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BEFORE THE COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION

COMMENTS ON
CONSERVATION AND LOAD MANAGEMENT ISSUES
ON BEHALF OF THE
SOUTHERN ENVIRONMENTAL LAW CENTER

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I. Introduction and Overview

These comments respond to the Commonwealth of Virginia State Corporation Commission's Order to initiate an investigation into regulations and policies for conservation and load management programs. In our report, we address these issues first by examining the role of utilities in promoting energy efficiency and the least-cost planning objectives they should attempt to meet. A set of guidelines for demand-side resource acquisition follows, and finally, we consider rate issues associated with utility conservation expenditures.

Almost every home, building, or factory has the potential for energy-efficiency savings for less than avoided supply costs. However, strong market barriers prevent customers from realizing this potential on their own. The utility's least-cost planning obligations are to design and implement programs that capture as much of this potential in as many buildings as cost-effectively as possible.

This does not mean that utilities should pursue only the cheapest and easiest savings available. Such a cream-skimming approach forfeits more costly but still cost-effective savings, which raises total energy-service costs by requiring utilities to make up for the lost savings with unnecessary supply. To realize the goal of least-cost resource planning, utilities must take a more direct and comprehensive approach to realizing cost-effective demand-side potential than has become traditional in the 1980s. Programs must target specific customer segments with strategies aimed at overcoming myriad market barriers, and must avoid a piecemeal approach to DSM resources (e.g., mistakenly focussing on one end-use at a time).

To design programs to acquire all cost-effective demand-side resources, utilities need a rational and consistent approach to demand-side resource planning. Economic screening of potential DSM programs must be conducted with unbiased cost-effectiveness tests that incorporate full avoided costs, including benefits that are real but may be difficult to quantify (e.g., environmental externalities).

Resource allocation decisions -- choices about how much and when to commit to demand and supply options -- must recognize the realities of current utility capabilities to deliver demand-side resources, as well as the unique nature of critical demand-side opportunities. Particularly important is the need for utilities to carry DSM programs through a capability-building stage of planning and implementation as a precursor to full-scale acquisition. Demand-side programs will not be viable resource options until and unless utilities can effectively deploy them. Utilities must be able to count accurately, and count on, costs and savings. Studies and experiments will not provide this capability. Such capability-building efforts are directly analogous to the costly engineering and permitting process associated with large-scale supply options.

Further, utilities must place a high priority on capturing "lost-opportunity" resources -- one-time opportunities for savings that disappear once they are missed. Opportunities are most commonly lost in new construction and equipment replacement, when customers do not incorporate energy-efficiency choices that are much more expensive or impossible to retrofit later.

More and more regulators and utilities are beginning to understand and embrace these fundamental principles of program design and resource allocation, as seen in recent Commission decisions and in DSM programs developed through collaborative processes in New England, Maryland, and California.

Finally, we believe that regulators must come to terms with the substantial disincentives that traditional ratemaking presents for least-cost utility investment in DSM resources. Improving energy efficiency reduces utility sales revenue, cutting into short-term profit. Mechanisms to address this problem must balance the interest of utilities against the goal of cost control and rate stability. In addition, utilities need clear rules for cost recovery of DSM expenditures. Incentives for superior performance should be balanced against the ratepayer risks associated with management failure.

II. Role of Utilities in Promoting Energy Efficiency

The goal of utility resource planning should be to minimize long-run costs of providing adequate and reliable energy services to customers. Minimizing total costs requires that utilities choose resources with the lowest costs first, drawing on progressively more expensive options until demand is satisfied.[1] But much of the demand being forecast by utilities arises because most customers are unwilling to spend more than a small fraction of the price they pay for using electricity on saving it. This market failure leaves a significant but currently unquantified potential for economical efficiency investment available for less than the cost of utility supply.

Least-cost planning therefore requires utilities to pursue savings their customers would otherwise miss due to market barriers.[2] These efficiency gains are worth pursuing to the point that

[1] Uncertainty and risk complicate this task. Future demand is unknown. This makes some resources riskier than others. In general, larger resources with longer lead times carry greater risks for the system. Once utilities gain the capability to deploy efficiency resources, they can be acquired in small increments over short lead times. Some efficiency resources, such as programs to raise new buildings' efficiency, coincide with demand growth. More efficient loads generally are more stable loads, implying lower load uncertainty.

[2] This requirement is implicit in Indiana's Public Utility Law, which does not limit Commission review of utility permit applications to other supply options. "In acting upon any petition for the construction, purchase, or lease of any facility for the generation of electricity, the commission shall take into account ... other methods for providing reliable, efficient and economical electric service, including ... conservation [and] load management." Chapter 8-1-8.5-4 (2).

any further savings would cost more than supply -- counting all costs incurred by both utilities and their customers. How much of this untapped efficiency potential is economical depends on (1) the shape of "efficiency supply curves," and (2) where customers have positioned themselves in relation to utility avoided costs.[3]

Because market barriers are so strong and pervasive, almost every building has a definite potential for cost-effective efficiency investment. This potential is limited by physical characteristics as well as behavioral constraints. The challenge for Virginia utilities is to design and implement programs that capture as much of this cost-effective potential in as many buildings as possible, and to minimize the societal costs of achieving these savings.

Virginia utilities should pursue *all* achievable potential for cost-effective efficiency resources, not just the most cost-effective potential. Every construction project, every equipment replacement -- even every retrofit -- undertaken by utility customers presents an opportunity for New York utilities to secure additional, long-lasting demand savings at less than the cost of new supply. Every time utilities miss an economical opportunity for greater efficiency savings, they must meet that resulting higher demand with either more supply or with another demand-side program later on. Both alternatives involve unnecessarily higher costs.

A. Evidence of the Market's Failure to Capture All Cost-Effective DSM

According to microeconomic theory, pricing electricity at marginal cost will automatically lead to optimal resource allocation. But in reality, customers are willing to spend much less to save electricity than they pay to use it. Evidence of this phenomenon is widespread: customers routinely decline efficiency investments that, if evaluated with a utility's economic yardstick, would appear to be extremely attractive resources. Based on utility price signals -- which often exceed estimates of long-run marginal costs -- typical customers require efficiency investments lasting as long as 30 years or more to pay for themselves within two years. By contrast, utilities choose among supply options with the same investment horizons and accept those with apparent payback periods of 12 years or longer.

Evidence is mounting that market barriers to energy-efficiency investments are widespread. As NARUC's observed in "Least-Cost Utility Planning: A Handbook for Public Utility Commissioners," Vol. 2, The Demand Side: Conceptual and Methodological Issues, December 1988:

> According to extensive surveys of customer choices, consumers are generally not motivated to undertake investments in end-use efficiency unless the payback time is very short, six months to three years. Moreover, this behavior is not limited to residential customers. Commercial and industrial customers implicitly require as short

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[3]The Vermont PSB reached a similar conclusion in its Decision (P for D) in Docket 5270. The Board wrote:

> In theory, the amount of economical demand-side potential remaining in Vermont depends on three fundamental factors: (1) the costs and technical performance of the specific technologies available; (2) the extent to which utilities and customers have already taken advantage of available technologies; and (3) how much the demand savings are worth in terms of the supply resources they avoid. (Decision, Vol. III at 23.)

> or even shorter payback requirements, sometimes as little as a month. This phenomenon is not only independent of the customer sector, but also is found irrespective of the particular end uses and technologies involved. Id. at II-9.[4]

By persistently forgoing efficiency investments that would otherwise reduce electric demand, consumers compel utilities to expand supply. This disparity between individuals' and utilities' investment horizons constitutes a "payback gap" that leads society to over-invest in electricity supply. Utilities can bridge the gap between customer and utility investment horizons, and thereby avoid more expensive supply investments, by investing directly to overcome market barriers. Without utility market intervention, the payback gap will lead customers to under-invest in efficiency and utilities to over-invest in supply. As the NARUC least-cost planning handbook states:

> Demand-side resources are opportunities to increase the efficiency of energy service delivery that are not being fully taken advantage of in the market. To make use of demand-side resources requires special programs, which try to mobilize cost-effective savings in electricity and peak demand. Without such programs, these savings would not have occurred or would not have materialized without significant delay, and in any case could not have been *relied upon*, forcing utilities to construct expensive back-up capacity and causing higher rates. (Id. at II.1; emphasis in original)

Explicitly acknowledging the payback gap as evidence of market barriers leads to two conclusions about the potential for cost-effective utility investment in demand-side resources, and strategies needed to realize this potential:

- Utility price signals are much weaker than most analyses assume as a tool for stimulating investment changes.[5]

- There is a vast amount of economical efficiency potential left for utilities to tap as demand-side resources.

B. Market barriers to customer choices of cost-effective efficiency

Customers may have a wide range of rational reasons for neglecting efficiency measures that are cost-effective for the utility. An aversion to capital-intensive electricity substitutes may be perfectly valid, especially since efficiency is paid for so much differently from electricity. The simplest reason that efficiency is so regularly passed over in favor of "business as usual" is that, as an investment, it is not available on the same pricing terms as electricity or fossil fuels already being purchased by customers. If it were -- either through market innovation, utility market intervention, or both -- even short-payback customers would be much more likely to choose efficiency whenever it was priced below electricity. However, purchasing efficiency generally

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[4]The NARUC handbook provides an extensive list of sources and studies confirming this finding for all customer classes. For example, Nevada utility experience suggests that commercial customers may require lighting efficiency investments to yield 1-month paybacks. Id.

[5]The payback gap caused by market barriers can be expressed as an implicit market by customers in the societal costs of energy-efficiency. For example, a 2-year payback requirement on a measure lasting 20 years implies that customers are willing to pay eight times as much to use electricity as they will spend to save it. See NARUC, op. cit. at II-10.

requires greater customer time and effort, and exposes the customer to more risk, than does purchasing electricity.

Other factors that compound the costs and dilute the benefits of efficiency measures to utility customers:

1. *Limited access to relatively high-priced capital* can constrain payback periods to durations far shorter than the useful lives of the investments;

2. *Split incentives* between decision-makers (e.g., landlords, plumbers, architects, HVAC contractors) and bill-payers (e.g., tenants, or customers dependent on various professionals for specifying, purchasing, or designing their equipment), diminish the benefits the decision-making party receives from efficiency investments by conferring them on the bill-payer, while often leaving the decision-maker with extra costs and/or risks;

3. *Real and apparent risks* of various forms impede individual efficiency investments, particularly the illiquidity of conservation investments (financial risk); uncertainty over market valuation of efficiency (market risk); fear of "lemon" technologies, equipment, or installation (technological risk); the risk of additional time and effort requirements for resolving disputes and evaluating the quality of the installation; the possibility of regrets and recriminations; and

4. *Limited experience, access and information* regarding efficiency technology, suppliers and installers can create high search and evaluation costs, in terms of a customer's own time, effort and inconvenience.

Different market barriers require different market-intervention strategies to overcome them, as discussed further below.

1. Access to capital

Limited access to capital obviously constrains efficiency investment, either because the customer is in no position to obtain capital to fund such commitments, or because the customer is unwilling to deplete his/her financial reserves to finance all economically justifiable efficiency investment.[6] Where capital can be borrowed to finance desired efficiency investments, borrowing terms are often far shorter than the life of the efficiency investment. The short amortization schedule pushes debt-service costs above the cashflow savings of the efficiency investment, creating cashflow problems.

For some customers, capital problems can be overcome by market-rate loans for energy efficiency. However, experience indicates that energy efficiency loan programs tend to have only

[6]Lenders often fail to appreciate the value of efficiency, either as an increase in their security value in the building, or as an improvement in the borrower's ability to repay other debts. This market barrier is partially an institutional problem, and partially a further consequence of inadequate information.

limited success, for a number of reasons, including:

- the difficulty of many customers in obtaining loans under normal banking rules, due to lack of credit or collateral;
- the difficulty of many institutional and governmental customers in getting authorization to borrow money;[7]
- customer uncertainty as to whether bill reductions will balance the debt repayment;
- customer concern that the increased resale value of the building will not cover the outstanding debt; and
- most importantly, the failure to reduce the other market barriers.

The inadequacy of loan programs to produce all cost-effective efficiency savings is obvious, given the fact that most customers can afford much higher efficiency than they actually buy in end uses such as refrigerators and lighting, where incremental capital requirements are small.

2. Split incentives

Split incentives are notoriously difficult to overcome. Many property owners do not pay the utility bills of the buildings they lease. Many building occupants do not own the buildings for which they pay utility bills. Making investments to lower the operating costs of tenants is rarely a high priority for landlords, just as spending money to raise property values (and therefore rents) is not terribly attractive to renters.

Equally serious institutional impediments retard efficiency investments at other stages of the real estate market. Developers do not pay to operate the appliances, heating and cooling systems, or lighting in the homes and offices they build. Quite often they see their objective as minimizing the completion costs of their buildings. Engineers and architects may incur higher uncompensated time requirements to design more efficient buildings or specify more efficient equipment; if an unusual design encounters problems (whether related to the efficiency measures or not), the designer may be subject to greater liability than if standard designs were followed. Similar concerns arise for plumbers (who select most replacement water heaters), lighting designers and electrical contractors (who collectively are responsible for most lighting design choices, other than those determined by architects) and HVAC contractors (who select most replacement heating and cooling equipment).

These split-incentive situations may require that the utility pay the entire incremental cost

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[7]They may also have problems getting approval to spend operating funds (appropriated for utility bills) on capital improvements (reducing utility bills), and may have to go through very complex bidding arrangements for even minor capital improvements. Combined with serious split incentives (government building managers and their department may not get to keep any of the reduction in utility costs for other purposes), these barriers make governmental and institutional facilities very difficult to motivate with conventional incentives.

of the DSM measure (as in the tenant/landlord split), or all of the incremental design costs (as in the designer/owner splits). Many utilities provide independent efficiency design services. The utility may also need to provide some certification procedure (to bless the non-standard designs and improve marketing prospects for participating designers and builders) and some training.

3. Perceived risk

Energy efficiency investments expose individual consumers to a variety of real risks. Any retrofit project (for efficiency or for other purposes) can have higher-than-expected costs, or operate less effectively than expected. Unusual designs may not always work quite right, especially when they are first put into service. For each customer, this risk is not diversifiable; even if the chance of a major problem is only 1:100, the customer may risk financial disaster by investing in efficiency. For example, if 100 residential customers are offered the opportunity to invest $3000 apiece in ground-coupled heat pumps, with a 99% probability of bill savings worth $6,000 in present value and a 1% probability of no savings (and thus a $3000 net loss), they might all decide that the risk of being the unlucky one was an unacceptable risk. The utility can reduce this risk through *diversification* in its demand-side resource portfolio. If the utility invests in all 100 heat pumps, and one saves no energy, the utility's net benefit is not significantly reduced.

Utilities can also reduce risk by providing various design, procurement, delivery, review and maintenance services to ensure that equipment is properly selected, installed and used. However, the assumption and diversification of risky investments by the utility is probably the most effective tool for reducing the risk-related barriers to efficiency investments.

4. Insufficient information

Lack of accurate information about efficiency options can create significant market barriers to efficiency investments, where acquiring and critically evaluating information on the costs and performance of competing efficiency options is expensive in time and money. That effort can be prohibitive for new technologies for all but the largest and most sophisticated end-users. Consumers often have a difficult time finding high-efficiency equipment they can examine and see in operation. Seeing a photograph of a light bulb in a catalog tells the potential purchaser little about whether it will fit in his/her fixtures, how it will look, whether it will hum, and how the light it emits will look. Only seeing, handling and turning on the bulb (and ultimately taking it home) will answer these questions. This leads to a vicious circle, in which suppliers tend not to carry more expensive, high-efficiency equipment if customers do not ask for it, and customers do not order the equipment because it is not available.[8]

If left to their own devices, consumers not only need to understand individual technologies; they need to know how measures interact. Energy savings from combining some measures (e.g., lighting efficiency and cooling systems) are less than the sum of their individual energy savings, but

[8]Special orders also tend to be more expensive; once the efficient equipment is stocked normally, its price is likely to fall, and customers are more likely to accept it.

one measure may reduce the cost of another (e.g. lighting efficiency improvements may allow for the downsizing of chillers). More importantly, customers need to be able to select and to supervise providers, designers and installers. Unless they know someone who has undertaken a similar project, the choice of providers may be formidable.

Loans and rebates are apt to have negligible value in inducing customers to undertake efficiency measures they do not understand, to purchase products they cannot find, or to seek out specialists whose work they cannot assess. Utilities will be able to overcome these barriers only with strong measures, including direct delivery of services, creation of markets for efficient products, and building the capability of local business to deliver efficiency equipment and services.

Providing customers with more information about efficiency opportunities is necessary but not sufficient for fully realizing economical efficiency potential. Utility experience confirms that *reinforcing information* with aggressive marketing, financial incentives and installation assistance yields increased savings at lower program costs. This point is well illustrated by the utility experience with the Residential Conservation Service (RCS). Throughout the U.S., utilities spent millions of dollars on programs to provide energy audits to their customers between 1981 and 1986. But relatively few utilities did much to help customers *act* on this information. Consequently, few customers participated in the audit programs, and even fewer participants installed the costly but ultimately cost-effective measures recommended by the audits. Costs were high, and savings were low in a program that most observers agree yielded disappointing results.[9]

At the opposite extreme of the RCS program was Bonneville Power Administration's Hood River Conservation Project. This program sought to establish the outer limits of cost-effectiveness by deliberately installing as many measures as possible in as many homes as possible, including those previously treated under previous utility weatherization programs. The result was 90% participation and large savings.[10]

C. Conclusions on market barriers and utility market intervention

Overcoming market barriers will require a comprehensive approach to program design and implementation. Addressing market barriers individually might be appropriate if market barriers operated in isolation, but this is typically not the case for groups of customers. It is the *multiplicity* of strong and *mutually reinforcing* market barriers that explains why most customers require such a short payback period on such a wide variety of available efficiency measures. Individual customers may decline particular cost-effective efficiency measures for one reason or another; but chances are that a variety of barriers explain why any given group of consumers do not tap economically feasible efficiency potential. Short of customizing a different program for every customer, utilities need to design programs that address the full array of obstacles preventing least-cost customer efficiency investments.

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[9]See Centaur Associates, Update of the Evaluation of the Residential Conservation Service Program. September 1986.

[10]See "Five Years of Conservation Costs and Benefits: A Review of Experience Under the Northwest Power Act," 1987, pp. 15-20.

For many market sectors, utilities should offer direct design and/or installation services. For example, a residential heating retrofit program should provide for an audit, selection of cost-effective measures, and installation with as little demand on customer time as possible. To the extent that the utility designs, arranges, finances, oversees and warranties the work, the customer avoids most of the hassle factors that complicate any major home improvement. This is particularly important for residential and small commercial customers, and may also be significant for larger customers in some segments.

In other cases, the utility may need to change the way products and services are priced and delivered in its service territory. Offering incentives to appliance dealers, heating contractors, plumbers (for water-heater replacement), and lighting dealers may be more effective than offering rebates to customers. For lighting, the utility may need to get compact fluorescents into homes through direct delivery or discount mail order (so customers gain some experience with them) and also get them onto store shelves (so customers can buy them). Information, loans and rebates may be appropriate as part of some programs, but they are often only part of the best solution, and are sometimes totally inappropriate.

III. Least-Cost Planning Objectives of Utility Demand-Side Management

Least-cost planning should seek to minimize customer bills and total resource costs, not average rates. So long as the level of service is equivalent, the customers are better off with lower total costs; they should be indifferent between higher and lower rate levels, as long as their bills are lower. "Bills," in this sense, should include not just the electric bill, but all other costs affected by the utility's DSM program, including participants costs for DSM measures, gas bills, water bills, and the costs of meeting environmental quality goals.

For example, demand-side management (DSM) programs that raise rates by an average of 5 percent while reducing kilowatt-hour sales by 10 percent, will reduce customer bills by 5.5%. A residential customer would clearly be better off paying 8.4 cents/kWh for 9000 kWh/year (or $756) than paying 8 cents for 10000 kWh (or $800). So long as the customer's house is as comfortable, as well lit, and so forth, the $44 savings is the only important difference between the two outcomes. Similarly, an industrial customer comparing costs for a new plant in Virginia with one in Ohio would prefer to pay 5 cents/kWh for using 6 GWH/year (or $300,000) in an efficient plant in Virginia, rather than 4.5 cents/kWh for using 8 GWH/year (or $360,000) in a standard-efficiency plant in Ohio. Thus, both new and existing customers will be better off with a cost-effective DSM program than without one.

To be sure, care must be taken to extend energy-saving opportunities to all customers to minimize if not eliminate the number of non-participants. In addition, customer expenditures on DSM measures need to be included in the cost-minimizing equation to ensure that all costs of energy saving are counted.

This is not to say that rates are irrelevant. On the other hand, utilities and regulators must be sensitive to the <u>incidence</u> of rate impacts on different customer groups. Customers with highly elastic demands (e.g., industrials which can shift operations to other plants, or cogenerate) may uneconomically bypass the utility system if their rates rise because of demand reductions by other customers. Customers without these options (e.g., residential) will just suffer from higher rates. Fortunately, these potential adverse rate impacts of least-cost demand-side investment can be easily mitigated, either by targeting DSM services to vulnerable customers, or by ensuring that the rate effects of DSM are borne by customer groups that can participate in the program.

A. The Economic Screening Test

In screening supply resources and DSM measures and programs, the utility should rely primarily on the societal or all-ratepayers test to compare benefits and costs. The societal test includes all costs and benefits to any portion of "society." The breadth of interests to be included in "society" must be determined, and may vary with the type of cost under consideration. Under the societal test, DSM benefits are not confined to the utility's avoided supply costs.[11] They also include all savings unrelated to electricity savings, such as reduced maintenance expenses, or the marginal value of other fuels or regulated utilities affected by the program (e.g., water, gas). Accurate resource comparisons using the societal test also include unpriced environmental externalities.[12] The social costs of DSM include the direct costs to the utility and to participants; administrative and monitoring costs; any increase in other energy and utility costs; and any quantifiable externalities.

The all-ratepayers test is a close cousin of the societal perspective, in that it counts all costs that are internalized in market prices to affected ratepayers.[13] Costs and benefits that fall on portions of society outside the set of ratepayers are ignored, as are all externalities that are not expected to show up as direct costs to ratepayers in another form.

Only the societal or all-ratepayers test will consistently reflect the true value of efficiency programs to the utility, its customers, and Virginia. *Any measure that passes the societal/all-ratepayer screening -- i.e., is cheaper than supply -- is worth pursuing.* Least-cost planning requires that the utility attempt to realize the potential of all such measures, since failing to do so would unnecessarily lead to higher total costs.

B. The No-Loser's Test

The no-loser's test (also called the non-participants' test or the rate impact measure)

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[11] Avoidable supply costs include fuel and variable O&M from existing generation; capital and operating costs of new, life-extended or reactivated units; purchases; transmission investments, operating costs, and wheeling charges; distribution investments and operating costs; line losses; and margins on off-system sales.

[12] The costs of control required for avoidable supply should be included in the all ratepayers test, as should any cost for fees paid because of emissions. Externalities for which the utility does not have to pay should be included in the societal test.

[13] Again, the scope may have to be defined for some costs. "Ratepayers" might include only the ratepayers of the particular electric utility, but the IURC would probably want to include costs and benefits to ratepayers of other Indiana electric utilities, and of Indiana gas and water utilities. As a practical matter, it may be easier to include out-of-state ratepayers of affiliated utilities (as through holding companies).

computes the effect of the proposed program on the bills of other ratepayers. The no-loser's test is not very meaningful on a measure-by-measure or program-by-program basis. The no-loser's test is a measure of equity, of the effect on other customers of the operation of a particular utility DSM program or measure. However, individual measures and programs cannot really be considered equitable or inequitable in isolation. Rather, the costs and benefits of the entire portfolio of conservation programs either produce an equitable outcome, or do not. The effect on equity of each program will depend on the cost recovery from that program, whether the participants in this program are already participating in other programs, and how the bills of members of various classes and sub-classes are affected by the program.

The no-loser's test is a misleading indicator for least-cost planning. The test leads utilities to reject efficiency savings whenever utility prices exceed utility marginal costs -- no matter what the cost of efficiency resources.[14] Virtually every regulatory authority which has seriously examined the no-loser's test has recognized its fallacies and rejected it as a threshold measure of resource cost-effectiveness.[15]

IV. DSM Resource Acquisition Guidelines

The purpose of utility DSM programs is to overcome market barriers to realize as much cost-effective demand-side resource potential as possible. The Commission should determine the appropriate scope of utility DSM program according to how well the programs pursue this objective. Three broad standards should guide utility investment in DSM and the Commission's determination of the adequacy and quality of such efforts: In addition to the criteria listed by the SCC in its Order Establishing Commission Investigation, the Commission should judge utility DSM efforts according to their success in building and maintaining delivery capability, the extent to which the utility pursues lost-opportunity resources, and the comprehensiveness of the utility's strategies for acquiring demand-side resources.

A. Comprehensiveness of program design

Successfully capturing economical energy efficiency requires that utility programs be

[14]For an analysis of this and other fallacies of the no-losers test, see "Lost Revenues and Other Issues in Demand-Side Resource Evaluation: An Economic Reappraisal," with Paul Chernick, 1988 Summer Study on Energy Efficiency in Buildings, American Council for an Energy Efficient Economy, Pacific Grove, CA, September, 1988.

[15]See Wisconsin PSC, Findings of Fact, Conclusions of Law and Order in Docket 05-EP-4, 5 August 1986, at pp. 8-9. Wisconsin re-affirmed its rejection of the no-losers test in its fifth Advance Plan decision in April 1989 in Docket 05-EP-5. Vermont utilities are prohibited from using the no-losers test to reject efficiency investments in the PSB's Recommended Decision in Docket 5270, pp. III 85-88. The Washington D.C. Commission rejected the no-losers test as a primary screen on demand-side investments in its March 1988 order in D.C. PSC F.C. 834 (Phase II). So did the Idaho Commission in Order No. 22299, Case No. U-1500-165 (Jan. 27, 1989); the Connecticut DPUC in its June 11, 1986 decision in Docket 85-10-22 at pp. 35-86; the Nevada Commission in its October 1986 decisions in Docket 86-701 regarding the resource planning of Sierra Pacific Power; and the New York PSC in its 26 July 1988 decision in Opinion No. 88-20 in Case 29409, pp. 23-49. The Massachusetts Department of Public Utilities firmly rejected the no-losers test in its Decision and Order in DPU 85-266-A/85-271-A, 26 June 1986, pp. 147-48. It reaffirmed this policy in subsequent orders, including DPU-86-36-E, November, 1988.

comprehensively targeted. Comprehensiveness in a utility's DSM strategies is essential for overcoming the market barriers arrayed against customers' pursuit of all cost-effective efficiency potential, and for achieving those savings minimum cost. This means that utilities should realize efficiency potential customer by customer, not end-use by end-use. Otherwise, utilities would have to re-visit their customers many times over to tap all available, cost-effective efficiency savings. In the end, less of the efficiency resource would be recovered at higher costs than if the utility extracted all the efficiency potential one customer at a time.

"Comprehensiveness" implies achieving all cost-effective efficiency improvements for each customer involved in a program, and addressing all customers and all market segments. The Vermont PSB's Decision in Docket 5270 provides the following definition:

> Utility demand-side investments should be comprehensive in terms of the customer audiences they target, the end-uses and technologies they treat, and the technical and financial assistance they provide. Comprehensive strategies for reducing or eliminating market obstacles to least-cost efficiency savings typically include the following elements: (1) aggressive, individualized marketing to secure customer interest and participation; (2) flexible financial incentives to shoulder part or all of the direct customer costs of the measures; (3) technical assistance and quality control to guide equipment selection, installation, and operation; and (4) careful integration with the market infrastructure, including trade allies, equipment suppliers, building codes and lenders. Together, these steps lower the customer's efficiency markup by squarely addressing the factors that contribute to it. (Vol. III, at 44)

Addressing technologies and end-uses comprehensively within customers avoids two common mistakes in utility efficiency programs: failing to account for interactions between technologies and end-uses; and "cream-skimming" -- neglecting measures which would be cost-effective at the time other measures are installed but whose savings would not justify the administrative, diagnostic, and other overhead costs of a "re-retrofit" later. Savings per dollar invested always decrease as more measures are applied to a single building or factory, even though total savings will increase. However, unit costs of saved energy are likely to be significantly higher if individual measures are engineered and installed singly and administered under separate programs.

B. Lost-opportunity resources

The Northwest Power Planning Council defines lost-opportunity resources as those "which, because of physical or institutional characteristics, may lose their cost-effectiveness unless actions are taken to develop these resources or to hold them for future use." (Northwest Power Planning Council, 1986 Northwest Conservation and Electric Power Plan, Vol. 1, p. Glossary-3) On the demand-side, lost-opportunity resource programs pursue efficiency savings that otherwise might be lost because of economic or physical barriers to their later acquisition. ("Five Years of Conservation Costs and Benefits: A Review of Experience Under the Northwest Power Act," at 7)

Opportunities to secure inexpensive efficiency savings present themselves when new residential and commercial buildings are designed and constructed. Similar one-time opportunities also arise when households and businesses add or replace appliances and equipment. Once foregone, these "resources" will have to be replaced in the future either with alternative supply or more costly conservation (e.g., as retrofits to the newly built facilities). In the case of new equipment such as appliances, all efficiency potential may be lost until the end of its useful life. (*Id.*

at 9)

These opportunities represent rapidly vanishing resources because builders, businesses and consumers are making essentially irreversible choices on a daily basis. The window of opportunity for influencing these decisions is quite short. For new commercial construction, this window may be a matter of weeks or months; for appliances, a utility's opportunity to acquire cost-effective savings may be limited to hours or at most days. The consequences of these decisions can last anywhere from a decade to a century.

Moreover, lost-opportunity resources are the most flexible demand-side resources available to utilities. They tend to correlate with demand growth since rapid demand tends to correspond to construction booms and facility expansion. Unlike any other resource available to utilities, the acquisition of lost-opportunity resources will parallel the utility's resource needs.

Utilities should concentrate on capturing lost opportunities that arise in the marketplace due to inaction by customers or those acting on customers' behalf. Utilities should also make every effort to avoid creating lost-opportunities by their own incomplete action -- for example, efficiency programs that capture only the easiest and cheapest savings potential.

C. Capability-building

Demand-side programs will not be viable resource options until and unless utilities can effectively deploy them. To deploy them, utilities must be able to accurately count, and count on, costs and savings. To deploy them effectively, utilities must develop the most effective delivery mechanisms for achieving large savings from large number of customers. Utilities need to build and maintain the capability to deliver efficiency savings on a meaningful scale before they can deploy and integrate them as supply substitutes. Successful deployment depends on the utilities' demonstrated ability to motivate large numbers of their commercial, industrial and residential customers to install a wide variety of energy-efficient equipment.

Capability building is directly analogous to the pre-operation expenditures that utilities incur in the pursuit of promising supply-side resources. Demand-side programs require start-up and testing equivalent to the environmental, engineering, feasibility, and design studies that routinely precede commercial operation of utility supply resources.

Capability-building involves several challenges. Utilities must master new and rapidly advancing technologies; they must tailor and perfect marketing methods, incentive structures, and program delivery for different types of customers and efficiency measures; they must adopt reliable measurement and evaluation techniques, as well as management strategies that accept rapid feedback to allow mid-course correction. Most of all, it is essential that utilities advance the existing market infrastructure: the vendors, installers, engineers, and architects who need familiarity and confidence with energy-efficient equipment to specify and supply it.

Customers cannot invest in more efficient equipment if it is not available locally. Architects and engineers will not specify it if they are not familiar with it. Suppliers tend not to carry more expensive, high-efficiency equipment if customers do not ask for it. Utility demand-side programs will create the necessary demand for such products if they can overcome the market barriers to customer efficiency investment.[16]

Thus, utilities should not expect the capability-building programs themselves to be cost-effective. Instead, promising programs should be tested in a way that carries an expectation of program success, and, therefore, the presumption that programs will be continued as full-scale resource acquisitions, with mid-course correction during expansion. Only capability-building programs will inform a utility about the true costs, savings, and performance of programs as delivered. This is the purpose of impact evaluation. Further, only capability-building will allow a utility to determine the least-cost program for acquiring efficiency resources -- i.e. the best combination of marketing, incentive and deliver strategies for maximizing cost-effective savings. Process evaluation is the best tool for gauging the effectiveness of the specific program design.

D. Conclusion on lost-opportunity resources and capability-building

This Commission should recognize the need for utilities to pursue lost-opportunity resources and capability-building investment, as utilities and regulators have elsewhere. The Northwest Power Planning Council first urged Bonneville Power Administration and the region's utilities and regulators to pursue capability-building strategies and lost-opportunity in its 1983 Plan. Its 1986 plan reaffirmed this recommendation, in spite of a large capacity surplus. (1986 Northwest Plan, *op. cit.,* at 9-28 through 9-30) In Vermont, the Public Service Board and the utilities it regulates are making capability-building and lost-opportunity resources their top priorities.[17] The Idaho Public Utilities Commission recently ordered utilities under its jurisdiction to submit a "Lost Opportunities Plan" and a "Capability-building Plan." (See Order No. 22299, Case No. U-1500-165, January 27, 1989) More recently, the New York Commission has made lost-opportunity resources a high priority.[18]

The Wisconsin PSC also declared that utilities should not let such valuable yet transitory efficiency opportunities escape:

> The importance of improving the energy efficiency of commercial buildings as soon as possible must be emphasized. These buildings represent long-term investments (up to 70 years) which will significantly affect the use of energy once they are constructed. Retrofitting to achieve energy efficiency, as experience has shown, is usually expensive, if possible at all. Therefore the commission is not willing to allow these 'lost opportunities' for energy efficiency to continue unabated." (Fifth Advance Plan Order, *op. cit.*, at 33-34)

[16]For example, Low-E windows were available only on special order in the Pacific Northwest and in Connecticut prior to large-scale utility programs. Now they have become a stock item in these areas. Similarly, the availability of energy-saving electronic ballasts and T-8 lamps tends to coincide with aggressive utility lighting programs.

[17]P for D, Vol. III, at 58-59, 92-102.

[18]12/29/89 Decision in Case 28223, Appendix A at A6. The New York PSC Staff's recommendations on 1990 utility DSM plans also make numerous references to the need to pursue lost-opportunity resources. See, for example, 12/5/89 recommendations at 51, 62-63, and 90.

Northeast Utilities has adopted this same perspective in its demand-side programs, which it developed under an unprecedented collaborative design process spearheaded by the Conservation Law Foundation. (See, for example, CL&P Conservation and Load Management Program Plans, Filed in response to DPUC Order No. 3, Docket No. 87-07-01) Utilities in Massachusetts and Vermont are re-orienting their current demand-side strategies toward capability-building and lost-opportunity resources.

E. Incorporating Environmental Considerations Into Demand-Side Resource Planning

Reducing impacts on the environment from power plant operation creates many benefits. Tangible benefits can include health care and material cost savings, reduced risk of catastrophic events such as the destruction of the ozone layer and global warming, reduction in potable water use, and less risk to the utility of subjection to future environmental taxes or retrofit requirements. Less tangible but equally important benefits include improved visibility, water quality and other human aesthetic qualities, and alleviation of the environmental stresses on terrestrial and aquatic ecosystems.

We use the term "externality" to refer to any cost or benefit that is not reflected in the price paid by a utility or its customers for energy-related goods or services. Environmental externalities include: emissions of air pollutants that contribute to ozone or acid rain or have direct health impacts; emissions of greenhouse gases; consumption of water in cooling systems and the thermal and chemical impact on receiving water bodies; land use; and other potentially important effects including EMF from power lines.

While many of these benefits are difficult to assess for a variety of reasons, our society has indicated a high willingness to pay to reduce costs associated with environmental degradation and the risk of a catastrophic event. It is therefore prudent for the Virginia utilities to consider the benefits of avoiding these environmental effects and to anticipate future environmental taxes or other costs in resource decisions.

Environmental and other external effects of power plant construction and operation should be reflected in resource planning in three ways. First, for effects that will be mitigated, Virginia utilities should include reasonable estimates of the cost of mitigation. For example, the costs of complying with the Clean Air Act can be estimated and should be included in utility planning now to reflect the costs imposed by the bill on existing and new resource options. Second, for residual effects that will be internalized through taxes and fees, the Virginia utilities should include estimates of those internalized costs. Such a tax might be required for carbon released from fossil fuel combustion. Third, for the residual effects that remain after mitigation efforts and will not be internalized, the Virginia utilities should include estimates of the social cost of these effects. The costs in the third category are truly externalities and are discussed in detail in the following sections. The costs in the first two categories are simply projections of future internalized costs, and should be treated in the same manner as fuel price or other forecasts, as illustrated below.

V. Ratemaking Considerations

A. Ratebasing vs Expensing

The ratebasing of DSM investments, in itself, does not provide much of an incentive for utility investment in DSM. Utilities generally prefer to expense expenditures, and prefer to depreciate ratebase as quickly as possible.

Ratebasing of DSM does have certain benefits for utilities. First, it allows them to recover costs that were incurred between rate-case test years. Expenses in those periods are generally lost, while most of the capitalized costs can be included in rates in the next case. This may be important for utilities which are expecting to file rate cases only infrequently. The same benefit may be achieved by allowing utilities to defer conservation program costs, possibly with an AFUDC-like interest credit, until the next rate case. The details of the deferral (e.g., the allowance of an interest credit, the start and end dates for the credit calculation, the rate used in the credit calculation, and the amortization of the balance between rate cases) will determine the implicit incentive for DSM expenditures. More favorable treatment may be justified for utilities with aggressive programs.

Second, ratebasing allows the costs of DSM programs to be collected from ratepayers at roughly the same time they are receiving the benefits of the programs. Expensing DSM investments in 1991, which will reduce electric bills for ten or twenty years, results in a sharp mismatch of costs and benefits. With expensing, customer bills could rise in the first few years, to produce reductions in later years. This may be both inequitable and unnecessarily disruptive.

The depreciation or amortization period should usually be the same as the investment lifetime, as is true for supply. However, different treatment may be justified for administrative convenience, to moderate rates (including rate effects of non-DSM expenditures), and to assuage utility concern with regulatory risk.[19] In particular, it may be advantageous to expense or to amortize Virginia electric utility DSM expenditures rapidly over the next few years, so that the costs are out of the way prior to the effects of the Clean Air Act. This issue can be resolved on a case-by-case basis for each utility.

Eligibility for ratebasing of DSM expenditures should be defined to mimic the comparable rules governing supply options. In general, all pre-operation expenditures for supply (including design, planning, start-up, testing) can be capitalized, except for overall ongoing planning costs. Hence, DSM program design, evaluation, and implementation should all be eligible for ratebase treatment. For accounting reasons, the SCC may want to distinguish formal DSM ratebase items, which are owned by the utility, and depreciated, from utility investments in customer-owned

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[19] Utilities often express concern that DSM cost recovery will be allowed over an extended period, only to be denied by a subsequent Commission, depriving the utility of much of the value of its investment. This is probably not a real threat. Experience with cancelled plants over the last 10-15 years suggests that deferral of cost recovery is not particularly risky. Once cost recovery policy for a particular cost item has been established, PUCs do not often change their minds. If this is true for cancelled plants, which offer no continuing benefits, it should be even more true for DSM, which does provide continuing benefits.

equipment, which can be capitalized and amortized in a fashion that exactly mirrors ratebasing.[20]

B. General Cost Recovery

The second type of action simplifies DSM program cost recovery. For most costs, the public interest is served by encouraging utilities to avoid cost increases; regulatory lag tends to impose this type of discipline. For DSM, the public interest is frequently served best by rapidly increasing expenditures, often at times when the utility would have not otherwise chosen to file a rate case. It is therefore appropriate to make DSM cost recovery easier than recovery of other costs. This may be accomplished by flowing some DSM costs through an existing fuel adjustment mechanism, by creating a new adjustment mechanism, or (most simply) by allowing the deferral of DSM costs with a capitalized return, until the next rate case. Establishing a preapproval program for DSM program design may also be helpful.[21] Of course, utilities must continue to be responsible for implementing their programs prudently, including modifying them if new information reveals that the pre-approved design is not suitable.

C. Lost Revenues

At least four financial factors tend to make comprehensive demand-side investment much less attractive than conventional supply to investor-owned utilities. In decreasing order of importance, these deterrents to integrated resource strategies are:

1. Raising efficiency lowers short-run profit.

2. Uncertainties about the dependability and predictability of cost recovery for demand-side investments, and especially the potential application of prudence and "used and useful" tests may discourage DSM investment.[22]

3. DSM requires the expenditure of utility funds.

4. Demand-side expenditures do not offer the investor return of capital-intensive supply investments.

For every kWh of sales lost to more efficient use, the utility loses its sales margin. This margin is the difference between tariff price set by regulators and any short-run variable costs not

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[20]The Massachusetts DPU has made this distinction.

[21]In practice, the review of DSM program design in adversarial proceedings has been difficult. The best and most aggressive DSM program designs have been developed in collaborative processes between the utilities and their traditional critics. Those programs have generally been easier for regulators to review and approve, since at least some of the most interested parties have already had a chance to participate in program design, and to publicly dissent, if necessary.

[22]The predictability of cost recovery (i.e., that the costs will be recovered) is separate from the mechanism for cost recovery (i.e., when the cost will be recovered).

flowed through to ratepayers. The more effective a utility's demand-side efficiency investment, the more it loses. This is precisely the wrong signal to send a utility that should be reducing ratepayer costs with efficiency improvements.

Adjustments to test-year sales in the utility's previous rate case will not fully correct this problem. Even if a rate case reflects the expected savings from efficiency programs, the utility has no incentive to realize the sales losses accounted for in the efficiency-adjusted test year. Once costs are assigned to classes and then structured through rate design, the tail-block price fixes how much revenue a utility will collect on each additional kWh or kW sale. Each sale the utility can effectively retain from intended efficiency savings contributes to earnings.

In addition to the direct pressure exerted by the potential margin, lost revenues also tend to accelerate the need for utilities to file rate cases. Many utilities appear to be averse to general rate cases, which may occupy a large fraction of senior management time for many months.

To remove this perverse disincentive, regulators in a growing number of states, including New York, Vermont, and Massachusetts have begun to eliminate penalties for sales losses attributable to utility DSM programs. The systems differ in many respects, but the general approach is quite simple. Using a methodology reviewed and approved by the regulators, the utility estimates kWh and kW sales losses in each rate class, multiplies those sales losses by the net revenue per unit in the rate's tail block, and recovers the resulting lost revenues over time.

In any such performance-based system, the details of the methods, data requirements and assumptions all must be worked out. In particular, the precise approach for measuring demand-side performance should be settled in advance. A projection of lost revenues can be collected during the period the measures are being installed, but reliable estimates of the revenue losses will generally be available several months following that period. Thus, some reconciliation mechanism is usually included in the process. Actual cost recovery may flow through an adjustment clause, or be deferred with an AFUDC-like credit until the next rate case.

D. Incentives

The SCC can take two types of actions to reduce utility reluctance to invest in DSM. The first type reduces the uncertainty in the recovery of costs by clearly defining the role of the prudence and used-and-useful tests for DSM. In particular, these definitions must reflect the experimental nature for some DSM programs, especially in the process of building capability. Almost by definition, capability-building efforts require utilities to make mistakes. The SCC should clarify, as did the Vermont PSB in Docket 5270, that prudently implemented programs that were prudently believed to be likely to lead to cost-effective full-scale programs will be considered used-and-useful until their costs are fully recovered.[23] The prudence standard for program design and implementation should also be clearly defined to be limited to the level of case applied in continuing programs of comparable scale, as in distribution maintenance. Finally, the SCC should

[23]The Vermont PSB also clearly established that the results of collaborative design efforts between utilities and their traditional critics would carry a presumption of prudence.

reassure utilities that any supply-side plant which becomes or remains excess due to DSM will not cease to be used-and-useful.

Explicit incentives for utility performance in DSM may be justified to overcome certain barriers to enthusiastic utility participation in DSM implementation. These barriers include staff biases against DSM (from decades of promoting electric energy use), perceived risks related to higher unit prices, reduced competitiveness and future regulatory uncertainty. Regardless of whether these concerns are valid, utility (i.e., shareholder) incentives may be beneficial to ratepayers, to the extent that they accelerate utility DSM programs.[24]

Incentives should be designed with the following objectives in mind:

- Only superior performance should be rewarded. Mediocre performance does not justify an incentive, and sub-standard performance should be penalized. Minimum performance levels (roughly 40-50% of projected program performance) have been adopted by the Massachusetts DPU for Massachusetts Electric, Western Massachusetts Electric, and Boston Gas; and by the New York PSC for Orange and Rockland Utilities. The incentive should increase linearly from the threshold level, to a maximum significantly higher than the expected program results.

- Utilities should be rewarded for performance, not projections. Incentives should reflect the actual number and size of installations and actual energy savings, to the extent feasible. This will generally require a "true-up" mechanism. To limit utility risk, the true-up should become final at some previously-determined date, which may be 1-5 years from the end of the installation period. The exact period should be determined by the nature of the program, and the inherent lag in the evaluation process. For example, new-construction programs will require longer evaluation periods than will retrofits, since the effect is not observable until after the design, construction and occupancy processes are complete.

- Utilities should not be rewarded for doing what they do in the normal course of business. Sales promotions, time-of-use rate design, interruptible load programs and direct load control are long-standing utility programs that impose no new risks and should encounter little internal opposition; no incentives should be offered for such programs. Incentives are probably also not justified for DSM bidding, since the utility is not responsible for the cost or quality of the program design or execution.

- Utilities should be rewarded for maximizing total benefits, which involves both the total number of kWh (and KW) saved, and the reduction in social costs per kWh saved. Thus, all the lifetime costs and benefits should be reflected in the incentive computation.

- Superior performance should allow utilities to increase their earnings by a large

[24]This discussion assumes that direct program costs and lost revenues will be recovered, and does not include such recovery as "incentives." In fact, more favorable and less risky collection of these costs, as compared to other utility costs, may reduce the need for explicit incentives.

enough margin to warrant management attention and to overcome internal resistance. An increase in after-tax return on equity (ROE) on the order of about 1% should be sufficient for this purpose. The SCC may want to determine the exact incentive level on a case-by-case basis, considering the history of each particular utility and its progress over time.

The previous discussion covers positive incentives, the carrots that reward utilities for pursuing DSM. In addition, the SCC should put the utilities on notice that inaction on IRP and DSM may result in some negative incentives, the sticks that penalize utilities for sub-standard performance. Negative incentives can be directly coupled to the positive incentives; if superior performance on DSM can earn a utility a 1% increase in ROE, perhaps a lack of action should cost up to 1% on ROE.[25]

The SCC should also warn the utilities that failure to pursue DSM could result in general rate disallowances, as for the costs of power supply and T&D that would not have been necessary with DSM, or of proposed supply projects. If the utilities have not fully developed DSM, the SCC may not be able to determine that new supply facilities are needed.

1. Split-savings

Splitting net savings between ratepayers and shareholders is a reasonable structure for incentives, as discussed above. However, the utility cannot be paid for only a portion of the gross savings, as are some third-party contractors. If the utility must cover its direct costs, plus lost revenues, plus a compensation for risk, in a portion of the bill savings, it will invest only in measures that cost much less than supply. DSM measures that are only 20-30% less expensive than supply will not be funded.

As discussed above, incentives should be given only for extraordinary efforts and efficiency investments, as opposed to traditional utility functions such as providing information, load management, rate design, or sales promotion.

2. Higher Rate of Return for DSM

This is not a useful approach, for two reasons. First, any reasonable increment in return on a small investment may not be large enough to attract management attention, or overcome internal resistance. Second, this approach rewards the utility for spending money, not for achieving savings of kWh or total costs. Better program designs may save more kWh with less investment, so that improving the program reduces the utility incentive.

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[25] The Massachusetts DPU has assessed ROE penalties of 0.5% to 1%, and the DCPSC has penalized a utility by 0.15%, for inadequate DSM activity. The California PUC has imposed similar penalties for inadequate efforts to promote cogeneration. Both Massachusetts and Vermont have refused cost recovery for improperly designed IRP and DSM programs.

E. Program Costs

Program costs are often thought of as a parameter to be minimized. However, national experience indicates strongly that small program costs imply small program efforts, and hence small program effects. Instead of attempting to minimize program costs, utilities should be endeavoring to identify and achieve all cost-effective DSM opportunities. Utilities should also be using the dollars they spend as effectively as possible.

The economic potential for efficiency savings in a utility service area depends on the costs and performance of different technologies for providing energy services to its customers, and the extent to which customers will adopt them. As discussed, there is strong evidence that market barriers prevent customers from investing in efficiency measures unless they are extremely profitable. In determining how much Virginia utilities might cost-effectively spend on DSM, it is informative to review the commitments and plans of specific utilities which have taken DSM seriously as a resource.

Most of the utilities with aggressive conservation plans are in New England, California, or Wisconsin. The plans of New England and Wisconsin utilities are shown in Table 1a. The most interesting columns in Table 1a are columns [4], [6], [8], and [9]. Column [4] expresses each utility's conservation expenditures as a percentage of its projected revenues at the program midpoint. Column [6] expresses the total energy saved in the last year of the program as a percentage of projected sales for that year. Note that because the savings in the last year of the program include the effects of all the conservation measures installed in the course of the program, longer programs will tend to show more impressive results.

Column [8] shows the MW saved in the last year of each utility's conservation program, expressed as a percentage of projected peak load for that year. The percentages range from 1.6% for Wisconsin Electric (WEPCo) to 18.3% for New England Electric (NEES).[26] WEPCo's figure is low because it represents the results of only a two-year program. Savings are equivalent to about 0.5% to 1.2% of sales per program year.

Utilities making a concerted effort to tap all cost-effective DSM potential have identified demand-side resources sufficient to reduce annual anticipated sales growth by about 1%. To obtain such savings, these utilities are spending in the range of 3% to 5% of their annual operating revenues on conservation and load management programs.

Based on this national experience, it seems likely that Virginia utilities will find that gradually ramping up DSM spending to 3 to 5% of annual revenues will be cost-effective. The ramp-up rate will be constrained by the time required for building capability; in addition, the full-scale retrofit programs currently pursued by some other utilities may not be cost-effective in Virginia until the market for baseload energy becomes tighter.

[26]NEES filed more aggressive programs in Massachusetts in October 1990.

Table 1a: Summary of Conservation Expenditures and Savings for Selected Electric Utilities

Utility	Total DSM expenditures [1]	Program life, yrs [2]	Average Annual cost [3]	Prog cost as % of projected revenues at prog. midpoint [4]	Annual MWh saved at end of prog. [5]	MWh saved as % of projected sales at end of prog [6]	Total MW saved at end of program [7]	MW savings as % of projected pk load in last yr of prog [8]	Program capacity factor [9]
[a]: BECo	$213,800,000	5	$42,760,000	3.3%	526,801	3.7%	117	3.9%	51%
[b]: CL&P	$624,915,000	10	$62,491,500	2.5%	1,741,170	6.8%	466	8.9%	43%
[c]: COM/Electric	$69,000,000	5	$13,800,000	3.3%	246,936	4.8%	46	4.4%	61%
[d]: EUA	$60,000,000	5	$12,000,000	4.6%	183,172	4.3%	53	5.9%	39%
[e]: NEES	$1,546,255,000	20	$77,312,750	4.0%	2,285,000	6.5%	1162	18.3%	22%
[f]: WEPCo	$113,836,000	2	$56,918,000	4.3%	304,800	1.3%	74	1.6%	47%
[g]: WMECo	$117,742,000	10	$11,774,200	2.7%	306,755	6.5%	43	5.2%	82%

Notes:

EUA's plan only includes costs and savings from the C/I sectors, as their residential programs had not yet been reviewed and approved.

[1][a]: data from Boston Edison's "The Power of Service Excellence: Energy Conservation for the '90's" (3/90).

[1][b]: data from Northeast Utilities' "Status of Private Power Producers and Conservation & Load Management," (4/90).

[1][c]: data from COM/Electric's "Mass. State Collaborative Phase II Detail Plans" (10/89).

[1][d]: data from Eastern Utilities' "Plan for the 90's: Results from Phase II of the Collaborative Planning Process", (2/90).

[1][e]: data from the New England Electric System's "Conservation and Load Management Annual Report" (5/90).

[1][f]: data from Wisconsin PSC docket #6630-UR-103, WEPCo exhibit TJG-2, p. 3, 11, 40.

[1][g]: data from Western Mass Electric's " Conservation and Load Management Program Plan for the 1990's" (9/89) and "Conservation and Load Management Program Update" (1/90).

[2]: The duration of the program described in each utility's DSM plan, though it is likely that most programs will be run for a longer period of time.

[3]: [1]/[2]

[4]: see Table 1b for source of revenue projections.

[5]: sources same as for [1].

[6]: see Table 1b for source of sales projections.

[7]: sources same as for [1].

[8]: See Table 1b for source of each utility's peak load projection.

[9]: [5] / ([7] * 8760)

Table 1b: Background Assumptions for Table 1a.

Utility	Prog. length [1]	'88 Sales revenues [2]	Revenues projected to 90 [3]	'90 $? [4]	Revenues projected for prog midpoint [5]	'88 Sales, MWh [6]	Sales projected for '90 [7]	Sales projected for prog end [8]	Peak load forecast for last yr of prog. (MW) [9]
[a]: BECo	5	$1,072,002,516	$1,206,320,829	y	$1,280,157,315	12,496,672	13,001,538	14,354,748	3,016
[b]: CL&P	10	$1,621,621,143	$1,824,804,824	n	$2,451,229,505	20,076,014	20,887,085	25,461,240	5,244
[c]: COM/Electric	5	$354,596,712	$399,026,489	y	$423,450,102	4,512,961	4,695,285	5,183,974	1,053
[d]: EUA	5	$219,642,491	$247,162,957	y	$262,291,307	3,725,256	3,875,756	4,279,148	900
[e]: NEES	20	$1,424,000,000	$1,602,422,415	y	$1,953,343,983	22,641,000	23,555,696	35,002,526	6,335
[f]: WEPCo	2	$1,181,447,183	$1,329,478,545	n	$1,329,478,545	21,547,582	22,418,104	23,323,796	4,507
[g]: WMECo	10	$290,414,985	$326,803,007	n	$438,988,961	3,731,682	3,882,442	4,732,675	824

Notes:

[1]: length of DSM program, as described in each utility's DSM plan.

[2]: ultimate consumer revenues for '88, from 1990 Energy Information Administration (EIA) "Selected Statistics for Electric Utilities", except for NEES figure, which is from NEES' annual 1989 Annual Report, p. 19; note that NEES figure includes off-system sales.

[3]: adjust '88 revenues for '90 : [2] * (((1+growth_rate) * (1 + rate_increase)) ^ 2); growth rate = 2%, rate increase = 4%.

[4]: are the utility's DSM budget figures in 1990$ (y) or do they include inflation (n)? [4][a],[b],[c],[g],[i]: personal communication with utility representatives; [4][d],[e],[f],[h]: financial assumptions given in utility's report.

[5]: utility revenues, adjusted for program midpoint; if DSM budget is in real 1990$, then [5] is also in 1990$ but includes a sales growth rate of 2%; if the budget was given in nominal dollars, then [5] includes an adjustment for inflation (4%) as well as for growth (2%).

[6]: utility's 1988 ultimate consumer sales, also from EIA '90, except for [6][f] (NEES), which is from Table III-B-1, same source as [10][f]; note that this figure includes off-system sales.

[7]: [6] adjusted for 1990, assuming 2% growth rate; [6] * ((1+.02)^2).

[8]: [7], adjusted for program end, assuming 2% growth rate; [7] * ((1+.02)^[1]).

[i]: UI's budget figure was given in nominal dollars, assuming 4.5% inflation.

[9][a]: from BECo's "Long Range Intergrated Resource Plan, 1990-2014", vol II (5/90) p. 11.

[9][b]: from Northeast Utilities "Long Range Forecast of Electrical Loads and Power Facilities Requirements in Massachusetts," (1/88) vol.1, Table IV-1; the table only forecasts peak load through 1997, [10][b] represents the 1997 peak load of 5040 MW * (1.02)^2.

[9][c]: from Com/Electric's "Long Range Forecast of Electric Power Needs and Requirements..." (1/89), vol 1, Table E-11.

[9][d]: from EUA's "Long Range Forecast of Electric Power Needs and Requirements, 1989-98" (5/89), Table II-A1.

[9][e]: from NEES' "Supplement to Long Range Forecast 3," vol 2 (1/90), Table II-B-3.

[9][f]: from WEPCo's "Integrated Resource Plan in Support of the Concord Generating Station", (5/89), Table 2-1.

[9][g]: Ibid.; 1997 forecast of 800 MW was increased by (1.01)^2 to reflect growth.