Regulatory Incentives for Demand-Side Management

Review for West Kootenay Power’s DSM Incentive Committee

FINAL REPORT

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1. Introduction

This review outlines the basic considerations involved in establishing incentives for DSM. Its purposes are to provide background material for assessing West Kootenay Power’s DSM incentive mechanism, explore modifications to that incentive structure, and record the final incentive for 2000 that was adopted based on discussions informed by an earlier draft of this report.

The review includes sections on the early development of incentives for demand side management, the kinds of incentives most commonly in place in the 1990s, WKP DSM incentive mechanisms, and modifications to incentives that are occurring or may be needed in jurisdictions where electricity supply is deregulated. Accompanying these narrative sections is a summary of incentives in those jurisdictions in Canada and the United States that encourage or require DSM.
2. Incentives for DSM: Origins

All industries are regulated by government to a greater or lesser degree. The structure of government regulation of any industry establishes incentives. It creates a framework that promotes some kinds of actions and discourages others.

When regulators wish to promote demand-side management (DSM) activity by utilities over which they have jurisdiction, they must consider how to create incentives consistent with their objectives for DSM. They must review the entire framework of incentives created by the structure of utility regulation to see how it may need to be modified to promote DSM.

In the late 1970s, regulators in some jurisdictions began to think about DSM as a way of helping to reduce the total social cost of providing energy services. By intervening in the customers’ side of the market through DSM, utilities could help energy users increase their energy efficiency.

Utilities had already led the way with load management programs designed to reduce customer usage at time of peak demand, thereby avoiding reliability problems or deferring the need for new plant investment. Regulators were reactive, reviewing and approving load management programs. They did not need to create new regulatory incentives, because utilities were already interested in load management.

But when regulators began to see DSM as a way of promoting energy efficiency, they also began to encounter resistance from most utility managements. Energy efficiency focuses on reducing customers’ overall energy requirements, not just their peak demands. Energy efficiency means using better equipment, building practices, and energy management practices in ways that reduce the total cost of energy services over time. With energy efficiency, the overall level of utility sales and revenues is likely to be lower than would otherwise be the case. Since industry managements generally strive for maximum growth, regulators would need to be pro-active in order to promote energy efficiency.

During the period from the late 1970s to the late 1980s, regulators interested in energy efficiency used a variety of “sticks and carrots” to encourage DSM. Some of the regulatory incentives used were as follows:

- Guarantee that the utility could recover all its direct expenditures for approved DSM spending.
- Rate-basing of DSM expenditures so they could be amortised and earn a return for the utility.
- Provision for the utility to recover revenues lost between rate cases due to DSM programs reducing sales.
Overall rate of return penalty for utility failure to comply with regulatory DSM directives.

Overall rate of return reward for utility success in DSM.

Rate of return premium on the utility’s rate-based DSM costs.

Rate of return premium on utility’s rate-based DSM costs if savings targets are reached.

Disallowance of specific DSM costs when results were inadequate.

Share of net societal benefits produced by DSM awarded to utility.

Schedule of dollar rewards to utility based on DSM achievements.

Variations and combinations of the above “sticks and carrots” were applied in different jurisdictions. By 1990, regulators promoting DSM began to converge somewhat on a suite of three provisions – recovery of program costs, compensation for net lost revenues, and a share of net resource savings as a reward to the utility. These are described in the next section.
3. DSM Incentives in the Fully Regulated Environment

In the late 1990s, restructuring of the electric and gas industry began to be widely implemented in Canada and the U.S., with the objective of deregulating aspects of energy supply while providing for retail competition in energy supply. How such restructuring impacts DSM and DSM incentives is addressed later, in section 5 of this review. Here, we discuss DSM incentives in the 1990s, in the “fully regulated” environment, i.e., pre-restructuring. This discussion is particularly relevant for WKP, which operates in a fully regulated environment, as do the electric utilities of the many other jurisdiction where restructuring has not yet occurred or has been decided against.

Energy efficiency takes advantage of distribution utilities’ skills and access to customers to promote energy efficient technologies and practices in the market. Efficiency measures improve economic efficiency. By saving electricity, they reduce customer energy bills. Efficiency also improves the environment. Many electric and gas utilities in North America have demonstrated, based on results documented in DSM evaluation and cost-effectiveness studies, that energy efficiency can produce substantial net societal benefits as a direct result of utility DSM efforts.

Energy distribution utilities have business incentives to minimise operating expenses, to maximise short-term sales, and to promote long-term business growth. DSM incentives are designed to prevent these three business incentives from standing in the way of successful energy efficiency initiatives. There are three basic types of DSM incentive mechanisms: program cost recovery, lost revenue recovery, and rewards to shareholders based on DSM activity.

3.1. Program Cost Recovery

Mechanisms which allow the utility to recover from ratepayers only the actual amount it spends on approved DSM programs or activities are designed to eliminate the business incentive to underspend on DSM. These mechanisms assure the utility of program cost recovery only for its expenditures pursuant to DSM plans that were approved by regulators. The utility’s costs for DSM are usually “expensed” but sometimes they are amortised over several years, with or without a return. In many cases the utility’s program costs are collected through a special tariff rider. In other cases, the utility tracks variations from the level of DSM expenditures in the last rate case for deferred recovery in a future rate case. Whatever the specific design of the mechanism, interest is charged on under- or over-recoveries, often at the utility's weighted cost of capital.
3.2. Lost Revenue Recovery

Lost revenue mechanisms allow utilities to recover from ratepayers all of the fixed costs —costs that do not vary directly with sales— that they would have recovered had they not promoted sales reductions through energy efficiency. These mechanisms are designed to eliminate the incentive to minimise savings from DSM. Because it decreases the amount of energy needed to satisfy a given level of energy service or comfort, DSM reduces the volumes of energy sold by the utility. Some portion of the resulting lost revenue is offset by a reduction in variable costs that are avoided --for example, the cost of fuel for power plants. The remaining portion of lost revenue, that which is not offset by variable cost reductions, represents pure earnings losses to the utility. The most common type of lost revenue adjustment mechanism is based on the calculation of the amount of the reduction in a utility’s sales of energy that is due to its own DSM initiatives. This must be calculated net of any efficiency trends that are occurring independently of DSM, since sales losses due to other factors would have been experienced anyway. Lost revenue recovery is usually effected through the same procedure as is used for program cost recovery.

A few jurisdictions have put into place mechanisms that fully “decouple” revenues from sales levels between rate cases. In California, this was done through a mechanism enabling distribution utilities to recover the levels of non-fuel revenue requirements that were authorised in the base rate case —not more, and not less. Annual proceedings, incorporating mechanical adjustments, have been made to modify tariffs so as to collect the authorised levels of revenues until the next general rate case. Other jurisdictions have experimented with revenue-per-customer decoupling mechanisms, which periodically adjust rates between general rate cases on the basis of customer growth. Decoupling mechanisms remove the short-term utility incentive to increase sales, and prevent the loss of revenues due to sales reductions from DSM.

Today, mechanisms which decouple revenues from sales volumes are generally called revenue caps or targets. Revenue caps may be used in the context of multi-year performance-based ratemaking (PBR) mechanisms. The essence of revenue caps is to determine an allowed level of revenues over the PBR period and to adjust rates periodically in order to reconcile the actual and allowed levels of revenue. PBR mechanisms with revenue caps may also account for price inflation, expected productivity improvements, and quality of service indices. West Kootenay Power has completed one three-year period under PBR, 1996 through 1998, and is beginning its second three-year PBR regime.

3.3 Shareholder Incentives

The third basic type of DSM incentive mechanism provides shareholder rewards to utilities based on the effectiveness of their pursuit of DSM that is cost-effective or otherwise societally beneficial. By its nature, energy efficiency cannot be a force for increased total revenues for the utility. What shareholder incentives can do, however, is
compensate for energy efficiency’s inability to contribute to total revenue growth, by providing an opportunity to increase the utility’s rate of earnings. The basic purpose of shareholder incentives is to provide utilities with a positive incentive to continue to build and pursue energy efficiency. Sometimes penalties for underperformance are part of a shareholder incentive mechanism. If penalty provisions are present they are usually structured to be less likely than positive rewards. Shareholder incentives are intended to counter the business disincentives to DSM by making it a source of revenue and profit. They aim to create a business incentive for sustainable DSM initiatives that promote energy efficiency on an evolving, adaptive, multi-year basis.

One mechanism that has been adopted in some jurisdictions is the inclusion of DSM expenditures in the rate base. In this way these expenditures are transformed into investments that earn a return for the shareholder. One analysis of the rate-basing of DSM summarised its advantages as follows:

“[M]ore regulatory commissions should consider adopting a rate-basing approach, because it:

Promotes better matching of program costs and benefits, and thus improves intergenerational equity.

Provides an additional signal to utilities that all resource options are to be considered in a balanced manner.

Makes more practicable the undertaking of large-scale ‘conservation construction programs’.”

Rate-basing of DSM expenditures is a basic positive incentive for DSM in the current regulatory framework for West Kootenay Power. Rate-basing by itself is an incomplete incentive, in that it addresses only the need to invest in DSM, not the need to obtain results from that investment. At WKP, however, the DSM performance mechanism in the PBR framework has included components to encourage minimum results.

A variety of shareholder incentives have been used during the 1990s. The most common type has been a shared savings mechanism (SSM). The SSM approach provides the utility with a share of the net benefits—that is, benefits after all costs of efficiency measures including utility program costs have been deducted—and thus sends the signal to maximise the resource savings per utility dollar spent. SSMs usually provide for a small share of life-cycle benefits as a potential reward to shareholders. The SSM approach requires that both energy savings and the resource benefits flowing from those savings be quantified. The benefits are calculated over the lifetimes of the DSM measures.

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put into place. The utility receives a share of the total net present value of these life-cycle
benefits.

The scope of benefits considered in SSMs varies. Most commonly, a Societal
Perspective is used in which the benefits include utility avoided supply costs, other
resource savings, and non-economic environmental benefits, while the costs include both
the utility’s and the customers’ investment in DSM. Less often, a Total Resource Cost
Perspective is used, which is the similar to the Societal Perspective, but generally
includes environmental benefits only to the extent that they have a market value. The
most limited measure of net resource benefits is the Utility Perspective, in which the
benefits consist of the utility’s avoided supply (energy and capacity) costs, and the costs
are the utility’s total DSM-related expenses. A more detailed discussion of these tests and
their variations may be found the proceedings of a conference of the American
Association for an Energy Efficient Economy.²

SSMs are usually designed so that the utility receives its share of benefits up-
front. If future benefits turn out to be less than was estimated at the time the incentive
was paid, the shareholders will have been overpaid. Of course, future benefits may also
turn out to be greater than was estimated at the time the incentive was paid. SSMs are
often sensitive to the utility’s achievements relative to DSM goals or targets. Targets may
involve volumes saved, cost-effectiveness, or both.

3.4 Note on Utilities Not Owned by Private Investors

This report focuses on incentives as applied to investor owned utilities (IOUs).
There is no experience with DSM incentive mechanisms at other types of utilities —
whether crown corporations, public authorities, rural co-operatives, municipal
distribution companies, or other public or quasi-public structures. It might be possible to
structure performance incentives for the managements of such entities. However, this
report limits itself to the IOU sector, from which there is a body of experience to draw
upon in considering approaches that may be appropriate for WKP.

²Mark Fulmer and Bruce Biewald, “Misconceptions, Mistakes and Misnomers in DSM Cost
4. West Kootenay Power

4.1 Incentives in Place As of 1999

WKP’s 1999 DSM incentives are detailed in Annex 2. Three aspects of WKP’s current regulatory regime impact DSM:

- The amortisation of DSM costs over eight years, with a return on the unamortised balance, provides an incentive for the Company to consider DSM a long-run investment opportunity.
- A three-year performance-based ratemaking framework for operating expenses, because its cost drivers are largely the number of customers, assures that if the Company helps reduce electricity use per customer it will not lose revenues in the short term.
- The current DSM Incentive Mechanism provides an incentive for the Company to reach its electricity savings targets while minimising its short-term costs of DSM delivery.

WKP’s incentive structure already has the basic types of elements that are needed to comprehensively address the utility’s business disincentives to DSM that exist under traditional regulation. WKP’s structure is unusual in that its performance-based component, the DSM Incentive Mechanism, focuses management attention on the reduction of DSM operating costs, rather than on increasing the results of DSM programs. Under the DSM Incentive Mechanism, WKP receives 50% of DSM operating cost savings achieved relative to budget, provided 90% of targeted volumetric savings are achieved, as detailed in Annex 2. Performance-based DSM mechanisms elsewhere create opportunities for rewards to management based on the amounts of energy saved, the cost-effectiveness of the energy saved, or both.

4.2 Modifying DSM Incentives to Emphasise Results

The draft of this report suggested, and the DSM Incentive Committee in the Fall of 1999 considered, an incentive approach that rewards results as well as cost containment. This could be done by shifting to a shared savings mechanism. Providing WKP with a share of the net benefits expected from its achieved DSM activity would create a reward structure that incents maximum results per utility dollar expended. Rewards can be increased by increasing results at any level of cost, or by decreasing costs for any level of result.

Using the Total Resource Cost perspective, gross benefits consist of the utility’s avoided energy and capacity cost savings. Deducting the utility’s and the participating customers’ DSM investment costs yields net benefits.
Providing a share of utility net benefits could address an issue of interest to WKP and many members of the DSM Incentive Committee — the desirability of controlling demand during peak usage periods, both system-wide and in locations where transmission and distribution upgrade requirements are especially severe. Gross benefits include three avoided cost elements — savings in energy procurement by WKP, savings in capacity charges to BC Hydro, and potential savings in the schedule or size of its own transmission and distribution system upgrades. Thus load shifting, which does not save energy and is not incented by the present DSM Incentive Mechanism, would be encouraged wherever cost-effective from the utility system perspective.

With the above considerations in mind, the DSM Committee considered shifting to a shared savings mechanism for the year 2000. A shared savings design suggested in the draft of this report is outlined in the box below.

### Possible Shared Savings Incentive

<table>
<thead>
<tr>
<th>Basis of savings:</th>
<th>Net present value (NPV) of life-cycle benefits expected based on the actual level of DSM impacts achieved by the Company through the end of the year.</th>
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<td>Share of net benefits:</td>
<td>Four percent of all NPV benefits.</td>
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<td>Threshold:</td>
<td>WKP forecasts the targeted year 2000 DSM impacts and the net benefits expected therefrom in its DSM Business Plan. If WKP attains 90% of its aggregate targeted net benefits, shared savings occurs.</td>
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<td>Cap:</td>
<td>WKP is eligible for a four percent share of NPV benefits up to a maximum of 150% of targeted benefits. If actual benefits exceed 150% of targeted benefits, WKP’s reward is 4% of 150% of targeted benefits.</td>
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<td>Sectoral Issues:</td>
<td>This design is based on aggregated costs and benefits across all DSM programs in all customer sectors. WKP is expected to target DSM net benefits in residential, general service, and industrial sectors. Simplicity of design is indicated for the initial shared savings mechanism.</td>
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The draft of this report suggested that if the Committee desired to retain the type of incentive mechanism in place in 1999 instead of shifting to a shared savings incentive, it could consider modifying the existing mechanism to provide that the utility receive an increasing share of any cost savings as the electricity savings achieved increase —for
example, 50% of cost savings if 90% of electricity savings are achieved, 75% of cost savings if 100-110% of electricity savings are achieved, and 100% of cost savings if over 110% are achieved. Note that, in order to incent demand reduction achievements as well as energy conservation, the electricity savings targets should be expressed in terms of the net present value of utility avoided cost benefits.

4.3 The New DSM Incentive for 2000

Following extensive consultations and consideration of a variety of alternatives, the DSM Incentive Committee agreed upon a new mechanism employing the shared savings approach. The mechanism will be utilised for year 2000 DSM and may be extended to 2000 and 2001 following future reviews by the DSM Incentive Committee.

The new DSM incentive mechanism provides that WKP receive shares of net DSM benefits that vary by sector based upon the difficulty of achieving results: 3 to 6 percent in the residential market, 2 to 4 percent in the general (commercial) market), and 1 to 3 percent in the industrial market. The incentive is to be calculated by sector. The shared savings reward for results in any sector is available only if net benefits exceed 100 percent of those targeted in the year 2000 DSM budget. Should benefits from residential DSM fall below 90 percent of targeted levels, a penalty of 3-6 percent of realised net benefits is imposed on WKP. Should benefits fall below 95 percent of targeted levels, a penalty of 1-4 percent (general), or 0.5-3 percent (industrial) of realised net benefits is imposed. On an overall basis (all sectors) WKP shall not be penalised. These and other features of the new mechanism are detailed in Annex 3.
5. DSM Incentives after Restructuring

Many jurisdictions in Canada and the U.S. have been deregulating their electric and gas industries so that energy is supplied on a competitive market basis, while price regulation is retained for the transmission and distribution of energy. While this has not occurred in British Columbia, it could. For this reason it is instructive to briefly consider the implications of deregulation for DSM.

- Some jurisdictions, emphasizing the goal of deregulation, have determined that the services demand side management provides are competitive and should be delivered by the market any funding from utility ratepayers. These jurisdictions ended DSM as part of restructuring.3

- Other jurisdictions, emphasizing opportunities to reduce market barriers to energy efficiency and promote its environmental benefits, have retained ratepayer funding. Some of these jurisdictions have not restructured. Others have restructured and have included ratepayer funding for efficiency, generally through distribution level charges, as part of the restructuring policy package.4

Among jurisdictions that see DSM as consistent with restructuring, two general approaches to delivering DSM have emerged. One is continued reliance on distribution utilities as entities well-positioned to promote efficiency amongst energy users. The other is shifting to non-utility entities to administer the DSM programs supported by utility ratepayer funds. When efficiency funds are simply collected through utilities and remitted to other entities that will apply them, the kinds of incentives that are appropriate for program administrators must be re-thought.

When distribution utilities continue to deliver DSM, the kinds of incentives discussed in prior sections of this review continue to be relevant and applicable. After restructuring, energy distribution utilities still have business incentives to minimise operating expenses, to maximise short-term sales, and to promote long-term business growth. DSM incentives are still appropriate to prevent these business incentives from standing in the way of energy efficiency initiatives.

However, restructuring and the emphasis on competition that accompanies it have led to a changed emphasis among advocates of DSM as to the purposes of DSM itself. There is less emphasis on DSM as a resource procurement option in the context of integrated supply-demand planning, and more emphasis on DSM as a set of interventions designed to create self-sustaining changes in the functioning of markets for energy-

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3 In the U.S., states ending all or most DSM include Arkansas, Georgia, Maryland, Michigan, Nevada, Ohio, Pennsylvania, and some others.

4 In the U.S., states that have made explicit provision to secure funding for efficiency as part of their restructuring process include Arizona, California, Connecticut, Maine, Massachusetts, Montana, New Jersey, New York, Oregon, Rhode Island, Vermont, and others.
efficiency products and services. In shorthand, the shift in strategic focus is from “resource procurement” to “market transformation.”

This does not mean the idea of procuring demand-side resources is no longer relevant after restructuring. If DSM can help a distribution utility to avoid costs on its system, such a result has value.

In some jurisdictions, the emphasis on market transformation has led to evolution in DSM performance incentives. Where once they focussed almost exclusively on energy and demand savings, and the costs and benefits of achieving those savings, some jurisdictions now use a variety of indirect performance indicators in their incentive structures. This can be seen by examining the shareholder incentive provisions in California and Massachusetts, as summarized in Annex 2.

While the increasing emphasis on market transformation has been correlated with the restructuring movement, it is also a factor in jurisdictions that have not restructured, but wish to maximize the long-term gains from DSM.

In my view, to the extent a focus on market transformation is desirable, it is better applied to the design of DSM programs than to the design of DSM incentives. DSM performance incentives should still emphasize energy resource savings and correlated benefits, since those resource benefits are the ultimate objective of market transformation efforts.
Annex 1: Demand Side Management Cost

Recovery Mechanisms

A number of jurisdictions in North America have developed cost recovery and incentive provisions aimed at encouraging the pursuit of cost-effective demand-side management. The following table lists jurisdictions in which three types of provisions were being applied to at least one investor-owned utility in 1999. These provisions are:

- Program cost recovery, referring to full recovery of utility expenditures for approved demand-side programs.

- LRAM or RevCap. LRAM refers to lost revenue adjustment mechanisms that make the utility whole with regard to fixed costs lost through sales reductions from energy efficiency. RevCap refers to revenue caps, which provide for a maximum level of revenues during a multi-year period, during which revenues are decoupled from changes in sales.

- Shareholder incentive, referring to additional profits provided to the utility based on demonstrated DSM performance. The cost recovery and incentive provisions for jurisdictions in this category are described in more detail in Annex 2.
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<th>Jurisdiction</th>
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<th>Program Cost Recovery</th>
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¹ Oregon's revenue cap is applied to distribution level revenues only.
Annex 2: Shareholder Incentives for Demand Side Management Performance

Introduction

DSM incentives should be designed based on the policy and regulatory framework, utility structure, and economic and energy situation, that exist within the jurisdiction considering the incentives. Nevertheless, the nature of DSM mechanisms employed elsewhere is a matter of background interest.

This annex synopsises DSM incentives recently in place (1998-1999) in several North American jurisdictions. The summaries focus on jurisdictions where there is some type of shareholder reward for DSM.
British Columbia

1998

General Treatment of DSM and its Costs: Recovery of program costs and shareholder incentives are currently in effect for investor owned utilities. These are BC Gas Utility, Ltd. and West Kootenay Power, Ltd. (BC Gas and WKP).

DSM Funding: Expenditure levels are proposed by the distribution utilities and established by the BCUC when it approves the utilities’ DSM Plans.

Recovery of Program Costs: Full DSM program cost recovery is allowed. The amortisation period for the outstanding balance of deferred DSM costs for WKP is 8 years.

Lost Revenues: There is no lost margin recovery for BC Gas or WKP. Within WKP’s multi-year performance-based ratemaking framework, operating expense targets are largely based on the number of customers, a RevCap approach that can offset the need for an LRAM.

Shareholder Incentives: BC Gas Utility Ltd. BC Gas receives a share of the net present value of benefits from DSM, based on the Total Resource Cost Test. If the quantity of energy saved is 75% up to 100% of that forecasted at the start of a DSM plan, the share of savings to the utility is 3%. If the quantity of energy saved is 100% or more, the share is 5% of net benefits. The BCUC stated that results “from programs developed within the utility but which at some point are moved outside the utility will be included in the DSM calculation where those program results are tracked by the utility”.

Shareholder Incentives: West Kootenay Power Ltd. WKP amortises its DSM costs, earning a return on the unamortised balances. This constitutes a positive shareholder incentive for DSM investment. WKP also has a DSM incentive plan with the objective of achieving cost-effectiveness while also encouraging the attainment of DSM energy savings targets. During 1996-

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8 Consolidated Settlement Document, ibid., page 5.
1998, the DSM incentive was based on variable costs and energy savings. If the variable costs of providing DSM programs was lower than forecasted, while still achieving forecasted kWh savings, then the difference between actual and forecasted variable costs was shared equally with customers. The incentive was calculated by multiplying the actual kWh savings times the difference between the target and actual variable costs, and then dividing this product by two. Variable costs are those that fluctuate strongly as a function of DSM program delivery —advertising, rebates, marketing costs, travel expense, etc. WKP would receive this incentive if 90% of its forecasted energy savings were achieved.  

1999

WKP’s DSM incentive for 1999 added two features to the structure described above. The incentive was calculated separately for the residential, general service, and industrial components of DSM, then summed. Additionally, a component related to fixed costs was added, and works as follows. If the Company would be due an incentive based on energy savings attained and variable costs reduced, as described above, then fixed cost variations are considered. The fixed cost base is the lower of $422,000 or 1998 labour and training costs for delivery activities. The difference between 1999 fixed costs and the fixed cost base is added to the variable cost difference, increasing the incentive (if fixed costs have been reduced) or decreasing the incentive (if fixed costs have grown).

Ontario

1999

General Treatment of DSM and its Costs: The Ontario Energy Board requested each regulated gas distribution utility to implement the demand-side aspects of integrated resource planning in 1993. Approved DSM program costs are recovered separately from each major rate class.

DSM Funding: DSM budgets are set annually by the Board in the context of rate cases.

Recovery of Program Costs: Variance accounts are provided for utility program cost variations from the budgeted levels that were included in rates.

Lost revenues: LRAMs are in place for both Enbridge Consumers Gas and Union Gas.

Shareholder Incentives: An SSM for Enbridge Consumers Gas was approved in 1999 and became effective with the utility’s 1999 fiscal year. The utility’s reward or penalty is 35 percent of the difference of “actual” DSM benefits less the benefits targeted in the DSM Plan pre-approved in each year’s rate case. Benefits are calculated as the net present value of resource benefits based on the Total Resource Cost test. Actual benefits are projected on the basis of DSM activity accomplished through the end of the fiscal year.

Impact of Restructuring: Bill 35, passed by the Ontario legislature in October 1998, establishes a far-reaching competitive electricity market structure for Ontario in 2000 (Chapter 15, Statutes of Ontario, 1998). Schedule B of the Act, which is the Ontario Energy Board Act, 1998, states that one of the electricity-related objectives of the Board is “to facilitate energy efficiency and the use of cleaner and more benign energy sources in a manner consistent with the policies of the Ontario government” (Part I, section 1, objective 6), and that one of its gas-related objectives is “to facilitate opportunities for energy efficiency in a manner consistent with the policies of the Ontario government” (Part I, section 2, objective 5). Because the Act includes energy efficiency as an OEB objective, it does not disturb the OEB’s existing policies to encourage gas utility DSM. Because it extends the Board’s regulatory jurisdiction to cover electric distribution utilities, the Act could provide a basis for the Board to encourage electric DSM.


12 Enbridge Consumers Gas, OEB case EBRO 497-01, Exhibit C, Section 9.0.
1999

**General Treatment of DSM:** The smallest of the three utilities regulated by La Régie de l’énergie (the Energy Board), Gazifère, has proposed its first DSM Plan. The Plan is currently pending in the Régie’s docket R-3430-99. It is a response to the Régie’s encouraging the utility, in its prior rate case, to prepare an environmental improvement program. Gazifère proposes to receive a 5% bonus on all its DSM spending, plus a stepped dollar reward for volumes saved through DSM, beginning at 60% of volumes budgeted. No LRAM is proposed. If adopted, this would be the first shareholder incentive for DSM in Québec. The Régie has also encouraged Gaz Métropolitain to pursue DSM, but that utility has not included a DSM incentive proposal in its current rate application.
California

1998

General Treatment of DSM and its Costs: Electric utilities are in a transition period during which they administer DSM programs with funds collected at the distribution level through a Public Goods Charge (PGC) that is in effect. Recovery of program costs and shareholder incentives are currently in effect. After 2001 administration may shift to some form of independent state-wide administration.

DSM Funding: Transitional funding levels are specified by law for San Diego Gas and Electric Co., Southern California Edison Co., and Pacific Gas and Electric Co.

Recovery of Program Costs: Electric utilities collect costs through the PGC. Gas utility DSM program costs remain fully recoverable through rates until the Public Utilities Commission (PUC) imposes a PGC for gas.

Lost Revenues: Utility revenues have been decoupled from sales through adjustment mechanisms that reconciled utility revenues to the amount authorised in the last rate case (adjusted annually for certain cost changes in an attrition proceeding). These have offset the need for LRAMs. Electric decoupling is being phased out, but gas utility revenues are still decoupled from sales and reconciled to the amount authorised in the prior rate case (adjusted for certain cost changes).

Shareholder Incentives: The PUC approved similar structures of shareholder incentives for 1998 for all four investor-owned utilities in the state. San Diego Gas and Electric's follows.

1. For programs that produce quantifiable streams of resource benefits, 5% of program expenditures plus a 15% share of net benefits, based on utility avoided costs only.

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13 Per the electric restructuring statute known as Assembly Bill 1890.

2. **For programs that provide information and technical assistance,** or promote market transformation without the benefits being readily quantifiable, 5% of program expenditures.

3. **For Standard Performance Contract programs** there are two types of performance incentives. One is a fixed set of dollar awards based on achievement of program roll-out and management milestones. The other provides a share of net benefits provided that actual SPC activity yields at least 20% of expected benefits. The share ranges from 16 to 26%.

The total of all types of incentives was capped at 14% of SDG&E's total DSM program budget.

**1999**

Basic provisions remained the same as in 1998. Shareholder incentive mechanisms for the California utilities were modified slightly, in order to cap the total of all types of performance incentives at 11% of the utilities’ total DSM program budgets, and to adjust the details of the performance metrics in the direction of emphasizing impacts upon markets.¹⁶

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¹⁵ SPC programs pay fixed prices for verified and measured energy savings as they are delivered over a multi-year contract period.

¹⁶ PUC Energy Division, Resolution E-3578, March 18, 1999.
Colorado

1998

**General Treatment of DSM and its Costs:** A demand-side cost recovery mechanism that includes recovery of utility costs and shareholder incentives is in effect for the Public Service Company of Colorado (PSCO). PSCO is the major utility in Colorado with DSM programs. Costs are recovered from ratepayers as a whole.

**DSM Funding:** Colorado emphasises all-source or DSM-only bids to procure electric resources or their DSM equivalent. During the mid-1990s, PSCO also delivered several utility-administered DSM programs. Currently, DSM program costs consist largely of payments to successful bidders, plus the net costs of developing and administering bids.

**Recovery of Program Costs:** DSM program costs may be fully rate-based and earn a return while being amortised over 7 years.

**Lost Revenues:** There is no lost margin recovery for PSCO.

**Shareholder Incentives:** In addition to the return on rate-based DSM, a shareholder incentive applies. A base annual incentive is calculated as 5% of the price per kW of a representative supply-side investment displaced by DSM. This base incentive is then adjusted to reflect two factors. These are changes in the expected lifetime of DSM projects implemented, and deviations in the cost of DSM contracts signed from a target price per kW of DSM. This yields an adjusted DSM incentive, which may be claimed as follows:

- 35% of the incentive may be claimed based on demonstrated efforts to establish the actual effects of DSM on the Public Service system.
- 65% of the incentive is available if actual DSM project performance turns out to be at least 90% of expected; below 90%, the 65% portion is itself scaled back.

1999

Provisions remain as described above.

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Connecticut

1998

**General Treatment of DSM and its Costs:** Utility expenses for approved costs (called conservation and load management, or C&LM) are fully recoverable from ratepayers through a C&LM Adjustment Mechanism. Provisions for the largest utility, Connecticut Light and Power Company (CL&P), are described here.

**DSM Funding:** Before restructuring, the Department of Public Utility Control established annual budgets for C&LM programs. The 1998 law deregulating electricity generation established Systems Benefit Charges to fund DSM beginning January 1, 2000. The SBC for DSM is 3 mills per kWh. Additional amounts are collected for renewable energy programs and low-income programs.

**Recovery of Program Costs:** A portion of CL&P's C&LM expenditures have been placed in rate base where they earn a return based on the weighted cost of capital.

**Lost Revenues:** No lost margin recovery is in place for CL&P.

**Shareholder Incentives:** The Company is eligible for a bonus rate of return on its rate-based DSM. The bonus is based on a performance ratio which compares actual to budgeted life-cycle energy savings. Budgeted energy savings are those projected from the C&LM activity in the approved plan, while actual energy savings are those projected from the level of C&LM participation realised by the end of a year. CL&P's additional return on rate-based C&LM varies with 1998 performance ratios as follows:

<table>
<thead>
<tr>
<th>Ratio</th>
<th>Bonus</th>
</tr>
</thead>
<tbody>
<tr>
<td>&lt; .75</td>
<td>0 %</td>
</tr>
<tr>
<td>≥ .75 &lt; 1.1</td>
<td>1 %</td>
</tr>
<tr>
<td>≥ 1.1 &lt; 1.25</td>
<td>2 %</td>
</tr>
<tr>
<td>≥ 1.25</td>
<td>3 %</td>
</tr>
</tbody>
</table>

The bonus rate of return does not take into account cost-effectiveness because cost-effectiveness was demonstrated in prior years.

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1999

In 1999, new shareholder incentive structures are under consideration for the era of SBC funding of DSM. In the meantime provisions described above remain in effect.
Hawaii

1998

**General Treatment of DSM and its Costs:** Recovery of utility expenses for approved DSM plans, lost margins, and shareholder incentives have been available since 1994, and are enjoyed by the major electric utilities. Provisions for the largest utility, Hawaiian Electric Co. (HECo), are described here.

**DSM Funding:** DSM expenditure levels are proposed by the distribution utilities and established by the Public Utilities Commission when it approves the utilities’ Plans as part of the overall Integrated Resource Planning process.

**Recovery of Program Costs:** DSM costs for residential programs are fully recoverable from HECo's residential rate classes, and costs for non-residential programs are fully recoverable from the non-residential rate classes.

**Lost Revenues:** An LRAM provides for full recovery of net lost margins.

**Shareholder Incentives: HECo.** HECo's shareholder incentives are, for most of its DSM programs, 10 percent, *post-tax*, of all electricity cost savings (measured from the utility perspective) expected to accrue over the lifetime of the DSM measures installed under HECo's programs, net of the direct costs of the programs themselves. This is equivalent to about 13.3% pre-tax. For a service program with less readily quantifiable resource benefits, the Company receives 5 percent, *post-tax*, of program costs as a shareholder incentive. The shareholder incentives are collected annually based on completed DSM activity. As with other DSM costs, shareholder incentives for residential programs are recovered from HECo's residential rate classes, and incentives for non-residential programs are recovered from the non-residential rate classes.

1999

Provisions remain as described above.

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20 The cost recovery and incentive provisions were approved by the Public Utilities Commission in Decision and Order No. 14638, approved April 22, 1996, and Decision and Order No. 14730, approved June 5, 1996.
Kentucky

1998

**General Treatment of DSM and its Costs:** Recovery of utility expenses for approved DSM plans, lost margins, and shareholder incentives have been available since 1994.\(^{21}\)

**DSM Funding:** Utilities may apply to the utility regulatory commission to implement a DSM Adjustment Tariff in order to recover costs and net lost revenues, and to receive incentives for the implementation of DSM programs. DSM costs, lost revenues, and incentives are collected from the customer classes that benefit from the programs.

**Recovery of Program Costs:** DSM program costs are fully recoverable through the DSM cost recovery mechanism.

**Lost Revenues:** The LRAM provides for full recovery of net lost margins from approved DSM programs.

**Shareholder Incentives:** Louisville Gas & Electric Co, American Electric Power, and Cinergy. Each of these utilities receives a shareholder incentive. The incentive is computed by multiplying the net resource savings expected from approved programs that are to be installed during the upcoming 12-month period by 15%.\(^{22}\) Net resource savings are defined as program benefits less the cost of the program, where program benefits are the present value of the utility's avoided costs over the expected life of the program, and include both capacity and energy savings.

The DSM incentive amount is divided by the expected sales for the upcoming 12-month period and included in the DSM cost recovery mechanism. Reconciliation occurs subsequently. DSM incentive amounts are assigned for recovery purposes to the rate classes whose programs created the incentive.

1999

Provisions remain as described above.

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\(^{21}\) Pursuant to 1994 Kentucky Acts, chapter 238, section 2.

\(^{22}\) There are no penalties in the shareholder incentives.
Maryland

1998

General Treatment of DSM and its Costs: Maryland’s electric restructuring law, Senate Bill 300, passed in 1999, eliminated previous requirements for electric utility DSM programs. By the time the law was passed, the Public Service Commission (PSC) had ended gas and electric utility DSM. Provisions in effect for pre-1999 DSM programs are described here. Electric utilities recovered program costs, lost revenues, and shareholder incentives. Provisions for Potomac Edison Company follow.  

DSM Funding: Potomac Edison applies an Energy Conservation Surcharge (ECS) to designated Rate Schedules in order to recover eligible DSM program costs applicable to the customer classes served by those Rate Schedules. Eligible costs were approved by the PSC based on project descriptions as filed by Potomac Edison to the PSC. They are reconciled annually.

Recovery of Program Costs: All program costs are deferred and amortised over seven years.

Lost Revenues: The LRAM provides for full recovery of net lost margins.

Shareholder Incentives: Potomac Edison could earn a “performance-based shared savings incentive” by attaining specified goals. Achievement is based on aggregate energy saved by all active, approved DSM programs. The incentive is a share of the net savings from each program as calculated using the Total Resource Cost Test (TRC) filed by Potomac Edison and approved by the Commission. In 1998 the aggregate goals and Potomac Edison’s shared savings amounts, after tax, were:

<table>
<thead>
<tr>
<th>% Goal Achieved</th>
<th>% TRC</th>
</tr>
</thead>
<tbody>
<tr>
<td>Less than 80%</td>
<td>0%</td>
</tr>
<tr>
<td>80%-99%</td>
<td>6%</td>
</tr>
<tr>
<td>100%-119%</td>
<td>7.5%</td>
</tr>
<tr>
<td>120% &amp; Over</td>
<td>10%</td>
</tr>
</tbody>
</table>

The pre-tax incentive rate for the 7.5% TRC level is 12.41%. The highest percent incentive determined above applies uniformly to the aggregate total of all net savings of all of the programs used in establishing the goal. Recovery of any incentive awarded through the ECS is based on the actual amount earned in the previous year.

1999

The 1999 restructuring law scheduled a study of the need for energy resource initiatives. The study is to be undertaken in 2001. There may be new DSM initiatives after the study is completed.
Massachusetts

1998

**General Treatment of DSM and its Costs:** The Massachusetts Division of Energy Resources (DOER) is to annually file a report with the Department of Telecommunications & Energy (DTE) on proposed funding levels for energy efficiency programs. The DTE will review and approve energy efficiency expenditures after determining that implementation of such programs will be cost-effective. There are several investor-owned utilities in Massachusetts. This description focuses on the two largest electric utilities and the largest gas utility.

**Energy Efficiency Funding:** A per kWh charge (SBC) was established by law to fund electric utility energy efficiency programs. The 5-year SBC schedule is as follows:

<table>
<thead>
<tr>
<th>SBC Level</th>
<th>Duration</th>
</tr>
</thead>
<tbody>
<tr>
<td>3.3 mills/kWh</td>
<td>3/1/98-12/31/98</td>
</tr>
<tr>
<td>3.1 mills/kWh</td>
<td>1999</td>
</tr>
<tr>
<td>2.85 mills/kWh</td>
<td>2000</td>
</tr>
<tr>
<td>2.7 mills/kWh</td>
<td>2001</td>
</tr>
<tr>
<td>2.5 mills/kWh</td>
<td>2002</td>
</tr>
</tbody>
</table>

For gas utilities, DSM expenditure levels are proposed by the distribution utilities and established by the DTE when it approves the utilities’ DSM Plans.

**Recovery of Program Costs:** Electric utilities receive full program cost recovery for approved programs. DSM budgets are based on the mandated SBC charges multiplied by projected kWh sales. If revenues collected are over or under actual spending in any one year, that difference is reconciled in subsequent years. Gas utilities also receive full cost recovery for approved programs, generally through a non-bypassable per therm charge to all distribution customers that is subject to annual reconciliation. At Boston Gas Co., low income program costs are recovered from all customers, while other Residential, C/I, and Multi-family program costs are recovered on a sector specific basis.

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24 *Electric Utility Restructuring Act, November 25, 1997.*
Lost Revenues: Boston Edison and Massachusetts Electric Company do not collect lost margins. Boston Gas receives net lost margin recovery for three residential DSM programs only.

Shareholder Incentives: Massachusetts Electric Co. For programs resulting in measured savings, if MECO achieves at least 50% of targeted savings it receives a fixed incentive per lifetime kWh and kW saved. In addition, the amount of that volumetric incentive (at 100% of targeted savings) is scaled by the ratio of the target benefit-to-cost (B:C) ratio to the actual B:C ratio realised. This further amount is added to the volumetric incentive, unless the B:C ratio is under 1.0. If all targets and performance thresholds are met for program year 1998, the Company receives an amount equivalent to 7.5% of net benefits, after tax, with a maximum benefit of 8%. On a pre-tax basis the target incentive is equivalent to a 12.9% share of net benefits. There is no penalty. For programs less susceptible to measured savings, such as new construction, support for market-transforming technologies, and support for building codes, a variety of fixed dollar rewards are tied to program-specific performance indices such as the number of program participants.

Shareholder Incentives: Boston Edison Co. BECO can earn incentives on all of its energy efficiency programs. The maximum incentive BECO could earn for 1998 is $2 million. This is based on 11.5% of eligible planned program expenses.

For 1998, if BECO’s achievement of individual program metrics exceeds a performance threshold of 85%, then the maximum incentive for that metric will be earned. If less than 50% of the performance metric is achieved, then no incentive will be earned for that metric. If 50% of the performance metric is achieved, then 50% of the maximum incentive will be earned. If between 50% and 85% of the performance metric is achieved, then the incentive earned will be prorated between 50% and 100% of the maximum incentive for that metric. This incentive structure applies to all programs, whether performance is measured based on actual kWh savings or by a proximate indicator (such as the number of rebates awarded or completing a market assessment study).

75% of BECO’s energy efficiency programs are traditional installation (“retrofit”) programs where success is measured based on kWh savings. The remaining 25% of programs are new programs where proximate indicators based on program activity are used to measure success. In the long run, the measure of success for these programs is expected to switch from the proximate indicators to actual energy savings.

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25 MECO is one of three NEES electric distribution utilities. The others, in New Hampshire and Rhode Island, receive shareholder incentives of similar design.


Shareholder Incentives: Boston Gas Co. For residential and non-residential DSM programs where lost margin recovery is not allowed, BG instead receives performance incentives. These incentives are based on a variety of indices of program activity and documented impacts on the market. Receipt of the full incentive for each indicator depends on actual vs. targeted results, as follows:

<table>
<thead>
<tr>
<th>Actual v. Target</th>
<th>Portion of Full Incentive</th>
</tr>
</thead>
<tbody>
<tr>
<td>&lt;65%</td>
<td>0</td>
</tr>
<tr>
<td>65-85%</td>
<td>75%</td>
</tr>
<tr>
<td>&gt;85%</td>
<td>100%</td>
</tr>
</tbody>
</table>

The maximum performance incentive for 1998 is $600,000.28

1999

In 1999, new shareholder incentive structures are under consideration in the DTE’s generic DSM cost-effectiveness proceeding. In the meantime provisions described above remain in effect.

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Minnesota

1998

**General Treatment of DSM and its Costs:** Utilities file 2-year “Conservation Improvement Plans” with the Department of Public Services (DPS). The DPS makes recommendations on the Plans to the Public Utilities Commission (PUC), which ultimately acts on the Plans. Full recovery of program costs for approved DSM plans, recovery of 75-100% of lost margins, and shareholder incentives are currently in effect for investor-owned utilities. Incentives vary by utility. Three examples are given here.

**DSM Funding:** The 1991 Omnibus Energy Act requires gas utilities to spend 0.5% of gross revenues on Conservation Improvement Plan programs. Investor-owned electric utilities must spend 1.5% annually.

**Recovery of Program Costs:** Utilities are allowed full recovery of program costs for approved DSM programs.

**Lost Revenues:** Minnegasco and Great Plains Natural Gas Company both recover 100% of lost margins. Northern States Power Company recovers 75% of lost margins.

**Shareholder Incentives:** Minnegasco and Great Plains Natural Gas Co. Minnegasco and Great Plains both enjoy the same stepped bonus mechanism. The bonus allows the gas utilities to claim an additional 10% of their actual lost margins if their annualised savings are 75% to 100% of their DSM program savings goal. If annualised savings exceed 100% of the program goal, the utilities may claim an additional 25% of lost margins as a bonus.

**Shareholder Incentives:** Northern States Power. Northern States Power receives a shared savings incentive of 10% of the first 20% of actual net benefits in excess of 100% of planned benefits.

1999

Provisions remain as described above.

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New Hampshire

1998

**General Treatment of DSM and its Costs:** Granite State Electric Co. (GSE) is the only utility in New Hampshire with DSM programs. GSE has been allowed program cost recovery and shareholder incentives since 1990.

**DSM Funding:** Granite State is entitled to recover prudent direct costs of programs which are demonstrated to be cost-effective and consistent with least-cost integrated resource planning principles.

**Recovery of Program Costs:** GSE recovers DSM program costs through a per-kWh charge, allocating the costs of specific programs to the customer classes eligible to participate in those programs. Under- and over-collections are reconciled annually.\(^{31}\)

**Lost Revenues:** There is no LRAM.

**Shareholder Incentives:** GSE's shareholder incentive is a two-part shared savings mechanism. The first part, the maximising incentive, is calculated separately for residential and commercial and industrial (C&I) programs. GSE may earn 5% of the total adjusted program value created by the utility's residential programs and 3.5% for C&I programs. Total adjusted program value is program value net of program evaluation costs and customer direct costs.

The second part, the efficiency incentive, is equal to 10% of total adjusted program value less the costs associated with producing those savings and less the amount of the maximising incentive. The total program value created by GSE's DSM programs depends on both the number and type of kW and kWh saved by the programs.

GSE's incentives are subject to a threshold equal to 50% of projected value of DSM program net savings. Once the utility has achieved the threshold, it may earn the incentive based on the entire value achieved. GSE recovers incentives in the year following the year during which they were earned.

1999

Provisions remain as described above.

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New Jersey

1998

General Treatment of DSM and its Costs: Recovery of utility expenses for approved DSM plans, lost margins, and shareholder incentives have been available under the NJ DSM rule adopted by the Board of Public Utilities (BPU) in late 1991. Approved costs are recovered from ratepayers as a whole.

DSM Funding: DSM expenditure levels are proposed by the distribution utilities and established by the BPU when it approves the utilities’ DSM Plans. Under the 1999 law providing for the restructuring of the electric and gas industries, minimum levels of statewide funding for energy efficiency programs are established for the period 2000 through 2008. DSM funds are being and will be collected as a component of the Societal Benefits Charge levied at the distribution level. Initial SBCs were established for the electric utilities in the latter part of 1999.

Recovery of Program Costs: Full program cost recovery is effected through DSM cost recovery riders that are periodically reconciled, and now included as a component of utilities’ SBCs.

Lost Revenues: Net lost revenue recovery is allowable for “performance-based” programs as discussed below.

Shareholder Incentives: Utilities may offer “performance based” DSM in two forms.

1. Shared savings. The utility may propose a share of net resource benefits. The state's second largest utility, GPU Energy, chose the shared savings alternative. That utility received a 25% share of all net benefits from performance-based programs under its first DSM Plan. No share was included in its second Plan, now in effect, because of the very small expected net resource benefit. Performance-based programs have been the greater portion of the Company's DSM budget.

2. Standard pricing offer (SPO). Under the SPO, the utility pays a price to customers and ESCOs for verified DSM savings. This price is somewhat less than avoided costs plus environmental externality benefits. The utility's opportunity to profit comes from its ability to procure saved m³ of gas or kWh

33 NJ also requires utilities to deliver certain "Core" public benefit DSM programs such as low-income services and new construction programs, for which no incentives other than full program cost recovery are available.
34 NJAC 14:12, Chapter 3. There are no penalties in the NJ rule. However, if net resource benefits are negative the utility receives its share of negative benefits using the shared savings percentage in its approved plan.
of electricity through its own for-profit conservation subsidiary. The largest utility, Public Service Electric & Gas Co., chose the SPO, depending upon contracts with its energy conservation subsidiary as a source of shareholder profit from DSM. Expenditures for the SPO have been the greater part of the Company's DSM budgets.

1999

In 1999, new shareholder incentive structures were under consideration in the BPU’s “Comprehensive Resource Analysis” proceeding. In the meantime, provisions described above remain in effect.
Rhode Island

1998

**General Treatment of DSM and its Costs:** Recovery of program costs and shareholder incentives are currently in effect for investor owned utilities.

**DSM Funding:** By law, an SBC of 2.3 mills/kWh is to be collected by all RI electric utilities to fund energy efficiency and renewable energy resources. The charge is to be collected for a 5-year period, which began January 1, 1997. In 1998, the SBC was expected to raise $19.9 million, of which $1.3 million was to go towards renewable energy resources, and $18.6 million towards energy efficiency.

**Recovery of Program Costs:** Full recovery of costs for approved DSM programs is provided for.

**Lost Revenues:** No LRAMs are in place.

**Shareholder Incentives:** Shareholder incentives have been in existence since 1990. Utilities receive a small percentage of the savings that are achieved through DSM measures (SSM). The SSM is designed so that utilities are given an incentive to maximise the amount of savings achieved through their DSM programs as well as administer them as cost-effectively as possible. Provisions are similar to those for Massachusetts Electric Company (Massachusetts) and Granite State Electric (New Hampshire) as described above.

1999

Provisions remain as described above.

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36 Kilmarx, Mary, RI PUC, Phone interview, August 14, 1998.
Annex 3: Demand Side Management Incentive Mechanism for 2000

The 2000 DSM incentive mechanism for West Kootenay Power is a shared savings mechanism (SSM). It is based on recommendations in the study of DSM incentive mechanisms for WKP by David Nichols of the Tellus Institute. It may be extended to 2001 and 2002 upon consensus of the DSM Committee at the next annual review.

The SSM has been the most commonly used shareholder incentive during the 1990s. This approach provides WKP with a share of the net benefits from its DSM activities. Benefits are defined as the value of avoided energy and capacity costs and deferred capital expenditures. All utility program costs and the customer costs of energy efficiency are deducted from the benefits to arrive at net benefits. This mechanism sends the signal to maximize the resource savings per dollar spent on energy efficiency measures. The SSM provides for a small share of the life-cycle benefits as a potential reward to the shareholders. It also introduces a penalty for not achieving a threshold level of net benefits.

The SSM approach requires both the power savings and the resource benefits flowing from those savings to be quantified. The benefits are calculated over the lifetimes of the DSM measures put into place. WKP will receive a share of the total net present value of these life-cycle benefits.

Gross Benefit Values
For 2000, the benefits are valued at 2.6¢ for each kWh (energy savings) and $28 for each annual kW (capacity savings) and $36 for each annual kW saved from peak (deferred capital expenditures). The lifetimes of DSM measures range from 5 years to 20 years.

SSM Incentive or Penalty Rates
The DSM Committee modified the report recommendation by introducing different incentive or penalty levels based on WKP’s performance compared to Plan Net Benefits in 2000 for each of the three sectors. Incentives for the sectors are calculated for performances of 100% to 150% of the plan net benefits. There is no calculation for performance between 90% and 100% of plan net benefits for the residential sector and 95% and 100% for the general service and industrial sectors. Calculations for performances less than 90% for residential and less than 95% for general service and industrial result in negative amounts. Maximum penalty is applied to performances of less than 50% of plan net benefits. If the sum of the sector results is greater than zero,
then the sum is the DSM incentive for WKP for the year. If the sum is less than zero, then there is no DSM incentive for WKP for the year and no penalty is charged.

| TABLE A for Incentives (+) or Penalties (-) at Selected Performance Levels |
|---------------------------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|
| % of Plan Net Benefits          | <50% | <70% | <90% | <95% | 95-100% | >100% | >110% | >120% |
| Residential                     | -6.0% | -4.5% | -3.0% | 0.0% | 0.0% | 3.0% | 4.5% | 6.0% |
| General Service                 | -4.0% | -3.0% | -2.0% | -1.0% | 0.0% | 2.0% | 3.0% | 4.0% |
| Industrial                      | -3.0% | -2.0% | -1.0% | -0.5% | 0.0% | 1.0% | 2.0% | 3.0% |

Plan Net Benefits for 2000
For purposes of the SSM, Table B is WKP’s Plan Net Benefits for 2000:

<table>
<thead>
<tr>
<th>TABLE B (with maximum and minimum values of +/- 50% of plan)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sector ($000)</td>
</tr>
<tr>
<td>Residential</td>
</tr>
<tr>
<td>General Service</td>
</tr>
<tr>
<td>Industrial</td>
</tr>
</tbody>
</table>

This plan will form the basis for the application of incentives or penalties from Table A. For incentive purposes, WKP expenditures will be capped at 110% of the planned $1254K for program delivery. Planning and evaluation expenditures of $288K will not form part of the incentive calculation. DSM expenditures and targets for 2001 and 2002 will be established at the WKP annual reviews proceeding each year.