energy Efficiency and Conservation Act As Required By…..Statutes and the Biennial Report on the Florida Energy Conservation Standards Act As Required by….Statutes*, February, 2002. Available from the PSC. The 2003 Report should be available soon.

Legal Environmental Assistance Foundation
850-681-2591
Deb Swim
dswim@leaflaw.org

4. ILLINOIS

(1999 Utility Statistics from www.eia.doe.gov)

Population (2001 Census Estimate)	12,482,301
Net Summer Capability (MW)	34,338
Electricity Consumption (MWh)	136,874,068

	Investor-Owned	Public	Federal	Coop-erative	Total
Number of Utilities	9	41	0	27	77
Percentage of Retail Sales	92.4	4.5	0	3.1	100.0

Mechanism: Pro rata share of $3million, based on prior year's kWh sales
Creation: Legislative
Duration: Automatically repealed in 10 years (December 2007)unless renewed by an Act of the General Assembly
Administration: Illinois Department of Commerce and Economic Opportunity (formerly Department of Commerce and Community Affairs)
Budget: $3million/year
Program Name: Energy Efficiency Trust Fund
Benefit Cost Measure: Utility Test
Specific Incentives: None associated with this program

Survey Questions

1. Process and timeline

   1997 deregulation legislation, PA 90-561 (the Act) created the funding mechanism. The first Energy Efficiency Trust Fund contributions were due June 1998. Programs began in 1999.

2. Organizational structure

   This $3million program serves residential customers of the IOUs that contribute to the program. The focus is on low to lower-middle income residents.

   Department of Commerce and Community Affairs (DCCA)
   (Recently renamed the Department of Commerce and Economic Opportunity)

   The DCCA invoices the utilities, and deposits and disburses the funds. The DCCA determines which projects will promote energy efficiency. DCCA staff members plan, implement and evaluate the programs. About six DCCA staff members contribute part-time effort to program planning, implementation and evaluation resulting in about 1 FTE effort.

   Distribution Utilities (DUs)

The Act requires the electric distribution utilities (DUs) to remit energy efficiency contributions to the DCCA. According to DCCA staff, only investor-owned regulated electric utilities contribute at present. As the deregulated market evolves the Illinois Commerce Commission will decide who else this Act applies to.

Advisory Council

Originally DCCA took suggestions from a survey of stakeholders. There is no formal advisory group.

3. Funding mechanisms

   The DCCA staff administering these programs are paid with Petroleum Violation funds, and federal funds that support the state's conservation activities.

   The DUs annually remit to DCCA their pro rata share of $3million based on the previous year's kWh sales. This works out to approximately 0.03mills/kWh.

4. Degree of association with a long run resources plan

   There is no long range planning required by the State since deregulation. The market is supposed to meet needs.

5. Guidelines for program effectiveness and success

   The Act requires a focus on low income households and rental properties. The Act suggests specific proven programs such as appliance, lighting and window replacement. DCCA staff has targeted individual households with low-cost but effective measures like compact fluorescent replacement bulbs. More comprehensive and costly measures must be implemented in demonstration settings.

6. Pre-implementation program evaluation guidance

   DCCA staff set goals and evaluate the programs. They use a version of the Utility Test to report benefits of the program. They track the number of households reached, and estimated energy savings and demand savings (assuming measures are installed).

7. Results of program evaluation

   There has been no independent evaluation of Illinois' programs. The DCCA is required to submit an annual report to the General Assembly evaluating program effectiveness.

   The 2001 report was summarized at www.repp.org/sbf_map.html, and reported the following results:

   136 new single family homes built 40% more efficient than code;

3945 refrigerators replaced, saving $55/unit/year;
23,000 efficient lighting kits distributed, saving 3.5million kWh/year;
21,500 torchiere lamps replaced, saving $1.3million/year; and
3,000 rebates for efficient air conditioners distributed.

8. Financial or performance incentives

   There are no financial incentives related to the Energy Efficiency Trust Fund programs for utilities or the administrative agency (DCCA).

Issues and Special Situations

Illinois Clean Energy Community Trust

Illinois experienced a one-time windfall payment of $250million from Commonwealth Edison. $25 million was given to Southern Illinois University for Clean Coal Initiatives. The remainder was used to establish the Trust. The Trust funds are administered by the Illinois Clean Energy Community Foundation. The Foundation supports programs and projects that will improve energy efficiency, develop renewable energy resources and preserve and enhance natural areas and wildlife habitats throughout the state.

Resources

Department of Commerce and Economic Opportunity, formerly
Department of Commerce and Community Affairs (DCCA)
www.illinoisbiz.biz
David Kramer 217-785-2765
Dkramer@commerce.state.il.us

Illinois Clean Energy Community Foundation
www.illinoiscleanenergy.org
Jim Mann, Director
312-372-5191

Text of PA 90-0561
www.legis.state.il.us/legislation/publicacts/pubact90/acts/90-0561.html

5. MAINE

(1999 Utility Statistics from www.eia.doe.gov)

Population (2001 Census Estimate):	1,286,670
Net Summer Capability (MW)	2,956
Electricity Consumption (MWh)	15,530,372

	Investor-Owned	Public	Federal	Coop-erative	Total
Number of Utilities	3	5	0	3	11
Percentage of Retail Sales	95.6	3.4		1.0	100.0

Mechanism:	Ratepayer charge with floor and cap
Creation:	Legislative
Duration:	statutorily defined as non-lapsing; no sunset
Administration:	Maine Public Utilities Commission
Budget:	$14million+/-, once earlier DSM programs are paid for
Program Name:	Efficiency Maine
Benefit Cost Test:	Modified Societal Benefits
Utility Incentives:	None

Survey Questions

1. Process and timeline

   Legislation passed in May 1997 required resulting T&D utilities to implement conservation programs consistent with a plan to be developed by the State Planning Office (SPO). PL2001, Chapter 624 (the Act) made the Maine Public Utility Commission ("PUC") responsible for the planning, design, and implementation of the electrical energy conservation programs, effective April 2002. All interim programs must terminate or meet criteria to become ongoing programs by December 2003.

2. Organizational Structure

   Maine Public Utilities Commission (PUC)

   The Act gives the PUC responsibility for developing and implementing conservation programs consistent with an overall energy strategy developed by the PUC. The Act directs the PUC to implement programs by contracting with service providers. The Act does not require the PUC to be the administrative entity, but the PUC has chosen to perform that function at the present time.

   The Act directs the PUC to establish a conservation administration fund, from utility assessments of not more than $1.3million/year. Due to state deficit issues, the Legislature is expected to use close to half the conservation administration fund for other state expenses. As a result, in 2003 the conservation administration budget will be about $700,000.

Presently the Energy Efficiency Team ("EE Team") at the PUC is composed of 3 full-time staff members (3 FTE) and 6 staff who contribute the equivalent of 1.5 FTE for a total of 4.5 FTE effort. All PUC staff who perform work related to the conservation programs bill their hours to the conservation administration fund.

Transmission and Distribution Utilities ("utilities")

All utilities in the State of Maine, including publicly owned utilities, pay into the Conservation Fund established by the PUC. The utilities continue to operate all conservation efforts authorized by the PUC prior to March 1, 2002, until their contracts expire or they are accepted by the PUC as interim or ongoing programs.

Advisory Board

There is no Advisory Board. The PUC solicits feedback through the usual PUC proceedings, as well as an extensive service list/e-mail list and their website.

3. Funding mechanisms

The Act requires the PUC to assess the utilities to collect funds for conservation and administration. The PUC determines the assessment amount. The funds are to be collected in rates. For each utility, the amount of assessment plus utility expenditures for prior PUC-approved conservation efforts must be no less than 0.5% of the utility's total revenues and no more than 1.5mills/kWh. Presently only one utility in the state is assessed at the ceiling level of 1.5mills/kWh. The other utilities are closer to the 0.5% revenue floor, which translates to about 0.3-0.4mills/kWh.

The utilities will be assessed $13.6million in 2003. However, energy conservation expenditures/commitments in 2003 could top $19million, due to the existence of $6million in conservation funds set aside under the previous statute.

The 2003 budget is tentatively estimated to be:

$6.1million	(collected prior to the Act; committed to interim programs)
$8.4million	(2003 assessments; prior utility commitments/programs*)
$0.7million	(2003 assessments; administration fund)
$4.6million	(2003 assessments; available for PUC programs)

*Note: over $7million in 2003 expenditures will be paying for CMP's Power Partners contracts. These will decrease significantly in 2004, then decrease gradually until full expiration in 2012.

4. Degree of association with a long run resources plan

Since the Restructuring Act passed there has been no Integrated Resource Planning.

5. Guidelines for program effectiveness and success

The Act gives many guidelines for program success, including:
Conservation programs are defined as those reducing inefficient electricity use.
Programs must be cost effective, as defined by the PUC.
They must be consistent with an overall energy strategy developed by the PUC.
Programs should be considered that:
Increase consumer awareness of cost-effective options for conserving energy;
Create more favorable conditions for the increased use of efficient products and services; and
Promote sustainable economic development and reduced environmental damage.

The PUC shall:
Target 20% of funds to programs for low-income residential consumers;
Target 20% of funds to programs for small business consumers; and
To the extent practicable, apportion the remaining funds among customer groups and geographic areas such that all other customers have a reasonable opportunity to participate in one or more programs.

6. Pre-implementation program evaluation guidance

In September 2002, the PUC has directed the EE Team to :
Develop tracking and evaluation criteria and procedures for each program; and
Evaluate programs to a level sufficient for business decision-making.

In November 2002, the PUC adopted the Modified Societal Test to measure cost-effectiveness of the energy conservation programs.

Specific goals for kWh savings and other measures will be included in the Energy Conservation Plan that will be completed by mid-2003.

7. Results of program evaluation

The program is too new to have program results yet, but the EE Team expects to utilize third-party evaluators.

8. Financial or performance incentives

There are no financial incentives for utilities.

Interim Programs (with cooperating entities noted)

Low income lighting program. (Maine State Housing Authority)

Low income refrigerator replacement. (MSHA and CAP agencies)
Residential energy efficient lighting.
Small business energy conservation loan program. (Department of Economic and Community Development)
Small business program.
Large C&I program.
Building operator certification. (Public schools statewide, expanded to higher ed and non profit hospitals and municipalities in Aroostook.) NEEP conducts program.
New school construction. (Maine Department of Energy and Maine School Management Association)
State building survey and retrofit.
LED traffic light program. (Maine Department of Transportation)
Maine Energy Education Program.
Maine Energy Curriculum Investigation. (Maine Math and Science Alliance)

Resources

Maine Statute Title 35-A, Chapter 32 Section 3211 (the "Act")
http://janus.state.me.us/legis/statutes

Maine Public Utilities Commission
207-287-3831
www.state.me.us/mpuc/homepage.htm
Many resources can be accessed through this website, including:
Order Establishing Goals, Objectives and Strategies for Conservation Programs, Docket 2002-162, September 24, 2002
Order Amending Chapter 380 of the Rules, "Statement of Factual and Policy Basis," November 6, 2002
2002 PUC Conservation Report presented to the Utilities and Energy Committee, December 1, 2002
Efficiency Maine Program Update, February 3, 2003
Commission Staff Report on the Potential for Energy Efficiency in Maine and Recommendations for Conservation Program Funding, Docket 2002-162, February 11, 2003

Resource for this paper:
Phil Hastings, Efficiency Maine Program Director until April, 2003
Future inquiries should be directed to:
Linda Viens, Program Manager, Efficiency Maine
207-287-7327, linda.viens@maine.gov
See also the new website: www.efficiencymaine.com

6. MASSACHUSETTS

(1999 Utility Statistics from www.eia.doe.gov)

Population (2001 Census Estimate):	6,379,304
Net Summer Capability (MW)	11,805
Electricity Consumption (MWh)	54,162,546

	Investor-Owned	Public	Federal	Coop-erative	Total
Number of Utilities	9	40	0	0	49
Percentage of Retail Sales	85.7	14.3	0	0	100.0

Mechanism:	2.5mills/kWh wires charge, including Low Income funding
Creation:	Legislative
Duration:	Sunset December 31, 2007
Administration:	Utilities, with direction and oversight from the State
Budget:	$115-120million/year
Program Name:	No statewide program name
Benefit Measure:	Total Resource Cost test, plus report on post-market effects
Incentives:	Shareholder incentive tied to goals; No lost revenue recovery

Survey Questions

1. Process and timeline

   Restructuring legislation, GLC 164 (the 1997 Act) passed in November, 1997; effective March, 1998. Utility conservation plans approved in 1998. Chapter 45 of the Acts of 2002 (the 2002 Act) extended programs through 2007.

2. Organizational Structure

   <u>Distribution Utilities (DUs)</u>

   Investor-owned electric distribution utilities (DUs) administer EE programs, delivered by competitive procurement as much as possible. The DUs develop their program plans with input from the Collaborative (see below). They submit their budget and plans to the Division of Energy Resources (DOER), which makes recommendations to the Department of Telecommunications and Energy (DTE) for approval or modification. The DUs submit program results to DOER for review and reporting purposes, and to DTE for incentive determination.

2001 Utility Planning and Administration (P&A) Costs

Utility	P&A Costs*	Total EE program	Percent
Mass Electric	$1.8million	$64million	2.8%
NSTAR	$3.6million	$58million	6.2%
Western Mass	$1.43million	$10million	14.3%
Fitchburg	$307,000	$1.615million	19%
Total	$7.14million	$133.6million	5.3%

*NOTE: These figures for planning and administration do not include marketing, evaluation, research and other activities that might be considered administrative by other organizations. These four utilities do not use the exactly the same accounting or administrative definitions. They do include expenses of the Collaborative.

DOER staff provide about 2.6 FTE effort from six individuals to the EE programs.
DTE staff provide less than 1 FTE effort from 4 individuals to the EE programs.

The Collaborative

Members of the Collaborative are self-appointed, but they must demonstrate they represent some significant segment of consumers impacted by the programs, and they must agree to observe Collaborative rules such as confidentiality. In March 2003 the Collaborative hired a Coordinator, who will work at the rate of 0.4 FTE.

The role of the Collaborative is to assist the DUs in planning, designing and evaluating programs. There is no rule that representation has to be proportionate to consumer share. At the end of 2002 the Collaborative included DOER, one low-income representative for each utility's service territory (they take turns voting), the Attorney General's office, the Northeast Energy Efficiency Council, the Energy Consortium, the Associated Industries of Massachusetts, and the Massachusetts Climate Action Network (MCAN).

The Collaborative employs 14 part-time consultants in four areas: Residential, C&I, Evaluation and Policy. They are used "as needed." They design and monitor the utilities' programs and evaluations.

According to DOER staff, the total Collaborative budget for 2003, including consultants, will be $650,000, about 1/2% of the total EE/LI budget.

3. Funding mechanisms

The 1997 Act replaced a regulatory non-bypassable wires charge with a statutory charge to fund energy efficiency (EE) and low-income (LI) programs. The charge started at 3.3mills/kWh in 1998 and ramped down to 2.5mills/kWh in 2002. The EE/LI funds were predicted to average about $130million/year in the first five years.

The 2002 Act extended the EE/LI wire charges until December, 2007. The minimum rate of

2.5mills/kWh under the previous statute became the required rate for EE/LI programs during the remainder of the time period. The funds are expected to average close to $117million/year from 2003-2007.

Overall Energy Efficiency Program Budget

The total ratepayer-funded energy efficiency expenditures in 2000 were $130.5million. This included funds from the 2000 wires charges as well as unspent funds from previous years and the interest earned on those funds. This is the percentage breakdown, according to the most recent DOER annual report.

Rebates to Customers	45%
Implementation	31%
Performance Incentives	10%
Administration	7%
Evaluation	2%
Marketing	3%
Other	1%

4. Association with a long run resources plan

   There is no association with a long run resources plan. There is no IRP process.

5. Guidelines for program effectiveness and success

   From the DOER "Third Annual Report on Energy Efficiency Activities":

   Overall Statewide Energy Efficiency Goal:
   Strengthen the economy and protect the environment by increasing the efficiency of energy use.

   Energy Efficiency Operational Objectives:
   (1) Reduce the use of electricity cost-effectively.
   (2) Ensure that energy efficiency funds are allocated to low-income customers consistent with legislative requirements, and allocated equitably to other customer classes.

   Energy Efficiency Programmatic Objectives:
   (1) Reduce customer energy costs by balancing short-run and long-run savings from energy efficiency programs.
   (2) Support the development of competitive markets for energy efficiency products and services.

   The 2002 Act directs the DOER to ensure that ratepayer funding for EE is equitably allocated among customer sectors based on sector contribution to the fund.

6. Pre-implementation program evaluation guidance

Specific Energy Efficiency Programs

The consultants to the Collaborative work with utilities to design measurement and evaluation into their programs, using guidance from DOER and DTE. Utilities contract with independent evaluators to audit programs and verify results.

Starting in 2000, pursuant to DTE 98-100 Order and Guidelines, programs will be screened for cost-effectiveness using the Total Resource Cost test. Quantifiable benefits can include the avoidance of non-energy costs such as water, gas, and operation and maintenance costs. The DTE 98-100 Order also required program administrators to report on post-program effects.

Several new performance metrics will be measured by DUs if a new shareholder incentive is accepted. They include the efficiency of acquisition, and non-energy performance metrics such as market transformation.

Overall Program Evaluation

Legislation requires DOER to report directly to the legislature on the effectiveness and need for EE programs before they lapse in 2007.

7. Results of program evaluation

The DOER "Third Annual Report on Energy Efficiency Activities in Massachusetts" summarizes program results and measurement strategies.

Highlights:
EE programs improved reliability and lowered wholesale electricity prices through demand reduction by nearly $6million in 2000.
Participants saved over $19million on their 2000 electric bills.
Savings projected to grow to approx. $295million over lifespan of installed measures.
4,147million kWh estimated to be saved over lifetime of the investments.

Some of the results for Year 2000 programs include:

Total Participant Annual Energy Savings	$19million
Total Participant Measure Lifetime Energy Savings	$295million
Average Cost for Conserved Energy	4.1cents/kWh
Total Participant Annual Demand Savings	$1.2million
Interruptible Service Credit Payments	$3.1million
Savings due to Lower Wholesale Energy Clearing Prices	$5.7million
New Jobs Created	1,183
Disposable Income from Net Employment	$48million
NOx Emissions Avoided Annual and Measure Lifetime	705/6,558 tons
SO2 Emissions Avoided "	1,405/9,086 tons CO2

Emissions Avoided "	253,100/2,042,400 tons
Benefit-Cost Ratio with and without Post Program Effects	1.9 and 2.4

8. Financial or performance incentives

Shareholder incentives have been available to utilities participating in DSM activities since the early 1990's. In recent settlements negotiated with the Collaborative, three of the four DUs agreed to forego lost-base revenue in return for clear and consistent shareholder incentives. The fourth DU litigated, requesting both the shareholder incentive and loss-based revenues, and lost.

In Docket DTE 98-100, the DTE determined that all costs associated with program implementation would be included in the calculation of the incentive, including marketing, administration, evaluation, etc.

The Collaborative and utilities have negotiated a new shareholder incentive proposal they will present to DTE in 2003. The DUs agreed to more stringent goals (including energy savings, acquisition efficiency and market incentives) and accountability with the Collaborative in return for a more reasonable shareholder incentive. If DUs achieve 100% of their "performance metrics", they earn back 5% of their EE expenditures, after taxes. The threshold for payment would be 75% attainment. Exemplary performance would be capped at 110%, earning an incentive of 5.5%.

Issues and Special Situations

Consumer Awareness/Branding

Consumer awareness is not a metric of success. In fact, the Collaborative has discouraged the use of resources for broad media buys and consumer awareness. They see more payback from training utility energy efficiency staff and account representatives, and vendors/contractors to sell the technologies/programs.

The Collaborative has struggled with the concept of statewide "branding." To date they have decided not to pursue it. They see good results from DUs having independence and ownership in their service areas.

Standardized Reporting

The DUs propose EE plans to DOER using standardized tables. They report program performance data to DTE and DOER using a set of standardized tables. These allow for easy comparison between years and across programs. The consistent use of these tables eases administrative and evaluation burdens over the years.

Cape Light Compact: Example of Local Administration

They are a "municipal aggregator" as allowed by statute, serving 170,000 consumers. They administer about $5million in EE funds per year. Very flexible. Each town (18 towns) has 6 months to use their allotment; if they don't someone else can during the last 6 months. Contact: Kevin Galligan, Program Manager, 508-375-6828.

Resources

Chapter 164 of the Acts of 1997, effective 3/1/98
www.state.ma.us/legis/laws/seslaw97/s1970164.htm

Chapter 45 of the Acts of 2002, effective 2/28/02
www.state.ma.us/legis/laws/seslaw02/s1020045.htm

DOER, *Third Annual Report on Energy Efficiency Activities in Massachusetts: 2000 Energy Efficiency Activities*, Summer 2002. Executive Summary and full report at: www.state.ma.us/doer/ Scroll down page to Third Annual Report.

DTE 98-100 Order and Guidelines (RE: cost-effectiveness, DOER review, and shareholder incentives) issued 11/10/98
www.state.ma.us/dpu/electric/98-100/finalguidelinesorder.htm

Dept of Telecommunication and Energy (DTE), formerly Department of Public Utilities
www.state.ma.us/dpu/
617-305-3500
Gene Fry, Economist (he authored much of 98-100, new cost-effectiveness rules)
617-305-3654
Gene.Fry@state.ma.us

Division of Energy Resources (DOER)
www.state.ma.us/doer/
617-727-4732 x 139
Bruce Ledgerwood, Energy Efficiency Team Leader
bruce.ledgerwood@state.ma.us

Northeast Energy Efficiency Partnership (NEEP)
www.neep.org
781-860-9177
Julie Michals (former DOER staffer and principal author of DOER energy efficiency legislative reports)
Jmichals@neep.org

7. MINNESOTA

(1999 Utility statistics from www.eia.doe.gov)

Population (2001 Census Estimate)	4,972,294
Net Summer Capability (MW)	10,157
Electricity Consumption (MWh)	60,169,575

	Investor-Owned	Public	Federal	Coop-erative	Total
Number of Utilities	5	125	1	47	178
Percentage of Retail Sales	68.4	14.1	0.1	17.5	100.0

Mechanism:	1.5-2.0% of each electric utility's gross operating revenues
Creation:	Legislative
Duration:	New plans every two years; no sunset
Administration:	State agency sets goals, approves and evaluates programs. Utilities retain funds; design and implement programs.
Budget:	$53million+/year
Program Name:	Generally known as Conservation Improvement Programs (CIPs)
Benefit Measure:	Modified Societal Benefits
Incentives:	Cost recovery and performance incentives

Survey Questions

1. Process and timeline

   The 1982 Conservation Improvement Program (CIP) statute required utility commitments to energy efficiency. 1991 CIP legislation required specific revenue percentage investment in end-use efficiency, and involved the State in planning and evaluation. 2001 CIP legislation clarified utility investment and priorities.

2. Organizational structure

   State regulated utilities (primarily investor-owned "IOUs") administer electric and natural gas energy efficiency programs (CIPs). IOUs submit two-year CIP plans to the Department of Commerce (DOC) for approval or modification. The DOC sets energy savings goals for CIPs. DOC staff, with technical assistance from the Energy Office, review plans, monitor programs and make recommendations to the DOC Commissioner. The Commissioner can add, delete, or modify programs and spending. The IOUs submit program results to DOC for review and reporting purposes. They submit results to the Public Utilities Commission (PUC) for incentive determination and planning purposes.

   Municipal and cooperative utilities have statutory CIP responsibilities. However, the DOC

can only make recommendations to increase the effectiveness of their activities.
The utilities use a variety of accounting methods, leading to differences in administrative costs reported.

A variety of staff from the DOC Advocacy Unit, Advisory Unit and from the Energy Office contribute a total of 4-5 FTE effort to the CIP effort.

Advisory Board

There is no advisory board. Information about every CIP filing will be sent to all persons who request to be on the CIP Service List.

3. Funding mechanisms

The new statute requires every electric utility (IOUs and all others) to invest 1.5% of their in-state gross operating revenues in energy conservation improvements. A utility operating a nuclear plant in the state must invest 2% of its revenues. Gas utilities must invest 0.5% of their revenues. Up to 3% of the funds may be used for program monitoring and evaluation.

DOC reports indicate that in 2002:
Regulated natural gas utilities spent \$9.79 million;
Regulated electric utilities spent \$46.39 million; and
According to DOC staff munis and coops spent over \$32 million in 2002.

The work the DOC does for the CIP is on a fee for service basis, billed to the appropriate utilities. Costs are recovered through the usual PUC procedures.

4. Association with a long run resources plan

Statutes require that major gas and electric utilities, including the G&T entities that provide electricity to municipal and cooperative utilities, file biennial Integrated Resource Plans (IRPs) and Transmission plans with the PUC.

The PUC assumes energy savings goals determined in CIP planning are the minimum attainable, and may call for higher investments by the utility. At least three utilities are contributing more funds than statutorily required due to the IRP process.

5. Guidelines for program effectiveness and success

The statute requires programs to be cost-effective, and an “adequate amount” of residential CIP funding must directly address the needs of renters and low-income persons.

According to DOC staff, CIPs must meet the energy savings goals, reach all customer groups, address a broad spectrum of end uses and be cost-effective.

By statute, the municipal and cooperative utilities must spend a gradually increasing percent of funds on programs that achieve energy savings, rather than load management. The "2002 CIP Primer" prepared for municipalities gives guidance for meeting this requirement.

6. Pre-implementation program evaluation guidance

   Both the PUC and the DOC use a modified societal benefits test when assessing cost-effectiveness of programs and energy efficiency potential. Due to their statutory and regulatory differences, the IOU plans are held to a benefit/cost evaluation by the DOC, but the municipal and cooperative utilities are not.

   The statute requires the DOC to evaluate CIP plans for effectiveness and to make recommendations for further changes. The State Energy Office helps with engineering assumptions and other technical matters.

7. Results of program evaluation

   Although the DOC may order an independent audit of CIPs, generally utility reports are accepted, since assumptions were discussed when the plan was accepted.

   The following results from the 2001 Energy Planning Report cover accomplishments of the IOUs, which provide about two-thirds of the electricity in the State:

   From 1997-2000 electric IOUs spent an average of $42.7million/year on CIPs.
   Five-year demand savings (1996-2000) totaled 641MW (average 128 MW/year)
   Average cost of capacity saved was $343/kW.
   Five-year energy savings totaled 1,680,843 MWh (average 336,169 MWh/yr)
   DOC anticipates 1999-2000 CIP investments will save 21.8billion kWh over the lifetime of the investments, at an average cost to utilities of 1.4cents/kWh.

   Each municipal and cooperative utility must report biennially on its CIP and results. They must analyze CIP cost-effectiveness with the help of the DOC.

8. Financial or performance incentives

   By statute, utilities are allowed to recover CIP expenses required by the DOC.

   In 1999 the PUC agreed to a performance-based incentive with a threshold of 91% goal attainment. Exemplary performance is capped at 150%, making the utility eligible for "shared net benefits" of 30% of the program budget. Ratepayers fund this incentive during the following year when the PUC adjusts rates. Recently these charges have been on the order of 1.45%.
   The non-State-regulated municipal and cooperative utilities do not have these incentive options, but they also have few consequences for poor performance.

Issues and Special Situations

There is a large customer opt-out provision.

There is some concern about the method for computing some industrial energy savings. There can be disagreement about how to compute incremental energy savings when industry goes through a process line expansion.

Programs

The statute requires energy-efficient lighting programs, and supports rebates for high-efficiency appliances, rebates or subsidies for high-efficiency lamps, small business energy audits, and building "recommissioning." All IOU load management programs must result in actual energy savings.

Resources

Minnesota Department of Commerce, Energy Planning and Advocacy Unit
651-296-4026
Chris Davis, Senior Utility Rates Analyst, evaluated CIP for Chapter 4 of Plan
651-296-7130, Christopher.Davis@state.mn.us
Lois Mack, Manager of CIP and Special Projects
651-296-8900, Lois.Mack@state.mn.us
2001 State Energy Planning Report, January 2002, Department of Commerce
www.state.mn.us/mn/externalDocs/Energy_Planning_Report_121602022402_2002PlanningRpt.pdf

Minnesota Statutes 2002, Chapter 216B, 216B.24 "Energy conservation improvement"
www.revisor.leg.state.mn.us/stats/216B/241.html

Center for Energy and Environment *2002 CIP Primer* prepared for the Minnesota Municipal Utility Association, May 2002
www.mncee.org/ceedocs/cipprimer.pdf

Minnesota Public Utilities Commission 2001 and 2002 Annual Reports
www.puc.state.mn.us/docs

ME3 (Minnesotans for an Energy Efficient Economy)
www.me3.org
Michael Noble, Executive Director
651-225-0878, Noble@me3.org

8. NEW JERSEY

(1999 Utility Statistics from www.eia.doe.gov)

Population (2001 Census Estimate): 8,484,431
Net Summer Capability (MW) 16,651
Electricity Consumption (MWh) 73,140,489

	Investor-Owned	Public	Federal	Coop-erative	Total
Number of Utilities (Elec.)	4	9	0	1	14
Percentage of Retail Sales	98.5	1.4	0	0.2	100.0

Mechanism:	Societal benefits charge on electric and gas customers of 7 major utilities
Creation:	Legislative
Duration:	Minimum 8 years (2001-2008); comprehensive analysis every 4 years
Administration:	Electric and Gas Utilities, initially
Budget:	Minimum $107.5million/yr. 2003: $124.126million+carryover
Program Name:	New Jersey Clean Energy Program, but often referred to as Comprehensive Resource Analysis (CRA) programs
Benefit Measure:	Total Resource Cost utilized by utilities, but no formal approval.
Incentives:	Performance incentives and lost revenue recovery concepts approved. No specifics decided upon.

Survey Questions

1. Process and timeline

   Restructuring legislation, SB7 ("the Act") passed in February 1999. Utility plans filed in February 2000. Board of Public Utilities (BPU) approved initial plans and budgets in March 2001. New energy efficiency (EE) programs began in May 2001.

2. Organizational structure

   Seven major electric and gas distribution utilities (DUs) were given administrative and implementation responsibilities for the first year's EE programs and one renewable program. They chose to work together through a collaborative (see below).

   The BPU determined system benefit charges (SBC) for each utility and approved utility plans, budgets, cost recovery and incentive measures. During the first year the BPU retained a consultant to recommend a permanent administrative structure for Comprehensive Resource Analysis (CRA) programs. The report was submitted in April 2002. The utilities have continued to administer the approved programs in the absence of a new structure.

New Jersey Clean Energy Collaborative (the "Collaborative")

Six of the seven major utilities chose to approach their CRA planning requirement together. They reached a settlement with the Natural Resources Defense Council (NRDC) and other parties, and submitted their plans jointly to the BPU in February, 2000. The seventh utility ultimately joined. The DUs and NRDC formed the Collaborative to develop statewide approaches for planning, programs and evaluation. The Collaborative formed a Management Team, and Program Teams, and contracted with advisors for technical and management expertise

The Management Team and Program Teams were primarily staffed by appropriate utility personnel. Facilitation and technical expertise were provided through contracts with advisors as necessary. Technical advisors provided a wide range of program design and evaluation capabilities to the program teams.

The Collaborative submitted quarterly and annual reports, annual program plans and budgets, evaluation proposals and other filings on behalf of the members to the BPU.

A ballpark figure given for non-utility Collaborative costs per year is $0.5-1million.
An advisor to the Collaborative estimated that about 30 FTE staff in the utilities are working on the EE programs. The utilities have reported administrative costs of 6%.

In the Clean Energy Collaborative Annual Report 2001, the following overall administrative and related cost percentages were reported for utility CRA programs:

Administration		6%
Sales	6%	
Marketing	7%	
Training	1%	
Market Research	7%	
Grants and Implementation Contracts		73%

By the end of the first quarter of 2002, the grants and implementation expenditures were up to 79%, due to decreases in start-up costs. The Collaborative allowed for some joint purchasing opportunities. The Davies Report (see below) includes a detailed discussion of the DUs administrative costs. It also concluded that program results are a more important indicator of effective administration than the size of the administrative budget.

Clean Energy Advisory Council

The BPU directed the formation of this group in December, 2002. They will make recommendations on program administration and design in the near future. The utilities may have to operate their CRA programs on a month-to-month basis until the BPU hears from this Council and issues decisions regarding program administration.

3. Funding mechanisms

The Act required electric and gas utility customers to contribute funds to new CRA programs, with 25% of those funds supporting renewable energy projects. The BPU had to determine how much money the utilities were spending on DSM activities as of the date the law went into effect (2/9/99), then take at least half that amount and direct it to new CRA programs. The remainder would continue to be collected and used to pay off prior commitments or continuing programs that would not be considered CRA. The Act requires that as spending for prior commitments goes down, spending for CRA programs should go up. The BPU determined that the total SBC would be $215million, including the new CRA spending and continuing recoverable expenses due to old DSM programs. Funds remain with the utilities.

"System benefit charges…[for new programs, that] range from 0.4 to 1.8 mills/kWh and 4.7 to 8.9 mills/therm, are based largely on the level of efficiency funding in rates at the time the restructuring legislation was enacted" (D. Bryk et al)

The March, 2001 BPU Final Order, as adjusted in its August, 2001 decision determined the following budget amounts for the new CRA programs. The total SBC is $215million/year:

	EE	Renewables	Total for new programs
2001:	$86.25million	$28.75million	$115million
2002:	$89.5million	$29.8million	$119.3million
2003:	$93.1million	$31million	$124.1million

4. Degree of association with a long run resources plan

The Act requires the BPU to conduct a comprehensive analysis of CRA programs every four years, requiring four-year plans from utilities, but there is no long run resources plan. The BPU can, and does change programs, funding and administration within the four year period.

5. Guidelines for program effectiveness and success

The Act set program goals of "transforming markets, capturing lost opportunities, making energy services affordable for low-income customers and eliminating subsidies for programs that can be delivered in the marketplace without…customer funding." The BPU indicated in their March, 2001 Final Decision and Order that the goals of the Act were to: stabilize utility rates; lower the high cost of energy; provide clean air by locating and developing new sources of renewable energy, and deliver energy efficiency in a competitive marketplace.

6. Pre-implementation program evaluation guidance

In July 2001 the Collaborative filed with the BPU the variety of measures, including the Total Resource Cost test with environmental adders, they would use to assess energy savings, environmental benefits and attainment of other program goals. The utilities are following the proposed protocols in the absence of other guidelines.
The utilities use conversion formulas developed by the New Jersey DEP to determine annual, lifetime and cumulative lifetime reductions in SO_2, NO_x, CO_2 and mercury due to electricity

and gas efficiency program implementation.

The Objectives of the Collaborative's evaluation activities are:
Assessing goal attainment by programs;
Assessing energy impacts, lost revenues and cost-effectiveness;
Providing timely feedback to program managers; and
Providing necessary information for program design and decision-making.

7. Results of program evaluation

The Collaborative issued RFPs and contracted for evaluation. Some contractors have assisted with oversight of evaluation issues, such as designing evaluation measures into programs. Others contractors evaluated the effectiveness of programs

BPU required utilities to report goals and incentive metrics compared to achievements. Utility by utility figures can be seen in the appendices to quarterly reports submitted to the BPU, posted on the BPU website.

Here are the broad results reported in the Collaborative's 2001 Annual Report. Details for each program and utility are available in the Report and its appendices.

Energy Savings, actual, Dekatherms	270,762 Dth
Energy Savings, committed, Dekatherms	100,754 Dth
Energy Savings, actual, MWh	54,969 MWh
Energy Savings, committed, MWh	69,639 MWh
Demand Savings, actual, MW	224 MW
Demand Savings, committed, MW	22 MW
Annual Emissions Savings, Electric Programs only:	
CO_2	27,485 metric tons
NOX	80 metric tons
SO_2	128 metric tons
Hg	1.2 pounds
Actual Expenditures	$57,520,000
Committed Expenditures	$22,207,000
Benefit/Cost, Residential (not Low Income)	1.52
Benefit/Cost, Non-residential	1.80

In July, 2002, the BPU suspended utilities' program evaluation activities, so that BPU staff could review the bids from independent contractors for evaluation. Those contracts have not been approved. There has been no independent evaluation since that time. However, the utilities are continuing to use the measures proposed by the Collaborative in July, 2001 to report results.

8. Financial and performance incentives

The Act, according to the BPU, required the BPU to determine "the level of cost recovery and performance incentives for old and new programs, and whether the recovery of DSM costs may be reduced or extended."

In 1991 the BPU approved the use of performance incentives in the DSM program regulations. In March 2001 the BPU rejected the Collaborative's performance protocols as too heavily weighted towards administrative goals. The utilities filed modified incentive proposals consistent with the BPU's concerns in July 2001, in November 2001 and November 2002. These filings are pending before the BPU.

In March 2001, the BPU indicated it would approve lost revenue recovery related to CRA programs, if tied to approved savings protocols. The Collaborative filed proposed protocols. No decision to date. The utilities are "booking" the lost revenues.

Issues and Special Situations

The Future of the Collaborative
The utilities presently have no authority to enter contracts, so they are operating on month-to-month contract extensions. The Collaborative's purpose, to support the utilities and NRDC in joint program planning, implementation and evaluation, appears at least temporarily moot. The Davies report recommended that the BPU give formal recognition to and require accountability of the Collaborative, but that has not happened yet. The BPU has hired more staff who are working closely with utility management teams on the CRA programs. This may improve the regulatory lag that has led to program planning and evaluation delays.

The 75/25 split
The Act requires each utility to split CRA funds, 75% for EE and 25% for RE over the first eight-year period of the program. The BPU, in March 2001, stipulated that utilities were to maintain this ratio each year. The utilities requested that they be held to a multi-year requirement for the 75/25 ratio. This filing is pending before the BPU.

Program Budgets
The BPU last approved program budgets in August, 2001. Technically the BPU must approve budget changes. The utilities have requested BPU permission to modify program budgets. The BPU had not made decisions re: these filings to date.

Parity between Suppliers
The funding for different programs is uneven between service territories. The BPU-approved amounts are based on prior spending with some modifications, not on the actual cost of programs in each service territory reaching the same percentage of customers.

Rate Increase
The rate cap and mandated decreases created by the Act will expire August 2003. During the CRA proceedings that resulted in the March 2001 Final Decision and Order, the BPU acknowledged there would be rate impacts after the end of the rate freeze, and that new program

spending plus existing commitments could exceed collections. Revenue recovery will be an issue in rate cases.

Advisory Group
No official advisory group was formed initially for the CRA programs. The Collaborative members viewed themselves more as a working group to get the utilities' job done. However, in the absence of an advisory board, some expected the Collaborative to serve a more public purpose. The new Clean Energy Advisory Council will most likely fulfill this role.

Resources

New Jersey Board of Public Utilities
609-777-3300
www.bpu.state.nj.us
Final Decision and Order, March 9, 2001.
New Jersey Clean Energy Collaborative 2001 Annual Report and quarterly reports.
New Jersey Clean Energy Collaborative 2003 Program Plan, November 1, 2002.
On the BPU website. Scroll down on the right and choose "Clean Energy Program".

SB7 Electric Discount and Energy Competition Act February 1999 (The Act)
www.bpu.state.nj.us/wwwroot/energy/EX00020091ORD.pdf

New Jersey Clean Energy Program
www.njcleanenergy.com

Dale Bryk, Senior Attorney, Natural Resources Defense Council
212-727-4480, Dbryk@nrdc.org

Michael Ambrosio, Collaborative facilitator, Deloitte Touche Tohmatsu
973-683-7383 Mambrosio@deloitte.com

Susan Coakley, Northeast Energy Efficiency Partnership
Former Collaborative facilitator, most recently technical advisor team leader
781-860-9177 x 12 Scoakley@neep.org

D. Bryk, J. Plunkett, and S. Coakley, *Utility Administration of System Benefit Charge-funded Energy Efficiency Programs in New Jersey: Model or Mess?* ACEEE Summer Study Session on Building Efficiency, Summer, 2002. Communication from Dale Bryk.

9. NEW YORK

(1999 Utility Statistics from www.eia.doe.gov)

Population (2001 Census Estimate)	19,011,378
Net Summer Capability (MW)	33,742
Electricity Consumption (MWh)	147,545,430

	Investor-Owned	Public	Federal	Coop-erative	Total
Number of Utilities	8	49	0	4	61
Percentage of Retail Sales	72.4	27.4	0	0.1	100.0

Mechanism:	System Benefits Charge
Creation:	Regulatory
Duration:	Present plan ends June 30, 2006. Will be reviewed in 2005.
Administrator:	NYSERDA (statewide public benefits corporation)
Budget:	$150million/year, excluding public power authority programs
Program Name:	New York Energy $mart
Benefit Measure:	Total Resource Cost, Participant Test, Utility Test
Incentives:	No incentives for utilities

Survey Questions

1. Process and timeline

   In May 1996 the Public Service Commission (PSC) declared its intention to establish system benefits charges (SBC) to fund public benefit programs during restructuring. Initial SBC rates were established in individual rate cases during 1997 and 1998. In January 1998 the PSC named the New York State Energy Research and Development Authority (NYSERDA) as the third-party administrator. In May 1998 NYSERDA filed initial plans. In July 1998 NYSERDA's plans were made effective by the PSC. In January 2001 the PSC extended the SBC for five years and expanded funding.

2. Organizational Structure

   The administrative operating arrangements were laid out in the March 1998 Memorandum of Understanding (the "MOU") among NYSERDA, the PSC and the DPS. The PSC establishes overall program policies and priorities, including budget priorities. NYSERDA, a legislatively created public benefit corporation, develops program plans for PSC approval and administers the New York Energy $mart (NYE$) programs, using a combination of in-house staff and outside contractors to implement programs through competitive responses to Program Opportunity Notices (PONs) and Requests for Proposals (RFPs). The DPS provides guidance and planning support to NYSERDA, and monitors program progress and evaluation. Two investor-owned electric distribution utilities (DUs) are running SBC-supported low-income programs pursuant to PSC order.

The MOU also outlined the creation of the System Benefits Charge Advisory Group ("Advisory Group"). The Advisory Group meets regularly with NYE$ staff to provide guidance and direction for program design and implementation. They also act as the "Independent Program Evaluator," certifying evaluation results to the PSC.

The MOU indicated the Advisory Group would be made up of representatives of interested parties, including, the DUs, electricity generators, energy services providers, the research and environmental communities, and industrial, residential/small commercial, and low income customers. Presently the Advisory Group is made up of twenty three members, including members who liaison with the State Assembly and Senate.

The NYE$ programs are statewide, but organized by focus, not geography or customer group. The three major program areas delineated by the PSC are:

Energy Efficiency, Peak Load Reduction, Outreach and Education for customers;
R&D (including Environmental Monitoring and Protection); and
Low Income Energy Affordability.

NYSERDA has flexibility within the defined program areas, but may not transfer funds among the three major program areas without public input and PSC approval. NYSERDA can reassign funds within the three major program groups, giving NYSERDA flexibility to respond quickly to opportunities and challenges.

The NYE$ program does have some sector limitations. The programs are termed "statewide" but they are not available to customers of LIPA and the NYPA or others who do not pay the System Benefits Charge. This would include consumers on Long Island, and the municipalities and large industrial customers of NYPA.

NYSERDA contracts with consultants for administration and program process and evaluation assistance.

NYSERDA had a pre-existing statewide energy efficiency mandate. Staff were experienced with DSM programs, emerging technologies, energy planning and analysis. NYSERDA had existing technical assistance and R&D capabilities. Administrative controls were already in place. NYSERDA had a historically good working relationship with DPS staff. NYSERDA was experienced with a market-based approach, using competitive bidding through Program Opportunity Notices (PONs) and Requests for Proposals (RFPs). Their unique corporate identity allows for quick turn-around time, and flexible hiring and procurement practices.

NYSERDA now has a total staff of about 208 FTE and a total budget of about $200million/year. The SBC budget is close to $139million/year. About 110 FTE work on NYE$, the SBC program. Of these, about 76 are program staff and 34 provide a variety of support such as finance, contracting, analysis, etc.

3. Funding mechanisms

Originally the SBCs were established within individual electric utility rate cases held during 1997-98. Their effective rates varied from 0.613mills/kwh to 1.01mills/kwh. The July1998 PSC Order established the following total allocations for the three-year life of the program: Energy Efficiency $161.6; R&D: $40.4million; Low Income: $29.3million; Environmental Disclosure: $3.0 million. Total: $234.3million.

During the first three years, the SBC budget for the NYSERDA's NYE$ program was about $58million/year. The utilities retained about $20million/year for PSC-approved, on-going public benefits programs. The PSC allowed NYSERDA 5% of the budget, or $2.9million/year, for administration.

On January 26, 2001, the PSC raised the SBC to $150million/year, with NYSERDA administering $139million/year. It extended the program for 5 years, until June 2006. NYSERDA may spend no more than 7% on administration or about $9.3million/year.

The 1/26/01 PSC Order changed the SBC rate determination. The PSC set a total annual SBC fund of $150million, with utilities' contribution proportionate to their share of gross 1999 electric operating revenues. The resulting contributions were 1.23% of 1999 revenues. Utilities must transfer SBC funds to NYSERDA at least quarterly. Utilities were directed to determine their own SBC collection rates based on projected sales and to “true” them up annually.

The 1/26/01 PSC and subsequent Orders included fairly detailed directions for the use of the funds over the five-and-a-half year period ending June 30, 2006:

$436million for peak load reduction, energy efficiency and customer outreach and education;
$200million for research and development;
$114million for low-income programs (EE and access to benefits of competition).

4. Association with a long run resources plan

   With the advent of restructuring there is no long run resource planning to associate with. The market is supposed to respond to demand by obtaining needed resources.

   NYSERDA staff are involved in ongoing planning efforts that impact energy policy and demand forecasting such as the State Energy Plan, the Independent System Operator's demand management planning and the DPS Price and Reliability Task Force, convened by the PSC Chair to examine demand and supply issues.

5. Guidelines for program effectiveness and success

   Program focus, and therefore evaluation measures, was dictated by the PSC in various orders and opinions. The original 1998 goals established were to:

   - Promote competitive markets for energy efficiency services.

- Provide direct benefits to electricity ratepayers, or be of clear economic or environmental benefit to the people of New York.

These goals were amended by the PSC when it extended and expanded the SBC program. The new goals, as summarized in the "Revised Operating Plan" are to:
- Improve system-wide reliability [and peak reduction] through end-user efficiency actions.
- Improve energy efficiency and access to energy options for underserved customers [i.e. low-income].
- Reduce environmental impacts of energy production and use.
- Facilitate competition to benefit end-users.

NYSERDA's business approach puts an additional spin on criteria for success. They "'fund only programs that have the ability to develop the economy of New York.'" (Hall, N. pIV-30) NYSERDA is looking for long-term economic improvements and market transformation.

Although utility service area parity is kept in mind, it is not a rigid requirements. In fact the 1/26/01 PSC order required NYSERDA to focus on peak demand reduction in the southern part of the state, recognizing that might be a disproportionate use of resources. Over the five year period, NYE$ staff expect SBC expenditures will track parity fairly closely.

6. Pre-implementation program evaluation guidance.

All proposed programs must have measurable goals and objectives. NYSERDA uses the Total Resource Cost (TRC) test as the primary instrument for determining the cost-effectiveness of the NYE$ programs. It also uses the Participant test and the Utility test (considering NYSERDA's costs to be the "utility" costs in the test), when needed.

"Technical Evaluation Panels", which always include DPS staff, are assembled by NYE$ staff to review PONs and RFPs before release, and then to choose the best responses to PONs and RFPs, using the evaluation criteria mentioned above.

NYE$ staff receive program evaluation guidance from consultants, DPS staff, and the SBC Advisory Group. They continually refine evaluation metrics and performance measurement. They use evaluation to measures programs and process, to reveal opportunities to improve performance by changing program or process design.

Early evaluations were carried out on a measure-specific level and a program level. Key near-term measure-specific data items included:
- Annual energy savings estimates (seasonal allocations where applicable);
- Peak load reduction/capacity savings estimates (seasonal allocations if applicable);
- Average measure lives;
- Incremental cost of premium efficient measures vs. cost for standard efficient practice; and

- Other resource benefits (e.g. water, fuel, economic and environmental), where appropriate.

The long term outcomes NYE$ staff hope to cause and measure are changes in attitudes and behavior to support energy efficiency; improvements in infrastructure to support energy efficiency; changes in market share of energy efficient products; and changes in manufacturing standards and regulatory codes. They hope to look at models for causality to clarify the linkage between NYE$ programs and observed outcomes.

7. Results of program evaluation.

Independent program evaluation is increasing. The total evaluation budget for the first three years was about $700,000. As a result NYE$ staff did most of the evaluation legwork. Now two percent of the budget is allowed for evaluation, or $2.8million annually. Staff expect to get more specialized evaluation assistance, both in-house and from consultants.

The "Report to the System Benefits Charge Advisory Group: Initial Three-Year Program. January 2002" www.nyserda.org/02sbcreport.html describes many details of program goals, evaluation methodology and results (see the Report's Appendix C).
Some of the reported results as of 6/30/01 were:

312.5million kWh/yr saved from installed measures
927.7million kWh/yr anticipated saved from funds committed
126.1million kWh/yr clean generation from funds committed
216.9 MW demand savings from installed measures
521.3 MW anticipated demand savings from funds committed
$0.016/kWh average program cost
$902/KW average program cost
$119.1million anticipated energy bill reductions from funds committed
NOx anticipated annual emission reductions: 960 tons
SO2 anticipated annual emission reductions: 1,680 tons
CO2 anticipated annual emission reductions: 671,915 tons
$617.7million anticipated co-funding and leveraged investment
2,311 jobs sustained or created

The ratio of co-funding and leveraged funds to SBC committed funds was 3.1. NYE$ Program portfolio level Benefit Cost ratio was 1.4. Comparing $119.1million in bill savings to the total of SBC and leveraged funds equals a 14.5% return on investment.

The PSC requires detailed SBC Program status and evaluation reports biennially and NYSERDA files interim reports. PDF files with the full text of the evaluation reports containing budget status, as well as process and progress results through the period of the report can be accessed at the NYSERDA website.

8. Financial or performance incentives

There are no financial or performance incentives for utilities.

New York Energy $mart Programs

Business and Institutional Energy Efficiency Programs

- Commercial/Industrial Performance Program
- Energy Smart Schools Comprehensive Energy Strategies Program
- Advanced Monitoring Program
- Peak Load Reduction program (including Cooling ReCommissioning)
- New Construction Program
- Smart Equipment Choices Program
- Premium-Efficiency Motors Program
- Small Commercial Lighting Program
- Commercial HVAC Program
- New York Energy $mart Loan Fund
- Commercial and Industrial Innovative Opportunities Program
- Technical Assistance Program
- Energy Audit Program
- FlexTech Program

Residential Energy Efficiency Programs

- Energy Star Products and Residential Energy Star Marketing
- Energy Star Products Bulk Purchase Program
- Keep Cool (Room Air Conditioner Bounty) Program
- New York Energy Star Labeled Homes Program
- Home Performance with Energy Star
- Residential Technical Assistance Program
- Residential Special Promotions Program
- New York Energy $mart Communities Program
- Residential Comprehensive Energy Management (CEM) Program
- Website Hosting and Re-Design

Low-Income Energy Affordability Programs

- Low-Income Aggregation Program
- Low-Income Oil Buying Strategies Program
- Low-Income Energy Awareness Program
- Low-Income Forum on Energy (LIFE)
- Low-Income Assisted Multifamily Program (AMP)
- Assistance Home Performance with Energy Star and Weatherization Network Initiative

Research and Development Programs

- Wholesale Renewable Energy Market Development
- End-Use Renewable Energy Market Development
- Willow Plantation Development
- Environmental Monitoring, Evaluation and Protection Program
- Municipal Water and Wastewater Treatment
- Alternative Fuels Power Generation and Energy Storage
- Distributed Generation -= Combined Heat and Power

Next Generation Energy Efficient Technologies
Enabling Technologies for Peak Load Management
Time-Sensitive Pricing Demonstrations

Resources

New York Energy Research and Development Authority (NYSERDA)
www.nyserda.org
Gary Davidson, NYSERDA, Assistant to the President
518-862-1090x3289 gsd@nyserda.org
Brian Henderson, NYSERDA, Director, Energy Efficiency Services
518-862-1090x3305 bmh@nyserda.org
Larry Pakenas, NYSERDA, Energy Analysis Program Manager
518-862-1090x3247 ljp@nyserda.org
Peter Smith, NYSERDA, Vice President for Programs
518-862-1090x3320 prs@nyserda.org

"Report to the System Benefits Charge Advisory Group: Initial Three-Year Program. January 2002" at www.nyserda.org/02sbcreport.html;
"New York State Energy Plan, June 2002" at www.nyserda.org/sep.html
"System Benefit Charge: Revised Operating Plan for New York Energy $mart Programs (2001-2006), June 12,2002" at www.nyserda.org/sbc2001-2006.pdf

New York Public Service Commission (PSC) and Department of Public Service (DPS)
www.dps.state.ny.us
Fred Carr, NY DPS, Utility Supervisor,
518-474-1932 frederick_carr@dps.state.ny.us
Craig Jones, NY DPS, Utility Supervisor,
518-474-1932 craig_jones@dps.state.ny.us
John McLaughlin, NY DPS, Energy Efficiency Analyst
518-489-2883 John_mclaughlin@dps.state.ny.us

For PSC orders and opinions related to Case 94e0952 go to
www.dps.state.ny.us/fileroom.html#
"Memorandum of Understanding Between New York Public Service Commission, New York State Department of Public Service and New York State Energy Research Development Authority", dated 3/11/98, amended 9/00 and 12/01.

Hall, Nick (TecMRKT Works) and Sumi, David (PA Consulting Group) "A Comparative Examination of the Northwest Energy Efficiency Alliance and the New York Energy Research and Development Authority" prepared for the State of Wisconsin Department of Administration, Division of Energy. October 2001. Communication from the author.

10. OHIO

(1999 Utility statistics from www.eia.doe.gov)

Population (2001 Census Estimate):	11,373,541
Net Summer Capability (MW)	27,083
Electricity Consumption (MWh)	165,717,257

	Investor-Owned	Public	Federal	Coop-erative	Total
Number of Utilities	9	85	0	25	119
Percentage of Retail Sales	90.8	5.6	0	3.7	100.0

Mechanism:	temporary rider collected by electric utilities of 0.10758 mills/kWh
Creation:	Legislative
Duration:	January 2001 – December 2010, or until $100million in fund
Administration:	Ohio Department of Development
Budget:	$15million/year for 5 years; $5million/year until $100million total
Name:	Energy Efficiency Revolving Loan Fund
Benefit Measure:	Simple payback less than five years or other measures
Incentives:	None for utilities

Survey Questions

1. Process and timeline

   The Energy Efficiency Revolving Loan Program ("Loan Fund") was established by the Ohio General Assembly under the 1999 electric restructuring act (the "Act") in Sections 4928.61 - 4928.63 of the Ohio Revised Code. The rate of the rider was set in August 2000. Utilities began collecting the temporary rider January 1, 2001. Programs were announced in 2002.

2. Organizational structure

   The Loan Fund is administered by the Office of Energy Efficiency (OEE). OEE is part of the Ohio Department of Development's ("Development's") Community Development Division. Three individuals were noted as Loan Fund staff on the OEE website.

   The Public Utilities Commission of Ohio (PUCO) and the Public Benefits Advisory Board advise the director of Development re: strategies for the administration of the Loan Fund and a separate Low Income program. The Advisory Board will consist of 21 members including 13 governor appointees, 2 members of the House, 2 members of the Senate, the director of Development, the chair of the PUCO, the Consumers' Counsel, and the director of the Air Quality Development Authority.
   Any Ohio resident, non-profit entity, low-income housing developer, educational or local

government institution, small business, industrial or agricultural customer of one of the participating electric utilities is eligible. They can apply to the Loan Fund to help finance energy efficient or renewable energy technologies, products or services.

Existing financial institutions, approved by OEE, are used for project financing.

3. Funding mechanisms

The Loan Fund is financed through a rider on the electric bills of the customers of the five investor-owned electric utilities in Ohio. The utilities remit the funds collected to the Ohio Department of Development on a quarterly basis. The riders will be eliminated by January 1, 2011, or when the Loan Fund reaches $100million, whichever comes first.

The director of Development determines the amount of money to be raised each year. The PUCO calculates the rate of the rider necessary to meet the target. Up to $15million/year can be raised through 2005. No more than $5million/year may be raised in any year after that. The PUCO set the initial five-year rate for the rider at 0.10758mills/kWh.

The Act allows assistance to be provided through approved lending institutions in the form of loans at below market rates, loan guarantees for such loans, and linked deposits for such loans. Generally, the Loan Fund is used to allow participants to borrow money at a rate as low as half the standard bank interest rate to finance qualifying energy efficiency or renewable energy projects. It is a revolving Loan Fund, and appropriate loan payments are deposited back in the Loan Fund.

Customers of the municipal utilities and rural electric cooperatives are not paying a rider on their electric bills toward the Loan Fund. Therefore, they can not qualify for this program at this time.

4. Association with a long run resources plan

Generation has been deregulated. There is no Integrated Resource or other long range resource planning for this program to associate with.

5. Guidelines for program effectiveness and success

According to the Act, approved projects must improve energy efficiency in a cost-efficient manner, and benefit citizens' economic and environmental welfare.

According to OEE, the Loan Fund is designed to provide incentives through interest rate reduction for investments in energy saving products, technologies or services that will:

- conserve energy;
- increase the use of renewable energy technologies; and/or

- reduce energy consumption and costs for Ohio residents and businesses.

The State of Ohio also hopes to promote a "diverse and robust supply of energy resources."

The Act set a goal for assistance to be distributed proportional to utilities' contributions to the fund, to the extent feasible given approved applications.

6. Pre-implementation program evaluation guidance

   According to the Act, approved projects must use both the most appropriate national, federal, or other standards for products as determined by the director, and the best practices for use of technology, products, or services in the context of the total facility or building.

   Projects must meet energy efficiency performance standards determined by OEE. In general, eligible residential projects will be those that meet a pre-existing standard (e.g. Energy Star) or that are specified by specially certified raters or installed by specially trained contractors.

   Eligible business projects will meet the Energy Star® standard where such standard applies, or have a 5 year (or less) simple payback period, or result in 15 percent more energy efficiency than existing conditions and the expected measure life must be longer than the payback period.

   Borrowers must apply to the private lender for the loan and apply to OEE for "Energy Efficiency Project" approval. The recommended first step is to talk to an Energy Loan Fund staff member.

7. Results of program evaluation

   The Act does not require independent evaluation, but does give the director of Development authority to contract with technical monitors and evaluators.

8. Financial or performance incentives

   No financial incentives for utilities were noted in the literature.
   Participants benefit from up to a 50 percent reduction in the interest rate on their bank loan, and their project is likely to reduce their monthly energy bills.

Programs

<u>Business & Institutional Loans</u>
(energy efficiency for buildings, equipment and processes)
Interest rate reductions of up to 50 percent through loan participation with private lenders or through linked deposits. The Loan Fund participation is limited to 50 percent participation of the loan at a minimum of $5,000 and a maximum of $250,000. The term can be up to eight years.

Residential Loans
Interest rate reduction is available on bank loans from a minimum of $1,000 up to a maximum of $20,000 for a term of up to 8 years. The Loan Fund's actual participation is at 50 percent of these loan amounts.

Rental Housing Linked Deposit Program
(open to developers of low-income rental housing tax credit projects as part of the Ohio Housing Finance Agency's "Housing Credit Allocation Plan")

Renewable Energy Financial Assistance Program
(for use of renewable power by residential, business and institutional customers)

- The Renewable Energy Financial Assistance Program promotes investment in energy efficient products, technologies or services that use clean, renewable energy resources.

For residential renewable energy projects, the Loan Fund participation is limited to a minimum of $500 and a maximum of $25,000. For business and institutional renewable energy projects, the Loan Fund participation is limited to a minimum of $5,000 and a maximum of $500,000.

Resources

Office of Energy Efficiency, Ohio Department of Development
www.odod.state.oh.us/cdd/oee/energy_loan_fund.htm

Public Utilities Commission of Ohio
614-466-3016
www.puco.ohio.gov

The Act
www.dsireusa.org/library/docs/incentives/OH03R.htm

11. OREGON

(1999 Utility Statistics from www.eia.doe.gov)

Population (2001 Census Estimate): 3,472,867
Net Summer Capability (MW) 11,192
Electricity Consumption (MWh) 48,066,498

	Investor-Owned	Public	Federal	Coop-erative	Total
Number of Utilities	3	17	1	19	40
Percentage of Retail Sales	71.5	18.9	0.4	9.3	100.0

Mechanism:	Public Purpose Charge, 3% of electric IOU retail sales revenue
Creation:	legislative
Duration:	10 years, beginning 3/1/02. Renewal report due January 2011
Administration:	independent non-profit third party "Energy Trust of Oregon, Inc."
Budget:	$45-50million/year for the Trust's EE and RE programs
Program Name:	Energy Trust of Oregon, Inc.
Benefit Measure:	Societal Benefit Test and Utility Test
Specific Incentives:	No lost revenue; no performance incentives for Trust or utilities

Survey Questions

1. Process and timeline

   Restructuring legislation, SB 1149 (the "Act"), passed in July 1999. The Public Utilities Commission (PUC) approved the concept of a non-profit administrator in October 2000, and appointed a board of directors in February 2001. Final agreement between the PUC and the Energy Trust of Oregon, Inc. (the "Trust") became effective March 1, 2002; and utility-run transition programs and pilot programs began. First new, full-scale Trust program was launched in February 2003.

2. Organizational structure

   The Trust is a tax-exempt, non-profit, non-government corporation with a volunteer citizen board of directors. The Trust administers most energy conservation and renewable energy programs funded by the public purpose charge (PPC), under contract with the PUC, for all customers of the two major investor-owned electric utilities (IOUs) that contribute to the fund, Pacific Power and Portland General Electric. These two IOUs serve about 70% of the electric customers in Oregon.

   The Trust develops plans with input from advisory councils and other public processes. The Trust submits two-year action plans and five-year strategic plans to their Board for approval, and to the PUC for review and comment. The Trust updates action plans and budgets annually. Present plans call for competitively-selected contractors to manage major programs with a broad range of contractors implementing program elements.

The PUC hired legal, financial, organizational and planning consultants to assist in creating the Trust. It created a search committee to find potential board members and appointed the initial board of directors. The PUC determines the collection and expenditure of PPC funds. The PUC contracts with the Trust, and reviews strategic and action plans. The PUC appoints an individual to oversee the contract with the Trust. The PUC appoints a non-voting ex-officio Trust board member.

The Trust's board of directors (the "Board's") first responsibilities were to incorporate, develop a strategic plan, develop a contract with the PUC and hire an executive director. As a 501(c)(3) organization the Board has fiduciary and legal responsibilities for management of the Trust.

The Final Agreement between the PUC and the Trust calls for the Board to have the "skills and demographics to be effective and the diversity to support the mission." Members must avoid financial conflicts of interest. Present board members have experience in law, finance, utility site management, renewable resources, communication, utility/energy management, public interest advocacy, regulation, policy-making and other areas. As a new organization, the decision-making process is evolving, as is the power-sharing between Board and staff.

The Trust has two advisory councils, the Conservation Advisory Council and the Renewable Resources Advisory Council. The role of both advisory councils is to provide consultation, not decision-making.

The Board and the Trust strive for a very open process. Plans, agendas, minutes, and reports are all posted on the web site. The public may attend advisory committee meetings or provide input through the website or other means.

According to the most recent organizational chart, the Trust employs 20 FTE, including the Executive Director, 5 Program Directors and various program managers, coordinators, and support personnel.

In the final agreement between the PUC and the Trust there are general guidelines for administrative costs. They are supposed to be "reasonable." They must balance the lowest possible administrative costs with overall organizational effectiveness. The Trust should also avoid cross-subsidizing administrative costs between programs supported by the PPC and those that are not.

3. Funding mechanisms

The Act required the IOUs to collect a PPC of 3% of their revenues from generation, transmission and distribution for five public purpose funds. The Trust administers almost three-quarters of these funds. Initially the utilities advanced the Trust $750,000 for start up costs to be paid back with PPC funds. The Trust took out a $400,000 loan, and the Energy

Foundation paid the interest. The Trust took on a $4million line of credit for cash flow. The PUC ensures that the appropriate PPC funds collected are paid directly to the Trust, not less than monthly, except as otherwise provided in laws or regulatory agreements.

By statute, the PPC funds are to support programs in the following proportions:

New Cost-effective Conservation and market transformation	56.7%
Above-market costs of new Renewable Energy	17.1%
New Low Income Weatherization	11.7%
Energy Conservation in Schools	10.0%
Low Income Housing	4.5%

The Trust administers the first two programs under a contract with the PUC. The last three programs are administered by existing agencies.

Expenses plus dedicated funds, including carryover funds in CY 2003 are expected to be $56,621,027 with the following expenditure breakout:

Management and general administration:	2.4%
Communication and outreach	2.1%
Renewable Programs	10%*
Energy Efficiency Programs	90%
Within the Energy Efficiency Programs:	
Utility Transition Programs	30%
Energy Trust-designed Residential Programs	29%
Energy Trust-designed C&I Programs	37%

* Many renewables are paid for as savings are delivered; therefore requiring significant dedication of future funds.

4. Degree of association with a long run resources plan

   The electric IOUs are still required to complete least-cost planning and Transmission and Distribution planning. The Trust's Action plan calls for the Trust to provide input to the electric IOUs' resource planning, and to integrate information about utility load forecasts in planning Trust programs. The Trust Action plan also calls for the Trust to "work with utilities to identify where projects could reduce or delay T&D expenditures and improve power reliability."

5. Guidelines for program effectiveness and success

   The mission of the Energy Trust is "to change how Oregonians produce and use energy by investing in efficient technologies and renewable resources that save dollars and protect the environment." (from the Trust's Final Action Plan for 2003-2004)
   Guidelines for program funding under an agreement with the Public Utility Commission include:

   - Coordinate with existing local, state and regional programs with related purposes.

- Provide benefits to all classes of electricity users and their geographic areas.
- Competitively bid work unless circumstances warrant an alternative approach.
- Encourage the development of competitive markets for energy efficiency services and renewable resources.
- Design efficiency programs to be cost-effective and independently evaluate them on a regular basis.
- Use funds for new renewable resources to offset all or a portion of their above-market costs and provide benefits to funding customers.
- Spend or commit the majority of funds in the year received.

The Trust's goals, as laid out in the Final Strategic Plan for 2002-2007, are to:

- Invest in programs to help consumers save 300 aMW of electricity by 2012. (An aMW indicates 8760 MWh/year, from 24 hours/day x 365 days = 8760 hours.)
- Provide 10% of Oregon's electric energy from renewable resources by 2012. (Anticipate 35aMW by October 2004; 115aMW by October 2007).
- Extend energy efficiency and on-site renewable energy programs and benefits to underserved consumers. (Strategic Plan: The Trust will pay up to 10% more per kWh of energy saved to increase participation by historically underserved consumers.)
- Contribute to the creation of a stable environment in which businesses that promote energy efficiency and renewable energy have the opportunity to succeed and thrive.
- Encourage and support Oregonians to integrate energy efficiency and renewable resources into their daily lives.

6. Pre-implementation program evaluation guidance

The Trust Board has adopted the Societal Benefit test and the Utility test as important measures of program cost-effectiveness and effective utilization of Trust funds. The Action Plan calls for an evaluation plan and tracking system to be designed into every program to track energy saved/produced, market development and other goals.

Results will be summarized annually by service territory for overall energy and peak savings and, where significant, other environmental, economic and participant benefits. Issues of load shape, diversity, reliability, availability and power quality will be addressed when critical to determining the value of savings. Evaluations regarding these issues will be developed in cooperation with the utilities.

The Act requires the PUC and the Office of Energy to jointly choose an independent nongovernmental entity to report to the legislature on proposed modifications to the public purpose programs. The report is due on January 1, 2007. A report regarding program renewal is due on January 1, 2011. The Trust must contract for independent management review at least every 5 years, with the first review within 3 years of March 1, 2002.

7. Results of program evaluation

The Trust's programs are just beginning to be implemented. Several pilot programs and utility transition programs have been evaluated. An evaluation contractor pool has been created. The Action Plan indicates that most evaluations will be contracted out.

8. Financial and performance incentives

   The utilities had a negotiated agreement with the Trust that included an incentive payment of $150,000/aMW for legacy programs during the transition. Once transition contracts are completed, the utilities will have no regulatory or statutory incentives based on the conservation and renewable programs of the Trust.

   The Trust deliberately does not have performance based incentives in their contract with the State. They are a non-profit formed to achieve the State's goals in energy conservation, market transformation and renewable energy acquisition. The incentive is that the Trust keeps the contract with the State if the Trust performs the job.

Energy Efficiency Programs

- Pilot Programs:
  - Mobile home duct sealing
  - Green light-emitting diode (LED) traffic lights
  - Restaurant energy management programs
  - Small-scale energy loan program rate buy-down
- Long-term Programs
  - Existing Commercial and Industrial Buildings, launched 2/1/03
  - New Commercial and Industrial, expected 8/03
  - Existing Residential, launched 4/03
  - New Residential, expected Summer '03
  - Industrial Process, expected 5/03
  - Efficient Home Products, expected Fall '03
  - Building Operation and Maintenance, expected Fall '03
  - Support Programs (e.g. training, community-based cross sector programs)

Issues and Special Situations

Agreement between the Trust and the PUC

The agreement between the PUC and the Trust recognizes that the Trust was formed to act as the nongovernment entity envisioned by the Act. This responsibility was not put out to bid, like in Vermont. The agreement is a contract between equals, with provisions for either party to formally express a "notice of concern" or terminate the agreement early. The agreement is effective for three years, after which automatic extension procedures are available. The agreement will continue to be renewed every year on the anniversary of the effective date of the agreement, absent written notice from a party.

Administrative model

In order to get programs running quickly, the Trust chose to have a very "lean" staff, while outsourcing much program management to contractors. The Trust will be examining this model closely during the first two years to see if it is truly the most efficient, effective and economical way to go. This model will be reviewed and refined.

The Trust decided, in most cases, not to use performance incentives when designing the contractor RFPs. They are clear about goals and principles, and expect them to be met. They negotiate for low contractor overhead. Keeping in mind the goal for market transformation, the contracts for major program administrators are written in such a way that they will have to solicit a variety of qualified subcontractors.

Equity

The residential sector will pay ~ 43% of the PPC, but there are more potential savings in the commercial and industrial sectors, and the cost of savings is less in those sectors. So, there are competing goals: maximizing cost-effective savings vs. providing benefits to all customers who contribute to the fund. The Trust is finding more cost-effective opportunities in residential efficiency (e.g. lighting, duct sealing, heat pump tune-ups) which may improve the balance.

Gas Utilities

Natural gas utilities in Oregon must file least-cost plans with the PUC, including energy conservation budgets and programs. They must offer statutorily mandated conservation programs. NW Natural, which serves most of the state's population of gas customers, completed a partial decoupling settlement with the PUC and proposed a PPC for conservation programs. NW Natural is close to finalizing a contract with the Trust to administer new or enhanced energy efficiency programs for all NW Natural's non-industrial customers.

Publicly-Owned Electric Utilities

Oregon's publicly-owned electric utilities do not collect a PPC as a result of the Act or file least-cost plans with the PUC. They fund efficiency and renewables with their own funds and funding from the Bonneville Power Administration. In addition, the Oregon Office of Energy Resources administers an extensive series of residential and business efficiency tax credits that are available to customers of the publicly-owned utilities and the IOUs that contribute to the Trust. The Trust expects to work with interested publicly owned utilities to expand program offerings.

Self-directed Large Customers

Customers with >1MW loads may "self-direct" and offset up to 68% of their related portions of the PPC for their own expenditures on new EE measures and/or up to 19% of the PPC for above-market costs of new RE, less administrative costs. These credits must be pre-certified through the Oregon Office of Energy. There are credit provisions if an independent auditor determines there are no available conservation measures with a simple payback of 1-10 years. The Trust has elected to offer efficiency and renewable programs to self-directing energy users, but with reduced financial assistance compared to other customers.

Northwest Energy Efficiency Alliance (NWAlliance)

The Trust is providing $13million over four years to the NWAlliance, to continue market-change programs formerly supported by the utilities. This will "emphasize opportunities to save energy through more efficient household appliances, lighting, equipment, operations, maintenance, and other Alliance market-change efforts." (Action Plan)

Portland General Electric for sale

Portland General Electric is for sale on the open market by Enron. If PGE loses its status as a regulated IOU, there is some question as to whether the public purpose charge would be assessed. Interested parties are attempting to assure that the Trust's work would continue under new ownership.

Resources

Energy Trust of Oregon
www.energytrust.org
503-493-8888
Fred Gordon, x202, Director of Planning and Evaluation, fred@energytrust.org
Maureen Quaid, x210, Communications Manager, maureen@energytrust.org
At this website:
Final Strategic Plan for 2002-2007, Final Action Plan for 2003-2004, CY03 Final Budget, Organization Chart, Board of Directors and Advisory Council information

Oregon Public Utilities Commission
www.puc.state.or.us
Lynn Kittilson, Senior Economic Analyst
Lynn.Kittilson@state.or.us, 503-378-6116
The Final Agreement between the Trust and the PUC can be seen at
www.puc.state.or.us/erestruc/indices/finlagre.pdf

Oregon Office of Energy
www.energy.state.or.us
Energy Conservation and Renewable Resource Programs in Oregon

SB 1149 ("The Act") available on the web at:
www.leg.state.or.us/99reg/measures/sb1100.dir/sb1149.en.html

12. VERMONT

(1999 Utility Statistics from www.eia.doe.gov)

Population: 613,090

Net Summer Capability (MW)	992
Electricity Consumption (MWh)	5,637,619

	Investor-Owned	Public	Federal	Coop-erative	Total
Number of Utilities	6	15	0	2	23
Percentage of Retail Sales	83.0	13.5	0	3.6	100.0

Mechanism: Energy Efficiency Charge not>2.9mills/kWh
Creation: Legislative and Regulatory
Duration: EEC budgets approved through 12/31/05. No sunset legislation.
Administrator: Independent Energy Efficiency Utility (EEU)
EEU contract renewed for three years, through 12/31/05
Budget: Not to exceed \$17.5million/year. Presently about \$14million/year

Survey Questions

1. Process and timeline

- 1999 law (S137) gave the Vermont Public Service Board (PSB) authority to establish volumetric wire charges to fund statewide EE through a non-utility entity, replacing utility programs. Set an annual budget limit for statewide programs of \$17.5million/year (approx. 3.3% of Vermont's total electric bill)
- September 30, 1999 (Docket 5980) PSB approved the Memo of Understanding (MOU) supported by the State, utilities, business, and environmental and efficiency advocates. The parties agreed that the PSB would approve and order an EEU to deliver statewide energy efficiency programs. It defined a set of seven initial "Core Programs" that would be implemented statewide. The MOU outlined the new administrative structure, operational and fund-handling details of the EEU. It relieved VT distribution utilities of obligation to deliver energy efficiency programs, but made provisions for certain utilities to implement core programs in their service area. It established a schedule for implementation of the EEU, including formation of the Transition Working Group to achieve an orderly transfer of programs from utilities to the EEU. The MOU set initial five year budgets for the EEU and determined that initially the EEC would be individually set with each utility. It also outlined the continuing role and responsibility of electric distribution utilities.
- December, 1999 PSB chose Vermont Energy Investment Corporation (VEIC) from a field of six competitors to serve as the EEU contractor.
- March, 2000 the EEU Program dba "Efficiency Vermont" began operation.

2. Organizational structure

Vermont Public Service Board (PSB): The PSB makes final determinations regarding the EEU's performance and contract renewal. It establishes EEC annually. It issues RFPs, and hires the EEU contractor, Contract Administrator, and Fiscal Agent. It approves EEU plans, programs and major budget modifications annually. It appoints the Advisory Committee and reports annually to the legislature on EEC revenues.

Energy Efficiency Utility (the EEU): The PSB issued an RFP for an EEU contractor, which could not be an agent of a distribution company. The contract was awarded to a non-profit Burlington-based consortium anchored by VEIC, Inc. The result is a single, statewide non-utility entity dba "Efficiency Vermont" (EVT). EVT provides statewide administration of the Core Programs and any "System-wide" energy efficiency programs approved by the PSB. EVT is responsible for program administration, design, marketing, delivery and implementation under terms of an extensive and detailed contract with PSB.

EVT has chosen to implement many programs using their own staff, rather than subcontracting activities. Staffing levels at EVT are about 70 FTE. Close to 50 are directly involved in business or residential program implementation. The rest are involved in customer service, IT, marketing, business development, accounting, etc.

The initial contract was a three-year, performance-based contract, renewable for up to three more years. The contract was recently renewed through 12/31/05. The new contract continues to be performance-based, but with less program-specific measures. The new contract increases EVT's flexibility to target resources across programs.

Contract Administrator (CA): The PSB issued an RFP and hired an independent contractor. The CA handles day-to-day EEU contract administration responsibilities on behalf of the PSB. The CA also resolves disputes concerning the EEU's performance and refers them to the PSB if settlement not reached. The CA also works with DPS to define and verify the EEU's compliance with contractual performance indicators. Time required to meet these responsibilities has varied but is presently 0.75 FTE.

Fiscal Agent (FA): The PSB issued an RFP and hired an independent contractor. The FA's primary responsibility is to receive EEC funds from the distribution utilities, and disburse them upon approval by the CA to the EEU, the DPS (for EEU evaluation efforts) and other relevant entities. The FA reports directly to the PSB and provides the PSB with monthly, quarterly, and annual financial statements and accounting reports. Funds collected never become funds of the State. The FA is presently National Exchange Carrier Association (NECA), a nationally known organization that also handles finances in the telecommunications industry.

Vermont Department of Public Service (DPS): The DPS serves as Vermont's consumer advocate and energy office. It provides evaluation of PSB-approved EEU programs, including annual verification of savings claims, usually through contracts with independent consultants. After approval by the CA, the FA reimburses the DPS for these evaluation activities from the EEC funds. The 2003 budget for Program Evaluation by DPS is $462,000.

The DPS also updates avoided cost calculations used in EEU program and measure screening. The DPS advises the PSB on economically achievable energy efficiency potential, and makes recommendations regarding EEU program changes and budgets. Although no single individual at the DPS works full-time on EEU activities, over the course of a year, EEU matters will require 3-3.25 FTE of staff effort.

Advisory committee: The PSB appoints an advisory committee to the EEU to provide substantive input on program design, annual re-allocation of program funds and other issues. The Advisory Committee includes representatives from the DUs, consumers, the DPS, and others deemed necessary by the PSB. It meets at least quarterly, generally six times per year, to provide advice to the EEU. It has no budget or authority. The EEU may also develop other advisory committees itself, e.g. for specific market segments, as needed.

The MOU includes specific procedures utilities must follow to deliver Core Programs in their service areas. Burlington Electric Department (BED) offers the Core Programs in its service territory. Washington Electric Cooperative (WEC) implemented a Residential New Construction Program (a Core Program) in its service area.

3. Funding mechanisms

S.137 sets a maximum annual budget of $17.5million for the total EEU, approximately 3.3% of Vermont's total electric bill. The MOU set another limit. During the first five years the EEC could not exceed the equivalent of 2.9mills/kWh of total statewide retail sales. These funds presently cover at least the following expenditures each year:

The EEU contractor costs, including performance incentive fees;
Customer Credit Program costs;
BED "Core Program" implementation costs;
DPS evaluation costs;
Contract Administrator costs;
Fiscal Agent costs;
Independent audit of the EEC fund; and
Costs for advertising the new EEC rate.

Through 2002, the methodology for calculating the EEC was based on revenues. The EEC rate varied by utility, based on factors unique to each service territory, and was set individually with each company in bilateral agreements or individual rate cases. It was based in part “on a reasonable estimate of eligible markets for the core programs in each service territory.” (MOU) “The EEC has been set for each year in an annual contested case proceeding." (DPS Report, May, 2002.) For utilities that had active DSM spending at the time of the MOU, the EEC was often offset by rate reductions during the initial three-year period (2000-2002). The average annual funding over the first 5 years was expected to be about $13million/year.

In their May 2002 report the DPS recommended basing the 2003 calculation on kWh usage with a “uniform volumetric charge”. However, due to concerns from the business community, industrial ratepayers and others, DPS modified its proposal. The 10/31/02 PSB Order (Docket 6741) approved a combination revenue and usage-based methodology. The exact amount to be collected from each utility was set in this Order as well. As a result of this calculation methodology, just as in 2002, residential customers pay 44 percent of the total amount collected via the EEC (while using 38 percent of Vermont's electricity). Business and non-residential customers pay approximately 56 percent of the total EEC charges (while using 62 percent of Vermont's electricity).

The $14million 2003 budget for all EEU-related activities established by the 12/30/02 PSB Order represents a decrease from the amount of $16,172,252 agreed to by the PSB in August 2002. This was due to vigorous advocacy by some business and industry representatives to improve the business climate by reducing the immediate cost of electricity. The DPS "with reluctance, during a time of intense economic pressure" proposed the reduced amount and PSB agreed, with a strong dissenting opinion written by the PSB Chair.

Burlington Electric Department (BED) In the MOU, BED contracted to deliver the Core Programs in its Service Territory. Implementation was funded by a "revolving loan" fund from a bond issued in the early 90's, so no EEC was levied on BED customers during the first three years. Also, the funds spent on Core Program activities were not separated out on BED customer bills. Beginning in 2003, the PSB and BED agreed to include BED customers and programs in determining the EEC for the year.

4. Degree of association with a long run resources plan.

The EEU has a strong association with long run resource planning. The distribution utilities (DU) in Vermont are required to prepare a least-cost integrated plan (IRP) for provision of electricity services every three years. The law defines a least-cost integrated plan as "a plan for meeting the public's need for energy services, after safety concerns are addressed, at the lowest present value life cycle cost, including environmental and economic costs, through a strategy combining investments and expenditures on energy supply, transmission and distribution capacity, transmission and distribution efficiency, and comprehensive energy efficiency programs." All 22 DUs will file IRPs during 2003 and 2004.

According to the MOU, the DUs' responsibilities will now include least cost transmission and distribution system planning and implementation. As long as the PSB finds that the System-wide programs of the EEU are satisfying existing statutory and regulatory requirements for energy efficiency programs, the DUs will only be obligated to include strategic DSM when it can cost-effectively achieve delay or avoidance of transmission and distribution investments. If, for any reason, the PSB finds the EEU structure or programs inadequate for meeting existing requirements, the DUs would resume those responsibilities as well.

According to the MOU, the DUs must "maximize coordination among themselves and with the EEU for planning inputs and implementation capability." The EEU is required to make customer-specific data available to the DU serving the customer, for use in DU planning, load forecasting, DSM program planning, distributional equity determinations and other specified purposes. The MOU anticipates that the EEU will have a role in the implementation of DSM related to transmission and distribution planning.

5. Guidelines for program effectiveness and success (upfront)

The overall scope of work to be accomplished by the EEU was laid out in Attachment A of the original contract:

Achieve the maximum magnitude of societal net benefits;
Shift from utility-based to market-based energy efficiency;
Increase the emphasis on market transformation strategies; and
Effectively capture "lost opportunity" markets.

These were modified slightly as seen in Attachment I of the 2003-2005 contract:

Achieve the maximum magnitude of societal net benefits while acquiring comprehensive cost-effective electric efficiency savings;
Respond appropriately to markets in order to increase the level of and comprehensiveness of energy efficiency services to Vermonters;
Effectively capture potential "lost opportunity" markets; and
Strive for distributional equity across customer classes and geographic regions.

The original EEU contract with PSB included detailed performance indicators including quantified goals for:

Cumulative annual energy savings* of 83,592 MWh;
Committed Electricity Savings Target of 4,700 MWh;
Total Resource Benefits at the end of three years, as well as
33 additional activity milestones and performance indicators.
*This figure refers to the sum of new energy savings acquired or effected each year. Cumulative savings, taking into account measure life, would be much larger.

The renewed three-year EEU contract continues to be performance-based. Goals include, but are not limited to:

Cumulative annual energy savings* of 117,373MWh;
Committed Electricity Savings Target of 6,200 MWh;
14.834 MW summer peak reduction*;
Total Resource Benefits* of $74.5million (in 2000 dollars);
Double market share of Energy Star homes;
Increased participation of small business in EVT programs;
Less activity milestones since programs are operational; and
Goals organized more by sector, less by program, compared to firstcontract.
*Some of these goals were modified downwards to reflect the reduced budget decision made by the PSB on 12/30/02.

BED had an initial three-year goal of 4148 cumulative annual MWh savings and other performance indicators. The Commercial and Industrial Customer Credit Program ("Customer Credit Program") had a three year goal of 5163 MWh.

6. Pre-implementation program evaluation guidance

   "The Contractor shall work with the Contract Administrator and the DPS to establish reasonable savings estimates for new prescriptive energy efficiency measures offered in Core Programs, prior to their inclusion in programs." (From the 2000 PSB Contract with the EEU Contractor, Attachment C "Performance Incentive Mechanism")

   "When assessing the cost-effectiveness of efficiency measures, the Contractor shall utilize the Societal Test as described by the Board [PSB] in its April 16, 1990 Order in Docket No. 5270. The Contractor shall use statewide cost-effectiveness screening tools provided by the DPS in its planning and implementation activities. The Contractor shall use the externality values approved by the Board (currently 0.7 cents/kWh). The Contractor shall incorporate into its screening tools any new avoided costs and externality adjustments approved by the Board…Changes to existing measure characterizations and program assumptions, and all assumptions for new measures and programs, shall be coordinated with the DPS. All changes shall be documented in the Technical Reference Manual, including the basis for the new assumption." (From the 2003 PSB Contract with the EEU Contractor, Attachment I "Scope of Work.")

   The DPS must provide an annual review of the EEU's energy savings claims and costs. By statute, the PSB must contract with an independent auditor for a triennial review of energy savings and cost-effectiveness of EEU programs. First report filed 12/02.

7. Results of program evaluation

   The *Report and Recommendations to the Vermont Public Service Board Relating to Vermont's Energy Efficiency Utility,* 2002, available on the DPS website, includes many results of independent program evaluation overseen by the DPS.

   The 2001 Annual Report of the EEU indicated that EVT spent $8.5million and participants paid $5.5million, for a total of $14million, to achieve close to 37,000MWh of energy savings in 2001. Over their lifetime these measures are predicted to result in close to 545,000 MWh of savings. Measures also resulted in peak demand reduction of 4.2MW in summer and 6.6MW in winter, 2001.

   The PSB, in 12/30/02 Order findings of fact, stated:
   "In 2001, energy efficiency was obtained by the EEU at a cost of 2.6 cents per kilowatt-hour…using total costs for the EEU for that year, including participant and third-party investments in the cost of the measures installed, of $14,014,124….The average delivered cost of purchased power for Vermont utilities…was 7.3 cents per kWh…the average retail rate…charged by Vermont electric utilities for delivered power was 10.6 cents per kWh."

   "The economically achievable potential of energy efficiency in the state continues to far exceed any level of savings that could be secured by the activity of the EEU at the budget levels proposed…Vermont needs to spend three to four times as much money as is currently devoted to the EEU budget to achieve the potential energy efficiency savings shown in the DPS Report."

"When Vermont purchases power from outside the state it does not generate as much employment as the EEU which is labor-intensive."
Energy efficiency investment made by businesses working with the EEU produced on average "an internal rate of return of 71 percent."
EEU assistance to Vermont dairy farmers resulted in "an average annual rate of return of 62 percent."
EEU assistance to Vermont ski operations yielded "an average annual rate of return of 67 percent."

Burlington Electric Department: After two years, BED acquired 4,754 annualized MWh savings. This was well over its three year goal of 4,148 MWh. An assessment by GDS Associates found that BED had adequate coordination with the EEU; BED is on track to meet its performance indicators; and there is not a significant increased administrative burden or reduced program benefit as a result of delivering programs only within its service territory.

8. Financial or performance incentives

Incentives for the Distribution utilities (from the 1999MOU)

When the EEU was created, the existing lost revenue adjustment for DU activity (known as ACE) was phased out under the terms of the MOU. The MOU anticipated the possible need to change the regulatory process "to allow DUs the reasonable opportunity to earn their allowed return, and set a process in motion to determine necessary changes by January 1, 2001." To date, no changes have been deemed necessary. However, it is an open question whether ACE might apply to DU efficiency investments, used to cope with Transmission and Distribution issues.

Incentives for the EEU

A certain portion of the EEU budget is retained by the PSB for incentive payments to the EEU for achievement of performance indicators. The total amount of potential incentive payments for the first three years was $795,000, or about 2.9% of the contract value for 100% result attainment. The maximum performance incentive award for the second three years is $1.28million.

Each performance indicator has a target, and a threshold below which no incentives are paid. Each indicator has a predetermined weight as a percent of the total potential award. A chart indicates the relationship between percent attainment and percent of possible incentive. The contract defines a documentation and verification process for each performance indicator. Incentive funds not released until after the end of the three-year contract.

Performance Indicators in the 2003-2005 contract include:
Cumulative total of annual electric savings (at generation and net of free riders);
Electric savings for projects under development;
Total Resource Benefits (electricity, fossil fuels, water, no other externalities);
Summer Peak kW Demand Savings; and
Residential and Business Markets (Individual and cross-program indicators).

In the new contract, performance awards for any performance indicator are also contingent on achievement of three minimum performance standards:

- Minimum electric savings;
- Minimum low-income spending; and
- Minimum participation by small, non-residential customers.

Programs

Seven initial Core Programs:

- Commercial/Industrial Market Opportunities
- Commercial/Industrial New Construction
- Dairy Farm Program (now integrated into C/I Market Opportunities)
- Residential New Construction (and remodeling)
- Residential Low Income (including Low Income Multifamily)
- Efficient Products Program
- Emerging Markets Initiatives (Residential and Commercial)

The 2003-2005 Contract reorganizes and re-names the core market energy efficiency services and initiatives as follows:

- Business Sector
  - Business New Construction (includes multi-family)
  - Business Existing Facilities
  - Customer Credit
  - Commercial and Industrial Emerging Markets

- Residential Sector
  - Residential New Construction
  - Residential Existing Buildings
  - Energy Efficient Products
  - Residential Emerging Markets

Resources

Vermont Public Service Board
www.state.vt.us/psb/news/EEU_info.htm

Ann Bishop, Policy Analyst
802-828-2358, Abishop@psb.state.vt.us
Relevant docket proceedings and Contracts for EEU, Contract Administrator and Fiscal Agent can be viewed at this website.

Efficiency Vermont
www.efficiencyvermont.com
Blair Hamilton, Managing Director
802-860-4095 x 1024, Bhamilton@veic.org
Efficiency Vermont 2001: A Year of Progress and Success, March 2002, available at www.efficiencyvermont.com/about/annualreport2001.pdf

Vermont Dept of Public Service
802-828-2811, www.state.vt.us/psd/ee/ee.htm
Scudder Parker, former Director of the Energy Efficiency Division
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DPS, *Report and Recommendations to the Vermont Public Service Board Relating to Vermont's Energy Efficiency Utility*. May 29, 2002, available at www.state.vt.us/psd/EEU2002Report/Report.PDF

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13. WASHINGTON

(1999 Utility Statistics from www.eia.doe.gov)

Population (2001 Census Estimate):	5,9887,973
Net Summer Capability (MW)	26,106
Electricity Consumption (MWh)	100,436,978

	Investor-Owned	Public	Federal	Coop-erative	Total
Number of Utilities	3	42	1	18	64
Percentage of Retail Sales	32.2	47.2	16.9	3.7	100.0

Mechanism:	Surcharge, aka tariff or conservation rider
Creation:	Regulatory
Duration:	Various start dates; no sunset
Administration:	Utilities
Budget:	Varies with utility
Program Name:	No single name
Benefit Cost Measure:	Total Resource Cost and Utility Test
Utility Incentives:	No lost revenue recovery. Cost Recovery. Some penalties.

Survey Questions

1. Process and timeline

   Investor-owned electric utilities (IOUs) have been acquiring conservation resources using rate-based ratepayer funds for over twenty years in Washington.

2. Organizational structure

   The investor-owned electric and natural gas utilities (IOUs) propose energy conservation programs and budgets to the Washington Utilities and Transportation Commission (WUTC) for consideration and approval, with costs to be recovered in rates. The IOUs administer the programs in their service territories for all customer sectors, with input from advisory boards (see below). In general, IOUs have the flexibility to move funds from one program to another within their conservation budgets. They must justify their program expenditures when held to a standard of prudence during their next rate case.

   The programs and processes are fairly mature and stable, so the Commissioners themselves do not spend much time on these dockets. Program filings are often not controversial; cost recovery filings can be, if they involve a rate increase. Two WUTC staff members monitor and assist the IOU programs and attend Advisory Board meetings. Total effort of WUTC staff is estimated at 1.5 FTE.

The three electric IOUs have chosen to have separate Boards and pursue conservation independently of each other. Advisory Boards generally meet twice per year to review program delivery and results, discuss current issues and future programs, and provide input to the IOUs. The boards include environmental, consumer, low income, technical and State agency representatives.

3. Funding mechanisms

Each IOU sets a target for kWh or therm acquisition, and proposes conservation programs and budgets to the WUTC. A surcharge is set as a percent of revenue to generate the proposed budget amount. The allocation of program costs among customers is a decision unique to each utility. The WUTC approves allocation formulas after considering utility and stakeholder input. At the present time:

- The Puget Sound Energy (PSE) surcharge is 1.9% of electric revenues and generates $20 million for electric conservation programs.
- The Avista surcharge is 1.48% of electric revenues and 0.5% of gas revenues, and generates $4 million in electric rates and $950,000 in gas rates for programs.
- The PacificCorp surcharge is 2.3% of revenues and generates $4.5 million for electric conservation programs.
- Northwest Natural was authorized to defer gas conservation program expenditures, with recovery through Purchase Gas Adjustment filings. Annual expenditures are expected to be around $350,000.
- Cascade Natural [gas] expects to spend about $800,000 on a residential conservation program in 2003.

In some cases surcharges pay for past undercollections, in addition to present conservation programs. A utility has another option if it undercollects or overspends. It can request a rate increase for the next budget year. In 2001, all three electric IOUs overspent their conservation budgets. Two of the utilities requested rate increases on the order of 1% to recover costs. If a utility overcollects, it can carry the funds forward to support the following year's programs.

4. Degree of association with a long run resources plan

All electric IOUs must file Integrated Resource Plans using Least Cost Planning with the WUTC every two years by rule, so their conservation programs are examined in the context of a long run resources plan.

5. Guidelines for program effectiveness and success

According to WUTC staff, the primary goal of the conservation expenditures is to acquire conservation resources that conform to the IOUs' Least Cost Planning goals. Equity is not a strict goal on an annual basis. Over the long term, it is expected that cost-effective efficiency opportunities will be utilized in all customer sectors

- Avista has a target to conserve at least 40 million kWh and 240,000 therms each year in their multi-state service area. About 70% of these goals apply to Washington.
- PSE's goal is to save 133 million kWh annually, and over 2 million therms each year.
- PacificCorp's goal is to capture about 19 million kWh annually in electricity savings.

6. Pre-implementation program evaluation guidance

   The IOUs, in collaboration with their Advisory Boards, set kWh and therm savings goals. The WUTC reviews these targets for appropriateness. The IOUs propose measure and verification procedures in their plans. Programs must meet cost-effectiveness guidelines using both the Total Resource test and the Utility test.

   According to WUTC staff, Avista staff do their own measurement and verification (M&V). PacificCorp contracts for M&V. PSE's most recent filing included an evaluation plan with a mixture of self-reported and contracted M&V. In all cases, the advisory boards review the program evaluations. Avista's advisory board has the option of requesting an independent third-party evaluation, but has found the staff M&V to be adequate to date.

7. Results of program evaluation

   The IOUs report savings, costs and evaluation results to the WUTC on a regular basis.

   Recently Avista staff testified that they had spent $18million and saved 197million kWh during a 32 month period in their multi-state service area. Their portfolio resulted in a Total Resource Benefit of 1.21 and a Utility Test Benefit of 2.71.

   Generally, the IOUs meet their savings goals. Recently intervenors have not been happy with the performance of PSE, the largest IOU. As a result of negotiations among the parties in PSE's most recent filing, there will be shareholder penalties of up to $750,000 if PSE does not meet its most recent two-year conservation targets.

8. Financial or performance incentives

   The IOUs are allowed to recover costs in rates. Costs are initially recovered in annual WUTC filings when IOUs "true up" their conservation expenditures and revenues. That cost recovery can be "undone" in the next formal rate case, if the WUTC determines the expenditures were not prudent. There is no lost revenue recovery.

Issues/Special Situations

<u>Regional Technical Forum (RTF)</u>

The RTF, which provides technical advice about program design, conservation value and evaluation methodology to the Bonneville Power Administration (BPA), is having an impact on the conservation programs of the Washington IOUs. The RTF has become a credible third party authority on efficiency program effectiveness in the Pacific Northwest. Advisory Boards and the public can compare IOU program offerings and evaluation methods to those supported by the RTF, and question differences. The RTF is creating a threshold for program standards that did not exist before. For more information on the RTF, see the BPA section of this report.

Resources

Washington Utilities and Transportation Commission
360-664-1160, www.wutc.wa.gov
Joelle Steward, Regulatory Analyst
360-664-1308, jsteward@wutc.wa.gov

Liz Klumpp, Senior Energy Analyst
Washington Department of Community Trade and Economic Development
360-956-2071, ElizabethK@ep.cted.wa.gov

Avista
www.avistautilities.com/saving/default.asp
For Avista's testimony on conservation spending and savings
Go to: www.wutc.wa.gov/
Choose "Energy"; Under "Key Historical Cases," choose "Avista Rate Case UE-011595"
Choose Direct Testimony of Bruce W. Folsom, December 2001.

Pacific Power, www.pacificpower.net/

Puget Sound Energy, www.pse.com/energy/index.html

Northwest Natural Gas, www.nng.com/home/home.asp

Cascade Natural Gas, www.cngc.com/index.asp

Northwest Energy Efficiency Alliance (NWAlliance)
503-827-8416, www.nwalliance.org
All three electric IOUs provide funding to the NWAlliance and have seats on its Board of Directors.

14. WISCONSIN

(1999 Utility Statistics from www.eia.doe.gov)

Population (2001 Census Estimate): 5,401,906
Net Summer Capability (MW) 13,136
Electricity Consumption (MWh) 66,307,813

	Investor-Owned	Public	Federal	Coop-erative	Total
Number of Utilities	12	82	0	24	118
Percentage of Retail Sales	84.2	11.4	0	4.4	100.0

Mechanism:	Gas and electric utility rate-based fees and new statutory fees from all electric utilities
Creation:	Legislative
Duration:	No end date; major re-evaluation during fifth year.
Administration:	Wisconsin Department of Administration (DOA) subcontracts most program administration to non-profit corporations
Budget:	$62.3 million+/year possible
Program Name:	Focus on Energy
Benefit Measure:	Total Resource Cost and Societal Benefits Tests
Incentives:	Some shared savings. Some tax exemptions.

Survey Questions

1. Process and timeline

   In 1998 the Wisconsin Department of Administration (DOA) ran a pilot public benefits program under contract with a utility. October 1999 legislation, 1999 Wisconsin Act 9 ("the Act"), directed DOA to administer public benefits programs using existing regulatory fees and new statutory fees. August 2000 the Public Service Commission (PSC) determined the regulatory fees. Spring 2001 DOA signed contracts with two program administrators. First programs began in June 2001. Regulated utility programs ended December 2002.

2. Organizational structure

   The Act transferred funding and responsibility for public benefits programs, including low income, energy efficiency (EE) and renewable energy (RE) programs, from the investor-owned electric and gas utilities (IOUs) to the DOA over a three-year period ending December 2002. The Act also created a new flat fee to be levied on all electric utilities to augment program funding. This discussion will focus on EE and RE program administration.

   The Act required the PSC to devise a scheme to phase public benefit programs and expenditures out of the IOU programs and into the DOA programs over the three-year period ending December 31, 2002.

DOA named the new EE and RE programs "Focus on Energy". As primary administrator, DOA is responsible for Focus on Energy plans, policies, programs, public hearings, rule-making and contract administration. DOA must use a competitive bidding process to contract with non-profit organizations to administer specific programs. DOA determines the new fees required by statute. DOA is responsible for program oversight and evaluation coordination. DOA is charged with determining on an annual basis, beginning FY 2004-2005, what programs should be continued or discontinued, and what funding will be required.

The Council on Public Benefits was created by the Act to provide input to DOA. It consists of 11 members, primarily appointed by legislative leadership. In practice the Council has met twice a year in what could be characterized as briefing sessions.

All IOUs are required to participate. Municipal utilities and electric cooperatives can opt into the programs, or conduct programs themselves. Currently all 12 IOUs and 19 municipal utilities participate in the Focus on Energy program. These utilities serve about 85% of the state's electricity customers. Rural cooperatives and some municipal utilities have chosen to offer their own programs known as "Commitment to Community" programs.

DOA entered into contracts, usually three-year contracts with option to renew, with the following non-profit entities for program implementation:

Business	Milwaukee School of Engineering	began July 2001
Residential	Wisconsin Energy Conservation Corp.	began June 2001
Renewables	Wisconsin Renewable Energy Network	began March 2002
Research	Energy Center of Wisconsin	began April 2002

Program contractors are responsible for details of program design and implementation using their market-oriented expertise.

DOA also contracts for consultants in marketing, compliance, and evaluation and market research.

Presently 6 full-time positions and 2 half-time positions at DOA, resulting in 7 FTE, are supported by the Focus on Energy funds.

During the present fiscal year statewide program support costs are estimated to be 10-13% of the budget, including DOA staff, compliance, marketing and IT consulting, and third party evaluation costs.

3. Funding mechanisms

Focus on Energy funding comes from two sources: public benefit funds already included in IOU rates, which will be termed "IOU fees", and "new fees" established by this legislation.

The IOU fees are collected from IOUs by the PSC and deposited in the "conservation escrow account." Initially these funds were used to continue utility programs, but over a three-year period PSC transferred them to DOA programs. The new fees are flat fees collected from customers of all electric utilities.
The DOA invoices participating utilities every month for payment of the new fees. These funds, along with funds from the PSC, are deposited into what the State calls a "segregated account."

IOU fees: In August 2000, Docket 05-BU-100, the PSC determined that the following amounts would be transferred to the PSC for deposit in the utility public benefits fund, based on 1998 expenditures:

Low-income	$21,329,056
Energy conservation and efficiency	$45,110,357
Environmental R&D	$ 624,546
Renewable Resources	$ 91,131

The amounts for Low Income and EE are $12.5million and $18million lower, respectively, than originally estimated. This is partly because the PSC agreed it would be reasonable for utilities to continue certain activities, such as low income early identification, and "customer service conservation or load management" activities.

The PSC determines the allocation of these collections among utilities and among utility customer classes and types of utilities.

New fees: The Act requires all electric utilities and retail electric cooperatives to collect new flat fees set to generate a total of $24million/yr for low-income programs and a total of $20million/yr for all other energy programs. DOA is required to set the fees by rule.

The municipal and cooperative utilities must collect fees that average $16 per customer per year. They may charge different fees for different customer classes. This formula results in collections of about $7million each year. Half these funds are applied to low-income programs, and half to energy programs.

The electric IOUs must make up the difference between the municipal and cooperative fees collected, and the required program totals of $24million/yr and $20million/yr. The IOUs must collect 70% from residential customers and 30% from all others. The IOUs must include the new fee in fixed charges for electricity in customers' bills, but may not present it as a separate charge. DOA is required to set the fees by rule. The law set a fee cap of 3% of all other charges or $750/month, whichever is less, through 6/30/08.

The DOA developed a formula to determine how much each utility must contribute to the new fees. The customer base of each utility is one factor, since one goal was to have uniform residential customer fees. The amount of federal funding available for low-income programs must be part of the formula. DOA has tried to adjust the formula so that the energy program fees are stable, and only the low-income fees fluctuate with federal funding.

Legislative rules impact the DOA funds. The Joint Finance Committee has oversight over the "general operations" budget (administrative), which can result in a cumbersome process. These funds may not be carried over for subsequent years' administrative uses. By contrast, the program funds are considered to be a "continuing appropriation". Unexpended funds may be carried over into the next fiscal year and legislative approval is not required for program budget changes.

Commitment to Community programs: if a municipal utility or rural electric cooperative chooses to offer a public benefits program, it will retain ½ of the new fees collected for the low-income program and/or ½ for an energy program. If it chooses not to offer either program, it must remit the fees to the DOA. All rural electric coops and most municipal utilities have chosen to run their own programs.

4. Degree of association with a long run resources plan

   Poor, but may improve. 1997 legislation replaced the advance plan process with the strategic energy assessment (SEA). The advance plan process incorporated integrated resource planning, with horizons in the 10-20 year range. The SEA compiles biennial reports from all electric suppliers on reliability and adequacy issues during the previous 2 years and forecasts the next two to three years. The PSC and Focus on Energy staff have agreed that achievement from Focus on Energy programs will be comprehensively reflected in the SEA in the future.

   Statutes do require the PSC to consider alternatives when IOUs propose new generating facilities. In recent generation proposals the utilities have declared that they have included all energy efficiency potential in their forecasts. The need to quantify the state's energy efficiency potential, for use by both the PSC and the DOA, was identified and it was determined that the PSC and the DOA should work toward meeting this need.

5. Guidelines for program effectiveness and success

   The Act did not give clear guidance for program effectiveness. According to a Legislative Council Staff memo ("LCS Memo"), priority must be given to proposals directed at (a) sectors of the energy conservation and efficiency services market that are least competitive; and (b) promoting environmental protection, electric system reliability or rural economic development. The criteria for program continuation vs. discontinuation requires the DOA to determine whether the "private sector market" is meeting the need for the program.

   As a result DOA and Focus on Energy staff have responsibility for developing program success measures. They took direction from the Governor's Energy Policy 2001 and established short term goals of energy savings through EE and RE. They also set long-term goals of pollution reduction, economic benefits, indoor air quality benefits, development of cooperative partnerships and market transformation.

6. Pre-implementation program evaluation guidance

LCS Memo: DOA must annually provide for an independent audit and report to the legislature describing:

Expenses of administering the programs;
Effectiveness of the programs, and
Other topics identified by DOA, Council on Public Benefits, Governor, Speaker of the Assembly or the Majority Leader of the Senate.

LCS memo: any utility that implements a Commitment to Community program must submit annual reports to DOA including: accounting of fees charged to customers, program expenditures and credits claimed for programs, and description of programs.

DOA works closely with program administrators and the evaluation contractor to develop agreed-upon evaluation metrics and designs that accurately assess the achievement of specific outcomes. Cost-effectiveness is measured using the Total Resource Cost and Societal Benefits Cost tests.

7. Results

Resource acquisition is now reported quarterly, including emissions reductions. Economic impacts are reported twice per year. Annual savings estimates are made by program administrators. Then adjustments are made for free ridership, accuracy of engineering estimates and verification of installation by program evaluators.

From the 2002 Annual Report, covering July1, 2001 – June 30, 2002:

Business Programs* (energy savings adjusted by evaluator)

26,681 MWh
11,257 kW
1,393,379 therms of natural gas

Residential Programs, gross installed savings (not adjusted by evaluator yet)

26,073,800 kWh electricity
1,102,597 therms of natural gas

Total program emission savings

276,757 pounds of nitrogen oxide
467,028 pounds of sulfur dioxide
1.772 pounds of mercury

8. Financial or performance incentives

At the time of the transition from utility to DOA-administered public benefits programs, one utility was operating a "shared savings" energy efficiency program with a rate of return comparable to riskier investments. This utility is attempting to gain regulatory or legislative support to continue this arrangement. In Wisconsin, rates are set using a forward-looking test year, which incorporates estimates of efficiency-related savings and minimizes lost revenues. Public benefit fees collected by electric utilities and coops are excluded from the calculation of utility license fees ("gross receipts tax") and from sales tax.

Issues and Special Situations

Budget

The DOA deposits the public benefits funds into a "segregated account," for funds earmarked for a special purpose. However, the legislature can vote to use it differently. Last year each house proposed that some of the funds be used for other purposes, and a utility lobbied to have its contribution returned. No single proposal was successful. This year there is a budget shortfall. DOA has proposed that $4.7million in carryover funds (due to slow start-up) be contributed to close the budget gap, and notes that other funds are contracted. However, there is concern that as the original three-year contracts with program administrators lapse, the State may consider public benefits funds up for grabs.

Parity

Parity is not a requirement of the public benefits programs. As a result, some utilities are beginning to co-market programs with Focus on Energy and refer their customers, to be sure their customers will get the benefits.

Program Management

The Focus on Energy program is unique in its structure. Management strategies are evolving as a result. The Program Coordinator identified some interesting approaches:

- The marketing program development was time-consuming but worth it for the unified message. DOA waited until all 4 program administrators were chosen, so they all participated in the RFP process. The consultant hired had to develop an overall marketing campaign acceptable to all, and then program specific campaigns were negotiated at the program level.

- The RFPs for program administrators were written to communicate the Focus on Energy "market preparation" approach. For example program administrators had to agree to spend at least 50% of program funds on performance-incentive programs that would be bid out--looking for the most kWh reductions for the least dollars expended. Because this was considered to be a new approach, the RFP also directed that administrators would assist companies who desired to put together a bid.

Resources

Department of Administration (DOA) http://doa.wi.gov
Cheryl Rezabek, DOA, Chief, Public Benefits Section (aka "Program Coordinator")
608-261-7754, Cheryl.Rezabek@doa.state.wi.us

Wisconsin Public Service Commission http://psc.wi.gov
Carol Stemrich, Electric Division Engineer, Conservation
608-266-8174, carol.stemrich@psc.state.wi.us
Strategic Energy Assessment Report: Executive Summary. December, 2002.

Prepared by Public Service Commission staff.
Available on the web. http://psc.wi.gov/electric/cases/sea/ind_sea.htm
Also see Docket 05-BU-100 re: public benefits program fees, and
Docket 6680-UR-112 re: WP&L Shared Savings Program

Wisconsin Focus on Energy www.wifocusonenergy.org

Wisconsin's Public Benefits Programs: Annual Report. Focus on Energy Programs. Home Energy Assistance Programs. September, 2002. *Prepared by DOA. Available on the web. Go to* www.wifocusonenergy.org *Select "about us." Select "September 2002 Annual Report."*

Wisconsin Legislative Council Staff
www.legis.state.wi.us/lc
New Law on Electric Utility Regulation--the "Reliability 2000" Legislation,
Information Memorandum 99-6, Revised December 22, 1999
See also 12/2/99 Memo to Interested Legislators, "Overview of New Law…Act 9"
(Referred to as "LCS Memo" in this report)

Hall N, *State of Wisconsin Department of Administration, Division of Energy, FINAL: Focus on Energy II Pilot Study, Organizing and Delivering Energy Efficiency and Market Effects Programs--Learning From Others*, prepared for PA Consulting Group. October 2001. Available from author and DOA.

15. BONNEVILLE POWER ADMINISTRATION (BPA) PROGRAMS

Program Names:	A. Conservation and Renewables Discount (C&RD) B. Conservation Augmentation (Con/Aug)
Mechanism:	A. 0.5mill/kWh discount on wholesale price of electricity B. Custom contracts and Limited Standard Offerings between BPA and wholesale customers for resource acquisition.
Creation:	A: 2002 BPA Power Subscription Strategy ["Rate Case"] Decision B: In response to the NWPPC Conservation Acquisition Target
Duration:	A: October 1, 2001 through September 30, 2006 B: March 1, 2001 through September 30, 2006
Administration:	Both: Administered by utilities in partnership with BPA
Budget:	A: ~$35million/year B: ~$152million over the five year rate period
Benefit Measure:	A: BPA pays the value of savings to the bulk power system B: BPA pays the lowest possible cost for first year akWH savings
Specific Incentives:	Both: No lost revenue recovery

Survey Questions

1. Process and timeline

   C&RD program planning began in 1998. In February 2000 preparation began on the C&RD Implementation Manual ("the Manual"). The Manual was finalized in the Administrator's Record of Decision 2/12/01. Programs began October 1, 2001.

   BPA began the Con/Aug public planning process in 2000. Con/Aug purchases began March 2001 in response to the urgent need for resource acquisition.

2. Organizational structure

   Both programs are directed toward customers of the BPA throughout its entire service area, which is the Columbia River Basin. Most customers are in Idaho, Oregon, Washington, and west of the continental divide in Montana.

   Customers eligible for C&RD are those subscribing to BPA under the 2002 Rate Case. These customers are primarily publicly owned utilities, some direct-service industries, including aluminum plants, as well as some IOUs. Con/Aug targets publicly-owned utilities. BPA's customers serve all customer sectors. Over 45% of the power used in the Pacific Northwest comes from BPA.

   Programs are voluntary; customers administer and implement the programs they choose. The customers' programs can address any and all retail consumers. The administrative structures are too varied to describe in this report, since they range from tiny rural cooperatives to large municipal and investor-owned utilities.

In the C&RD program, BPA contracts with customers, offering them a rate discount for the five-year rate period in return for equivalent spending on conservation or renewable measures. The BPA, with assistance from the Regional Technical Forum (RTF), determines acceptable measures and activities, and their C&RD energy savings and discount value. The customer's CPA or auditor must certify that the customer's accounting systems are adequate to document C&RD-related activities.

In Con/Aug BPA contracts with customers, third parties or other federal agencies for the lowest possible negotiated price/aMW conserved, including administrative costs. Utilities may receive a $0.01/kWh performance payment. This tends to be negotiated in contracts that require more intensive administrative efforts by the customers.

Customers that choose to conduct both a C&RD and a Con/Aug program must explain to BPA how they will keep program achievements separate.

The BPA utilizes the services of about 30 BPA staff to support the C&RD program at an annual rate of about 5 FTE. Two of these staff members are full-time with C&RD.
The BPA utilizes the services of about 40 BPA staff to support Con/Aug at an annual rate of about 13 FTE.

The Regional Technical Forum (RTF) is hosted by the Northwest Power Planning Council (NWPPC) and chaired by Tom Eckman, a member of the Council's staff. RTF membership is voluntary and is made up of technical experts, BPA engineers and program staff, utility staff, and consultants. The RTF meets to discuss technical issues concerning the C&RD. The RTF considers proposed additions, deletions, and/or changes of a technical nature to the Manual. The RTF makes recommendations to BPA. BPA uses the technical review of a credible third party to back up its decisions.

3. Funding mechanisms

The costs of both programs are embedded in wholesale power rates for the five-year rate period ending 9/30/2006.

C&RD

BPA forecasts the upcoming year's C&RD for each customer by estimating the customer's Net Requirements Load and multiplying it by the rate discount of 0.5mills/kWh. The discount is spread over twelve months and shows up as a credit on the customer's monthly bill from BPA. At the end of the five-year rate period, the customer must document that the value of the customer's conservation and renewable activities equals the total credits received through the C&RD.

Administrative costs of the C&RD program are reduced by the use of the Manual and web-based reporting. The Manual, developed by BPA with the help of the RTF, integrates diverse engineering, performance and technical assumptions to produce a "deemed" value of kWh savings and dollar values to the C&RD program for hundreds of conservation and renewable measures. If a measure becomes the norm, then it is no longer considered incremental, and it will be deleted from the Manual.

Customers have several options for meeting their discount savings spending requirement. Small customers (<7.5 aMW load) have a special Small Utility Option involving minimal paperwork. All other customers have chosen Option B: Value of Savings. With this option the customer receives $32,850 or 20% of its conservation spending (customer choice) for administration, marketing and related activities, and
the customer's conservation activities are credited at 80% of their deemed value.

Historically, the payment for conservation and renewable actions taken under the C&RD program has been more generous than payment under the Con/Aug program. However, due to finite limits on C&RD funding, or the size of project, or for other reasons, BPA customers also take advantage of the Con/Aug program.

<u>Con/Aug</u>

Through <u>Con/Aug</u>, BPA seeks to purchase conservation from customers for less than it costs BPA to supply energy. BPA will consider all cost-effective activities until acquisition goals are satisfied. Payments for custom programs are individually negotiated. BPA does not pay the customer until the savings are actually "delivered", invoiced, and confirmed by BPA.

Upfront willingness-to-pay levels have been established for a few Limited Standard Offerings, but not for custom programs. A recent LSO was paying $0.035 to $0.12/kWh for first year savings, depending on measure life.

In some cases BPA includes pacing requirements in contracts, so that a threshold of conservation has to be "delivered" before the remainder of the contract goes into effect. Unexpended funds can be mutually de-obligated, freeing BPA to apply them to new contracts.

4. Degree of association with a long run resources plan

   Strong. The Northwest Power Planning Council (NWPPC) is directed by federal legislation to assure the region of an adequate, efficient, economical and reliable power supply. Presently NWPPC has a five year goal of 220 aMW in conservation to be reached by the combined efforts of Con/Aug, C&RD, Northwest Energy Efficiency Alliance activities and Low Income weatherization programs.

5. Guidelines for program effectiveness and success

   The C&RD program was initially conceived during a time of reduced conservation activity. One of its guiding principles was to keep 100% of utilities involved in promoting energy efficiency to keep the EE/RE market/infrastructure alive. Credits were set to reflect the value of conservation to the bulk power system, therefore they are often the highest possible cost-effective value.

Con/Aug, on the other hand, is presently BPA's primary tool for reaching the NWPPC's target for 220 aMW conservation acquisition by purchasing energy savings. Con/Aug seeks to purchase the resource at as low a system cost as possible. Con/Aug requires significant cost-sharing by the customer and minimal free riders.

Since Con/Aug is purchasing conservation to meet load requirements, the customers' actions must provide reliable and certain energy savings.

The C&RD Manual states that simple energy payback must be one year or greater for C&I projects. However, highly cost-effective measures can be combined with less cost-effective measures to qualify.

The C&RD program is expected to save 15 aMW* per year, or 75 aMW over the five year rate period.
The Con/Aug program goal is to deliver 100 aMW during the rate period. The Con/Aug plans and budgets are based on a steady state delivery of 20 new aMW/year.

*aMW = an average of one MW per hour per year, or 8760 MWh/year.

BPA requires certification that all programs/projects for both C&RD and Con/Aug provide incremental energy savings.

6. Pre-implementation program evaluation guidance

In C&RD the customers must report accomplishments once/year and provide a final reconciliation at the end of the five-year rate period. The Manual, and the C&RD Program Tracking and Reporting Software (C&RD Software) provide customers with very specific technical measure and evaluation guidance. Customers use the web-based C&RD Software to report their projects. This software incorporates the "deemed" values for conservation and renewable activities from the Manual. Reports include kWh savings by sector and the number of units installed. The Manual and Software are designed so that the RTF can track the regional conservation achievement of the customers. The RTF and BPA will issue a report of conservation achievements.

The customers' financial auditors must prove the customer spent the C&RD funds on approved conservation and renewable activities.

BPA requires that customers have certified energy auditors inspect conservation work to insure that installed measures are in substantial compliance with the C&RD program's technical specifications.

During the first round of each invitation period for the Con/Aug program, the BPA evaluates proposals based on the cost of delivered energy savings. Customers propose programs and measurement verification methodology, often using proposal templates developed by BPA. BPA engineering staff or contractors standardize and update M&V protocols whenever possible.

During the second round, the BPA and customers negotiate the project's details, including the verification process. Each project is carefully negotiated using historical data and experience of BPA engineers, NWEEA and other entities. Due to the specificity of contracts, BPA does not use third party evaluators for Con/Aug.

In Con/Aug, BPA uses the Utility Cost test to determine the Benefit:Cost. BPA compares the cost of programs to BPA's avoided supply costs, including generation or purchase, transmission and distribution.

7. Results of program evaluation

   According to BPA staff, <u>C&RD</u> programs have been meeting their participation and savings goals. 130 of 131 eligible customers participate. Close to 18 aMW were saved in the program's first year. Very few C&RD projects are large enough (over 100,000 akWh) to require third party energy savings verification. Independent financial auditing occurs in all cases.

   <u>Con/Aug</u> acquired 4 aMW before its expected start date in October 2001. During its first full year (October 2001-September 2002) it acquired 23 aMW. This year and next year Con/Aug expects to acquire 15 aMW each year. The final two years of the program, Con/Aug expects to acquire 21-22 aMW/year to reach its goal of 100 aMW. BPA had to temporarily slow the pace of conservation acquisition due to capital outlay issues. Accurate measurement and verification activities and close oversight by BPA allow the Con/Aug staff to change the pace of invitations for new projects to match goals and achievements.

   According to the BPA website, Con/Aug delivered its goals in its first year "at a cost that is substantially below what was originally projected." Con/Aug staff has found custom programs to be the most BPA-staff intensive. However, they can result in the cheapest acquisition of resources, for example an industrial process change-up.

8. Financial or performance incentives

   No lost revenue recovery for utilities.

Issues and Special Situations

<u>Northwest Energy Efficiency Alliance (NWAlliance)</u>

The regional market transformation activities of the NWAlliance are supported by BPA. In addition, contributions to the NWAlliance are allowed under the C&RD program.

<u>BPA Conservation Activity</u>

The 1996 Comprehensive Review of the Northwest Energy System recommended that utilities, rather than BPA, invest their revenues in conservation. This did not happen with any consistency in the public or private sectors. The C&RD was developed in part to assist utilities in meeting this goal.

<u>BPA Finances</u>

According to staff, BPA, for the first time in its history is in a financial bind. There are several major reasons. Rates were fixed for five years, from 2001-2006. At the same time, BPA agreed to provide over 3,500 aMW more than its own fixed assets could deliver. It now has to buy power to meet its contractual obligations. Con/Aug was developed to help meet this need for resource acquisition.

As a result all programs are being scrutinized. The C&RD program is built into rate agreements and has limited flexibility. However, one element that can change is the "deemed" value of conservation activities. These amounts were in hindsight too generous at first. Many are being revised downwards, so that customers will have to do more conservation to show they have used their savings appropriately.

<u>Con/Aug "Willingness to Pay"</u>

The Con/Aug budget has been reduced due to market conditions (cost of short term power purchases lower than forecasted) and experience (Con/Aug has been able to contract for conservation at lower-than-expected costs to BPA). As a result, BPA's "willingness to pay" level has dropped considerably.

It has been a source of frustration to BPA customers that BPA won't commit to a specific "willingness to pay" ($/aMW) figure, other than in the limited standard offers. However, BPA has found it advantageous to negotiate custom contracts, and, despite frustration, has found enough willing customers to meet BPA's goals.

Recently BPA has had to slow the pace of Con/Aug resource acquisition to minimize the impact on rates. According to staff, although the 2002 Rate Case set the rates for five years, there was a "safety net crack" in the rates that allows them to be emergency-adjusted upwards. There will be a near-term rate increase and Con/Aug has been directed to slow the pace of capital outlay to minimize the increase.

<u>C&RD T&D systems</u>

Efficiency improvements to customers' T&D systems qualify for C&RD credit. BPA is developing engineering protocols and credit determinations for these measures.

Equity

The wholesale customers are under no obligation to provide equitable distribution of conservation opportunities.

Resources

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503-230-7669, Mejohnson@bpa.gov
Tim Scanlon, Con/Aug Lead
206-220-6773, tjscanlon@bpa.gov
See www.bpa.gov/Energy/N/projects/conserve_augmentation/index.shtml for Con/Aug documents.
See www.bpa.gov/Energy/N/projects/cr_discount/index.shtml for C&RD docs.

Northwest Power Planning Council
503-229-5171, www.nwppc.org

Northwest Energy Efficiency Alliance,www.nwalliance.org

16. AUSTRALIA: NEW SOUTH WALES

According to IPART:
NSW 2003 population is 6,678,400
Total NSW electricity demand is 63,178 GWh

Mechanism:	Costs passed on to consumers; no specific levy
Creation:	Legislative
Duration:	January 2003-2012
Administration:	Independent Pricing and Regulatory Tribunal (Regulatory body)
Budget:	None, market-driven
Name:	New South Wales Greenhouse Gas Abatement Certificates
Benefit Measure:	Market-driven
Incentives:	Penalties for missing targets

Survey Questions

1. Process and timeline

   The Electricity Supply Act of 1995, effective 1997, made reduction of greenhouse gas (GHG) emissions a condition of retail electricity supplier licenses, and required parties to submit draft strategies to the New South Wales (NSW) Minister of Energy for negotiation. Emission targets were not reached. The Electricity Supply (Greenhouse Gas Emission Reduction) Amendment Bill 2002 (the "Act") passed through the NSW Parliament June 2002. This expanded the scope of mandatory participants and, beginning January 2003, set mandatory targets for abating GHG emissions from electricity production and use. Abatement certificates may be traded. There are penalties for noncompliance.

2. Organizational Structure

   The Scheme Administrator ("Administrator") is appointed by the Minister for Energy. Currently the state regulatory body, the Independent Pricing and Regulatory Tribunal (IPART) will administer the program. The Administrator is responsible for:
   - Accrediting abatement certificate providers (first task in staged implementation);
   - Monitoring benchmark participants' compliance with benchmarks;
   - Verifying abatement activity;
   - Imposing penalties if required;
   - Maintaining a registry of certificates; and
   - Reporting compliance results to the Minister for Energy.

   Benchmark participants ("participants") meet their targets by surrendering New South Wales Greenhouse Gas Abatement Certificates (NGACs) purchased from low-emission electricity generators and other persons accredited as certificate providers.

Persons that may be accredited as abatement certificate providers are those who:
Generate electricity in ways that reduce GHG emissions/MWh; or
Conduct activities that result in reduced consumption of electricity; or
Capture carbon from the atmosphere in forests; or
Large users that elect to reduce on-site emissions (see Special Situations, below).

3. Funding mechanisms

Participants must obtain NGACs on the open market.
NGACs can be created in three ways:
Reduction of greenhouse intensity of electricity generation;
Demand side abatement activities that result in reduced consumption of electricity
The capture of carbon from the atmosphere in forests (Carbon sequestration).
NGACs can be traded. Participants pass the costs of the NGACs on to customers.

4. Degree of association with a long run resources plan

This program represents the electricity sector of NSW's contribution to the nationally agreed-upon policy of GHG emission reductions. The program and its achievements are integrated into state and national GHG policy planning.

In addition, Distribution Network Service Providers are required to investigate cost-effective demand side solutions before augmenting their networks. These providers are State government-owned and regulated monopolies. (See the Demand Management Code: www.doe.nsw.gov.au/industry_performance/index.htm)

5. Guidelines for program effectiveness and success

The NSW government set a state-wide benchmark of reducing per capita greenhouse gas emissions from the production and use of electricity to 5% below 1990 levels by 2007, and maintaining that level until at least 2012. This equates to a reduction from 8.65 to 7.27 tonnes of CO_2 equivalent per capita. The benchmarks are set progressively tighter each year leading to the final 2007 level.

Participants are responsible for their share of the state-wide benchmark based on percent share of NSW electricity sales.

One NGAC represents one tonne of CO_2 equivalent emission abatement.

The number and ways in which demand-side abatement NGACs can be created is determined by the *Greenhouse Gas Benchmark Rule (Demand Side Abatement)No.3 of 2003*, available at www.greenhousegas.nsw.gov.au/

6. Pre-implementation program evaluation guidance

The Administrator determines and publishes key factors used to set benchmarks statewide and for each participant, for the next year. These include:

NSW pool coefficient for greenhouse emissions;
Total state electricity demand;
Total state population;
Electricity Sector Benchmark;
Attributable emissions for benchmark participants; and
Number of abatement certificates an accredited certificate provider can produce per unit of production.

7. Results of program evaluation

Participants must surrender NGACs within six months of the end of the calendar year in which the abatement occurred to document target achievement. Participants must submit an annual benchmark statement to the Administrator confirming the number and details of NGACs surrendered to ensure they met their benchmark.

The program is too new to be evaluated. The Administrator will use third party verifiers to audit and verify abatement activity and abatement certificate providers.

8. Financial or performance incentives

Since the NGACs can be traded there are market incentives. There are also penalties of \$10.50 per tonne of CO_2 equivalent for the amount of any shortfall. A participant may carry forward a shortfall of up to 10% of their benchmark to the following year without incurring a penalty. If the amount carried forward is not abated in the following year it will be subject to the penalty.

Issues and Special Situations

<u>Mandatory Benchmark Participants</u>

Mandatory participants include:

Electricity retail suppliers;
Generators with contracts to supply electricity directly to customers; and
Electricity customers taking supply directly from the National Electricity Market.

<u>Elective Benchmark Participants</u>

Large electricity users (using more than 100 GWh/year at one site, or at multiple sites as long as one site uses more than 50 GWh/year) may elect to participate and manage their own emissions not directly related to the acquisition or use of electricity. They apply to the Administrator for participation, and the liability for their benchmark is transferred from their retail supplier to the large electricity user. The Large User Abatement Certificates they create and surrender are <u>not</u> transferable.

<u>Renewable Energy Certificates</u>

A national law requires all electricity suppliers to meet Mandatory Renewable Energy Targets according to the Renewable Energy (Electricity) Act. Suppliers redeem Renewable Energy Certificates as proof of purchase. These certificates can also count towards their NSW GHG benchmark.

Resources

Independent Pricing and Regulatory Tribunal (IPART)
IPART, according to their website, "is an independent body that oversees regulation in the water, gas, electricity and public transport industries in NSW. IPART has six core functions, which are conferred by legislation and codes and access regimes established by legislation."
www.ipart.nsw.gov.au/index.htm

Information about the Act and how the scheme will operate is maintained by IPART at:
www.greenhousegas.nsw.gov.au/

Electricity Supply Act 1995 is available at
www.doe.nsw.gov.au/environment/guidelines/env_gd13.html

Sustainable Energy Development Authority (SEDA)
www.seda.nsw.gov.au

Funded by the State government to administer the Sustainable Energy Fund, act as a market transformation agent, work as a partner with others as a service provider and reduce GHG emissions.
Annual Report:
www.seda.nsw.gov.au/pdf/ANNUAL_REPORT2002.pdf

Energy Futures Australia
www.efa.com.au/dsmdocs.html
Discussion of recent history of demand side management and sustainable energy policies in Australia.

17. BRAZIL

(Statistics are estimates from www.eia.doe.gov)

Population (2001): 174.4 million
Electric Generation Capacity (2000): 68.8 GW (87% hydro)
Net Electricity Generation (2000): 342.3 billion kWh
Net Electricity Consumption (2000): 360.6 billion kWh

Mechanism:	1% of utility revenues must be spent on energy efficiency
Creation:	Regulatory
Duration:	Began July 1998; no sunset
Administration:	Utilities, with support from PROCEL and regulatory oversight
Budget:	~$200million/year
Name:	No name
Benefit Measure:	Utilities determine
Incentives:	None

Survey Questions

1. Process and Timeline

   In 1985, national legislation (Act 1877) established a national electricity conservation program known as PROCEL. In July 1998, as Brazil underwent utility sector restructuring, the new federal regulatory agency, the National Agency for Electrical Energy (ANEEL) announced it would require all distribution utilities to spend at least 1% of revenues on energy efficiency improvements (ANEEL resolution 242/98). Utilities began proposing projects in September 1998.

2. Organizational Structure

   ANEEL is responsible for defining efficiency priorities and approving utilities' annual plans. ANEEL is funded by an assessment on the utilities. ANEEL was created in 1997.

   ANEEL reached an agreement with PROCEL that it would provide technical support to analyze the plans. PROCEL is assisting utilities with preparation of EE plans and certifying that utilities are carrying out adequate programs. PROCEL is a federal agency funded by the government with more than 15 years' experience in funding and developing energy conservation programs. It is housed in Eletrobras, the former federal electricity monopoly, which now is responsible for the integration of Brazil's electricity sector. PROCEL also receives assistance from and cooperates with European, Canadian, US and international agencies and experts.

   More than 60 distribution utilities are responsible for program design and implementation in their service territories.

3. Funding mechanisms

   From 1985 until 1998 PROCEL was funded by the federal government. It also leveraged funds from a variety of sources. It provided direct investments and low-interest financing for major energy efficiency projects from a loan fund known as RGR. PROCEL continues to leverage grants and loans to finance its activities.

   Beginning in 1998, all distribution utilities must spend at least 1% of their revenues on energy efficiency improvements. This requirement is included in the concession contracts ANEEL signs with utilities. ANEEL determines priorities. Initially at least 25% must be spent on end-use efficiency projects. Ten percent must be invested in research and development. The rest (65%) is available for supply side improvement. The utilities keep the funds and specify their investment plans.

4. Association with a long run resources plan

   Electricity expansion plans now made in market environment by private sector. The new National Energy Policy Council is a government entity that should be very influential in determining overall energy policies on energy conservation and its role in the macro-energy policies. As of 1999 it was not operational.

5. Guidelines for program effectiveness and success

   PROCEL's goal is to save 77 TWh/year by 2010, equivalent to approximately 15% of projected electricity use in Brazil in 2010 without efficiency improvements. Utilities submit their goals to ANEEL for approval.

6. Pre-implementation program evaluation guidance

   Initially utilities proposed projects that met their cost-effectiveness guidelines. According to Mancuso da Cunha the financial benefits of the saved energy had to pay for the funds invested.

   USAID has recently worked with ANEEL to develop new guidelines for EE projects proposed by utilities that were more focused in measurement, verification and evaluation of results.

7. Results of program evaluation

   PROCEL's 1998 Results, according to PROCEL, summarized by Geller:
   5.3 TWh/year saved;
   1.4 TWh additional power production due to plant improvements;
   1560 MW new capacity avoided; and
   Avoided investment (US$) $3.1billion in new power plants and T&D.

There is no independent verification of results built into the new 1% of revenue program. However, Dr. Jannuzzi, professor at the State University of Campinas in Sao Paolo planned to independently evaluate projects funded by the 1% "to analyze their nature, quality and objectives."

8. Financial or performance incentives

   As of 1998 (Geller) federal regulations allowed utilities to recover DSM program costs in tariffs, but in practice it was not occurring. Utilities could not recover net loss revenues. Now, there are no incentives and there may be disincentives due to fixed distribution tariffs and multi-year agreements. "Under rate systems commonly in effect, even modest changes in the level of consumption by a distribution company's customers will have dramatic effects on the rate of return earned by the company's owners." *Energia: Recommendacoes para uma estrategia nacional de comate ao desperdicio,* Chapter 8, USAID-Brasil (August 2001)

Issues and Special Situations

The utilities can use 65% of the efficiency funds to improve their own supply side efficiency. According to Jannuzzi, in a deregulated, competitive environment it seems utilities would choose to invest their own funds in these improvements. This large diversion of the 1% makes it less likely that alternative plans that are less financially interesting to utilities, but with potentially greater societal benefits, will be proposed. There has been very little debate about the "issues of governance, administration and public policy strategies associated with the use of such funds."

Jannuzzi notes:

It is likely that only programs that present favorable cost-benefit ratios from the utility point of view will be proposed and implemented by the utilities, unless ANEEL considers public benefits more prominently.

It will limit R&D to short-term and proprietary research, rather than public interest research.

Regional disparities will be aggravated. The more profitable utilities are in the southeastern part of the country along with the higher per capita income. End-use efficiency programs could have greater societal benefits in other parts of the country but won't have the same access to funding.

Some of the priorities stated by ANEEL would be done any way by profit motivated utilities. This fund could be used for investments not favored by market forces.

RAP notes:

Funds available for EE through ANEEL's mandate might be more effective if pooled for national and regional programs.

Utilities need incentives. Consider revenue caps instead of price caps.

Resources

Januzzi, G.deM, *Energy Efficiency and Restructuring of the Brazilian Power Sector,* 1999.

www.fem.unicamp.br/~jannuzzi/congressos/mexico99.PDF

Geller, H, de Almeida, M., Lima, M., Pimental, G., and Pinhel, A, *Update on Brazil's National Electricity Conservation Program (PROCEL)*, 1999. www.aceee.org/pubs/i992.htm

USAID
www.usaid.gov/country/lac/br/512-002.html

Mancuso da Cunha, A. *Fighting Electricity Waste in Brazil: the Role of the Regulatory Agency,* 1999. www.gwu.edu/~ibi/minerva/Spring1999/Alexandre.Mancuso.da.Cunha.html

Geller H, Jannuzzi G M, Schaeffer R, and Tolmasquim M T, *The Efficient Use of Electricity in Brazil: Progress and Opportunities*, 1998. Energy Policy 26 (11), 859-872.

USAID-Brasil , *Energia: Recommendacoes para uma estrategia nacional de comate ao desperdicio,* Chapter 8, (August 2001)

18. NORWAY

(Statistics are estimates from www.eia.goe.gov)

Population (2001): 4.5 million
Electrical Generation Capacity (2000): 27.2 GW (99% hydro)
Electricity Generation (2000): 141 billion kWh
Electricity Consumption (2000): 112 billion kWh

Mechanism:	Levy on distribution tariffs; as well as national budget funds Creation: Legislative
Duration:	Began 1 January 2002; ten-year budget framework
Administration:	ENOVA, a national government agency
Budget:	~60million Euro/year
Name:	No program name
Benefit Measure:	Cost-effective
Incentives:	No utility incentives

Survey Questions

1. Process and timeline

   Norway has funded energy efficiency measures since the 1970's. Responsibilities for voluntary initiatives were divided among the grid companies and the national regulatory agency. In March 2001 the Storting (Norwegian Parliament) relieved other parties of efficiency and renewable responsibilities, and approved the establishment of a new public agency, ENOVA SF. It became operational in January 2002.

2. Organizational Structure

   According to the Secretary of the Norwegian Ministry of Petroleum and Energy (MPE), ENOVA is "owned by the government of Norway, represented by the Ministry of Petroleum and Energy." ENOVA serves the entire country and is located in the center of Norway. ENOVA will act as an advisor to the MPE, and participate in international work in its area of responsibility. ENOVA is expected to use existing organizations that are willing to compete for assignments and tasks. For example, existing regional energy efficiency centers, funded through the former system, will have to compete to provide public information and guidance.

3. Funding mechanisms

   According to the Secretary of the MPE, ENOVA is funded "from a levy on the distribution tariffs and from ordinary grants over the State budget." The funds are deposited in a separate energy trust. According to the IEA Update, Enova is in charge of the trust "which secures a long-term financial frame over the years to come." Funding will be up to NOK 5 billion (about 650million Euro) over a ten-year period. The budget in 2002 was about 60million Euro.

4. Degree of association with a long run resources plan

    In Norway, energy efficiency and renewable energy efforts are considered in the context of planning to meet the Kyoto Protocol, as well as other national and European environmental planning efforts.

5. Guidelines for program effectiveness and success

    According to the Secretary of MPE, objectives approved by the Storting are:
    "To limit energy use considerably more than would be the case if developments were allowed to continue unchecked;
    To increase annual use of central heating based on new renewable energy sources, heat pumps and waste heat by 4 TWh/year by the year 2010; and
    To construct wind generators with a production capacity of 3 TWh/year by the year 2010."

    The Secretary of MPE also indicated ENOVA must use funds cost-effectively, and promote environmentally friendly natural gas solutions.

    Norway's Kyoto commitment is to limit the increase in greenhouse gas emissions to 1% between 1990 and 2008-2012.

6. Pre-implementation program evaluation guidance

    The MPE sets the "operational targets" and will set "clear routines for reporting the results." Measurement and verification of energy savings will be a high priority.

7. Results of program evaluation

    The program is too new for results at this time. ENOVA itself will be evaluated after four years.

8. Financial incentives

    There are no incentives for specifically for utilities. The government did establish general incentives. Investment in most new renewable energy technologies, including solar energy systems, is exempted from investment taxes. Production from wind energy is supported by half the consumer tax on electric power/kWh produced.

Issues and Special Situations

Electricity Consumption/Generation

Historically Norway has met electricity needs through hydropower. Increased consumption and weather issues have resulted in demand outstripping hydropower capacity. According to the IEA, Norway has the highest per capita consumption of electricity in the world. Norway is attempting to reduce the environmental impact of non-hydropower generation of electricity by promoting energy efficiency, renewable generation and environmentally friendly use of natural gas.

Resources

ENOVA SF
www.enova.no (site is in Norwegian)
Email inquiries: post@enova.no

Review of Energy Efficiency, CO2 and Price Policies and Measures in EU Countries and Norway in 2001. www.odyssee-indicators.org/Publication/PDF/Norway-p01.pdf

IEA Energy Efficiency Update: Norway, March 2003
www.iea.org/pubs/newslett/eneeff/no.pdf

April 2002 Speech given by State Secretary Brit Skjelbred, Ministry of Petroleum and Energy at the IEA Industry Workshop in Oslo Norway.
http://odin.dep.no/oed/engelsk/aktuelt/p10002021/taler_politisk_ledelse/026021-090016/index.htm

19. UNITED KINGDOM

(Statistics are estimates from www.eia.doe.gov)

Population (2002): 59.8 million
Electrical Generation Capacity (2000): 72.4 GW (79.8% thermal, 17.9% nuclear, 2.0% hydro, 0.2% other)
Electricity Generation (2000): 355.8 billion kWh
Electricity Consumption (2000): 345.0 billion kWh

Mechanism:	Required energy savings targets with penalties for non-compliance
Creation:	Legislative
Duration:	April 2002- March 2005
Administration:	Office of Gas and Electricity Markets (Ofgem)
Budget:	~500million pounds over three years
Name:	Energy Efficiency Commitment (residential)
Benefit Measure:	Cost per tonne C saved
Incentives:	Market-driven

Survey Questions

1. Process and timeline

   From 1994-2000, under the Energy Efficiency Standards of Performance Program (EESoP), electricity suppliers (and, later, gas suppliers) were obliged to achieve specified energy savings in the domestic (i.e. residential) and small business sector using a special revenue allowance. In 2000 the allowance was1.2 pounds/customer/fuel/year.

   The Utilities Act 2000 transferred responsibility for EESoP from the regulator to the Department of the Environment, Food and Rural Affairs (Defra) beginning April 2002. The new program, the Energy Efficiency Commitment (EEC), requires major electricity and gas suppliers to meet environmental targets by focusing on domestic customers, with an emphasis on elderly and low-income households. There is no longer a specific levy. Energy savings goals increased three-fold, and suppliers have discretion to pass on costs to their customers.

2. Organizational structure

   The Department of the Environment, Food and Rural Affairs (Defra) sets the overall environmental targets and determines the measures to achieve them.

   The present Administrator is the Office of Gas and Electricity Markets (Ofgem), the national regulatory body. Ofgem determines which efficiency measures qualify and the savings attributable, approves proposed schemes, and monitors suppliers' performance against their targets. Ofgem apportions each supplier's target based on customer numbers with rules established by Defra. Ofgem oversees trading between suppliers, and advises Defra on the most cost-effective means to achieve targets. Ofgem can fine non-compliant suppliers.

Gas and electricity suppliers ("suppliers") in the UK with 15,000 domestic customers or more have energy savings targets, which must be achieved between 2002-2005 by installing energy efficiency measures in homes. Suppliers can contract out the work, do it themselves or enter collaborative arrangements. Suppliers submit schemes for Ofgem approval, but can begin work in the month before submission, at their own risk.

3. Funding mechanisms

Suppliers can pass on to customers as much of the energy savings costs as makes good business sense in the newly competitive supply market. Expenditures are estimated to be up to 3.60 pounds per customer per fuel per year to meet the energy efficiency targets. This is estimated to result in close to 500million pounds over the three-year period. Suppliers can trade either their obligations or their energy savings from approved measures to another supplier. However, since suppliers get marketing value from the program, little trading activity is expected. Under the EESoP, 21% spending on administration and marketing was average. Suppliers now have incentives to be more cost-effective.

4. Association with a long run resources plan

The EEC is one component of the UK Climate Change Programme, which is a comprehensive package of plans, programs and policies to meet the UK's Kyoto and domestic commitments to reducing CO_2 and other greenhouse gases (GHG). In addition, Ofgem must report annually to Defra on the EEC results.

5. Guidelines for program effectiveness and success

The UK has a legally binding target under the Kyoto Protocol to reduce its GHG emissions by 12.5% compared to 1990 levels for the 2008-2012 period, and a domestic goal to reduce CO_2 emissions to 20% below 1990 levels by 2010. The EEC is expected to contribute by reducing GHG emissions by around 0.4million tonnes Carbon/year by 2005. Defra has set the overall target for the Commitment at 62 fuel-weighted TWh reduction by 2005, including "deadweight" (free riders).

Ofgem provisionally divided the target among 11 supplier groups. Targets will be adjusted according to customer numbers at the end of 2002 and 2003. Suppliers can achieve EEC obligations through residential consumer savings of electricity, gas, coal, oil or LPG.

At least 50% of savings must be targeted at low-income customers (e.g. receiving income-related benefits or tax credits).

6. Pre-implementation program evaluation guidance

Ofgem issued a technical manual to provide guidance to suppliers delivering efficiency measures. Ofgem determines whether proposed actions qualify for the purpose of meeting the obligation. Ofgem determines what savings are attributed to the action, using recognized sources. Ofgem collects data on each scheme to estimate the actual energy savings achieved.

Specific improvements, already proven to be cost-effective, are expected under EEC including: wall and loft insulation, A and B-rated boilers, A-rated appliances, tank insulation, CFL's, draft-proofing, heating controls and fridge-savers (trade-in). Defra anticipates results will include 1 million homes with improved insulation, 750,000 energy efficient appliances, and 36 million EE lighting fixtures.

Ofgem will measure environmental progress using energy efficiency data including the amount of money spent on schemes, TWh of electricity saved, and tonnes of CO2 saved.

7. Results of program evaluation

   The program is too new for evaluation results. Ofgem uses contractors to help with the oversight of the EEC. The cost of oversight comes from Ofgem's budget, paid for through licenses. Ofgem will collect data to compare the total costs of the program against the economic, social and environmental gains from the program.

   During the EESoP, Ofgem was assisted by the Energy Savings Trust (EST) in assessing suppliers' compliance with targets. Results were verified by the National Audit Office. The EST found for every 1pound invested customers benefited by about 4.6pounds in reduced energy bills and increased comfort. EST continues to provide expert advice to Ofgem.

   EST estimates the last two years of the EESoP will result in lifetime savings of 2.3million tonnes of Carbon, 8.6million tonnes of CO2, 80,800 tonnes of SO2 and 27,900 tonnes of NOx.

8. Financial incentives

   The Government's EEC proposal indicated that "it will be up to suppliers to meet their targets cost-effectively: there will not be a specified amount of money that a company must spend in doing so." Since the costs of the program impact the suppliers' bottom line in a competitive market, suppliers have an incentive to operate the schemes efficiently.

Issues and Special Situations

<u>Climate Change Levy (CCL)</u>

The CCL was announced in November 1999 is an energy tax on the non-domestic sector (industry, commerce, agriculture and public sector) beginning April 2001. Rates are based on the energy content of different energy products, equivalent to 0.07pence/kWH for LPG; 0.15pence/kWh for gas and coal, and 0.43 pence/kWh for electricity. Energy intensive sectors with binding commitments (negotiated with Defra) to meet energy efficiency or carbon savings targets get up to 80% discounts on CCL rates

Revenue from the levy is expected to be around 1billion pounds in 2001/2002. Most CCL revenues are returned through a reduction in employers' National Insurance contributions.

The Carbon Trust will use about 50million pounds/year from CCL funds to conduct Carbon saving programs for business and industry. The Carbon Trust will also manage the Enhanced Capital Allowance Scheme (ECA), worth up to 200million pounds over two years. The ECA gives 100% capital allowance against taxable profits in the first year for investments in any of the energy efficiency technologies on the list published by the Carbon Trust.

The CCL is expected to save at least 5 million tonnes of Carbon a year by 2010: half from negotiated commitments; half from price effects, the ECA and other programs.

Resources

Office of Gas and Electricity Markets (Ofgem), www.ofgem.gov.uk
Charles Hargreaves, Head of Energy Efficiency
Charles.Hargreaves@ofgem.gov.uk
At this site you can view the EEC Administration Procedures, *Energy Efficiency Commitment 2002-2005: Technical guidance manual issue 1* and other papers.
The Environmental Action Plan Annual Review 2001-2002, June 2002, can be seen at
www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/1993_42eap.pdf

Department for the Environment, Food and Rural Affairs (DEFRA)
www.defra.gov.uk/environment/energy/eec/index.htm
Final version of the UK Climate Change Programme is available at:
www.defra.gov.uk/environment/climatechange/cm4913/index.htm

The Energy Savings Trust, www.est.org.uk/est/index.html
Independent non profit organization set up in 1992 to promote the efficient use of energy in the domestic, small business and transport sectors. Originally funded by a levy on gas and electricity customers. Presently bulk of funding provided by the government.

The Carbon Trust, www.thecarbontrust.co.uk
The Carbon Trust is charged with developing a fully integrated program of incentives for business–related carbon saving, including energy efficiency.

Review of Energy Efficiency, CO2 and Price Policies and Measures in EU Countries and Norway in 2001 www.odyssee-indicators.org/Publication/PDF/UK-p01.pdf

UK Energy Efficiency Update, November 2001
www.iea.org/pubs/newslett/eneeff/uk.pdf