Demand Side Response Cost Recovery Mechanisms

(Updated: Sept. 30, 2004)

Introduction

The Cost Recovery Mechanism subgroup examined the means by which DSR related costs incurred by an EDC could be recovered through rates. The subgroup identified the follow mechanisms for cost recovery: EDC distribution rates, participating customer fees, performance based ratemaking, and a systems benefit charge.

The subgroup also identified a number of principles that must be considered in any exploration of this issue: 1)Recovery of all reasonable costs; 2) Avoidance of deferred costs; 3) Simplicity; 4) Avoidance of cross subsidization among classes; 5) Proper matching of costs and benefits; 6) Entities benefiting from DSR; and 7) Awareness of the impact of the statutory rate caps. Another important issue to be aware of is the distinction between the various types of expenditure – i.e. capital versus expense. Both can be included in the cost recovery mechanism, but they may require different treatment. Capital expenditures would include depreciation, a return component, and taxes. Issues regarding the full ratemaking implications, reasonableness and legality of any specific cost recovery mechanism will have to be addressed in detail when considering each specific cost recovery mechanism.

It should be noted that no one of these mechanisms is necessarily intended to be considered to the exclusion of all others. A hybrid approach that combines one or more options may be the most appropriate.

1. EDC DISTRIBUTION RATES

The costs associated with DSR may be recovered through an EDC's distribution rates in a number of ways. Each of the following mechanisms has its own advantages and disadvantages, which will be briefly discussed.

A. The 1307(e) Surcharge

One method would involve the use of a surcharge recovered through an automatic adjustment clause pursuant to Section 1307(e), 66 Pa. C.S. §1307(e). The advantages of this approach include the timely recovery of costs, the avoidance of over or under recovery of costs, and ease of implementation. The surcharge would be based upon projected data in order to achieve timely recovery of costs. Programs would be tracked individually and summed up for any cost recovery filing. This method allows for some flexibility in implementation. For example, DSR programs could be started or canceled during a particular year as the surcharge is reconcilable. Any reduction in cost from canceling a program would be included in the annual reconciliation. If DSR costs were higher than projected due to greater participation, etc. these costs would still be recovered in the annual reconciliation.

One disadvantage with a 1307(e) mechanism is that it socializes the costs among all customers, so that costs do not necessarily match benefits. This mechanism results in non-DSR participant customers paying the same as participants, but not necessarily receiving the same level of benefits. The socialization of the costs could also result in cross-subsidization among the rate classes. A second disadvantage is that program cost recovery might not match the time when benefits are realized by the system. As with most cost recovery mechanisms, the issue of the rate cap is present. Depending upon the specific company circumstances, this charge could violate the rate cap. A potentially major legal obstacle to this approach is recent precedent prohibiting the recovery of capital costs through a demand side management mechanism. *See Pennsylvania Industrial Energy Coalition* v. PA PUC, 653 A.2d 1336 (Pa. Cmwlth. 1995). The Court reversed a Commission order that provided for a surcharge to allow an EDC to recover the costs associated with a DSM program. The Commission will need to take this precedent into consideration when evaluating this type of mechanism.

B. Single issue non-general rate case – 1308(a)

A variation of the 1307(e) surcharge is a single issue rate case filed pursuant to Section 1308(a). 66 Pa. C.S. §1308(a). This method is similar to the 1307(e) approach, in that it focuses on one issue. Unlike the 1307(e) process, the single issue case would set a level of expenditures going forward and would not require an annual filing. There is no annual reconciliation requirement. With no reconciliation there is a risk of either over collecting or under collecting, depending upon participation and program cost levels. This methodology also socializes the costs of the programs to everyone. If customer participation in a DSR program is growing the recovery of expenses would lag their incurrence. Additionally, this methodology does not guarantee cost recovery and could result in cross-subsidization among the rate classes. As with the 1307(e) mechanism, a single-issue rate case could violate the rate cap for companies still under a rate cap.

C. Base rate case

Filing a general distribution base rate case that includes some level of DSR expenditures is another option. The advantage of this approach is that, given the fixed funding amount, efficient program management is encouraged in order to avoid potential under recovery of costs. Base rate recovery is also a simple cost recovery mechanism as there is no annual cost recovery filing, although there might be an annual program filing or filings necessary when introducing new programs. This approach also reflects how utility costs are typically recovered, and may be the only legally supportable approach for the recovery of capital cost. The rate cap is not an issue with this approach as rate increases would not be available to those companies still under the cap.

There are a number of disadvantages to this approach. This mechanism might not guarantee full recovery of program costs. If customer participation is higher than anticipated, or the program is expanding, or if additional funds are needed, a new base rate case would have to be filed or another cost recovery mechanism used. Socialization is also a potential problem. The socialization of the costs could result in rate class cross-subsidization if costs are not allocated properly.

D. Deferral for future recovery

A variation on the above approach would simply be to defer DSR costs until the next distribution rate case. The EDCs would make the necessary investments and expenditures in DSR in the near future, with the expectation that a request for recovery of these costs would be included in some future distribution rate increase filing. This approach has many negatives, but is included so that the Commission is aware of all its potential options.

This methodology would obviously conflict with the previously stated principle of avoiding deferred costs. Future recovery would promote the use of hindsight in litigating the recoverable cost. Further, in order to assure full recovery under the deferral method, a return on the recovered amount would be necessary. As with the other mechanisms discussed in this section, DSR costs would be socialized to all customers. The socialization could be modified to be class specific but this still adds a layer of complexity. Another drawback of this methodology is that in the current accounting environment it is becoming more difficult to support regulatory assets. Under a Commonwealth Court case in *ARIPPA v. Pa. Pub. Util. Comm'n*, 792 A.2d 636 (Pa. Cmwlth. 2002), deferral of these costs for future recovery could be considered a violation of any applicable rate cap.

This approach has few advantages. As with the reconcilable mechanisms, a rapidly expanding program would not result in under recovery of costs here, as they would instead be deferred.

E. Summary

Each approach has advantages and disadvantages or legal impediments that need to be addressed. Combinations of approaches may be appropriate. Various ratemaking issues will need to be examined in more detail should the Commission adopt a particular policy regarding DSR.

2. PARTICIPATING CUSTOMER FEES

Where customer participation in DSR is voluntary, and viable programs are available, one cost recovery solution is a customer participation fee. The strongest argument for this methodology is that costs should largely be borne by those customers who benefit the most from DSR. As customers can see the true costs of DSR, and the potential benefits, it is easier for them to make the correct economic choice. In contrast, it can be argued that DSR participants often create benefits for other customers who should therefore share in costs. This approach is arguably the least burdensome to EDCs, as it does not require the deployment of DSR technology for every distribution customer. Rather, the most significant investment and challenge for an EDC in this approach is the development of an effective, DSR compatible billing system, particularly where participation is high. The company must be sure it can accurately bill the customer for their appropriate DSR program and administrative cost.

This approach is therefore best applied when:

- DSR programs are voluntary
- Clear information regarding actual benefits is directly available to participants
- Program costs are identifiable
- Costs are customer specific
- DSR equipment exists that provides the customer with the opportunity for direct savings through lower energy and demand use.
- DSR equipment exists that provides the customer the opportunity to earn a reasonable payback period on any fees paid.

Its distinctions, and perhaps advantages over other approaches, are:

- Avoidance of socialization of costs.
- Avoidance of litigation associated with distribution rate cases.
- Rate caps are not an issue.

The design of the fee should allow for the EDC to recover over a reasonable period of time the costs associated with the necessary equipment and infrastructure investments. Depending on the DSR mechanism, these costs could include all or a combination of the following items.

- interval meters
- smart thermostats
- communication systems
- billing systems
- program management

While the incorporation of the costs of the first three items above into a participant fee is fairly straightforward and customer specific, a more difficult proposition would be the recovery of the larger costs which could be required to modify the current EDC billing system or to procure a new system. These costs would be too prohibitive to incorporate into a participant fee and would most likely have to be captured through a more socialized approach. Benefits to other customers must also be analyzed before asking them to pay for the programs. Likewise, the costs incurred by the EDC to manage the DSR program would represent an on-going cost which would also not lend itself to be included in the participant fee.

From the customer perspective, each participant should expect to receive a reasonable payback through energy cost savings and/or billing credits associated with the program. This scenario provides measurable benefit to the individual customer participating in the program as opposed to a more socialized approach to cost recovery. Administrative and other EDC costs can be reduced if standards are established enabling participants to directly purchase equipment in the open market and have it installed at their direct expense.

Depending on the complexity of a particular DSR initiative, the program costs may or may not be able to be fully recovered through a participant fee alone. The more complex options which require significant infrastructure investment would undoubtedly require a combination of a participant fee and base rate increase. There must be benefits for the entire system though if all customers are to support these additional costs.

PARTICIPANT FEE ANALYSIS

PERSPECTIVE	PROS	CONS/RISKS
Customer	• One time charge • Measurable and identifiable energy and cost savings	• Realizable cost savings
EDC	• Program costs recovered from benefiting participants • No costly billing system changes required • Base/Single Issue Rate Case not required	• Will all costs be recoverable? • Adequate participation

3. SYSTEM BENEFIT CHARGES AND DEMAND-SIDE RESPONSE

Editor's note: Except where otherwise noted, this paper is primarily comprised of content excerpted from the Regulatory Assistance Project Issues Letter on System Benefits Charge (November 1994). Other sources are noted within and at the end of each paragraph.

Background

While efficient, affordable electricity serves as a cornerstone of American prosperity, the nation's electric system suffers from aging infrastructure, security vulnerabilities and operating instabilities and inefficiencies. Ratepayers also must foot the bill for costly mortgages on large capital assets sized to meet peak demands that occur only a few hours per year. The answer, according to Robert Pratt, scientist and spokesman for the Pacific Northwest National Laboratory (PNNL), is a complete transformation of the electricity system through use of information technology to integrate the traditional elements of supply and demand, transmission and distribution with new technologies such as superconductors, energy storage, customer load management, and distributed generation. By moving the energy system into the information age, information technologies and newly created market efficiencies can optimize the system, minimize the need for new infrastructure, lower costs and make the system more secure.[1]

According to studies conducted at the Pacific Northwest National Laboratory, more than $80 billion could be saved over the next 20 years by actively managing load to defer new construction, improving grid management to reduce outage costs and increasing customer efficiencies through advanced controls and diagnostics.[2] Such are the goals of Demand-Side Response initiatives, programs which are designed to deliver the same level of public benefits to the electric grid.

DSR may be literally defined as a customer response (generally assumed to be instantaneous) to a market signal that indicates the posting of electricity prices for a specific period of time. One envisions a bell ringing or a light blinking, and the electricity customer knows to check the "bulletin board" of electricity prices and decide whether to buy or to sell electricity, enabled by special metering devices. This is generally how wholesale markets work for generation. However, for a restructured, retail electric distribution system and a default electric generation provider (provider of last resort), it may be practical to borrow the generally accepted definition of Demand-Side Management Programs for DSR Programs. That is, *organized utility activities that are intended to affect the amount and timing of customer resource use*.[3] This definition opens the door of opportunity for funding DSR Programs through a System Benefit Charge.

What Are System Benefit Charges?

A system benefits charge (SBC) is a fee paid by ratepayers to fund certain "public benefits" that are placed at risk in a more competitive industry. These benefits include, but are not limited to, efficiency savings, a cleaner environment and the assurance of universal service. Programs funded by an SBC include assistance for low-income and physically-impaired customers, 911 emergency calling, renewable energy, research and development, and energy efficiency or demand-side management (DSM). (Roger Colton, "Electric Utility Restructuring and the Low-Income Consumer, Facts on File: No. 14," Fisher, Sheehan & Colton,

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[1] PNNL News – PNNL envisions Smart Energy approach projected to save billions. February 13, 2004. See http://www.pnl.gov/news/2004/04-05.htm.
[2] Ibid.
[3] Barrett's DSM Glossary, Barrett Consulting Associates, Inc., Colorado Springs, CO (July, 1992)

Public Finance and General Economics (October 1997), http://www.ncat.org/liheap/pubs/no14.htm) SBC funds also support a wide variety of related activities. For example the SBC funds of Connecticut, New Jersey, New York, Ohio, Pennsylvania, and Rhode Island provided funding for a 67-page report "Niche Markets for PV," prepared under the direction of Lewis Milford and Roger Clark of the Clean Energy Group and the Clean Energy Funds Network (March 18, 2002). New York State supports Demand-Side Response (DSR) technology deployments through SBC funds allocated to research and development. (System Benefits Charge, Issues Letter, The Regulatory Assistance Project)

A system benefits charge can come in many shapes or forms and under a variety of names including wires charge, access charge, universal service charge or distribution charge. Whatever the form or name, it must be both non-by-passable and competitively neutral. Placing a charge on the use of the distribution system (with distribution defined broadly to include both high and low voltage end use consumers) answers both concerns. It is non-by-passable because the distribution system, for the foreseeable future, will remain a monopoly and will be needed to deliver electricity to virtually every consumer. This includes large industrial customers who obtain high voltage electricity, customers who have municipalized and customers who self generate. Even self-generating customers are included because nearly all of them connect to the distribution system to receive supplementary or back up power. The charge is competitively neutral because all sellers are treated equally. With the same charge levied on customers no matter who supplies the power (or on suppliers regardless of who they sell to), users cannot bypass their share simply by choosing another provider. (System Benefits Charge Issues Letter, The Regulatory Assistance Project (RAP))

Structuring the System Benefits Charge

In most jurisdictions, the costs of services to be included in a benefits charge are collected on a volumetric basis (kWh or kW). The SBC is generally expressed in terms of mills per unit. One mill is equal to 1/10 ($0.001) cent. In other words, for every one million kilowatt hours consumed, a one mill charge would raise $1,000 (1,000,000 kilowatt hours times $0.001). (RAP. Also, Mark Wolfe, Contact, "The Role of the System Benefit Charges in Supporting Public Benefit Programs in Electric Utility Restructuring, NASEO Power Sector Issue Brief," Energy Programs Consortium (September 9, 1999) http://www.naseo.org/committees/energyproduction/documents /system_benefit.htm. Changing the SBC to a fixed charge per customer is an option, but doing this substantially changes existing cost allocation and means that smaller customers would be expected to pay a larger percentage than they currently do. This shift would not go unnoticed.

A hybrid approach could be to express the SBC in terms of dollars per customer based upon 100 percent participation for achieving a specific DSR targeted goal. In other words, if 1,000,000 kilowatt hours of DSR are targeted per year by a distribution company serving two million end-use customers, then each customer would be charged $.50/year or $0.04 per monthly bill, resulting in one million dollars available for this effort. The downside to this method is the increased costs that would be incurred by LIHEAP or other universal service programs for uncollectible accounts, however, this issue could be resolved by carefully designing a flexible, aggregated program.

For example, participation by multiple residential and small commercial load groupings, from geographically dispersed locations would support an aggregated load curtailment and price-responsive demand program. The ability to shed residential and commercial load at specific pricing nodes as well as over a wide geography is particularly applicable to areas that operate location-based pricing schemes, such as PJM. There must be motivation for the customer to reduce load in order for this to be effective. Individually, a residential or small commercial customer is not going to control enough load to influence prices, but if enough of these customers had interval metering with automated meter reading (AMR), their load could be aggregated to a sufficient level. This opportunity could be enabled by directly controlling load, such as air conditioning and pool pumps. (Mark Knight, “Load Curtailment,” Energy Markets, pp 56-58)

There is a range of legitimate opinions and concerns on whether the cost of services included in a benefits charge are collected on a volumetric basis or a fixed charge per customer. Proponents of volumetric charges contend that energy efficiency and renewable resources predominantly deliver energy and capacity and hence should be charged on a volumetric basis, in the same way that customers pay for energy and capacity costs. Those favoring a fixed charge argue that fixed customer charges are not by-passable by those who lower their energy consumption. They also assert that any usage charge in excess of marginal costs will distort the price signal and diminish the overall efficiency of consumption. (RAP)

The Washington Utilities and Transportation Commission and the Idaho PUC approved a two-year experimental rate rider (system benefits charge) assessed by customer class on a percentage basis in the mid-1990s for Washington Water Power for DSM. It was argued that a volumetric charge would place more of the cost on large users, but on the other hand, the resource potential is greater and generally more cost-effective for commercial and industrial customers than it is for residential customers. While it is good practice to tie DSM goals to resource needs, a reasonable compromise between those who want a fixed customer charge and those who prefer a volumetric charge may be a percent surcharge. (Ed Holt, "System Benefits Charge Case Studies," The Regulatory Assistance Project, August 1995)

The choice between volumetric and fixed costs need not be an all or nothing decision. The telecommunications industry, where both approaches have been used at the same time, serves as a useful model. In considering a melding of both approaches in the electric industry, it would be possible to levy a fixed charge for all customers based upon a minimum standard of use, say 250 kWh, and a per kWh charge for all use above that level. California charges are capped at 3% of customers' total bills. (See http://www.eere.energy.gov/state_energy/policy_content.cfm?policyid=29) To assure acceptance, care must be taken to make sure that any change from the existing cost allocation occurs at a slow enough pace. (RAP)

Who Manages The Money and Provides The Services?

Usually, states levy SBCs on the distribution of all electricity collected by the regulated distribution company and included in the bills distributed to all customers. There are no bypass transactions. The company collects fees and transfers them to the appropriate administering agency, which is typically a statewide private non-profit agency. Such an institution should have an independent Board of Directors, with that Board subject to the additional oversight of a publicly accountable commission. The general level of the charge and the categories of use for the collected funds are decided during the final deliberations associated with the adoption of a final restructuring plan. In many states, that level equals the amount needed to continue existing programs. This structure is used in Pennsylvania for low-income assistance and energy efficiency and for the Sustainable Energy Fund programs. Most states implement an SBC, including Missouri, Montana, New Hampshire, New Jersey, New York, Ohio, Rhode Island, Vermont, West Virginia, and Colorado to name a few. (Colton and Wolfe)

Once money is collected via a system benefits charge, there are a number of places—ranging from the utility to a non-profit or governmental entity—where it can be managed. Dollars will be most successfully spent if there is as little conflict as possible between the purpose of the particular benefit being funded and the interest of the managing organization. For instance, the profits of utilities with an unregulated generation arm will hinge on the market price of electricity. Because energy efficiency *and demand response (editorial changes in italics)* also reduces market price, the utility *may* have scant interest in investing in *these* *efforts*. In contrast, the same utility may have no such conflict in providing services to low-income customers. (RAP)

If the utility interest is at odds with the delivery of a particular service, the choices are regulatory or placing the responsibility for managing funds in the hands of an independent agency. Regardless of who holds the funds, a market means, such as competitive bidding, should be favored to decide who provides the services. Innovative approaches will be sought for the delivery of low-income and R&D services. (RAP)

System Benefit Program Funding

The data in Tables 1 and 2 comes from the NASEO Power Sector Issue Brief (previously cited) and provides a summary of system benefit program approximate funding and charges for states that have approved restructuring legislation as of September 1999. These tables do not include states that did not authorize funds for public benefit programs as of this date.

Table 1. Public Benefit Programs (in Millions of $'s)

	After Restructuring				
State	**Efficiency R&D Renewables**	**Rate Assistance**	**Weatherization**	**Total**	**Prior to Restructuring**
CA	$415.00	$125.00	$60.00	$600.00	$373.00
CT	103.00	0.0	6.00	109.00	46.60
DE	1.80	0.80	TBD	2.60	N/A
IL	7.50	75.00	10.40	92.90	N/A
ME	17.20	5.60	0.50	14.90	23.30
MD	N/A	34.00	TBD	34.00	N/A
MA	200.00	36.00	10.00	246.00	84.00
MT	12.50	1.40	1.00	14.90	11.00
NH	TBD	13.20	TBD	13.20	5.00
NJ	117.00	13.20	15.00	145.20	145.20
NY	67.40	0.0	9.80	77.20	N/A
OH	15.00	103.00	TBD	118.00	103.00
OR	42.20	10.00	7.80	60.00	N/A
PA	TBD	66.00	16.00	82.00	82.00
RI	17.00	2.00	0.40	19.40	10.00
TX	TBD	15.00	TBD	15.00	15.00
VT	17.50	0.0	TBD	17.50	17.50

Table 2. Equivalent System Benefit Charges (in Mills per kWh)

State	Efficiency R&D	Renewables	Rate Assistance	Weatherization	Total
CA	1.31	0.63	0.59	0.28	2.81
CT	2.80	0.75	0.00	0.20	3.75
DE	0.18	0.03	0.80	TBD	1.01
IL	0.06	0.04	0.60	0.07	0.77
ME	1.51	TBD	0.50	0.05	2.06
MD	TBD	TBD	0.60	TBD	0.60
MA	3.14	0.75	0.60	0.17	4.65
MT	0.91	TBD	0.19	TBD	1.10
NH	TBD	TBD	1.50	TBD	1.50
NJ	2.63	0.38	0.17	0.20	3.38
NY	0.52	TBD	0.08	TBD	0.60
OH	0.1	TBD	0.70	TBD	0.8
OR	1.0	0.30	0.60	TBD	1.90
PA	TBD	TBD	0.53	0.13	0.66
RI	2.20	0.50	0.33	0.07	3.10
TX	TBD	TBD	0.10	TBD	0.10
VT	3.30	TBD	TBD	TBD	3.30

System Benefit Charges for Demand-Side Programs

Since this paper specifically addresses a SBC for DSR, it is worth highlighting the state programs that target DSR and related activities. Except where cites indicate a different source, the following excerpts in this section are from the NAESO Power Sector Issue Brief (previously cited), which describes the status of SBC programs as of September 1999.

Arizona

The Arizona Corporation Commission approved a settlement agreement between the Arizona Public Service Company (APS) and other parties that established spending targets for renewable resources and DSM programs for each of three years beginning November 1994. APS must file an implementation plan that requires Commission approval and will recover costs through the Energy Efficiency and Solar Energy Fund (EEASE Fund). The EEASE Fund is created by the application of a system benefits charge based on kWh sales, with annual spending targets beginning at $10 million and increasing yearly through the first four years. Of the spending targets, at least $9 million over a three year period must be spend on renewables. (RAP)

Connecticut

The Connecticut public benefits program was enacted in April 1998. Along with other goals, the program provides a 3.0 mill/kWh charge for energy conservation and load management programs. This effort began on July 1, 2000.

Illinois

The Illinois public benefit program, enacted June 1997 is administered by the Illinois Department of Commerce and Community Affairs (including the state energy and weatherization offices). The program provides funding for energy efficiency, renewable energy, and low-income assistance. Though DSR or load management is not specifically targeted by program funds, what is interesting is that the program is supported through fixed per month customer surcharges. The customer surcharge is expected to raise approximately $92.9 million per year (equal to approximately 0.67 mills/kWh). The program is scheduled to sunset in 2007.

New Hampshire

New Hampshire enacted a low-income assistance program in May 1997 that will be funded with an estimated charge of 1.5 mills/kWh. The law also authorizes a systems benefit charge to fund other public benefit programs, including energy efficiency or DSM programs and a renewable energy program. A working group determined the scope and appropriate standards for the energy efficiency programs, as well as an appropriate level of funding and a plan for administration of the funds. The working group recommended a 2 mills/kWh SBC. The Governor proposed funding of 2.3 mills/kWh ($22 million) for an energy efficiency and renewable energy program.

New Jersey

The New Jersey legislature passed electricity restructuring legislation January 28, 1999. The law provides for about a 3.0 mills/kWh system benefit charge, which provides about $230 million per year for energy efficiency and renewable energy programs. The non-by-passable charge is imposed on all electricity public utility and gas public utility customers. The program continues for at least eight years with the Board of Public Utilities determining the appropriate level of funding thereafter.

The current utility DSM programs are funded at about $230 million per year. The law calls for collecting this level of funding, allocating at least 50 percent of the total to new energy efficiency and renewable energy programs. The current DSM commitments, including the standard offer commitments, could use up to 50 percent of the total funding.

New York

In 1997 New York implemented restructuring through regulatory orders by the Public Service Commission (PSC). A three year SBC fund of $234.3 million was established for the six utility service areas by PSC order, which designated the New York State Energy Research and Development Authority (NYSERDA) as the primary fund administrator. NYSERDA is administering $173 million of the fund; the utilities are administering the other $60 million. A 17 member SBC Advisory Group consisting of stakeholders was established to provide input and guidance to NYSERDA on program design and implementation. In its January 26, 2001 Order, the PSC extended the program for five years -- until June 30, 2006— and increased the funding from $78 million annually to $150 million annually. A major focus of the program is on achieving peak load reductions over the next few summers. (NASEO. Also, “System Benefits Charge,” at http://www.dsireusa.org/library/includes/incentive2...(DSIRE))

The New York SBC program covers energy efficiency, research and development, low-income programs and environmental disclosure. The research and development programs include DSR technology deployment. (NASEO) The New York Energy $mart Program shifted a 350 ton cooling load off-peak through $300,000 in incentives and night rates 10% of day rates for The Durst Organization (a 41 story commercial property in Manhattan). Direct Load Control deployed cellular communication, which activated pre-programmed curtailment settings, for 21 BJ’s Wholesale Club locations (1 MW), 16 Stop & Shop Supermarkets (0.8 MW), and 36 Home Depot locations (4.4 MW). In 2001-2002 R&D efforts to enable DSR assisted 190 participants through 13 projects to enable 198 MW through advanced metering and verification applications, e.g. energy information systems, communications infrastructure, and transaction software. (Brian Henderson, “Enabling Technologies for Load Management,” (PowerPoint presentation), NYSERDA, September 10, 2003)

During the first three years of implementation, the Program produced annual bill savings of approximately $121 million, reduced annual electricity consumption in the state by about 932 million kWh (enough electricity for about 155,000 households a year), achieved a statewide demand reduction of 452 MW, helped to create or sustain 2,300 jobs, and achieved emissions reductions roughly equal to the removal of 139,000 automobiles from the New York’s roadways. In addition, the SBC funds will leverage $341 million in co-funding from private-and public-sector partners raising the total investment in SBC activities for the first three years from $172 million to $513 million. (DSIRE)

Pennsylvania

Pennsylvania enacted electricity industry restructuring in December 1996. The law did not set a specific funding level for low-income and energy efficiency programs, but it did require that their funding be established at current levels or higher. The SBC programs are implemented through individual utility restructuring/rate proceedings and administered by the state's utilities. The customer education program is administered by a utility consortium of consumer groups. Some utility customer assistance programs are provided by local agencies under contracts to the funding utility. The low-income assistance programs are administered through utility payments to the State Department of Public Welfare and funded by a federal appropriation for the Low Income Home Energy Assistance Program (LIHEAP). The federally funded Weatherization Assistance Program is administered through the state Department of Community and Economic Development. The renewable energy programs are administered through independent boards established by utility stakeholder groups and monitored by the Public Utility Commission.

Texas

Texas electricity industry restructuring was enacted during June 1999. The legislation included a PUC administered systems benefit charge fund not to exceed 0.065 mills/kWh. The uses of the fund are limited to customer education and low-income assistance programs, and to replace potential state and local school funding reductions due to property tax revenue declines that may result from restructuring.

The Texas legislation requires utilities to acquire, through market-based standard offer programs or limited targeted market transformation programs, 10 percent of the annual growth in electricity. Also, the law requires the PUC to establish a minimum renewable capacity requirement for each retail energy provider to achieve an additional 1280 MW of renewables by 2003, ramping up to 2880 MW by 2009.

Vermont

Vermont has not enacted restructuring legislation; however, legislation was enacted in June 1999 authorizing the Public Service Board to establish a system benefit charge that is capped at $17.5 million per year and is to be used for energy efficiency programs. The funds are administered by a statewide non-utility organization.

Washington

Washington Water Power (WWP) proposed a two-year experimental rate rider (system benefits charge) to the Washington Utilities and Transportation Commission (WUTC) and the Idaho PUC in October 1994 to provide stable, predictable funding for DSM. They believed that this approach protects DSM from retail wheeling and reduces their risk of losing customers to competition because of DSM's rate impacts. The charge was approved by the WUTC in late 1994 and by the Idaho PUC in early 1995.

The systems benefit charge applied to WWP's electricity and natural gas sales and was assessed on a percentage basis by customer class. There was a 1.55 percent increase for electricity customers and a 0.55 percent increase for gas customers in Washington and a 0.6 percent increase for gas customers in Idaho. The lower gas assessment matched gas revenues with planned gas expenditures. Actual charges for electricity ranged from $.046 to $.108 per kWh and $0.097 to $0.197 per therm for gas customers. The charges yielded $4.7 million for electric DSM and $426,000 for gas DSM. All DSM expenditures funded through this mechanism were subject to a prudence review at WWP's next general rate case. This experimental program relied primarily on utility-designed and delivered programs.

Additional Policy Issues

As a member of the DSR Cost Recovery subgroup, the Pennsylvania Attorney General's Office of Consumer Advocate raised the question that there may be a legal issue with the use of an SBC for anything outside of a Universal Service Program or a program that has not been established by statute. Another potential issue identified by members of this subgroup is the placement of the SBC on the customer's bill, i.e. should the charge appear as a separate line item or be part of a blended set of costs? Finally, as with all cost recovery mechanisms, the benefits associated with specific costs recovered through an SBC should be carefully considered. In other words, there may be certain costs more applicable to a non-by-passable SBC than others, e.g., technology deployment.

4. PERFORMANCE-BASED RATEMAKING

A final approach to consider is performance based ratemaking. This section will provide a general overview of Performance Based Ratemaking ("PBR") and how it could potentially be applied to DSR. As much of the following material is excerpted from documents sponsored by the National Association of Regulatory Utility Commissioners ("NARUC"), we wish to acknowledge the contributions of NARUC to the continued research and study of performance based ratemaking.

Background

Section 2804 (4) of the Electricity Generation Customer Choice and Competition Act (the "Act") provided for rate caps on electric service for the duration of the transition period. 66 Pa. C.S. §2804(4). The rules established at section 2804(4), however, did not apply to new services offered for the first time after January 1, 1997, the effective date of the Act. 66 Pa. C.S. §2804 (4) (vi). Furthermore, Section 2806(i) expressly authorizes the Commission to use performance-based rates as an alternative to existing rate base/rate of return ratemaking, subject to the restrictions pertaining to rate caps in section 2804(4).

DSR is a tool for managing load to achieve specified goals and objectives such as deferring new construction, improving grid efficiencies or enhanced reliability at reduced cost. It is generally recognized that effective DSR can run contrary to the financial interests of regulated utilities, as it reduces kilowatt-hour sales revenue. PBR may provide a useful framework for cost recovery for DSR, as it can better match cost and benefits and financial incentives to EDCs to support DSR.

Framework for Designing and Evaluating a PBR Mechanism

There are three steps in designing and evaluating a PBR mechanism: (1) articulating the goals to be achieved; (2) selecting the right structure to meet the goals; and (3) "getting the numbers right."[4]

[4]Performance-Based Regulation for Distribution Utilities, NARUC Draft Report prepared by the Regulatory Assistance Project (July 2000).

A. PBR Goals

PBR mechanisms can be used to further various goals, including economic efficiency, technology innovation, reliability, environmental protection and customer choice. Effective DSR could potentially further all of these objectives. Table 1 below presents a sample list of PBR mechanisms that have been used by other states to achieve various policy objectives targeting the electric industry.

Table 1. PBR Options for Meeting Various Regulatory Objectives[5]

Regulatory Objectives:	**PBR Structure, Mechanism or Incentive:**
Price stability	Price cap, combination revenue-price cap
Lower purchased power costs	Price cap, revenue cap, targeted incentives
Maintain quality of service	Targeted incentives, performance standards
Maintain universal service	Targeted incentives, performance standards
Reliability	Targeted incentives, performance standards
Promote distributed generation	Price cap, revenue cap, targeted incentives, amortization
Reduce T&D losses	Price cap, revenue cap, targeted incentives
Improve power quality	Price cap, revenue cap, targeted incentives
Promote renewable resources	Targeted Incentives, amortization patterns

PBR would involve providing incentives or disincentives to encourage EDCs to meet DSR related objectives. The Commission would need to define specific objectives as part of any DSR related guidelines, rulemaking, etc.

[5] Performance-Based Regulation in a Restructured Electric Industry, NARUC Report prepared by Synapse Energy Economics, Inc. (November 8, 1997).

B. PBR Structure

The structure of a PBR mechanism determines what incentives will be given. PBR can be broad based or more narrowly targeted. Following is a brief discussion about possible approaches to designing a PBR structure to meet specified goals. There are two basic means of applying PBR to DSR.

1. Broad Based Approach

A broad-based PBR covers all or most costs under a single structure. Such an approach would likely involve mechanisms to address economic inefficiencies apparent in the traditional cost-of-service ("COS") ratemaking process. One example of inefficiency in the COS process is the use of a test year for setting rates that remain unchanged until the next rate case. If operational circumstances were to deviate significantly in the years which follow the test year, the vertically integrated utility would be forced to file another rate case.

The COS process also encourages increasing sales volume to retail customers. Profits derive from the sales revenue minus the costs. There is naturally a corresponding disincentive to reduce sales through effective DSR. By capping the revenue a distribution company can recover through its distribution rates, the incentive to maximize sales is thereby reduced. EDCs would be rewarded by being allowed to keep the savings they create through greater efficiency. Revenue caps can take the form of an absolute revenue cap on a particular rate or a cap on revenue-per-customers.

Price caps are a variation on this. In this approach, the regulator sets a cap on the price for a service. The utility then sets a price somewhere below that cap. Any earnings in excess of that price, but below the cap, accrue to the utility. Prices may change during the price cap term, subject to an approved formula.

It has been suggested that revenue caps are more appropriate where costs don't vary much with volume, while a price cap would conversely be a better mechanism where there was a strong correlation between costs and volume. *(Editor's note: Theoretically, both mechanisms could be applied on a program-by-program basis for an EDC that serves as both POLR and DSR provider)*

These caps would be adjusted every few years based on a reexamination of costs and other factors. The obvious risk of such an approach is that the associated cost-cutting could negatively impact other aspects of utility service, such as customer service or reliability.

A broad based PBR mechanism using price or revenue caps can be expressed with the following formula:

$$R = A*(1+(i-x)) + z$$

Where R is the total revenue, A is either revenue or price subject to the PBR mechanism, i is a measure of inflation, x is a productivity adjustment and z refers to items that are excluded from the PBR.

The main purpose of the x factor is to adjust the inflation factor (whatever it may be) so that the resulting multiplier (i-x) produces a reasonable level of revenue growth or a reasonable level of anticipated cost growth. An inflation-less, industry specific index, similar to the PPI used in Chapter 30 Telecom regulations, is widely used as the x factor.

Exclusions called z factors are exogenous items outside of the control of the utility. Examples include changes in income tax or other laws (certainly applicable in this example is 52 Pa. Code. §§54.91-54.98, relating to adjustment of Electric Distribution Company rates for changes in state tax liability), changes in environmental laws, or changes in FASB requirements or other accounting rules. Any cost subject to a z factor means it is a cost or a risk that the utility will not support. Additionally, the PBR could be subject to certain conditions, such that the z factor becomes effective only if a tax rate change is greater than a specified level, thus in effect creating a sharing of the risk.[6]

Finally, the use of earnings caps and sharing mechanisms should be handled carefully since they could reduce the power of PBR incentives. Sharing mechanisms relate to who benefits and who pays (shareholders and/or ratepayers) for changes in operational performance. The Regulatory Assistance Project advises that if used, sharing mechanisms should take effect only if earnings fall outside a very wide range.[7]

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[6] Performance-Based Regulation for Distribution Utilities, NARUC Draft Report prepared by the Regulatory Assistance Project (July 2000).
[7] Ibid.

2. Targeted Approach

This PBR mechanism does not involve price or revenue caps on overall distribution rates. Greater DSR deployment could be encouraged in areas of a EDCs territory where there are higher costs to serve relative to the rest of the territory. Current distribution rates are averaged and do not reflect the marginally higher costs to serve these locales. Costly distribution and transmission expansions and upgrades could potentially be avoided by this approach. By concentrating DSR in high-cost areas, cost savings can offset revenue losses and any net savings are available to use in a targeted shared-savings scheme to reward utilities for cost reductions and innovation.

C. Getting the Numbers Right[8]

Getting the numbers right is essential to prevent windfall gains or losses and to assure the long-term viability of the PBR. To get the numbers right is to decide what "right" means. The theoretical answer relating to efficiently run utilities and their ability to raise or lower prices might be difficult to explain to consumers. A practical approach is to set the numbers to approximate what would have happened without the PBR. Setting the numbers from the right starting point can usually be found at or near the conclusion of a cost-of-service rate case (within the past two years is recommended). After the starting point has been established, attention turns to the inflation index and related productivity factor. Following is practical advice that is offered by the Regulatory Assistance Project (RAP) for setting these factors appropriately.

The inflation measure should relate to what the industry faces, not what a particular utility faces. Whatever inflation measure is picked, it is essential that this factor be exogenous to the actual costs of the utility. Also, a lot of numbers need to be examined from multiple perspectives. At a minimum two sets of data should be compared for every possible criteria. First are historical cost data for the utility in question, for the industry and for a peer group of utilities, which should be reviewed in the aggregate and on a disaggregated basis, and second are historical revenue data broken out by customer class and distinguishing between new and existing customers.

Future innovation and technology should be considered, i.e. new computer systems, meter reading technologies and distributed resources, which will (or should) reduce future costs at a pace that exceeds historical trends. Finally, a

[8] Performance-Based Regulation for Distribution Utilities, NARUC Draft Report prepared by Regulatory Assistance Project (July 2000).

single inflation index with a x factor that matches is recommended. It is easier to explain to the public than regression analysis of historical data.

RAP suggests certain categories and priorities in gathering information. For example, revenue growth should be looked at more closely than cost growth, especially if revenue caps are used. Historical revenue growth and its origins also need to be understood. A distinction must be made between revenue growth due to increased use per customer and overall customer growth. The sensitivity of revenue growth and risk allocation to rate design, weather and the economy must also be taken into account. This information can be used to test the expected revenue growth for any proposed PBR relative to continuing cost-of-service regulation. PBRs should be designed with about the same revenue growth that traditional regulation would yield.