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March 3, 2014

<u>Via Email</u>
Original via Mail

Industrial Customers Group
c/o #301 – 2298 McBain Avenue
Vancouver, BC
V6L 3B1

Attention: Mr. Robert Hobbs

Dear Mr. Hobbs:

Re: FortisBC Inc. (FBC)

Application for Approval of a Multi-Year Performance Based Ratemaking Plan for 2014 through 2018 (the Application)

Rebuttal Evidence to the Evidence of Mr. Anthony Pullman, CA on behalf of the Industrial Customers' Group (ICG)

FBC respectfully submits the attached Rebuttal Evidence to the Evidence of Mr. Anthony Pullman, CA, on behalf of ICG, in accordance with the British Columbia Utilities Commission (BCUC or the Commission) Order G-10-14, establishing the Regulatory Timetable for the above noted proceeding.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC INC.

Original signed:

Dennis Swanson

Attachments

cc (email only): Registered Parties

FortisBC Inc. (FBC) Application for
Approval of a Multi-Year Performance Based Ratemaking Plan for
2014 through 2018

Rebuttal Evidence
of
FortisBC Inc.
to Evidence of Anthony Pullman, CA (ICG)

March 3, 2014

Q1: What is the purpose of this Rebuttal Evidence?

A1: The purpose of this Rebuttal Evidence is to provide FBC's response to aspects of the evidence of Mr. Anthony J. Pullman in FBC Exhibits C10-5, C10-7, C10-8 and C10-9, filed on behalf of the Industrial Customers Group (ICG). FortisBC disagrees with a number of aspects of Mr. Pullman's evidence. Our silence on particular matters in that evidence should not be construed as agreement.

Q2: Mr. Pullman states the following with respect to the practice of capitalizing overhead used by FBC:

> **A. The first item that struck my attention was the increase in capitalized overhead as a percentage of unloaded gross capex. …. As can be seen in the table the percentage has increased from less than 5% in 2004 to almost 30% in 2012. On a prima facie basis this would suggest that FBC's overhead capitalization policy requires further scrutiny. (Direct Evidence of Anthony J. Pullman, FBC Exhibit C10-5, pages 1-3)**

What is FBC's response to this statement?

A2: This statement and Mr. Pullman's subsequent calculations suggest that ICG has misunderstood the concepts of direct overhead and capitalized overhead. In calculating the increase in capitalized overhead as a percentage of unloaded gross capital expenditures, ICG has included not only the ratio for capitalized overhead as a percentage of unloaded gross capital expenditures, but also the ratio for direct overhead as a percentage of unloaded gross capital expenditures. This inclusion of direct overhead in capitalized overhead as a percentage of unloaded gross capital expenditures is not appropriate, and it should have been excluded from Mr. Pullman's calculations.

It also appears that Mr. Pullman has misunderstood that the direct overheads differ from capitalized overheads and that they are simply the result of a more efficient methodology to allocate costs that are directly associated with transmission and distribution capital projects, which would otherwise be direct charged to capital projects. Direct overhead is a direct cost that should be included in the total gross capital expenditures.

To properly consider capitalized overhead as a percentage capital expenditures, Mr. Pullman should have divided capitalized overhead by total capital expenditures including direct overhead. When the calculations are performed correctly, capitalized overhead as a percentage of unloaded gross capital expenditures for the periods 2004 to 2013 and 2014 to 2018 are as follows:

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013 Projection
Total Loaded Gross Capital Expenditure (1)	A	88,838	115,387	110,663	146,741	116,604	117,225	149,910	93,632	68,388	95,427
Less: Capitalized Overheads	B	2,563	3,392	8,382	8,836	9,062	9,315	9,529	10,777	10,969	11,524
Capital Expenditures net of Capitalized Oveheads	C	86,275	111,995	102,281	137,905	107,542	107,910	140,381	82,856	57,420	83,903
Capitalized Overheads as a % of C	D = B/C	3.0%	3.0%	8.2%	6.4%	8.4%	8.6%	6.8%	13.0%	19.1%	13.7%

Source: FBC Response to ICG IR2.29.2 [2013 added]

		2014	2015	2016	2017	2018
Total Loaded Gross Capital Expenditure (1)	A	98,303	95,073	81,541	110,801	103,933
Less: Capitalized Overheads	B	12,277	12,349	12,192	12,476	12,660
Capital Expenditures net of Capitalized Oveheads	C	86,026	82,724	69,349	98,325	91,273
Capitalized Overheads as a % of C	D = B/C	14.3%	14.9%	17.6%	12.7%	13.9%

Source: FBC Response to BCUC IR 1.19.3

Note (1) including AFUDC

Q3: In his response to information requests made by the Commission (FBC Exhibit C10-7), Mr. Pullman states the following with respect to including debt in rate base:

> **"FBC proposes to include the costs of raising its debt in its rate base and earn a full return on it. This is somewhat unusual and I recommend that it earn no return at all, and be amortized into the weighted average cost of debt" (Exhibit C10-5, Direct Testimony, p 17).**
>
> **12.2 Please explain and provide additional justification as to why the FBC practice is considered "unusual". What would the "normal" practice be for other comparable utilities?**
>
> **Response:**
>
> **Mr. Pullman considers the normal practice to be for a utility to defer the discount (if any) and the expenses of an issue of debt and to include in the embedded cost of that issue an amount that will amortize the original cost of the issue over the life of the debt.**
>
> **To illustrate, FBC states in its Application that it plans an issue of 30-year bonds, at a cost of \$1.6 million. The method normally followed recovers the costs of \$1.6 million over the life of the bonds (bullet repayment assumed). FBC's proposal requires its customers to pay an additional \$1.488 million return on "rate base" and \$0.203 million in income taxes over the same period.**

What is FBC's response?

A3: FBC's recovery and recognition of debt issuance costs in rate base is a reasonable and accepted practice. FBC forecasts its revenue requirements including the amortization of its debt issue costs over the life of the related debt which results in a recovery period consistent with what has been implied as "normal practice".

FBC's treatment of recognizing debt issuance as a deferred charge is consistent with US Generally Accepted Accounting Principles (US GAAP), which FBC is approved to use for 2014 pursuant to Commission Order G-117-11. US GAAP permits transactions costs incurred in respect of financial liabilities, such as debt issuance costs, to be deferred and recognized on the balance sheet as either a separate asset or as a reduction of the carrying value of the debt. Accounting Standards Codification 835-30-45-3 (see Appendix A) states that "issue costs shall be reported in the balance sheet as a deferred charge" which is consistent with Exhibit B-1, FBC's Application for Approval of a Multi-Year Performance Based Ratemaking Plan for 2014 through 2018 (the 2014-2018 PBR Application), which recognizes debt issue costs in rate base.

The inclusion of debt issuance costs in rate base is consistent with decisions in other jurisdictions, as described in the 2014-2018 PBR Application, Section D3 on page 248, which stated the following (emphasis added):

> As part of the Alberta Utilities Commission (AUC) Decision 2010-309 (July 6, 2010) for FBC's sister company, FortisAlberta Inc.'s (FAI) 2010-2011 Distribution Tariff Phase 1, the AUC elaborated on the financing of deferred debt issue costs to summarize its position how all deferral expenditures should be financed, as follows:
>
> > *"similar to tangible assets, these costs are capitalized and recovered through amortization charges over a period of years. This creates an intangible or financial asset that is effectively a long-term receivable to be collected over time from customers. Since necessary working capital is a part of rate base, the change indicated by FAI to classify this intangible asset as rate base rather than working capital does not affect the revenue requirement. The Commission considers that a deferred debt cost is a rate base asset that must be financed like any other rate base asset. Such an asset should be financed, like any other component of rate base, using the weighted average cost of capital and should not be considered to be financed by debt alone."*

Q4: With respect to FBC's overhead capitalization methodology, Mr. Pullman expresses the following concern:

> **Another problem with the methodology with its high effective rate of capitalization is that it engenders a belief among the utility management that every incremental dollar of O&M only has an impact of 80 cents on the revenue requirement. The consequences of this may include the danger that management incurs more O&M than it needs to and that interveners and other stakeholders focus on the 80 cents recovered rather than the full dollar spent (FBC Exhibit C10-5, pages 7-8).**

What is FBC's response to this statement?

A4: This apparent concern that FBC's methodology reduces management's attention on cost control by virtue of focusing on Net O&M does not accurately reflect the business practices utilized by FBC. The Company manages its costs on a Gross O&M basis. Department Managers at FBC do not see or receive credit for expenses associated with capitalized overhead, which is instead reported at the corporate-level only. Every month, Department Managers must review Gross O&M expenses, and must justify any variances between their actual Gross O&M expenses and the amounts that were budgeted. Accordingly, FBC's Departmental Managers are not influenced by Net O&M.

Q5: In FBC Exhibit C10-7 (BCUC IRs 1.9.1-1.9.3), Mr. Pullman responded to general questions from the Commission regarding the objectives of capitalizing versus expensing DSM expenditures. Further, in response to BCUC IR 2.2.3.2, (FBC Exhibit C10-9), ICG states that "In Mr. Pullman's view, sound rate making principles suggest that DSM expenditures should be recovered on a pay as you go basis."

What is FBC's response?

A5: Mr. Pullman does not specifically identify the rate-making principles upon which he relies for this conclusion.

The capitalization of DSM expenditures is consistent with regulatory principles. This issue of the appropriate treatment of DSM expenditures was analyzed in depth in a report prepared by Deloitte & Touche, entitled "Accounting for DSM Expenditures" (February 1991) (the "**Deloitte Report**"). A copy of the Deloitte Report is attached as Appendix B. The Deloitte Report was prepared for the Canadian Electrical Association, following a study of the accounting for DSM expenditures.

The Deloitte Report analyzes various methodologies that may be used to account for DSM expenditures, in the context of both the relevant accounting and regulatory considerations. While both capitalization and expensing DSM expenditures are considered, the Deloitte Report concludes that "Where there is reasonable assurance that a DSM expenditure will result in future benefit, it should be deferred and amortized as the future benefit is realized." (at p. ix). This conclusion is based on the fact that only capitalization satisfies the matching principle which requires that the costs of a regulated entity be matched to the period that benefits from the incurrence of the costs, and be recovered from customers in that same period (at pp. 22, 24). Likewise, only capitalization satisfies the principle of intergenerational equity, which recognizes that customers in any given time period should only be responsible for the costs necessary for them to be provided with service in that period, and should not be required to pay costs associated with providing customers with service in another time period (at pp. 21, 24). The analysis in the Deloitte Report of these regulatory issues is consistent with FBC's understanding.

Allowing the capitalization of DSM expenses also provides an incentive for utilities to maintain or increase DSM spending. In the article "DSM in the Rate Case" (B. Hedman & J. Steiner, Public Utilities Fortnightly (January 2013) at p. 34), attached as Appendix C, the authors note that "few jurisdictions continue to treat DSM as a simple operating and maintenance expense" (page 35, as doing so can create a disincentive for the utility to maintain or increase DSM spending between rate cases). This disincentive arises because between rate cases, any upward variance from costs projected erodes the bottom line, while decreasing DSM spending has the opposite effect of increasing returns for shareholders of the utility (at pp. 35-36). In contrast, allowing utilities to capitalize their DSM expenditures through deferral accounting and to amortize them over time, allows utilities to earn the same rate of return on the deferred balance as for any other capital assets. The article notes that there has been a recent resurgence in capitalization, as it most matches how supply-side resources are treated (at p. 36).

Further, in recommending that the Commission order FBC to cease capitalizing certain DSM-related expenditures, Mr. Pullman has ignored the very sizable rate impact that would result from expensing FBC's forecast 2014 $3.0 million (net of tax) DSM expenditures.

Further, Mr. Pullman cites the 2006 Summit Blue Report to CAMPUT (FBC Exhibit C10-7, ICG Response to IRs BCUC, 1.9.1-1.9.3) (the **CAMPUT Report**), in support of his position that most utilities in the United States commonly expense certain DSM-expenditures. However, the CAMPUT Report was prepared in 2006, and the Commission has since then considered the issue of capitalizing versus expensing expenditures, and found that it was appropriate to allow FEI to increase the degree to which it capitalizes Energy Efficiency and Conservation (EEC) Expenditures (Decision G-36-09). Accordingly, while certain DSM-expenditures may be expensed in the United States, the same practice has not been adopted in British Columbia. The CAMPUT Report is also inconsistent with the conclusions of the recent DSM Rate Case Article, cited above, which was prepared in 2013.

Q6: Does this conclude your Rebuttal Evidence?

A6: Yes.

Appendix A

US GAAP ASC INTEREST

Appendix A – US GAAP - ASC Topic 835-30-45-3, *Interest-Imputation of Interest*

General

COMBINE SUBSECTIONS ? RELATED EXPOSURE DRAFT ?

45-1 The guidance in this Section does not apply to the amortization of premium and discount and the debt issuance costs of liabilities that are reported at fair value.

SUBMIT FEEDBACK ? SUBMIT ANNOTATION ?

45-1A The **discount** or **premium** resulting from the determination of present value in cash or noncash transactions is not an asset or liability separable from the note that gives rise to it. Therefore, the discount or premium shall be reported in the balance sheet as a direct deduction from or addition to the face amount of the note. It shall not be classified as a deferred charge or deferred credit.

XBRL ELEMENTS ? SUBMIT FEEDBACK ? SUBMIT ANNOTATION ?

45-2 The description of the note shall include the effective interest rate. The face amount shall also be disclosed in the financial statements or in the notes to the statements.

XBRL ELEMENTS ? SUBMIT FEEDBACK ? SUBMIT ANNOTATION ?

45-3 Amortization of discount or premium shall be reported as interest expense. Issue costs shall be reported in the balance sheet as deferred charges.

XBRL ELEMENTS ? SUBMIT FEEDBACK ? SUBMIT ANNOTATION ?

Appendix B

ACCOUNTING FOR DSM EXPENDITURES 1991

Report for the

CANADIAN ELECTRICAL ASSOCIATION
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9003 U 765

ACCOUNTING FOR DSM EXPENDITURES

PREPARED BY:

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M5X 1B3

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Keith Boocock

FEBRUARY 1991

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ABSTRACT

This purpose of this study is to identify and analyze potential methods of accounting for DSM expenditures, identify existing practice used by North American Utilities, identify regulatory considerations of alternatives and identify the incentive and disincentive impacts for DSM expenditures.

The study reviews the nature of DSM expenditures. It sets out the accounting principles relevant to the treatment of DSM expenditures and, due to the ability of the regulatory process to affect what has to be accounted for, relevant regulatory principles. It also reviews the incentive impact of accounting alternatives. This is followed by a summary of the results of a survey of the accounting treatment for DSM expenditures by electric utilities. Finally, conclusions and recommendations are presented.

Keywords: Demand side management; conservation and load management; accounting; regulation

ACKNOWLEDGMENTS

We are grateful to the electrical utilities that responded to the survey on accounting for DSM expenditures. We would also like to thank Mr. R.E. Johnson and Mr. P.J. Elliott of Nova Scotia Power who were the technical advisors on this project and assisted the project team with their inciteful comments and advice.

SUMMARY

The Canadian electric utility industry is placing a growing reliance on demand side management (DSM). In the past, DSM expenditures were generally immaterial, however, their growth requires that they be properly accounted for. As a result, the Canadian Electrical Association has requested Deloitte & Touche to undertake a study of the accounting for DSM expenditures. The specific objectives of the study are:

a) Identify potential methods to deal with DSM costs and the theoretical accounting considerations associated with each method.

b) Inventory practices used by North American Utilities.

c) Identify regulatory considerations of each alternative as it would affect electricity rates.

d) Identify the different incentive and disincentive mechanisms for DSM programs.

For purposes of this study, DSM activities have been classified as research and development, investment, information, subsidy or rate activities.

This study reviews the nature of DSM expenditures, the accounting and regulatory principles relevant to DSM expenditures and the incentive impact of accounting alternatives. In addition, it presents the results of a survey of electric utilities on the accounting treatment for DSM expenditures. Finally, conclusions and recommendations are presented.

DSM EXPENDITURES

The purpose of DSM is to improve economic efficiency by reducing demand. In some cases, the marginal cost of power exceeds the value that customers attribute to it. A reduction in demand

decreases both revenues and the cost of providing power. As long as the reduction in costs exceeds the reduction in revenues, there will be a net benefit available to reduce total revenue requirements for the remaining level of service. In some cases, the cost savings will accrue directly to customers, thereby justifying DSM expenditures even when the net benefit to the utility is negative.

The reduction in costs may include both operating and capital related costs. The operating costs will tend to vary with the level of demand. The capital related costs, consisting of depreciation and financing costs, will depend on both the impact of DSM on demand and the level of surplus capacity. If the DSM expenditure results in a reduction in demand at a time that a new plant would otherwise be required, the savings will equal what the depreciation and financing costs would have been on the entire plant over the period that the plant is deferred.

ACCOUNTING PERSPECTIVE

Generally accepted accounting principles (GAAP) require that where there is reasonable assurance that DSM expenditures will result in a future economic benefit, the expenditures should be deferred and amortized over the period that the benefit is expected to be received. In all other cases, the expenditures should be expensed as incurred.

Regulatory bodies cannot determine GAAP, however, they can determine what costs a utility will be allowed to recover through rates and the period in which it will be able to recover the costs. Therefore, regulation can affect the amount and timing of a utility's cash flows and what should be reported in accordance with GAAP. Where a regulatory body defers DSM expenditures for recovery through future rates and it is reasonable to assume that the utility will be allowed to charge and collect such amounts from its customers, there will be a future economic benefit. Accordingly, the DSM expenditures should be deferred for accounting purposes and amortized as the expenditures are collected through rates. Where a regulatory body allows recovery of DSM expenditures in current rates or disallows the expenditures, it is unlikely that there will be any future economic benefit associated with the DSM expenditures. In such cases, the expenditures should be expensed.

Where significant, financial statements should report the amount of DSM expenditures incurred and expensed during the period and unamortized at the end of the period. This reporting may be in the financial statements, notes to the financial statements or supporting schedules. Also, where significant, the accounting policies related to the DSM expenditures should be reported in the notes to the financial statements.

REGULATORY PERSPECTIVE

The cost of service standard requires that a utility be allowed the opportunity to recover its DSM expenditures, including the cost of capital on any deferred DSM expenditures. Historically, DSM expenditures have been expensed in the period incurred, however, the amounts have generally been immaterial. With the growth in DSM expenditures, reliance on the principle of materiality may no longer be appropriate.

Where any of the benefits of a DSM activity are expected to be received in a future period, the matching principle requires that an associated portion of the costs should be deferred and recovered from those future periods. Problems can arise in quantifying the benefits of specific DSM activities and the timing of the benefits, however, this is also true of fixed assets that regulators require to be capitalized. More importantly, failure to defer the expenditures will result in current customers paying costs required to provide service to future customers, which is contrary to the principle of intergenerational equity.

The principle of rate stability and predictability may support either the deferral or expensing of DSM expenditures. For example, DSM expenditures are not necessarily incurred at an even rate in each year, therefore, deferral with amortization over a period of years would tend to increase the stability of rates. Alternatively, a utility may be faced with large cost increases in the future, therefore, immediate expensing rather than deferral would tend to improve rate stability.

INCENTIVE IMPLICATIONS

A utility should be indifferent to expensing or deferring its DSM expenditures as long as the utility is allowed to recover all of its costs, including the cost of financing any deferred DSM expenditures. However, to the extent that expensing or deferring creates an incentive, the strongest incentive to undertake DSM expenditures will tend to come with allowing the utility to recover and expense its expenditures in the period that the related benefit is received. This is consistent with the treatment that is normally applied to supply side costs and will result in the greatest comparability between demand side and supply side options. Moreover, it is consistent with what would normally be required by both accounting and regulatory principles.

SURVEY OF ELECTRIC UTILITIES

A survey on accounting for DSM expenditures was developed and sent to 31 Canadian electric utilities and 39 United States electric utilities. A total of 27 utilities responded and indicated that they had formal DSM programs. A problem with the results is that it is only recently that electric utilities have had significant DSM expenditures and, for many utilities, the amounts are still immaterial. As a result, existing practice may not be a good guide for future practice.

The survey indicated a bias to expensing DSM expenditures, especially in the U.S. This may be due to the historically immaterial level of these amounts. Where capitalized, it has generally been required that there be reasonable assurance of recovery in future rates and the existence of a future benefit. The amortization period has been based on the life of the asset, a pre-determined period or the life of the benefit.

Generally, neither the amount of DSM expenditures nor any unamortized amounts are disclosed separately in the financial statements. Moreover, the accounting policies for DSM expenditures are generally not disclosed. This may be due to the historically immaterial level of these amounts.

Except for one utility, all respondents stated that there were no differences between the accounting and regulatory treatment of their DSM expenditures.

CONCLUSIONS AND RECOMMENDATIONS

Where there is reasonable assurance that a DSM expenditure will result in a future economic benefit, it should be deferred and amortized as the future benefit is realized. In all other cases, the expenditure should be expensed.

Regulation can affect the amount and timing of cashflows and, therefore, whether or not there is a future economic benefit. Accordingly, in most cases, DSM expenditures that are deferred for regulatory purposes should be deferred for accounting purposes and amortized as the expenditures are recovered through rates.

The recommendations for the costs of the specific DSM activities are as follows.

a) Research and development expenses would normally be expensed as incurred. However, for regulatory purposes, it may be appropriate to defer the costs and amortize them over a short period of time, e.g., three to seven years. If this is done for regulatory purposes, it should also be done for accounting purposes.

b) The cost of new assets should be expensed over the useful life of the asset while the undepreciated cost of any replaced assets should be allocated over the period that benefits from the early replacement.

c) The cost of information activities should generally be expensed as incurred.

d) The cost of subsidy activities should be deferred and amortized over the period that benefits from the subsidy.

e) There are generally no expenditures related to rate activities to account for.

CONTENTS

APPENDICES

A - REGULATORY EVALUATION OF DSM ACTIVITIES

B - LIST OF SURVEY RESPONDENTS

C - SUMMARY OF SURVEY RESULTS

1. INTRODUCTION

The Canadian electric utility industry is placing a growing reliance on demand side management (DSM) to improve the efficiency with which it provides for electric power demand. Some utilities have had DSM activities in the past, however, it is only in recent years that major expenditures have been made.

DSM is part of least cost planning (LCP) which is designed to meet customer energy requirements in the most efficient manner, with an adequate degree of reliability. LCP includes both supply side management, which is concerned with the provision of a given supply of power in the most efficient manner, and demand side management, which has been defined as:

> "Actions taken by a utility or other agency intended to influence the amount or timing of customer's use of electricity. These actions can be divided into three groups: load growth, load shifting; and load reducing, which usually involves efficiency improvements."[1]

Although DSM can be directed to load growth with a view to the efficient use of fixed capacity and the achievement of economies of scale, the current focus has been on load shifting and load reduction. In fact, DSM is frequently referred to as conservation and load management (CLM).

The key rational for DSM is that the marginal cost of electric power generally exceeds the marginal value of the power to customers. Hence, amounts spent to induce customers to freely reduce their demand can result in net savings -i.e., reduction in costs less the value of load avoided - that exceeds the cost of the DSM programs.

DSM will change the costs and revenues of an electric utility, both through the cost of the DSM activities and through the impact of the activities on demand. The accounting principles employed

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1 Canadian Electrical Association, Demand Side Management in Canada - 1990, Canadian Electrical Association, Montreal, p.142.

to report these impacts are important because of their affect on the measured performance of the utilities.

- To the extent that the measured performance influences the perceived financial viability of the utility and the performance of its management, the accounting principles will affect the ability and incentive of a utility to take on DSM activities.

- To the extent that accounting principles are used in setting rates, the principles will affect the rates that customers will pay.

In the past, DSM expenditures were generally immaterial, however, their growth requires that they be properly accounted for. As a result, the Canadian Electrical Association (CEA) has requested Deloitte & Touche to undertake a study of the accounting for DSM expenditures. The four objectives that the CEA set for the study are as follows:

a) Identify potential methods to deal with DSM costs and the theoretical accounting considerations associated with each method.

b) Inventory practices used by North American Utilities.

c) Identify regulatory considerations of each alternative as it would affect electricity rates.

d) Identify the different incentive and disincentive mechanisms for DSM programs.

For purposes of this study, DSM activities have been classified as research and development, investment, information, subsidy or rate activities.

a) Research and development activities consist of basic research on DSM, feasibility studies, pilot projects, etc. Research and development could be undertaken for any one of the following activities but, due to the similar nature of all such expenditures, research and development have been considered to be a separate category.

b) Investment activities consist of asset purchases by a utility to reduce or shift load, where the equipment is owned by the utility. These activities would include upgrading street lighting, improving the insulation of utility owned buildings, installing equipment that allows the utility to control the power usage of selected customers at peak periods, etc.

c) Information activities attempt to make consumers aware of energy efficiency and how they can benefit from it. They may also inform manufacturers, distributors and retailers of a potential market for energy efficient products or products that would assist conservation. These activities would include advertising programs, the creation and distribution of informational pamphlets and the provision of consulting services to assist consumers in identifying how they can reduce their energy demand.

d) Subsidy activities provide cash or low interest loans to encourage customers to make energy efficient investments. They would include subsidies to improve insulation, to replace lighting fixtures with newer more energy efficient fixtures and to chose more energy efficient appliances and equipment when making a new purchase.

e) Rate activities create rate differentials to encourage customers to switch demand from the peak to off-peak period or to reduce demand.

In the next section, the nature of DSM expenditures is reviewed to identify what has to be a accounted for. Next, the accounting principles that should guide the treatment of DSM expenditures are set out. Due to the ability of the regulatory process to affect what has to be accounted for, relevant regulatory principles are reviewed. Since there may be a concern as to the incentive impact of accounting alternatives, these impacts are reviewed. This is followed by a summary of the results of a survey of electric utilities on the accounting treatment for DSM expenditures. Finally, conclusions and recommendations are presented.

2. DSM EXPENDITURES

The purpose of DSM is to improve the efficiency of providing for energy demand. Economic efficiency is achieved where the marginal benefits of electric power use are just equal to the marginal cost of providing that power. Where the costs exceed the benefits, efficiency gains can be made from reducing demand. Similarly, where benefits exceed costs, efficiency gains can be made from increasing demand. Utilities use DSM to either decrease or increase customer demand so that the difference between the marginal revenue and marginal cost is reduced. As stated in the introduction, the focus of this study is on reducing demand.

REQUIREMENT FOR DSM PROGRAMS

Customers will react to the price of electric power. They will tend to use power as long as the marginal benefit of usage exceeds the price they must pay and will tend to reduce demand if the marginal benefit falls below that price. Therefore, in theory, pricing electric power at its marginal cost should result in the efficient use of electric power. However, these theoretical objectives are not always achieved primarily as a result of one of the following situations:

a) average cost pricing;

b) informational problems;

c) breakdown between cost and usage;

d) financial barriers, and

e) social costs (i.e., negative externalities).

Average Cost Pricing

Electric utilities use their least cost generating sources first. As demand rises, they turn to increasingly more expensive sources. The marginal cost of meeting demand is equal to the costs of the last generating unit added while the average cost is lower due to the inclusion of lower cost units. Since Canadian electric utilities set prices on the basis of average cost, the marginal cost of electric power tends to exceed its price.

The problems with average cost pricing are accentuated by the use of embedded or historical costs. The cost of expanding or replacing capacity generally exceeds the embedded cost. Therefore, to the extent that demand requires the expansion or replacement of capacity, the difference between the marginal and average cost will be increased.

With average cost pricing, DSM expenditures will improve economic efficiency as long as they are less than the difference between the supply cost avoided and what average cost would be with the expanded demand.

Informational Problems

Customers are not always aware of the benefits of conservation. For example, they may not have information on the savings from insulation or what it would cost. Customers also face costs in searching out conservation alternatives, finding a reliable contractor, etc. Manufacturers, distributors and retailers may not be aware of the potential market for energy efficient products or products that can assist customers in conserving energy. In such cases, the cost of providing information on the benefits of conservation, how conservation can be achieved, reliable contractors or potential markets may increase economic efficiency. This would be the case where the cost of the information program was less than the difference between the net value[2] to the customer of the electric power saved and the supply cost avoided.

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2 The net value would equal the price of the power avoided due to the conservation measure less the cost incurred by the customer to achieve the conservation.

Breakdown Between Cost And Usage

A direct relationship between the cost of electric power and its usage is not always present. For example, in some apartments, electricity is included in the rent which does not vary with the amount of electricity used. As a result, customers will tend to treat the usage of electricity as if it were free. In such a case, DSM expenditures up to the supply cost avoided would improve economic efficiency.

Financial Barriers

Some customers may have extremely high discount rates, and in the case of customers without cash or available credit, the rates may be infinite. This will result in a bias against any investment in conservation. Hence, efficiency can be improved by having the utility finance the conservation investment and recover the associated costs through rates.

Social Costs

The production of electric power imposes social costs that are generally not reflected in the price of electric power. For example, the use of fossil fuels to generate power produces pollution. Since these costs are not reflected in rates, customers will tend to ignore social costs in determining their usage. Therefore, DSM expenditures up to the amount of social costs avoided would improve overall economic efficiency; however, exact or even crude approximations of these costs is difficult.

IMPACT OF DSM ACTIVITIES

The key objective of DSM activities is to reduce demand so as to improve economic efficiency. A reduction in demand will have a negative impact on revenues but will also reduce costs, both operating and capital related costs.

a) The operating costs would include fuel costs and any savings would generally be directly related to the reduction in demand.

b) The capital related costs would include both the cost of capital expenditures, which is reflected in depreciation, and the cost of financing the unrecovered capital expenditures. Due to the discrete nature of capital expenditures, the reduction in these costs will depend on both the reduction in the level of demand and the level of surplus capacity. For example, a DSM investment activity may produce a reduction in demand over a period in which there is excess capacity. In such a case, there would be no impact on capital expenditures and, therefore, no reduction in the capital related costs. However, if the activity occurred in a period where the results allowed a major generating plant to be deferred, the reduction in capital related costs would equal the savings in depreciation and financing costs for the entire plant over the deferral period.

DSM activities may also reduce costs to customers. To the extent that the activities encourage customers to reduce demand, there is a savings to customers equal to the price of the power saved less any costs to the customers associated with conserving, e.g., purchasing additional insulation.

In many cases, DSM activities can provide benefits to all. By reducing demand, the activities reduce both revenues and costs, providing a net benefit equal to the difference. Where the net benefit is more than the cost of the DSM activities, the revenue requirements to meet the remaining demand will be reduced, allowing a reduction in rates. However, where there is not a net benefit or the net benefit is less than the cost of the DSM activities, an increase in rates will be required.

DSM expenditures that require an increase in rates may still be economically efficient. For example, informational programs that make customers aware of potential energy efficiencies will provide benefits to at least some customers which, combined with the net benefit to the utility, may offset the cost of the program. However, such expenditures result in customers who do not benefit from the expenditures bearing part of the cost through increased rates.

DSM expenditures incurred in one year may produce benefits in a future year or years. For example, a program to subsidize the insulation of water heaters will result in an expenditure in the current year while the reduction in demand will occur over a period of years. From an accounting and a regulatory perspective, this will create a need to match the costs to the appropriate period in which the related benefits are received.

3. ACCOUNTING PERSPECTIVE

Accounting issues deal with the financial statement reporting of an electric utility's results; this reporting is guided by Generally Accepted Accounting Principles (GAAP). Since regulators follow established accounting principles in determining what costs will be recovered and in what period, accounting issues may impact on the setting of rates.

In Canada, the Canadian Institute of Chartered Accountants (CICA) is responsible for determining GAAP and its key pronouncements are published in the CICA Handbook. The authority of the CICA to set GAAP has been recognized by the Canadian Business Corporations Act. However, the CICA Handbook does not specifically address all financial accounting issues. Where an issue is not covered by the CICA Handbook, GAAP is determined by reference to various studies of the CICA, the writings of accounting academics and the standards set by authoritative accounting bodies in other countries.

ACCOUNTING PRINCIPLES

The key accounting issue with DSM expenditures is whether they should be expensed immediately or deferred and amortized to income over a period of time; hence, whether they represent an expense or an asset. Section 1000 of the CICA Handbook, Financial Statement Concepts, sets out the definition of an asset and an expense:

> "Assets are economic resources controlled by an entity as a result of past transactions or events from which future economic benefits may be obtained.
>
> Assets have three essential characteristics:
>
> (a) they embody a future benefit that involves a capacity, singly or in combination with other assets, to contribute directly or indirectly to future net cashflows;
>
> (b) the entity can control access to the benefit; and
>
> (c) the transaction or event giving rise to the entity's right to, or control of, the benefit has already occurred.

> It is not essential for control of access to the benefit to be legally enforceable for a resource to be an asset, provided the entity can control its use by other means."[3]
>
> "Expenses are decreases in economic resources, either by way of outflows or reductions of assets or incurrences of liabilities, resulting from the ordinary revenue-earning activities of an entity."[4]

Based on Section 1000, the issue of expensing or deferring DSM expenditures depends on whether there is a future net cashflow benefit, i.e., cost savings exceeding revenue reductions. If a future cashflow benefit is created, there is an asset and the DSM expenditures should be deferred. Moreover, since an asset is created by the expenditures, there is no decrease in economic resources as a result of the transaction. Therefore, the expenditures would not meet the definition of an expense. However, if there is no future net cashflow benefit, the expenditures would not meet the requirements for an asset, In addition, there would be a decrease in economic resources requiring that the expenditures be expensed.

Where a future net cashflow benefit is created, the DSM expenditures should be capitalized up to the amount of the net benefit. This is in accordance with Section 3060 of the CICA Handbook which deals with capital assets, including intangible assets. According to Section 3060, a capital asset should be recorded at cost[5] except that costs in excess of the net benefit should be expensed:

> "When the net carrying amount of a capital asset, less related accumulated provision for future removal and site restoration costs and deferred income taxes, exceeds the net recoverable amount, the excess should be charged to income."[6]

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3 Canadian Institute of Chartered Accountants, CICA Handbook, Canadian Institute of Chartered Accountants, Toronto, Section 1000, Paragraph 25 to 27.

4 Canadian Institute of Chartered Accountants, CICA Handbook, Canadian Institute of Chartered Accountants, Toronto, Section 1000, paragraph 35.

5 Canadian Institute of Chartered Accountants, CICA Handbook, Canadian Institute of Chartered Accountants, Toronto, Section 3060, paragraph 18.

6 Canadian Institute of Chartered Accountants, CICA Handbook, Canadian Institute of Chartered Accountants, Toronto, Section 3060, paragraph 42.

For example, a DSM expenditure of $10 million may have an expected demand reduction that would cause future costs to be reduced by $95 million and future revenues to fall by $90 million. In such a case, the expected net cashflow benefit is only $5 million ($95 million less $90 million). $5 million of the DSM expenditures should be deferred, while the remainder should be expensed. If the expected net cashflow benefit were $10 million or more, the entire $10 million in DSM expenditures should be capitalized.

GAAP only recognizes the costs to the reporting entity, it does not recognize social costs. Therefore, a reduction in social costs does not provide a net cashflow benefit to the utility. This would tend to indicate that all costs incurred to reduce social costs should be expensed as incurred. However, if a utility was required to undertake a DSM expenditure as a precondition for providing service in the future, e.g. install anti-pollution controls, there would be an economic benefit in that the utility would be allowed to continue providing service and earning revenue. Similarly, where a utility had a social obligation to minimize the social costs associated with the provision of its services, there would be a future economic benefit in that the utility would be able to earn future revenues without abdicating its social obligations. Therefore, where DSM expenditures are incurred to reduce the social costs associated with future production, the costs should be deferred, provided that there is reasonable certainty of recovery of the deferred costs in future rates and that the principle of conservatism is maintained.

The decision to defer DSM expenditures would be affected by the principles of conservatism and materiality. The principle of conservatism seeks to avoid favourable exaggeration without distorting an entity's financial reports.

> "Whenever uncertainty exists, estimates of a conservative nature attempt to ensure net assets or net income are not overstated. However, conservatism does not encompass the deliberate understatement of net assets or net income." [7]

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7 Canadian Institute of Chartered Accountants, CICA Handbook, Canadian Institute of Chartered Accountants, Toronto, Section 1000, Paragraph 18.

Hence, before deferring DSM expenditures there must be reasonable assurance that there will be future net cashflow benefits, at least equal to the expenditures. Even when all other factors would require deferral, materiality may dictate that they be expensed.

> "Investors, creditors and other users are interested in information that may affect their decision making. Materiality is the term used to describe the significance of financial statement information to decision makers. An item of information, or an aggregate of items, is material if it is probable that its omission or misstatement would influence or change a decision."[8]

In cases where DSM expenditures are small and immaterial, it is not necessary to incur the additional record keeping costs associated with deferral and the cost of determining whether there is reasonable assurance that there will be net cash flow benefits. The utility would be allowed to expense the expenditures as incurred.

In accordance with the matching principle, any deferred DSM expenditures should be amortized over the period that the net cashflow benefit is realized. The matching principle is a fundamental accounting principle; it requires that costs be matched to the period in which the related revenues are realized and be expensed in that period. In some cases, the cashflow benefit is a reduction in costs. However, a cost incurred to reduce the cost of earning revenue is a cost of earning that revenue.

The matching principle is consistent with the definition of an expense presented in Section 1000. As the cashflow benefit is realized, the amount of future benefit is reduced. Therefore, there is a decrease in the value of the asset and an expense.

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8 Canadian Institute of Chartered Accountants, CICA Handbook, Toronto, Section 1000, Paragraph 14.

As indicated above, if ever there is a reduction in the estimate of the future net cashflow benefits such that they fall below the carrying value of the asset, Section 3060 requires that the difference be charged to income.[8]

Section 3450 of the CICA Handbook, Research and Development Costs, provides specific guidance for dealing with costs that are similar to many DSM expenditures. Like many of the DSM expenditures, research and development costs are frequently incurred to provide a future benefit but do not represent physical assets. Section 3450 states that costs should be deferred only where there is reasonable assurance that the expenditures will result in future benefits that will allow recovery of the costs.

In the case of research costs, Section 3450 rejects deferral:

> "In most cases, research activities will not produce identifiable benefits in future periods; the amount of future benefits and the period over which they will be received are usually uncertain. In general, one particular period rather than another will not be expected to benefit from an expenditure on research and, therefore, it is appropriate that such expenditures be charged to expense as they are incurred."[9]

In the case of development expenditures, expenditures must also be expensed unless they can meet all of the following criteria:

> "(a) the product or process is clearly defined and the costs attributable thereto can be identified;
>
> (b) the technical feasibility of the product or process has been established;
>
> (c) the management of the enterprise has indicated it intention to produce and market, or use, the product or process;

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8 Canadian Institute of Chartered Accountants, CICA Handbook, Canadian Institute of Chartered Accountants, Toronto, Section 3060, paragraph 42.

9 Canadian Institute of Chartered Accountants, CICA Handbook, Canadian Institute of Chartered Accountants, Toronto, Section 3450, Paragraph 15.

(d) the future market for the product or process is clearly defined or, if its to be used internally rather than sold, its usefulness to the enterprise has been established;

(e) adequate resources exist, or are expected to be available, to complete the project."[10]

Achievement of the above criteria provides reasonable assurance that the development expenditures will produce future cashflow benefits.

IMPACT OF REGULATION

The existence of regulation can impact the decision as to whether an expenditure should be expensed or deferred. Although regulation cannot set the accounting principles that a regulated utility uses in its financial reporting, it can affect a utility's cash flows. It can determine the amount and timing of a regulated utility's revenues, hence, what should be reported in accordance with GAAP. This has been recognized by the Financial Accounting Standards Board (FASB) in the United States with its Financial Accounting Standard No. 71 (FAS71), "Accounting for the Effects of Certain Types of Regulation". FASB is the authoritative source for GAAP in the United States.

FAS71 is intended to apply to electric utilities that are regulated or which set their rates on a cost recovery basis.

"5. This Statement applies to general-purpose external financial statements of an enterprise that has regulated operations that meet all of the following criteria:

a. The enterprise's rates for regulated services or products to its customers are established by or are subject to approval by an independent, third party regulator or by its own governing board empowered by statute or contract to establish rates that bind customers.

b. The regulated rates are designed to recover specific enterprise's costs of providing the regulated services or products.

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10 Canadian Institute of Chartered Accountants, CICA Handbook, Canadian Institute of Chartered Accountants, Toronto, Section 3450, Paragraph 21.

c. In view of the demand for the regulated services or products and the level of competition, direct or indirect, it is reasonable to assume that rates set at levels that will recover the enterprise's costs can be charged to and collected from customers. This criterion requires consideration of the anticipated changes in levels of demand or competition during the recovery period for any capitalized costs." [11]

FAS71 specifically recognizes the ability of regulation to create an asset:

"9. Rate actions of a regulator can provide reasonable assurance of the existence of an asset. An enterprise shall capitalize all or part of an incurred cost that would otherwise be charged to expense if both of the following criteria are met:

a. It is probable that future revenue in an amount at least equal to the capitalized cost will result from the inclusion of that cost in allowable costs for rate-making purposes.

b. Based on available evidence, the future revenue will be provided to permit recovery of the previously incurred cost rather than to provide for expected levels of similar future costs. If the revenue will be provided through an automatic rate-adjustment clause, this criterion requires that the regulator's intent clearly be to permit recovery of the previously incurred cost." [12]

However, FAS71 does not give regulators unlimited scope to create assets. It must be probable that there will be additional future revenues as a result of deferring the costs, at least equal to the amount of the costs. This issue was specifically addressed in FAS92 which placed constraints on the recognition of phase-in plans for new generating plants where the plans had been approved by a regulatory body:

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11 Financial Accounting Standards Board, Financial Accounting Standard No.71, Accounting for the Effects of Certain Types of Regulation, Financial Accounting Standards Board, Norwalk, Connecticut, Paragraph 5.

12 Financial Accounting Standards Board, Financial Accounting Standard No.71, Accounting for the Effects of Certain Types of Regulation, Financial Accounting Standards Board, Norwalk, Connecticut, Paragraph 9.

"Observations of the actions of regulators over the past few years , since the first phase-in plan was initiated, suggests that some regulators did not view their actions or the resulting accounting to be constrained by the overriding principle that the cost of service generally should be charged to current customers. Phase-in plans have evolved from a tightly controlled plan, which deferred recovery of some costs for a short number of years and promised recovery of those deferrals through an automatic rate adjustment mechanism within a brief time period, to open-ended plans that deferred costs indefinitely and promised recovery only when, and if, future demand grew to the point that the capacity in question was needed."[13]

FAS71 also recognizes that regulation can require the expensing of costs that would normally be deferred:

"10. Rate actions of a regulator can reduce or eliminate the value of an asset. If a regulator excludes all or part of a cost from allowable costs and it is not probable that the cost will be included as an allowable cost in a future period, the cost cannot be expected to result in future revenue through the rate-making process. Accordingly, the carrying amount of any related asset shall be reduced to the extent that the asset has been impaired." [14]

FAS71 is consistent with Section 1000 of the CICA Handbook which defines an asset as a future economic benefit. With rate regulation, revenues are usually set on the basis of costs and the regulatory boards decide both which costs a regulated electric utility will be able to recover and in what periods it will be able to recover them. Therefore, the regulatory process determines if there will be a future cash flow benefit from expenditures and when it will be received. The same would be true where a utility was not subject to third party regulation but as a government owned entity has the authority to set its rates on a cost recovery basis. Although the CICA has not issued a specific standard on the effect of regulation, several of the CICA Handbook recommendations have reflected this position.

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13 Financial Accounting Standards Board, Financial Accounting Standards No.92, Regulated Enterprises - Accounting For Phase-in Plans, Financial Accounting Standards Board, Norwalk, Connecticut, Paragraph 57.

14 Financial Accounting Standards Board, Financial Accounting Standard No.71, Accounting for the Effects of Certain Types of Regulation, Financial Accounting Standards Board, Norwalk, Connecticut, Paragraph 10.

a) Section 1600 requires that intercompany gains and losses be eliminated on consolidation except where the transfer price is recognized for rate making purposes by a government regulatory body.[15]

b) Section 3060 allows a regulated company to capitalize the allowance for funds used during construction allowed by its regulator.[16]

c) Section 3060 requires that when the carrying cost of a capital asset is less than its net recoverable amount, the difference should be charged to income. It also states that in determining the net recoverable amount for the capital asset of a rate-regulated entity, consideration should be given to the extent to which rates will provide for the recovery of the cost of the asset.[17]

d) Section 3060 generally requires that, on the disposal of a capital asset, the difference between the net proceeds and the carrying amount of the asset should be recognized in income in the period of disposal. However, the difference may be deferred for a rate-regulated entity where there is reasonable assurance that any loss will be recovered through future rates or any gain will be used to reduce future rates.[18]

e) Section 3470 requires companies to use the deferred tax method which requires that a company expense its income taxes when the related income is earned. However, regulated entities are allowed to expense income taxes as paid if the taxes are recovered through rates on a taxes payable basis.[19]

In Canada, electric utilities are either subject to regulation by a government appointed body or are government entities charged with setting rates that bind customers. Therefore, GAAP would require DSM expenditures to be deferred if the following two conditions are met:

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15 Canadian Institute of Chartered Accountants, CICA Handbook, Canadian Institute of Chartered Accountants, Toronto, section 1600, paragraph 29.

16 Canadian Institute of Chartered Accountants, CICA Handbook, Canadian Institute of Chartered Accountants, Toronto, section 3060, paragraph 26.

17 Canadian Institute of Chartered Accountants, CICA Handbook, Canadian Institute of Chartered Accountants, Toronto, section 3060, paragraph 50.

18 Canadian Institute of Chartered Accountants, CICA Handbook, Canadian Institute of Chartered Accountants, Toronto, section 3060, paragraph 57.

19 Canadian Institute of Chartered Accountants, CICA Handbook, Canadian Institute of Chartered Accountants, Toronto, section 3470, paragraph 61.

a) the regulatory board, or the governing body that sets rates, has indicated that the costs will be recovered through future rates; and

b) it is reasonable to assume that rates set at levels that will recover the expenditures can be charged and collected from customers.

In all other cases, the expenditures should be written off as incurred. Where the expenditures are deferred, they should be expensed as they are recovered through rates.

FINANCIAL STATEMENT REPORTING OF DSM EXPENDITURES

Where significant, the amount of DSM expenditures incurred and expensed in the period and unamortized at the end of the period should be reported separately in the financial statements, even if it is in a supporting schedule or the notes to the financial statements. In the section dealing with general standards of financial statement presentation, the CICA Handbook states:

> "Financial statements should be prepared in such form and use such terminology and classification of items that significant information is readily understandable. Items, not significant in themselves, should be grouped with such other items as most closely approximate their nature." [20]

In addition, where the amounts are significant, a utility would also have to report its accounting policies for dealing with DSM expenditures. In the section dealing with the disclosure of accounting policies, the CICA Handbook states:

> "As a minimum, disclosure of information on accounting policies should be provided in the following situations:
>
> (a) when a selection has been made from alternative acceptable accounting principles and methods;

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20 Canadian Institute of Chartered Accountants, CICA Handbook, Canadian Institute of Chartered Accountants, Toronto, Section 1500, Paragraph 06.

(b) when there are accounting principles and methods used which are peculiar to an industry in which an enterprise operates, even if such accounting principles and methods are predominately followed in that industry."[21]

As will be discussed in Section 6 "Survey of Electric Utilities", there is considerable variability in the accounting treatment of DSM expenditures, in particular, the conditions for deferral and the amortization period for deferred expenditures. Therefore, where material, the disclosure of the accounting policies for DSM expenditures would be required.

APPLICATION OF ACCOUNTING PRINCIPLES TO DSM EXPENDITURES

Where there is reasonable assurance that DSM expenditures will result in a future cashflow benefit, the expenditures should be deferred and amortized over the period that the benefits are expected to be received. In all other cases, including where the benefit is received in the period the expenditure is incurred, the expenditures should be expensed as incurred.

Regulatory bodies cannot determine GAAP, however, they can determine what costs a utility will be allowed to recover through rates and the period in which it will be able to recover the costs. Therefore, regulation can affect the amount and timing of a utility's cash flows and what should be reported in accordance with GAAP. Where a regulatory body defers DSM expenditures for recovery through future rates and it is reasonable to assume that the utility will be allowed to charge and collect such amounts from its customers, there will be a future economic benefit. Accordingly, the DSM expenditures should be deferred for accounting purposes and amortized as the expenditures are collected through rates. Where a regulatory body allows recovery of DSM expenditures in current rates or disallows the expenditures, it is unlikely that there will be any future economic benefit associated with the DSM expenditures. In such cases, the expenditures should be expensed.

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21 Canadian Institute of Chartered Accountants, CICA Handbook, Canadian Institute of Chartered Accountants, Toronto, Section 1505, Paragraph 08.

Where significant, financial statements should report the amount of DSM expenditures incurred and expensed during the period and unamortized at the end of the period. This reporting may be in the financial statements, notes to the financial statements or supporting schedules. Also, where significant, the accounting policies related to the DSM expenditures should be reported in the notes to the financial statements.

4. REGULATORY PERSPECTIVE

Regulation can determine what costs will be recovered and the period in which they will be recovered. Therefore, by affecting the amount and timing of cashflows, the appropriate regulatory treatment of DSM expenditures will affect the appropriate accounting treatment for these costs.

REGULATORY PRINCIPLES

A key objective of rate regulation is to set just and reasonable rates. The determination of just and reasonable is guided by the following established regulatory principles:

a) cost of service standard;

b) intergenerational equity;

c) matching;

d) materiality; and,

e) no undue discrimination.

In some cases, the various principles will be in conflict. In such cases, the appropriate regulatory treatment will require a weighting of the principles that reflect the specifics of the situation.

Cost of Service Standard

At the heart of rate of return regulation is the cost of service standard, or as it is sometimes called, the revenue requirement standard. This standard states that a utility must be permitted to set rates that allow it the opportunity to recover its costs, including a fair return on its investment devoted to regulated operations. In most cases, rates are set prospectively based on anticipated costs. If a utility overrecovers, it keeps the excess; if it underrecovers, it bears the deficiency.

This standard reflects both fairness and the necessity of providing adequate incentives if regulated services are to be provided. In fairness, the investors in a regulated entity should have the opportunity to recover their costs including a fair return, i.e., what they could expect to earn if they were to invest in a non-regulated investment of similar risk. However, customers should not be required to provide investors with more than what the investors could expect to earn on alternative investments of similar risk. From an incentive perspective, unless investors have a reasonable opportunity to recover their costs, it will be difficult to attract the investment necessary to provide regulated operations. However, the expectation of recovering costs, including a fair return, should provide an adequate incentive to attract necessary funds.

Intergenerational Equity

The principle of intergenerational equity requires that customers in any period should pay only the costs necessary to provide them with service in that period. Customers should not be required to pay costs incurred to provide service to the customers of another period. For example, an entity is not allowed to earn a return on projects under construction since the costs are incurred to provide service to future customers; instead, the costs are capitalized and recovered over the period that the asset is used to provide service. This is consistent with setting rates that are just and reasonable within each period.

In accounting, the principle of conservatism places the onus on proving that there is a future economic benefit and that an expenditure should be reported as an asset rather than an expense. This tends to create a bias towards expensing rather than deferring expenditures, although the principle of conservatism does not justify the deliberate underestimation of income or assets. However, in regulation, the principle of intergenerational equity requires a more equal weighting between periods so that the customers of different periods are treated fairly.

Matching Principle

The matching principle requires that the costs of a regulated entity be matched to the period that benefits from the incurrence of the costs and be recovered from customers in that period, i.e., the customers in each period should pay all of the costs of providing them with service in that period.

The matching principle follows from the cost of service standard and the principle of intergenerational equity. Consistent with the first, all of the costs of the regulated entity should be recovered from customers. Consistent with the second, only customers in the periods that benefit from the incurrence of the costs should pay for the costs.

This principle differs from the accounting principle of the same name. In an accounting context, the matching principle determines when costs are to be expensed but has no effect on revenues. It requires that costs be matched with the revenues for which they were incurred and be expensed in the same period the revenues are realized. In a regulatory context, the matching principle determines when costs will be recovered and, therefore, has a direct impact on revenues. It requires that costs be matched to the period that benefits from the costs being incurred and that costs be recovered from customers in that period. However, even with non-regulated companies, the period that benefits from the incurrence of a cost is usually the period in which the related revenues are earned.

Rate Stability and Predictability

The principle of rate stability and predictability requires that rates should, as far as practicable, remain stable and predictable. This principle may require collecting costs from customers in periods other than the periods for which the costs were incurred. The principle is, therefore, inconsistent with the principle of intergenerational equity. However, the principle is justified because it recognizes the problems that customers can face adjusting to significant short-term fluctuations in rates.

As time passes, the make up and usage of the customer group changes. Accordingly, the longer the period that costs are deferred, the more potentially serious the breach of the principle of intergenerational equity (or the longer the period between early recovery and the period that service is provided). Therefore, where the principle of rate stability and predictability is applied, cost deficiencies should be recovered over as short a period as is reasonable so that the customer group that pays more is similar to the one that benefits.

It should be emphasized that this principle does not justify the delaying of required rate increases nor does it justify preventing a utility the opportunity to recover its costs. It only justifies a short term smoothing of the increases.

Materiality

Strict adherence to regulatory principles can be time consuming, expensive and possibly confusing. According to the principle of materiality, strict adherence to regulatory principles is required only where there would be a noticeable impact on rates.

No Undue Discrimination

The principle of no undue discrimination follows from the principle that rates must be just and reasonable, it requires that customers be treated on an equal basis: i.e., customers in similar situations should be treated the same while customers in different situations should be treated on a basis that reflects the differences. However, problems arise with what is meant by undue discrimination or even discrimination and, in practice, some discrimination is allowed.

Unintentional discrimination can arise for practical reasons. It would be expensive and confusing to develop and set a multitude of rates to accurately reflect the situation of different consumers. Customers, or at least the services used by customers, are usually grouped into classes and one rate is set for the entire class. Hence, customers may pay the same rate even though the cost of providing them with service differs.

Regulators may intentionally discriminate to achieve social policies. For example, the telecommunications industry has had long distance rates subsidize local rates and business rates subsidize residential rates so as to keep the cost of basic telephone service down and maximize the number of people on the network. Regulators may also discriminate between customers to maximize the level of service provided and decrease the costs to all customers. With the high fixed costs that are common to many regulated entities, the marginal cost of providing service is less than the average cost. Some customers may not accept rates that reflect average cost but are willing to pay some amount above marginal cost. Charging these customers less than average cost results in an increased contribution over marginal cost to cover the fixed costs; hence, the rates to the other customers can be reduced. For example, in the case of the gas distribution industry, some large customers have alternatives and may leave the system if charged average cost. To keep these customers on the system and contributing to fixed costs, they are offered lower rates.

APPLICATION OF REGULATORY PRINCIPLES TO DSM EXPENDITURES

The cost of service standard requires that a utility be allowed the opportunity to recover the cost of DSM expenditures, including a fair return on deferred DSM expenditures. This is required not only for fairness but to ensure that there are adequate incentives for DSM. Unless a utility is able to recover its costs including the cost of capital, it will be worse off as a result of DSM activities. In Canada, most of the electric utilities are owned by the government, however, they are generally expected to live within their budgets and to earn a return.

Historically, DSM expenditures have been expensed in the period incurred. However, the amounts have generally been immaterial. With the growth in DSM expenditures, reliance on the principle of materiality may no longer be appropriate.

Where any of the benefits of a DSM activity are expected to be received in a future period, the matching principle requires that an associated portion of the costs should be deferred and recovered from those future periods. Problems can arise in quantifying the benefits of specific DSM activities and the timing of the benefits, however, this is also true of fixed assets that regulators require to be capitalized. More importantly, failure to defer the expenditures will result in current customers paying costs required to provide service to future customers which is contrary to the principle of intergenerational equity.

The principle of rate stability and predictability may support either the deferral or expensing of DSM expenditures. For example, DSM expenditures are not necessarily incurred at an even rate in each year, therefore, deferral with amortization over a period of years would tend to increase the stability of rates. Alternatively, a utility may be faced with large cost increases in the future, therefore, immediate expensing rather than deferral would tend to create greater rate stability.

In some cases DSM expenditures will result in an overall increase in rates while benefiting only selected customers. For example, a utility may have an information program setting out ways in which customers can efficiently conserve electricity. It may be that the costs of the program exceed the net benefits to the utility, thereby requiring an increase in rates. The increased rates will be offset by savings to customers who conserve, however, those who do not conserve or who were already conserving will not have any offsetting cost savings. Ideally, the customers who benefit from the program should bear the full increase in rates, however, this may not be possible and some customers will be made worse off. It may be argued that this represents undue discrimination. However, regulated rates usually reflect "postage stamp" pricing where one rate applies to all customers in a class, even though the specific cost of providing service will vary for members of the class. For example, electric rates are generally the same for all residential customers in a city or district, even though the cost of power will increase as the distance between a customer and the generating source increases. Therefore, established practice would tend to support the inclusion of DSM expenditures in general rates, as long as the overall impact on rates was not significant.

5. INCENTIVES

With regard to the accounting for DSM expenditures, the main incentive issue is whether expensing or deferral will provide the strongest incentive for a utility to undertake DSM activities. In addition, the scope of this study includes the identification of incentive and disincentive mechanisms for DSM programs. These mechanism arise from the prospective setting of rates and the impact of DSM on utility growth opportunities.

EXPENSE VS. DEFERRAL

In theory, a utility should be indifferent as to whether DSM expenditures are expensed and recovered immediately from customers or deferred and recovered through future rates. This assumes that the utility is allowed to recover all of the costs associated with DSM expenditures, including the cost of financing any unrecovered costs. In a regulatory context, the financing costs are based on a "fair" return that should equal the return on comparable investments and adequately compensate for any costs associated with deferral. Therefore, with either expensing or deferral, the utility is just recovering its costs and should be indifferent. However, there are practical considerations.

a) Deferring recovery of the expenditures creates the risk that the costs may be disallowed in the future. For example, the current interest in DSM may give way in the future to a harder look at the impact of DSM on customer rates. Expensing the expenditures results in an immediate recovery of the costs, thereby eliminating the risk of non-recovery.

b) In the case of government owned utilities with limited access to equity funding, deferral will result in an increase in the debt equity ratio. This may have a detrimental impact on the perceived financial viability of a utility, resulting in a higher cost of capital and possibly greater difficulty in raising necessary capital.

c) Deferred DSM expenditures would represent a "soft" asset rather than a productive asset such as a generating plant. The requirement to fund a "soft" asset may have a detrimental impact on the perceived financial viability of a utility, resulting in a higher cost of capital and possibly greater difficulty in raising necessary capital.

d) Expensing a DSM expenditure that produced future benefits would have a negative impact on current rates. There would be an increase in costs but no immediate benefits to offset the costs, resulting in an increase in revenue requirements. This may reduce the demand for electricity, at least in the short run. Similarly, deferring an expenditure that has only current benefits would result in future rates bearing the cost of the expenditure without any offsetting benefit. This may reduce the future competitiveness of electricity and increase the risk associated with the eventual recovery of the expenditures.

e) Profit is based on the amount of rate base which is increased with deferral. However, as noted above, in theory, a utility should be indifferent to expensing or deferring.

There is not a definitive answer as to whether expensing or deferral will provide the best incentive for DSM expenditures, however, the following can be concluded.

a) Where there are no future benefits, the strongest incentive will tend to come from immediate expensing. In this way the utility will avoid the risk that the costs will be disallowed in a future regulatory hearing, a risk that will be increased due to the benefit having been for a past period. It will also avoid the negative impact on demand from an increase in future rates to recover a cost for which there are no longer benefits, the negative impact on the debt equity ratio and the negative impact from financing a "soft" asset.

b) Where there are future benefits, the strongest incentive will tend to come from deferral. In this way the utility will avoid the rate spike necessary to recover the cost when there are no current benefits to offset it, a rate spike that would have negative effects on demand and may increase the difficulty in having rates approved.

c) Where there are future benefits but they are uncertain, the strongest incentive will tend to come from deferral with a fast write off. In this way, the utility can reduce the possibility of a rate spike, or at least its size. It will also reduce the problem associated with recovering a cost through future rates for which there is no longer a benefit and the problem of financing of an asset that has no productive value.

Therefore the strongest incentives will tend to come where DSM expenditures are deferred if they result in future economic benefits while all other DSM expenditures are expensed. Moreover, this is the treatment that is normally accorded supply side investments. Hence, it will tend to improve the comparability of demand side and supply side alternatives.

PROSPECTIVE RATE SETTING

Under current regulatory practice, rates are set prospectively on the basis of expected demand. If a DSM activity is more successful than planned, demand will be less than expected. This will result in lower revenues and costs. Since a significant portion of an electric utility's costs are fixed, the impact on revenues will be greater than the impact on costs, resulting in an earnings shortfall. Hence there would be a strong disincentive for a utility to have a DSM program that was more successful than planned and even an incentive to have the program underachieve its targets. To offset this disincentive, modifications to the normal regulatory process will be required.

The offering of an incentive bonus based on the amount of DSM expenditures would help to offset the disincentive. However, the bonus would create an incentive to spend on DSM, not necessarily to achieve results with DSM. In addition, to be effective, the bonus would have to at least equal the potential lost revenues from pursuing DSM and may, therefore, give a utility the opportunity to earn more than a fair return.

A preferable solution is the equivalent of the fuel adjustment clauses that were common a decade ago. With this approach, the expected impact on earnings from a revenue shortfall or surplus would be identified when a utility's rates were set. To the extent that revenues deviated from plan, the associated earnings shortfall (surplus) would be charged (credited) to a revenue shortfall account. The shortfall would then be recovered through future rates while any surplus would be used to reduce future rates. With such a mechanism, the disincentive is eliminated since the ability of a utility to earn its allowed return will be unaffected by the success of its DSM activities.

GROWTH OPPORTUNITIES

DSM reduces demand and, therefore, the growth opportunities for a utility. From an investors perspective, this should not be a significant issue. A regulated utility is given the opportunity to earn a return that is comparable to what could be earned on alternative investments of similar risk. Therefore, a reduction in growth opportunities should result in a diversion of investment funds from the utility to such comparable investments. However, in practice, there may be a disincentive. More importantly, the impact on growth opportunities may provide a disincentive for management action.

The management of a utility may view its career opportunities as being related to the growth of the utility. Hence, it may be biased against DSM activities which are intended to reduce that growth. However, incentives payments will increase the return to investors, not management, and will not offset the impact of the DSM expenditures on the growth opportunities of the utility. There may be some positive incentive created in that management may see an improvement in return as improving their career prospects. However, an incentive would allow the utility to earn more than a fair rate of return and, in the case of the government owned utilities, profit maximization is not usually a utility goal.

Incentives may relate to the amount of DSM expenditures, either a bonus based on the expenditures or a higher allowed return on any deferred expenditures. Such incentives will be related to the amount of expenditure, not results. A preferable approach would be incentives that were related to the benefits achieved. Such an incentive plan would encourage not only expenditures but also results.

6. SURVEY OF ELECTRIC UTILITIES

To determine how electric utilities currently account for DSM expenditures, a survey on accounting for DSM expenditures was developed and sent to 31 Canadian and 39 United States electric utility companies. Canadian participants were selected based upon membership in the CEA. This group included fourteen companies with significant generating capacity (CGU) and seventeen companies whose activities are restricted primarily to the distribution of electricity (CDU). The thirty-nine United States electric utilities (USU) consisted of the 33 largest electric utilities in the United States, based on 1988 revenues as reported in Moody's Public Utilities Manual, plus six additional companies selected by the CEA.

Responses were received from thirteen CGU's (93%), eight CDU's (47%), and fourteen USU's (36%). This represents an overall response rate of 50%. A complete list of respondents is provided in Appendix 2 while the annual revenue requirements of the respondents is broken down in Table 1. A summary of the responses is presented in Appendix C.

TABLE 1
ANNUAL REVENUE REQUIREMENT OF UTILITIES
($ in thousands)

	Total	Under $500,000	$500,001 to $1,500,000	$1,500,001 to $2,500,000	Over $2,500,000
CGU	13	6	4	1	2
CDU	8	8	0	0	0
USU	14	0	4	4	6
TOTALS	35	14	8	5	8
% OF TOTAL		40	23	14	23

SURVEY RESULTS

All USU's plus all but one CGU and three CDU's indicated DSM programs were either in existence or being seriously studied for future implementation. However, only ten CGU's (71%), four CDU's (50%) and thirteen USU's (93%) reported formal DSM programs, a total of 27 utilities. Unless stated otherwise, the percentages presented below refer to the percent of all utilities that reported they currently have DSM programs.

DSM programs have been in existence in both the United States and Canada since the 1970's. However most utilities reported formal policies were first introduced in the 1980's. The average length a formal policy has been in place was slightly longer among U.S. utilities than Canadian utilities. Seventy-one percent of the Canadian utilities that have DSM programs indicated that formal programs were introduced in 1985 or later, compared to 31% of their USU counterparts. Most USU's (62%) indicated the implementation of formal DSM programs occurred in the years 1975 through 1984.

Canada's three largest utilities are among the most significant participants in DSM programs. Their projected average annual DSM expenditures are almost three and one half times greater than those of the US utilities. However, for the remaining reporting Canadian utilities, projected annual DSM expenditures were less than $2 million in all but one case. A summary of the mean (average), median (mid-point) and maximum projected annual expenditures reported by each group is shown in Table 2 .

TABLE 2
AVERAGE ANNUAL ANTICIPATED DSM EXPENDITURES
($ in Millions)

	#	MEAN	MEDIAN	MAXIMUM
CGU (Revenues greater than $1 billion)	3	141.2	187.5	210.0
CGU (Revenues less than $1 billion)	7	1.9	1.2	7.5
CDU	4	.4	.2	1.1
USU	12	40.9	22.6	162.3

Expenditures for advertising, promotion and education were the most common types of DSM expenditure. A summary of the most common types of expenditures, along with the percentage of utilities reporting these programs, is presented in Table 3.

TABLE 3
DSM PROGRAMS REPORTED (%)

	CGU REVENUES > $1 BILLION	CGU REVENUES < $1 BILLION	CDU	USU	TOTAL
NUMBER OF REPORTING UTILITIES *	3	7	4	12	26
ADVERTISING/EDUCATION	100%	71%	100%	100%	92%
REBATES AND SUBSIDIES	100	86	25	83	77
RESEARCH AND DEVELOPMENT	100	14	25	58	46
PEAK SHAVING/LOAD SHIFTING	100	29	0	42	38
WATER HEATING PROGRAMS	67	14	0	25	23
STREET LIGHT REPLACEMENT	33	29	25	17	23
ENERGY AUDITS	67	14	0	17	19

* Number of respondents which reported specific DSM programs.

CGU's showed a greater tendency to capitalize DSM expenditures than US utilities. Only one CGU, compared to 50% of USU's, indicated that all DSM expenditures were expensed as incurred. Of the four reporting CDU's, three expensed all their DSM expenditures, however, their expenditures were generally not material.

In determining whether to expense or capitalize, 70% of reporting CGU's indicated that reasonable assurance of recovery in future rates was a necessary condition. Over two-thirds of these utilities also indicated the existence of a future benefit was a further condition necessary for capitalization. Thirty-eight percent of USU's reported capitalization was dependent on the utility's ability to recover these costs in future rates. Almost half of the USU's reported that no capitalization policy was in place either because all DSM expenditures were expensed as incurred or the company had not been faced with the decision by virtue of the type of DSM expenditures that were being carried out. A small number of total utilities (11%) reported that DSM expenditures were subject to normal accounting capitalization and deferral policies.

The accounting policies related to the major types of DSM expenditures are as follows:

Advertising/Education

Of the respondents reporting these expenditures, 74% expensed the amounts as they were incurred. Where deferred, the costs were amortized over a period of five to ten years. Expense treatment was especially prevalent among USU's and CDU's where 83% and 75%, respectively, of the respondents indicated expense treatment.

Rebates, Subsidies,

Of the respondents reporting these expenditures, 55% indicated that they expensed the costs as incurred. Thirty-five percent indicated deferral over a predetermined period ranging from 5 to 15 years. Two utilities (10%) reported that expense or deferral treatment was determined on a case by case basis with reference to the nature of the expenditure. Once again, expense treatment was higher among USU's. Eighty percent of USU's favoured expense treatment, while 67% of the Canadian utilities favoured deferral.

Research and Development

Seventy-five percent of the utilities reporting these expenditures indicated they were expensed as incurred. Four utilities (25%) indicated these costs would be reviewed on a case by case basis; if a future benefit did result, the expenditure would receive deferral consideration. Once again expense treatment was favoured by USU's (71%). Only half of the CGU's automatically expensed R & D expenditures.

Peak Shaving/Load Shifting

Eight of the ten utilities that reported these expenditures indicated the accounting treatment used. All eight indicated these expenditures were expensed.

Energy Audits

Only three of the five utilities that reported energy audit programs indicated the accounting treatment for these expenditures. Two (CGU's) indicated these costs were expensed. One (USU) indicated deferral/amortization was determined by the policies of its regulatory authority.

Water Heating

Only four of the six utilities that reported on water heating programs indicated the accounting treatment for these expenditures. Three of the four indicated the expenditures were expensed while one (CGU) indicated that they were deferred.

Street Light Replacement

Only three of the six utilities that reported involvement in street light replacement programs indicated how those programs were accounted for. Of these utilities, all stated the costs of the program were expensed. Two utilities made reference to the expenditure for the actual light equipment, one stating these costs were deferred and amortized over their expected useful lives, one indicating these assets were not owned by the utility.

Fourteen utilities reported on how the amortization period was determined for deferred expenditures. The four alternatives indicated were:

a) the lesser of the life of the asset or the benefit (2 CGU's,1 CDU, 2 USU's);

b) a predetermined period ranging from 5 to 15 years (3 CGU's, 1 USU);

c) the life of the benefit, (3 CGU's); and,

d) a period set by the regulatory authority (2 USU's).

Where a predetermined period was used, the reason given was the difficulty in identifying specific future benefits associated with some DSM programs.

Twenty-one utilities reported policies in place for company owned equipment purchased as part of a DSM program. Seventy-six percent of these utilities indicted no difference between the accounting treatment for DSM expenditures and non-DSM expenditures. Twenty-four percent of the respondents indicated there was a difference in that the amortization period for the DSM expenditure would be equal to the life of the program benefits rather than the life of the fixed asset. All of the seventeen respondents that reported evaluation criteria, stated criteria that were similar to what would be expected for non-DSM expenditures. The most common criteria, cited by 82% of these utilities was that future benefits exceed costs.

Eleven utilities reported accounting policies in place for the treatment of gains or losses on the early replacement of assets due to DSM activity. One utility reported a departure from normal policy, stating a loss would be deferred and amortized over the life of the DSM benefit. The other ten utilities reported that their normal accounting policy would be followed, however, this normal accounting policy varied between the utilities. In six of these cases, this meant that the residual value would be written off through future depreciation charges, while in four cases, it meant the gain or loss would be recognized in the period of disposition.

Twenty-five utilities stated their policy for overheads. Seventy-six percent expensed DSM specific overhead while 24% deferred these costs over the life of the benefits resulting from the DSM program. Only four of these respondents (17%) included an allocation for general overhead in the cost of DSM programs:

- one utility expensed a general overhead allocation as incurred;
- three utilities deferred the expenditure and amortized the amount over the life of the DSM program benefit.

Ten utilities (5 CGU's and 5 USU's) indicated there was a review of capitalized or deferred DSM expenditures to ensure the continued existence of benefits. All five CGU's indicated that costs and amortization period would be adjusted to reflect new information with respect to these benefits. Only one USU reported that costs would be written off.

With respect to the requirements of regulatory authorities for allowing particular DSM expenditures to be recovered in rates, the vast majority of respondents in both countries (70%) reported no specific criteria. Of those stating a criteria, the most common was that benefits of the expenditure, measured in dollars, exceed the amount of the expenditures.

Only two USU's indicated a program for recovery of lost revenues caused by DSM programs. However, 38% of USU's indicated such a proposal had been made to their respective regulatory authorities or was currently under consideration. Canadian utilities unanimously reported either that such a recovery was specifically disallowed (29%) or that they had no experience with the issue (71%).

Only two USU's and no Canadian utilities indicated that their regulator provided incentives to undertake DSM activities. One incentive cited was a bonus or a penalty equal to 13.5% of the total resource cost, calculated on the basis of saved Kwh above or below target. The other incentive was a bonus or penalty up to 15% of the net benefit achieved on resource (technology) programs and up to 5% of the cost of customer service programs. Two USU's indicated such incentives had been proposed to their regulatory authorities and are currently under consideration.

Only one utility reported a difference between accounting and regulatory treatment for DSM expenditures.

Only five utilities (1 USU and 4 CGU's) indicated that DSM costs would be disclosed in the notes to their annual financial statements, if material. Only one of these utilities, a CGU, indicated that DSM costs were reported on its balance sheet. The remaining reporting utilities (20) indicated that no disclosure of these expenditures was made. With regard to the accounting policies for DSM expenditures, one USU and 3 CGU's indicated these would be disclosed in a note to the financial statements, if DSM expenditures were deemed to be material. The low level of reporting probably reflects the immaterial level of these expenditures, at least until recently.

CONCLUSIONS FROM SURVEY

Large DSM expenditures by electric utilities is a recent occurrence and, for many utilities, the amounts are still immaterial. As a result, existing practice may not be a good guide for future practice.

There is a bias to expensing DSM expenditures, especially in the U.S. This may be due to the historically immaterial level of these amounts. Where capitalized, it has generally been required that there be reasonable assurance of recovery in future rates and the existence of a future benefit. The amortization period has been based on the life of the asset, a pre-determined period or the life of the benefit. In almost all cases, the treatment of DSM expenditures is the same for both accounting and regulatory purposes.

Generally, neither the amount of DSM expenditures nor any unamortized amounts are disclosed separately in the financial statements. Moreover, the accounting policies for DSM expenditures are generally not disclosed. This may be due to the historically immaterial level of these expenditures.

7. CONCLUSIONS AND RECOMMENDATIONS

The conclusions and recommendations have been classified into those related to DSM expenditures in general, those related the costs of specific types of DSM expenditures and those related to incentive mechanisms for DSM.

GENERAL

GAAP requires that where there is reasonable assurance that the incurrence of a DSM expenditure will result in a future economic benefit, the expenditure should be deferred and amortized over the period that receives the benefit. In all other cases, including where the economic benefit is received in the current period, the expenditure must be expensed.

Where the impact on reported performance is immaterial, the principle of materiality may justify deviations from what would be required by strict adherence to accounting principles. This would be the case where the increased accuracy resulting from strict adherence did not justify the associated cost. In these cases, simpler accounting procedures may be used.

From a utility's perspective, the benefit of a DSM expenditure will equal:

a) the decrease in costs as a result of the fall in demand; less

b) the decrease in revenues as a result of the fall in demand; plus

c) any increase in revenues as a result of being able to recover DSM expenditures through future rates.

Cost decreases may occur in both operating and capital related costs. The savings in operating costs will generally be related to the fall in demand, however, any savings in capital related costs will be related to both the fall in demand and the level of surplus capacity. Where surplus capacity exists, there will be no savings in capital related costs. Where the decrease in demand allows for the deferral of new plant, the savings in these costs will equal what the depreciation and financing costs on the entire plant would have been over the deferral period.

Where the benefits of a DSM expenditure include the deferral of a plant, the benefits will tend to be skewed to the deferral period. Accordingly, the allocation of the DSM costs should be skewed to the same period. For example, a DSM expenditure may reduce demand over a five year period with half the benefits occurring in the fourth year when it will result in the deferral of a new generating plant. In such a case, half of the DSM expenditure should be deferred and expensed in the fourth year. However, where the impact on reported performance was not material, the principle of materiality would allow a simpler expensing pattern, e.g., straight line over the period that demand is expected to be reduced.

Regulatory principles require that the cost of DSM expenditures be matched to the period in which the related benefit is received and be recovered from customers in that period. Within the accounting context, the principle of conservatism creates a bias against the overstatement of assets and for expensing amounts in the current period rather than having expenses overstated in the future. Within the regulatory context, the principle of intergenerational equity requires a more equal weighting be given to different periods to ensure that the customers of different periods are treated equally. As a result, costs that would normally be expensed for accounting purposes may be deferred for regulatory purposes with recovery through future rates. In addition, other regulatory principles may affect the timing of cost recovery so that it differs from the period in which the cost would normally be expensed. For example, in accordance with the principle of rate stability and predictability, a cost that would normally be expensed and recovered as incurred may be deferred if immediate recovery would result in a sharp rate increase.

Deferring the recovery of DSM expenditures will result in an increase in rates. Not only will the rates have to recover the amount of the DSM expenditure, but also the cost of financing the unrecovered amount. However, where incurred to provide future benefits, the principle of intergenerational equity requires that the amounts be deferred - this is the same requirement that is applied to supply side expenditures.

As in accounting, there is a principle of materiality in regulation. Strict adherence to regulatory principles is not required where it would not have a material impact on the rates charged to customers.

Due to the ability of regulation to affect the amount and timing of cashflows, regulation can affect the accounting for DSM expenditures. To the extent that a regulator decides to defer the recovery of DSM expenditures, there is usually reasonable assurance of a future economic benefit, i.e, the eventual recovery of the expenditures. Accordingly, the costs should be deferred for accounting purposes and expensed as the costs are recovered through future rates. To the extent that a regulator allows the immediate recovery of a cost rather than deferral or disallows recovery of a cost, there will not be a future economic benefit. Accordingly, the cost should be expensed for accounting purposes. However, the ability of the regulatory process to create assets is not without limit. In addition to being allowed to include the cost in setting future rates, it must be reasonable to assume that the utility can collect from customers the rates necessary to recover the cost. Also, the regulatory process should be bound by established regulatory principles.

In a regulatory context, it may be appropriate to recognize customer savings as a benefit to be pursued by a utility. Since customer savings do not represent a benefit to the utility, the benefit would not be recognized for accounting purposes. However, to the extent the regulator allows the deferral of the costs with recovery in the period in which the customers receive the savings, a future cashflow benefit will be created for the utility. Such a cashflow benefit would be recognized for accounting purposes and justify the deferral of the DSM expenditure.

A utility should be indifferent to expensing or deferring its DSM expenditures as long as the utility is allowed to recover all of its costs, including the cost of financing any deferred DSM expenditures. However, to the extent that expensing or deferring creates an incentive, the strongest incentive to undertake DSM expenditures will tend to come with allowing the utility to recover and expense its expenditures in the period that the related benefit is received. This is consistent with the treatment that is normally applied to supply side costs and will result in the greatest comparability between demand side and supply side options. Moreover, it is consistent with what would normally be required by both accounting and regulatory principles.

Where amounts are material, the amount of the DSM expenditures, the amount of DSM related expense and the amount of unamortized DSM costs should be disclosed separately in the financial statements. Where individual categories of DSM expenditures are material, each category should be disclosed separately. The disclosure could be in the statements (e.g., income statement), in supporting schedules or notes to the financial statements. Also, where the amount of the DSM expenditures is material, the accounting policy for DSM expenditures should be disclosed in the notes to the financial statements.

SPECIFIC TYPES OF ACTIVITIES

As noted in the introduction, the DSM activities have been classified into five categories:

a) research and development;

b) investment activities;

c) information activities;

d) subsidy activities; and,

e) rate activities.

The costs associated with each of these activities is analyzed below and summarized in Table 4. The assumption is that the expenditures are material, if not, the principle of materiality may allow for a simpler treatment.

Research and Development Activities

Research and development costs consist of basis research into DSM, feasibility studies and pilot projects.

In the case of basic research, it is unlikely that there will be identifiable future economic benefits, a requirement for there to be reasonable assurance that such benefits exist. Accordingly the amounts should be expensed as incurred. In the case of feasibility studies, pilot projects and other development activities, it is unlikely that there would be reasonable assurance that there would be future economic benefits and the costs should also be expensed as incurred. However, it may be possible to demonstrate future economic benefits. In doing so, criteria equivalent to those set out by the CICA for development expenditures would have to be met:

a) the DSM program is clearly defined and the costs attributable thereto can be identified;

b) the technical feasibility of the DSM program has been established;

c) the management of the enterprise has indicated it intention to undertake the DSM program;

d) the future usefulness of the DSM program has been established;

e) adequate resources exist, or are expected to be available, to complete the DSM program.

If the above criteria can be met, the costs should be deferred and amortized as the benefits of the DSM program are received.

The normal accounting for research and development may not be appropriate for determining regulated rates. The research and development costs are incurred with the intention of benefiting future periods and, in accordance with the principle of intergenerational equity, should be deferred and recovered from future customers. Where the costs are significant and are not likely to be repeated in future periods, the principle of rate stability and predictability would also require deferral of the costs. Therefore, regulatory principles would tend to support the deferral of research and development costs. However, the expected benefits would be uncertain and, even if they do occur, would be difficult to identify. Therefore, the deferred cost should be amortized over a relatively short period of time, e.g., three to seven years.

Where the deferral of the costs was approved by the regulator and it appeared reasonable that the costs would be recovered through future rates, it would be appropriate for accounting purposes to defer the costs and amortize them over the period that the cost are recovered through rates.

Investment Activities

Investment activities consist of asset purchases by a utility to reduce or shift load, where the assets would be owned by the utility. These activities would include upgrading street lighting, improving the insulation of utility owned buildings, installing equipment that allows the utility to control the power usage of selected customers at peak periods, etc.

The purchase of assets to provide service should be deferred and expensed over the period that the asset will be used to provide service, the same as any other asset. Their contribution to future revenues, or to reducing costs necessary to provide future revenues, represents a future economic benefit. For example, where the lights in a building are replaced with more energy efficient lights, the cost of the new lights should be capitalized and depreciated over the period that the lights will be used to provide service and earn revenue.

The purchase of assets as part of a DSM program may result in the premature retirement of less energy efficient assets. Once disposed of, there is no future economic benefit associated with the replaced assets. Therefore, GAAP normally requires that the net gain or loss on the disposal should be recognized in income in the period of disposal. However, as noted earlier, the CICA Handbook explicitly recognizes that a rate-regulated entity may defer the gain or loss where there is reasonable assurance that any loss will be recovered through future rates or any gain will be used to reduce future rates[22].

The early replacement of assets with more energy efficient assets is done to provide future benefits, e.g., reduced energy related costs. Therefore, from a regulatory perspective, it would be appropriate that any unamortized cost of the replaced assets be deferred and recovered over the period that will benefit from the premature replacement. This would be the remaining life of the old assets had they not been replaced. Where a utility's regulator approves such a deferral, it would be appropriate to defer the cost for accounting purposes and to amortize it over the period that the cost are recovered from customers.

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22 Canadian Institute of Chartered Accountants, CICA Handbook, Canadian Institute of Chartered Accountants, Toronto, section 3060, paragraph 57.

Information Activities

Information activities attempt to make consumers aware of energy efficiency and how they can benefit from it. They may also inform manufacturers, distributors and retailers of a potential market for energy efficient products or products that would assist conservation. The activities would include advertising programs, the creation and distribution of informational pamphlets and the provision of consulting services to assist consumers in identifying how they can reduce their energy demand.

It may be difficult to identify the future benefits of information activities and thereby provide reasonable assurance of a future economic benefit. Where the benefits cannot be identified, the costs should be expensed as incurred. However, it may be possible to identify the future benefits. For example, studies may be conducted to determine the periods over which an energy conservation advertising program will impact demand. In such a case, the cost of the program should be deferred and amortized over the period that there is a quantifiable benefit from the reduction in demand.

From a regulatory perspective it may be appropriate to defer the recovery of the expenditures, even where they would normally be expensed. This would be the case where there were information activities that are designed primarily to produce future benefits. For example, an advertising program to encourage the use of water heater insulation is designed primarily to produce future savings over the period that the insulation is used. In such a case, a better weighing of customer interests between periods may require deferral of the advertising costs with recovery through future rates, even though it is not possible or practical to measure the future benefits associated with the activities. Moreover, even where the future benefits accrue to the customers rather than the utility, intergenerational equity would require that the expenditures be deferred since it will provide a better matching of the costs to the period and customers who benefit from the cost.

Where the deferral of expenditures for information activities is approved by the regulator, the costs should be deferred for accounting purposes and amortized as recovered through rates.

Subsidy Activities

Subsidy activities provide cash or low interest loans to encourage customers to make energy efficient investments. They would include subsidies to improve insulation, to replace lighting fixtures with newer more energy efficient fixtures and to chose more energy efficient appliances and equipment when making a new purchase.

Where a subsidy provides a future economic benefit to a utility, the costs should be deferred and amortized as the benefit is received. However, it may be difficult to provide reasonable assurance that there is a future economic benefit associated with the subsidies, especially since the replacement decision and future use of the asset is beyond the control of the utility. For example, a subsidy may be offered to industrial customers to replace energy inefficient equipment. Some of the problems in determining the amount and timing of the benefit include the following:

a) it will be difficult to determine whether the subsidy affects the replacement decision, i.e., some customers receiving the subsidy may have replaced the equipment without the subsidy;

b) it will be difficult to determine the period of time by which the replacement has been advanced; and

c) it will be difficult to determine the period of time that the replaced equipment will be used.

Even if the existence of a benefit period cannot be proven with reasonable assurance, from a regulatory perspective, it may be appropriate to defer the cost of the subsidies and to recover them over some assumed period of benefit. Such an approach would give a more equal weighting to customers of different periods and, therefore, be more consistent with intergenerational equity. However, the greater the uncertainty, the shorter the recovery period should be. This will limit the possibility that the utility will be required to finance a deferred cost for which there is not benefit.

As with the expenditures for information activities, the entire benefit of the subsidies may go to customers rather than the utility. From a regulatory perspective, deferral and recovery over the benefit period would provide a better balancing of customer interests than immediate recovery.

Where the deferral of expenditures for subsidy activities is approved by the regulator, the costs should be deferred for accounting purposes and amortized as recovered through rates.

Rate Activities

Rate activities create rate differentials to encourage customers to switch demand from the peak to off-peak period or to reduce demand.

Rate activities would not normally result in any additional expenditures. Therefore there would be no additional expenditures to account for or to recover through regulated rates.

TABLE 4

SUMMARY OF CONCLUSIONS & RECOMMENDATIONS (1)

		DEFER & AMORTIZE OVER			
	EXPENSE (2)	SHORT PERIOD 3-7 YEARS	ASSET LIFE	PERIOD IN WHICH BENEFIT IS RECEIVED	N/A
RESEARCH & DEVELOPMENT	x	x			
INVESTMENT ACTIVITIES					
- NEW ASSETS			x		
- UNDEPRECIATED COST OF REPLACED ASSETS				x	
INFORMATION ACTIVITIES	x				
SUBSIDY ACTIVITIES	x			x	
RATE ACTIVITIES					x

(1) As indicated in the accompanying text, these conclusions and recommendations may be modified by the circumstances of a specific situation.

(2) Activities, such as research and development or subsidy activities, may be expensed as incurred or, if a longer term benefit can be identified, wirtten off over a relatively short or benefit period.

INCENTIVE MECHANISMS

Prospective Rate Setting

The prospective setting of rates creates a disincentive to actively pursue DSM. If a DSM program is overly successful, allowed rates will be insufficient to provide a utility its allowed return. To offset the disincentive, a utility could be given an incentive bonus based on the amount of its DSM expenditures. However, such an incentive would encourage DSM expenditures, not results. A preferable approach would be to set up a mechanism that would allow for the deferral of any gain or loss in earnings as a result of shifts in demand - a deficiency would be collected from customers while any surplus would be returned to customers. With such an approach, the ability of a utility to earn its allowed return would be unaffected by the success of its DSM activities.

Growth Opportunities

DSM activities limit the growth opportunities for a utility. In theory, this should not be an issue. Investors can expect to recover their costs plus a fair return on their investment. This fair return is based on what could be earned on an alternative investment of similar risk. Therefore the investors should be indifferent to investing in the utility or an alternative investment of similar risk. However, from a practical perspective, investors may prefer a company with growth opportunities. More importantly, there will likely be a disincentive to managers whose careers may be related to the growth opportunities of the utility.

Incentives that are based on the amount of DSM expenditures or that allow a higher than normal return on deferred expenditures will tend to increase the amount spent on DSM. However, it would be preferable to base incentives on results, i.e., reductions in demand from what would otherwise be expected. Such an incentive would encourage DSM results, not just DSM expenditures.

APPENDIX A

REGULATORY EVALUATION OF DSM ACTIVITIES

Regulators have used various tests in evaluating the economics of DSM activities. A description of the various types of tests was set out in a manual produced jointly by the California Public Utilities Commission and the California Energy Commission[1]. In this manual five tests for evaluating DSM programs were presented:

- Participant Test
- Ratepayer Impact Measure Test
- Total Resource Cost Test
- Societal Test
- Utility Cost Test

Each test is designed to evaluate the programs against specific criteria and some are not appropriate for evaluating economic efficiency.

The Participants Test is a measure of the quantifiable benefits and costs to the customer due to participation in a program. It recognizes as a benefit only the reduction in the customers bill plus any incentives. It recognized as a cost only the additional costs to customers from participating. It is a minimum test of whether a program has adequate incentives to gain customer acceptance. However, it is too narrow to determine the acceptability of a program; for example, it ignores any resulting change in costs to the utility or increase in rates to non-participating customers.

The Ratepayer Impact Measure test measures what happens to customer bills or rates due to changes in utility revenues and operating costs caused by a DSM program. It recognizes as a benefit the

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1 California Public Utilities Commission and California Energy Commission, Standard Practice Manual, Economic Analysis of Demand Side Management Programs, December 1987.

avoided supply cost. It recognizes as a cost, the cost of the DSM program, any incentives to participants in the program and any resulting decrease in revenues. This test would indicate the acceptance of the program where the objective is to minimize rates.

The Total Resource Cost Test measures the net impact of a DSM program based on the total costs of the program, including both the participants's and the utility's costs. It recognizes the avoided supply cost as a benefit, and as a cost, any additional costs to either the utility or customers. Unlike the Ratepayer Impact Measure it does not recognize any redistribution from non-participants to participants. Hence, it is a broader measure that does not consider the impact on rates.

The Societal Test is a variant of the Total Resource Test that differs from this test in that it recognizes externalities, i.e, social costs. It would also include social benefits to the extent that they existed.

The Utility Cost Test measures the net costs of a demand-side management program as a resource option based on the costs incurred by the utility, including incentive costs, and excluding any net costs incurred by the participant. This test is similar to the Total Resource Cost Test except that it excludes any additional costs incurred by participants. Since it excludes participant costs, it is not a good test of the economic efficiency of a DSM program. Moreover, as with the Total Resource Cost test, it ignores the impact on rates.

APPENDIX B
LIST OF SURVEY RESPONDENTS

Canadian - Significant Generating Capacity

Alberta Power Limited
British Columbia Hydro and Power Authority
Edmonton Power
Hydro-Quebec
Manitoba Hydro
Maritime Electric Company, Limited
The New Brunswick Electric Power Commission
Newfoundland and Labrador Hydro
Newfoundland Power
Northwest Territories Power Corporation
Nova Scotia Power Corporation
Ontario Hydro
Saskatchewan Power Corporation

Canadian - Primarily Distribution

Burlington Hydro-Electric Commission
La Cie d'Energie MacLaren-Quebec
Markham Hydro Electric Commission
North York Hydro
The Public Utilities Commission of the City of Scarborough
West Kootenay Power Ltd.
Winnipeg Hydro
The Yukon Electrical Company Limited

United States Utilities

American Electric Power Company
Consumers Power
Florida Power Corporation
Florida Power and Light Company
Georgia Power Company
Jersey Central Power & Light Company
New York State Electric & Gas Corporation
Northern States Power Co. (Minneapolis)
Pacific Gas and Electric Company
Pennsylvania Power & Light Company
Public Service Company of Colorado
Public Service Electric & Gas Company
San Diego Gas & Electric
Virginia Electric and Power Company

APPENDIX C

SUMMARY OF SURVEY RESULTS

CANADIAN ELECTRICAL ASSOCIATION
RESEARCH STUDY
ACCOUNTING FOR DEMAND SIDE MANAGEMENT

Question: *What is your annual revenue requirement in $billions?*

	Less Than 0.50	.51 –1.50	1.51 – 2.50	Over 2.50	DNR
CANADIAN GENERATING UTILITIES	6	4	1	2	0
OTHER CANADIAN UTILITIES	8	0	0	0	0
UNITED STATES UTILITIES	0	4	4	6	0
TOTAL CANADIAN	14	4	1	2	0
TOTAL SURVEY	14	8	5	8	0

CANADIAN ELECTRICAL ASSOCIATION
RESEARCH STUDY
ACCOUNTING FOR DEMAND SIDE MANAGEMENT

Question: *In which year was formal DSM program first implemented?*

	After 1984	1980 to 1984	1975 to 1979	Prior to 1974	No Program Exists
CANADIAN GENERATING UTILITIES	7	0	2	1	3
OTHER CANADIAN UTILITIES	3	1	0	0	4
UNITED STATES UTILITIES	4	4	4	1	1
TOTAL CANADIAN	10	1	2	1	7
TOTAL SURVEY	14	5	6	2	8

CANADIAN ELECTRICAL ASSOCIATION
RESEARCH STUDY
ACCOUNTING FOR DEMAND SIDE MANAGEMENT

Question: *What type of DSM programs are carried out by your utility?*

	Advertising Education	Rebates Subsidies	R & D	Peak Shaving Load Shifting	Water Heating	Street Light Repl	Energy Audits
CANADIAN GENERATING UTILITIES	8	9	4	5	3	3	3
OTHER CANADIAN UTILITIES	4	1	1	0	0	1	0
UNITED STATES UTILITIES	12	10	7	5	3	2	2
TOTAL CANADIAN	12	10	5	5	3	4	3
TOTAL SURVEY	24	20	12	10	6	6	5

* – One USU reported a formal DSM program, but did not indicate specific programs.

Question: *How are advertising/ education expenditures treated for accounting purposes?*

	Expensed as incurred	Deferred 5 Years	Deferred 7 - 10 YRS	Determined by Regulator	DNR
CANADIAN GENERATING UTILITIES	4	1	2	0	1
OTHER CANADIAN UTILITIES	3	0	1	0	0
UNITED STATES UTILITIES	10	1	0	1	0
TOTAL CANADIAN	7	1	3	0	1
TOTAL SURVEY	17	2	3	1	1

CANADIAN ELECTRICAL ASSOCIATION
RESEARCH STUDY
ACCOUNTING FOR DEMAND SIDE MANAGEMENT

Question: *How are subsidy, rebate and incentive expenditures treated for accounting purposes?*

	Expensed as incurred	Deferred 5 -7 Years	Deferred 10 YEARS	Deferred 15 YEARS	Deferred Case by Case Am	DNR
CANADIAN GENERATING UTILITIES	3	2	2	1	1	0
OTHER CANADIAN UTILITIES	0	0	1	0	0	0
UNITED STATES UTILITIES	8	1	0	0	1	0
TOTAL CANADIAN	3	2	3	1	1	0
TOTAL SURVEY	11	3	3	1	2	0

Question: *How are research and development expenditures treated for accounting purposes?*

	Expensed as incurred	Deferred on Case by Case Basis	DNR
CANADIAN GENERATING UTILITIES	2	2	0
OTHER CANADIAN UTILITIES	1	0	0
UNITED STATES UTILITIES	5	2	0
TOTAL CANADIAN	3	2	0
TOTAL SURVEY	8	4	0

CANADIAN ELECTRICAL ASSOCIATION
RESEARCH STUDY
ACCOUNTING FOR DEMAND SIDE MANAGEMENT

Question: *How are peak shaving/ load shifting expenditures treated for accounting purposes?*

	Expensed as incurred	Deferred 5 Years	Deferred 7 – 10 YRS	Determined by Regulator	DNR
CANADIAN GENERATING UTILITIES	4	0	0	0	1
OTHER CANADIAN UTILITIES	0	0	0	0	0
UNITED STATES UTILITIES	4	0	0	0	1
TOTAL CANADIAN	4	0	0	0	1
TOTAL SURVEY	8	0	0	0	2

CANADIAN ELECTRICAL ASSOCIATION
RESEARCH STUDY
ACCOUNTING FOR DEMAND SIDE MANAGEMENT

Question: *How are energy audit expenditures treated for accounting purposes?*

	Expensed as incurred	Deferred 5 -7 Years	Deferred 10 YEARS	Deferred 15 YEARS	Deferred as Set by Regulator	DNR
MAJOR CANADIAN GENERATING UTILITIES	2	0	0	0	0	1
OTHER CANADIAN UTILITIES	0	0	0	0	0	0
UNITED STATES UTILITIES	0	0	0	0	1	1
TOTAL CANADIAN	2	0	0	0	0	1
TOTAL SURVEY	2	0	0	0	1	2

Question: *How are water heating program expenditures treated for accounting purposes?*

	Expensed as incurred	Deferred 5 Year Am.	DNR
CANADIAN GENERATING UTILITIES	1	1	1
OTHER CANADIAN UTILITIES	0	0	0
UNITED STATES UTILITIES	2	0	1
TOTAL CANADIAN	1	1	1
TOTAL SURVEY	3	1	2

Question: *How are street light expenditures treated for accounting purposes?*

	Expensed as incurred	Deferred Case by Case Am	DNR
CANADIAN GENERATING UTILITIES	1	0	2
OTHER CANADIAN UTILITIES	1	0	0
UNITED STATES UTILITIES	1	0	1
TOTAL CANADIAN	2	0	2
TOTAL SURVEY	3	0	3

CANADIAN ELECTRICAL ASSOCIATION
RESEARCH STUDY
ACCOUNTING FOR DEMAND SIDE MANAGEMENT

Question: *How are overhead costs treated for accounting purposes?*

	DSM SPECIFIC OVERHEAD			GENERAL OVERHEAD			
	Expensed as incurred	Deferred over DSM Benefit	DNR	No Gen Oh'd alloc to DSM	Expensed as incurred	Deferred over DSM Benefit	DNR
MAJOR CANADIAN GENERATING UTILITIES	6	3	1	6	1	2	1
OTHER CANADIAN UTILITIES	3	1	0	3	0	0	1
UNITED STATES UTILITIES	10	2	1	11	0	1	1
TOTAL CANADIAN	9	4	1	9	1	2	2
TOTAL SURVEY	19	6	2	20	1	3	3

CANADIAN ELECTRICAL ASSOCIATION
RESEARCH STUDY
ACCOUNTING FOR DEMAND SIDE MANAGEMENT

Question: *What factors must be present in order to capitalize or defer an expenditure?*

	Recovery in future rates	Future Benefit	Cause/ Effect Relationship	Measurable Benefit	Meet Normal F/A Policies	DNR, N/A
CANADIAN GENERATING UTILITIES	7	6	1	1	1	1
OTHER CANADIAN UTILITIES	1	1	0	0	0	3
UNITED STATES UTILITIES	5	0	0	0	2	7
TOTAL CANADIAN	8	7	1	1	1	4
TOTAL SURVEY	13	7	1	1	3	11

CANADIAN ELECTRICAL ASSOCIATION
RESEARCH STUDY
ACCOUNTING FOR DEMAND SIDE MANAGEMENT

Question: *If expenditures are deferred or capitalized, what is the basis for determining the amortization period?*

	Set by Regulator	Benefit Period	Pre- Det 5-10 yrs	Pre- Det 15 years	Life Asset or Benefit	N/A, DNR
CANADIAN GENERATING UTILITIES	0	3	2	1	2	2
OTHER CANADIAN UTILITIES	0	0	0	0	1	3
UNITED STATES UTILITIES	2	0	1	0	2	8
TOTAL CANADIAN	0	3	2	1	3	5
TOTAL SURVEY	2	3	3	1	5	13

Question: *Is there a subsequent review of deferred DSM expenditures to ensure contined existence of future benefits? If benefits are overstated, will costs be immediatly written off or the amortization period decreased? If benefits are understated, will the amortization period be increased?*

	Future Benefits Reviewed			If Benefits Change		
	YES	NO	DNR	Costs Written Off	Amort Period Decreased	Amort Period Increased
CANADIAN GENERATING UTILITIES	5	3	2	5	5	5
OTHER CANADIAN UTILITIES	0	0	4	0	0	0
UNITED STATES UTILITIES	5	0	8	1	0	0
TOTAL CANADIAN	5	3	6	5	5	5
TOTAL SURVEY	10	3	14	6	5	5

CANADIAN ELECTRICAL ASSOCIATION
RESEARCH STUDY
ACCOUNTING FOR DEMAND SIDE MANAGEMENT

Question: *Where a DSM activity requires the purchase of equipment that will be owned by the utility, what criteria are used in evaluating the expenditure?*

	Benefits Exceed Costs	Rate Impact	Payback Period	Participant Test	Energy Savings	DNR
CANADIAN GENERATING UTILITIES	8	1	0	1	1	2
OTHER CANADIAN UTILITIES	2	0	1	0	2	1
UNITED STATES UTILITIES	4	0	2	0	0	7
TOTAL CANADIAN	10	1	1	1	3	3
TOTAL SURVEY	14	1	3	1	3	10

Question: *Where a DSM activity requires the purchase of equipment that will be owned by the utility, is the accounting treatment for that equipment different than for non DSM equipment purchases?*

	YES	NO	N/A, DNR
CANADIAN GENERATING UTILITIES	1	7	2
OTHER CANADIAN UTILITIES	1	3	0
UNITED STATES UTILITIES	3	6	4
TOTAL CANADIAN	2	10	2
TOTAL SURVEY	5	16	6

CANADIAN ELECTRICAL ASSOCIATION
RESEARCH STUDY
ACCOUNTING FOR DEMAND SIDE MANAGEMENT

Question: *Where the DSM activity results in the early replacement of assets, what treatment is given the gain or loss on retirement?*

	Normal Accounting Policies		Written off over life of DSM Benefit	DNR
	Expensed	Residual Value Depr*		
CANADIAN GENERATING UTILITIES	3	3	1	3
OTHER CANADIAN UTILITIES	1	0	0	3
UNITED STATES UTILITIES	0	3	0	10
TOTAL CANADIAN	4	3	1	6
TOTAL SURVEY	4	6	1	16

* – Residual value written off through depreciation

Question: *How are the costs of the feasibility study treated for accounting purposes when the DSM program studied is not i*

	Expensed	Deferred Over DSM benefit life	No such studies to date	DNR
CANADIAN GENERATING UTILITIES	8	0	2	0
OTHER CANADIAN UTILITIES	3	0	1	0
UNITED STATES UTILITIES	11	1	1	0
TOTAL CANADIAN	11	0	3	0
TOTAL SURVEY	22	1	4	0

CANADIAN ELECTRICAL ASSOCIATION
RESEARCH STUDY
ACCOUNTING FOR DEMAND SIDE MANAGEMENT

Question: *Do DSM costs appear as a separate line item in your income statement or balance sheet?*

	NO	Balance Sheet	Income Statement	N/A, DNR
MAJOR CANADIAN GENERATING UTILITIES	8	1	0	1
OTHER CANADIAN UTILITIES	4	0	0	0
UNITED STATES UTILITIES	12	0	0	1
TOTAL CANADIAN	12	1	0	1
TOTAL SURVEY	24	1	0	2

CANADIAN ELECTRICAL ASSOCIATION
RESEARCH STUDY
ACCOUNTING FOR DEMAND SIDE MANAGEMENT

Question: *In the notes to the financial statements, what is reported?*

	No Disclosure	DSM Expenditures	Unamort. DSM Amounts	DSM Amort. Period	DSM Accounting Policy	N/A, DNR
MAJOR CANADIAN GENERATING UTILITIES	6	3	3	4	3	1
OTHER CANADIAN UTILITIES	4	0	0	0	0	0
UNITED STATES UTILITIES	11	1	0	0	1	1
TOTAL CANADIAN	10	3	3	4	3	1
TOTAL SURVEY	21	4	3	4	4	2

Question: *If DSM expenditures result in a drop in revenue, does your regulator allow your utility to recover DSM induced lost profits in future rates?*

	Yes	No	No Experience	No But Proposed or Considered
CANADIAN GENERATING UTILITIES	0	2	8	0
OTHER CANADIAN UTILITIES	0	2	2	0
UNITED STATES UTILITIES	2	6	0	5
TOTAL CANADIAN	0	4	10	0
TOTAL SURVEY	2	10	10	5

Note – Recovery of DSM expenditures in future rates was not considered to be a recovery of lost profits.

Question: *Does your regulator provide incentives to undertake DSM activities?*

	General Incentive Programs		Specific Incentive Programs	
	Yes	No	Yes	NO
CANADIAN GENERATING UTILITIES	0	10	0	10
OTHER CANADIAN UTILITIES	0	4	0	4
UNITED STATES UTILITIES	2	11	1	12
TOTAL CANADIAN	0	14	0	14
TOTAL SURVEY	2	25	1	26

Note – The ability to recover DSM expenditures in future rates was not considered an incentive.

Question: *Before allowing recovery for a DSM expenditure, what does your regulator require?*

	Revenue Requirement Reduction	Rate Reduction	Benefits Exceed Costs	N/A, No Experience
CANADIAN GENERATING UTILITIES	1	0	2	8
OTHER CANADIAN UTILITIES	1	0	1	3
UNITED STATES UTILITIES	1	1	5	8
TOTAL CANADIAN	2	0	3	11
TOTAL SURVEY	3	1	8	19

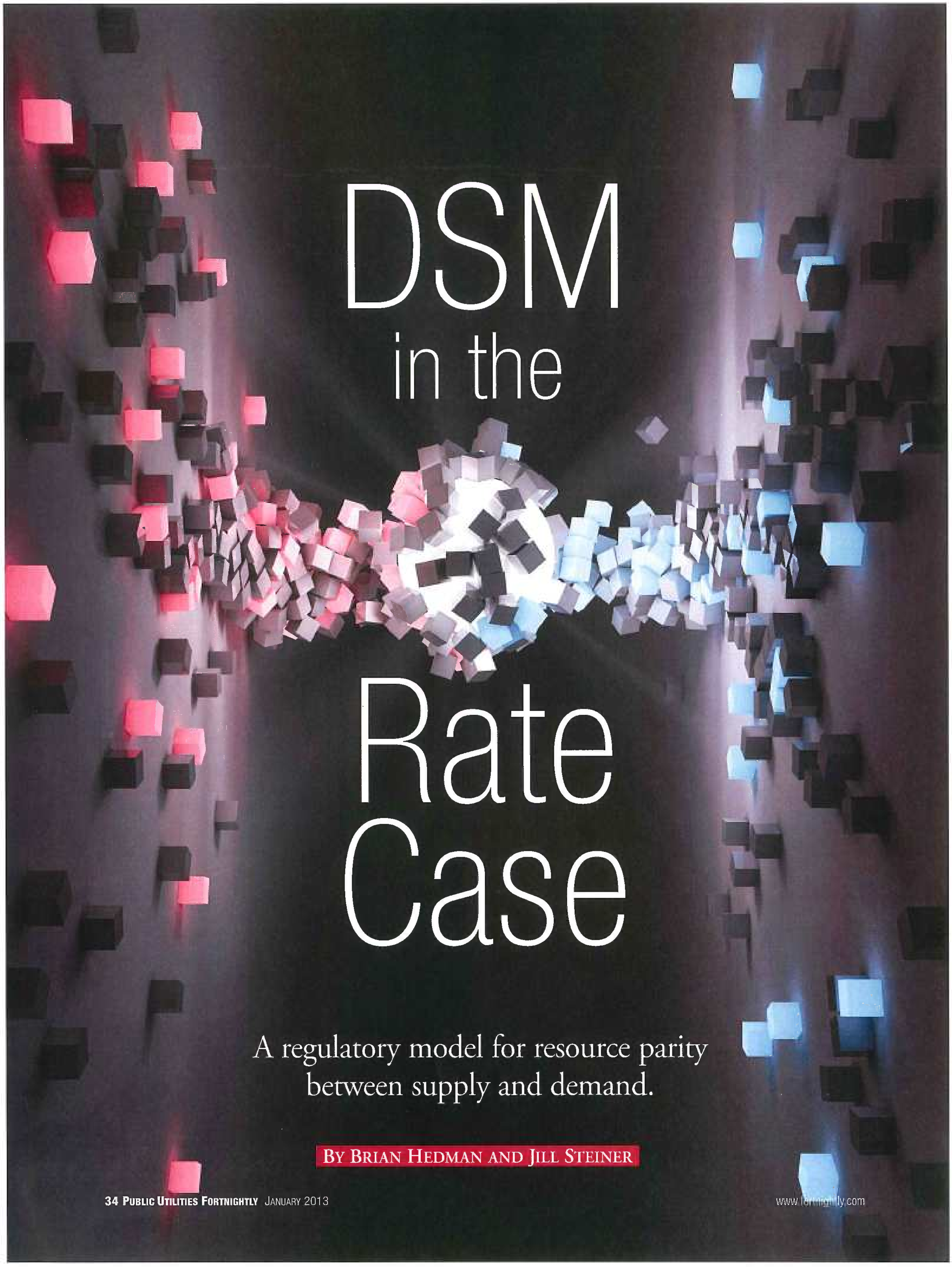
CANADIAN ELECTRICAL ASSOCIATION
RESEARCH STUDY
ACCOUNTING FOR DEMAND SIDE MANAGEMENT

Question: *Are there any differences between the accounting and regulatory treatment for DSM expenditures?*

	YES	NO	No Experience	DNR
MAJOR CANADIAN GENERATING UTILITIES	0	7	2	1
OTHER CANADIAN UTILITIES	0	3	0	1
UNITED STATES UTILITIES	1	9	2	1
TOTAL CANADIAN	0	10	2	2
TOTAL SURVEY	1	19	4	3

Appendix C

DSM IN THE RATE CASE 2013



DSM in the Rate Case

A regulatory model for resource parity between supply and demand.

By Brian Hedman and Jill Steiner

To be truly effective, integrated resource planning must give equal play ("comparable" treatment) to both supply- and demand-side resources. But that task can prove difficult. Direct comparisons can pose challenges, owing to the sometimes counter-intuitive nature of demand-side management (DSM), versus the more conventional notions of what such resources truly are.

We use the term DSM to refer to both energy efficiency and demand response programs. These programs provide incentives for customers to use energy more efficiently or to shift the time period in which they use it. In so doing, they can reduce the utility's future obligation either to provide energy or to stockpile capacity to meet demand. But DSM's characteristics differ from supply-side alternatives.

One key difference concerns the physical attributes of a supply resource, versus the virtual nature of its demand-side counterpart.

Supply-side resources are tangible. They typically take the form of a large-scale asset. The utility frequently owns the plant and earns a return on investment supplied by shareholders. That large-scale investment typically is sufficient to trigger a general rate case to roll the costs into the utility's prices.

DSM programs, by contrast, represent a larger number number of smaller investments. They are insufficient individually to trigger a general rate case. They don't typically create a regulatory asset booked on the utility's balance sheet. And without such treatment, there's no return on investment for shareholders. Further, DSM programs reduce future sales, whereas supply-side resources provide additional energy to serve increased sales.

These different characteristics have led regulators to treat the two classes of resources differently. More importantly, however, to ensure a level playing field for both demand- and supply-side resources, regulators must address three key issues:

- Recovery of program costs, including administration, marketing, and incentives;
- The effect of reduced future sales; and
- Shareholder expectations.

Regulators aren't blind to these ideas, however, nor are researchers or policymakers.

As far back as 1989, the National Association of Regulatory Utility Commissioners (NARUC) passed a resolution citing the need to "align utilities pursuit of profits with least-cost planning." The resolution urged its member state commissions to: "consider the loss of earnings potential connected with the use of demand-side resources; adopt appropriate ratemaking mechanisms to encourage utilities to help their customers improve end-use efficiency cost-effectively; and otherwise ensure that the successful implementation of a utility's least-cost plan is its most profitable course of action."[1]

Twenty years later, in 2009, the Lawrence Berkeley Lab released a study stating the same concern in slightly different terms: "A key issue for state regulators and policymakers is how to maximize the cost-effective energy efficiency savings attained while achieving an equitable sharing of benefits, costs and risks among the various stakeholders."[2] *(See "Missouri Shows Us.")*

Disputes can arise over the choice of method to calculate or estimate both net benefits and avoided costs.

These issues will only grow in importance. Recently the U.S. Energy Information Administration (EIA) indicated that $5.5 billion was spent on electric DSM programs in 2011, representing 1.5 percent of total electric retail revenues. It's clear that DSM has grown to have a significant effect on utility planning and rate structures. Optimizing the ratemaking treatment of DSM remains vital to giving comparable treatment to demand- and supply-side resources.

DSM Cost Recovery

Utilities and regulators commonly employ three mechanisms for recovering direct DSM program costs: expensing, deferral accounting, and contemporaneous recovery.

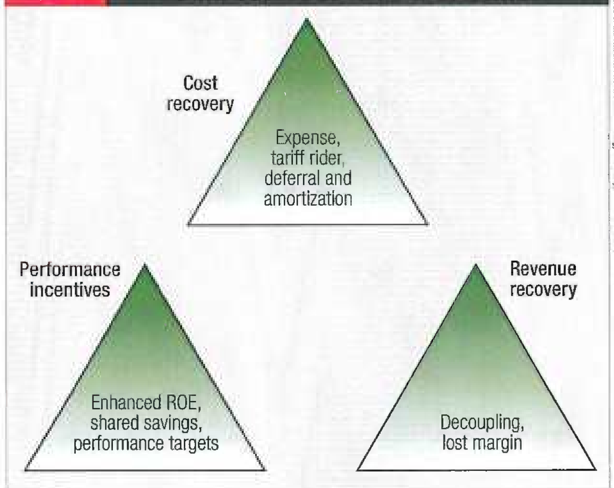
Few jurisdictions continue to treat DSM as a simple operating and maintenance expense, because this traditional ratemaking method can create a disincentive for the utility to maintain or increase DSM spending between rate cases, as only those costs incurred during the test period of the rate case are allowed in rates. The reason is simple. In between rate cases, any upward

1. Resolution in Support of Incentives for Electric Utility Least-Cost Planning, NARUC, July 27, 1989.

2. *Financial Analysis of Incentive Mechanisms to Promote Energy Efficiency: Case Study of a Prototypical Southwest Utility*, LBNL-1598E, March 2009.

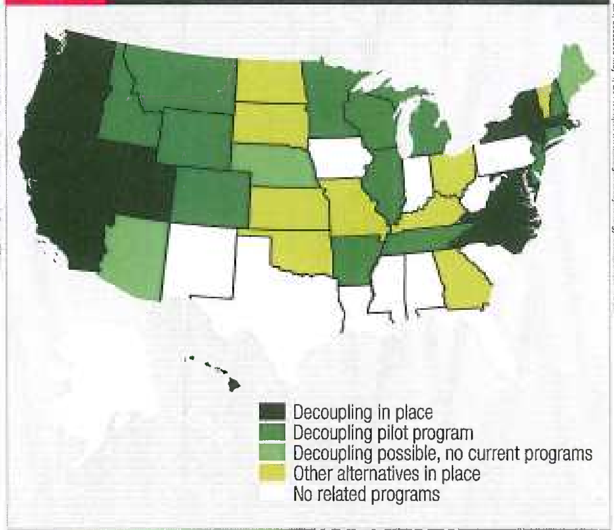
Brian Hedman is an executive director at the Cadmus Group and **Jill Steiner** is a principal.

Fig. 1 DSM Cost Recovery and Incentives



Source: Adapted from *Aligning Utility Incentives with Investment in Energy Efficiency: A Resource of the National Action Plan for Energy Efficiency*, November 2007.

Fig. 2 Utility Decoupling Mechanisms



Source: EIA, accessed May 4, 2011. http://www.eia.gov/todayinenergy/detail.cfm?id=1230#

variance from costs projected in the test period erodes the bottom line due to regulatory lag, while reducing DSM spending below the rate-case level will boost returns for utility shareholders.

The second method, deferral accounting, overcomes that disincentive. Utilities receive permission from regulators to defer and capitalize their DSM expenditures and amortize them into rates over time, earning the same rate of return on the deferred balance as for any other capital asset, or in some cases, a bonus rate of return. On the balance sheet, these deferred expenditures are treated as a regulatory asset. Amortization of the capitalized balance typically begins the year after the expense is deferred or at the time of the next rate case. The amortization period can be negotiated or can be tied to the expected lives of the DSM measures.

Nevertheless, this regulatory asset often is seen as less firm than other physical assets. It might be treated differently for accounting and tax purposes. And some stakeholders have raised concerns that market conditions or changes in future rate recovery proceedings might render such regulatory assets unrecoverable. Consequently, capitalization fell from favor during the restructuring period in the 1990s. Nonetheless, this method today is seeing a resurgence, as capitalization and amortization most closely matches the treatment accorded to supply-side resources, and provides the basis for other potential incentives.

The third mechanism for recovering DSM expenditures is contemporaneous recovery. Many jurisdictions have moved to or are planning to adopt this mechanism in an effort to support development and acceptance of DSM activities. In some cases, these result in a legislated system benefits charge (SBC); in others, they're proposed by utilities and noted in the form of a line item on the customer's bill—a tariff rider. Typically, an SBC is set as a percentage of the bill or a fixed $/kWh. The total revenue collected by the SBC determines the ceiling—*e.g.,* the budget—for the DSM programs.

In the case of tariff riders, the budget is determined by the integrated resource planning process or by expenditures needed to meet renewable resource standards or other targets. This budget is then converted to a line item on the utility bill, set at a level to recover the expenditures on an annual basis. Any over-collection or under-collection is accrued and added to the following year's budget. The line item charge is adjusted annually to recover that year's expected expenditures plus any carryover.

Overall, this third mechanism provides the utility with assurance that prudently incurred DSM expenditures will be recovered in the year they're incurred. Prudence is typically determined by a cost-benefit analysis of the proposed programs at the time the programs are implemented, and reviewed periodically through an evaluation, measurement, and verification process. Historical expenditures are generally recovered even in the event that a program fails a cost-effectiveness test, but the program is either modified to become cost effective or eliminated prospectively.

Recovering Lost Margin

Successful DSM programs reduce the utility's sales from what they otherwise would've been. This shortfall contrasts with the increased sales expected from supply-side resources. Thus, while the costs of a supply-side resource and a demand-side resource might be identical, those costs will be spread across dissimilar volumes of energy sales.

Further, utility prices typically recover a portion of the utility's fixed costs through the volumetric portion of the rate structure. Consequently, the decline in sales associated with successful DSM programs can cause an under-recovery not only of current operating costs, but also of the utility's authorized fixed costs. Three basic classes of mechanisms are available to address the potential under-recovery of fixed costs: lost-revenue adjustments,

Missouri Shows Us

A sample regulatory framework for demand-side management.

Overall Policy: Demand-side management (DSM) takes form through legislation, state codes and regulatory commission orders. Consider this example from Missouri *(Mo. CSR 4 CSR 240-22)*, which codifies state policy as follows:

"The fundamental objective of the resource planning process at electric utilities shall be to provide the public with energy services that are safe, reliable, and efficient, at just and reasonable rates, in compliance with all legal mandates, and in a manner that serves the public interest and is consistent with state energy and environmental policies. The fundamental objective requires that the utility shall [c]onsider and analyze demand-side resources, renewable energy, and supply-side resources on an equivalent basis, subject to compliance with all legal mandates that may affect the selection of utility electric energy resources, in the resource planning process."

Cost Recovery: Missouri also provides direction for DSM program cost recovery *(Title 4 CSR 240-20.093, para. 1m)*, by establishing and defining commission authority to implement cost recovery mechanisms:

"Demand-side programs investment mechanism, or DSIM, means a mechanism approved by the commission in a utility's filing for demand-side program approval to encourage investments in demand-side programs. The DSIM may include, in combination and without limitation: 1) Cost recovery of demand-side program costs through capitalization of investments in demand-side programs; 2) Cost recovery of demand-side program costs through a demand-side program cost tracker; 3) Accelerated depreciation on demand-side investments; 4) Recovery of lost revenues; and 5) Utility incentive based on the achieved performance level of approved demand-side programs."

Balancing Competing Interests: The Missouri Code *(CSR 240-20.093, para. 2c)* also recognizes that the cost recovery mechanisms help balance competing interests among shareholders, customers, and other stakeholders:

"The commission shall approve the establishment, continuation, or modification of a DSIM and associated tariff sheets if it finds the electric utility's approved demand side programs are expected to result in energy and demand savings and are beneficial to all customers in the customer class in which the programs are proposed, regardless of whether the programs are utilized by all customers and will assist the commission's efforts to implement state policy contained in section 393.1075, RSMo, to: 1) Provide the electric utility with timely recovery of all reasonable and prudent costs of delivering cost-effective demand-side programs; 2) Ensure that utility financial incentives are aligned with helping customers use energy more efficiently and in a manner that sustains or enhances utility customers' incentives to use energy more efficiently; and 3) Provide timely earnings opportunities associated with cost-effective measurable and/or verifiable energy and demand savings."

Such an approach provides clear guidance while retaining flexibility to address the individual circumstances of each utility.
–BH and JS

decoupling, and straight fixed-variable pricing. Figure 2 shows which states have implemented or authorized decoupling and other methods for recovering lost revenues.

The first class of methods, lost revenue adjustments, appears straightforward—but only on the surface. Lost revenues are calculated by multiplying the decline in sales attributed to the programs by a pre-determined fixed-cost component of the energy price. The lost revenues so calculated are either deferred into a regulatory asset and amortized during the next general rate case, or are recovered through a surcharge on the current rates, similar to the contemporaneous recovery of DSM program costs. This method is attractive as it tends to isolate the effect of the DSM program. However, implementation in practice has proven difficult. Calculating the lost revenue requires agreement on the sales impacts of the programs as well as the fixed component of the overall price structure, both of which can be contentious. A lost-revenue approach also creates a disincentive for utilities to support non-utility DSM efforts, such as state funded rebates and codes, that will reduce sales but won't be counted toward the lost revenue. Lost revenue mechanisms were popular during the early '90s but their application has declined due to these difficulties.[3]

The second class, decoupling, expands the concept of lost-revenue recovery to a symmetrical treatment for fixed costs. Fixed costs don't vary with sales and are decoupled from variable costs to be recovered separately. In concept, decoupling consists of a determination of fixed costs and a basis for fixed-cost recovery, typically the number of customers. The total revenue allowed to be recovered by the utility in a given period is determined by adding the allowed fixed costs (number of customers times the fixed-cost recovery rate) plus the variable

3. A September 2011 ACEEE survey of lost revenue mechanisms reports the mechanisms are seeing a resurgence of interest, primarily in jurisdictions with limited DSM program implementation experience.

FIG. 3 STATE REGULATORY MECHANISMS FOR RECOVERING DSM COSTS

State	Cost Recovery	Lost Revenue Recovery	Performance Incentives	Savings as % of Sales
Alabama	Rate case expense	Lost revenue recovery for electric and gas	Yes, electric and gas	0.08%
Alaska	Rate case expense	No	No	0.02%
Arizona	Tariff rider	Pending lost revenue for electric, pending decoupling for gas	Tiered shareholder incentive for APS	0.78%
Arkansas	Tariff rider	Lost revenue recovery for electric and gas	Pending for electric and gas	0.14%
California	System benefits charge, tariff rider, rate case expense	Decoupling for electric and gas	Risk-reward mechanism for electric and gas	0.88%
Colorado	Tariff rider	Partial decoupling for gas, disincentive offset for electric	Yes, electric and gas	0.50%
Connecticut	System benefits charge	Decoupling for electric, lost revenue for gas	Yes, electric	0.84%
Delaware	Rate case expense, tariff rider	Decoupling pending for electric and gas	No	0.00%
District of Columbia	System benefits charge	Decoupling for electric	Yes, electric and gas	0.46%
Florida	Tariff rider	Pending for electric and gas	Authorized by legislation, pending for electric and gas	0.16%
Georgia	Tariff rider	Lost revenue for electric authorized	Yes, electric	0.04%
Hawaii	System benefits charge	Decoupling for electric	Yes, electric and gas	1.12%
Idaho	Tariff rider	Decoupling for electric	No	0.82%
Illinois	Tariff rider	Decoupling for gas	No	0.40%
Indiana	Tariff rider	Decoupling and lost revenue for electric and gas	Yes, electric and gas	0.04%
Iowa	Tariff rider	Authorized, but not yet implemented	No	0.94%
Kansas	Tariff rider	Lost revenue for electric	Authorized, but not yet implemented	0.00%
Kentucky	Tariff rider	Lost revenue for electric and gas	Shared savings mechanism for electric and gas	0.07%
Louisiana	Rate case expense	Yes, electric and gas	Yes, electric and gas	0.00%
Maine	System benefits charge	Authorized, but not yet implemented	Authorized, but not yet implemented	0.83%
Maryland	Tariff rider	Decoupling in place for electric and gas	Authorized, but not yet implemented	0.44%
Massachusetts	System benefits charge	Decoupling in place for electric and gas	Yes, electric and gas – performance based	0.84%
Michigan	Tariff rider	Decoupling in place for electric and gas	Yes, electric and gas	0.38%
Minnesota	Tariff rider	Decoupling in place for gas, pending for electric	Yes, electric and gas	1.00%

costs (units of sales times the variable cost rate). The difference between the calculated revenues allowed to be recovered and the actual revenues received during a given period accumulates in a balancing account, which is either refunded to or recovered from customers in the subsequent period through a decrease or increase to rates.

Decoupling reduces the disincentive to support non-utility DSM efforts and creates a more stable revenue stream.[4] Because decoupling mechanisms don't differentiate between changes in sales due to the DSM programs, weather, economic conditions, or other factors, they can be less contentious and simpler to implement than a lost-revenue adjustment mechanism. Decoupled rates can exhibit higher volatility during periods of extreme weather or economic conditions. If the rate adjustments are capped to avoid this volatility, the associated balancing account might grow to unrecoverable levels in a sustained economic downturn.

The third approach, called straight fixed-variable pricing (SFV), deals with problems caused when a utility relies on volumetric sales revenues to recover fixed costs. Utility costs consist of components that vary with the volume of energy sold, such as fuel and purchased power, and components that are fixed, such as capital costs and associated maintenance. Typically, however, utility rates recover a portion of the fixed costs in the volumetric

4. In some jurisdictions the implementation of a decoupling mechanism has been accompanied by a reduced authorized return to reflect this stability.

State	Cost Recovery	Lost Revenue Recovery	Performance Incentives	Savings as % of Sales
Mississippi	Tariff rider authorized	Authorized, but not yet implemented	No	0.07%
Missouri	Recovery authorized through deferral or tariff rider	Straight-fixed variable pricing in place for gas	Authorized, but not yet implemented	0.11%
Montana	System benefits charge	Yes, electric and gas	Authorized, but not yet implemented	0.40%
Nebraska	Rate case expense	No	No	0.23%
Nevada	Tariff rider	Lost revenue for electric, decoupling for gas	Authorized, but not yet implemented	1.28%
New Hampshire	System benefits charge	Authorized, but not yet implemented	Yes, electric and gas	0.64%
New Jersey	System benefits charge	Decoupling for electric and gas	No	0.66%
New Mexico	Tariff rider	Pending, electric and gas	Yes, electric	0.27%
New York	System benefits charge	Decoupling for electric and gas	Yes, mandatory for electric, optional for gas	0.68%
North Carolina	Tariff rider	Decoupling or lost revenue for electric and gas	Yes, electric	0.04%
North Dakota	Rate case expense	No	No	0.02%
Ohio	Tariff rider	Lost revenue, decoupling and straight fixed-variable pricing	Yes, electric	0.36%
Oklahoma	Tariff rider	Lost revenue for electric	Yes, electric	0.04%
Oregon	System benefits charge	Decoupling for electric and gas	No	0.61%
Pennsylvania	Tariff rider	No	Penalties for failure to meet targets	0.19%
Rhode Island	System benefits charge	Decoupling pending for electric and gas	Yes, electric and gas	1.07%
South Carolina	Deferral and amortization recovered through tariff rider	Lost revenue for electric	Yes, electric	0.06%
South Dakota	Tariff rider	Lost revenue for electric and gas	Yes, electric and gas	0.20%
Tennessee	Rate case expense	Lost revenue for gas	No	0.13%
Texas	Tariff rider	No	Yes, electric	0.22%
Utah	Tariff rider	Decoupling for gas, pending for electric	Authorized, but not yet implemented	0.64%
Vermont	System benefits charge	Decoupling for electric	Yes, electric	1.64%
Virginia	Tariff rider	Decoupling for gas, lost revenue pending for electric	Authorized, but not yet implemented	0.00%
Washington	Tariff rider	Decoupling or lost revenue for gas	Penalties for not meeting targets	0.00%
West Virginia	Rate case expense	No	No	
Wisconsin	Tariff rider	Decoupling for electric, lost revenue for gas	Yes, electric and gas	0.88%
Wyoming	Tariff rider	Decoupling for gas, lost revenue for electric	No	0.04%

Sources: "2011 State Energy Efficiency Scorecard," ACEEE; "State Electric Efficiency Regulatory Frameworks," 2011, IEE; "State Energy Efficiency Policy Inventory," Regulatory Assistance Project 2011.

charge—leading to the potential for over-or under-recovery of fixed costs due to fluctuations in sales. Under SFV, however, the utility recovers fixed costs through a monthly customer charge, and recovers variable costs through a per-unit energy charge. One SFV variation creates tiered rates with all of the fixed costs recovered in the first tier. This first tier is set at a level such that all customers typically consume more than that amount. Subsequent tiers are reduced to the level of variable costs. This results in declining block pricing.

SFV most closely reflects economic theory for matching cost with revenue, but it too has a number of practical drawbacks. Fully recovering fixed costs in a monthly charge will decrease the variable portion of the rates, which could lead to increased energy use—or thwart efforts to increase efficiency—because the incremental cost of using additional energy is reduced. Further, monthly bills for lower-use customers would increase significantly as their bills will now reflect a larger portion of fixed costs. These drawbacks have typically restricted the use of SFV to distribution-only companies whose costs are largely fixed in nature.

Shareholder Incentive Mechanisms

In order to place DSM investments on a level basis with supply-side investments, it's not enough simply to recover the costs of the DSM programs and the lost margin; the earnings potential for the investment also must be considered. Utilities face capital constraints and must allocate expenditures where the use of their capital is maximized. DSM expenditures compete for capital with supply-side expenditures.

Utility investors earn a return on investments in utility owned assets. Typically, DSM programs don't produce a utility owned asset. Consequently, there might be no earnings associated with DSM programs. That can produce a bias toward supply-side investments. To allow DSM programs to be compared directly with utility owned supply-side resources, a variety of incentives can be employed that allow shareholders to earn a return on the DSM program expenditures. These mechanisms fall into three categories: shared savings, bonus payments, and enhanced return on equity. Some jurisdictions are using a combination of of all three.

The first category, shared-savings mechanisms, provides a shareholder return based on a percentage of the net benefits generated by the DSM programs. (Net benefits is the difference between the utility's program cost and its avoided cost.) The mechanisms vary by the calculation of the amount to be shared and the percentage of the net benefits retained by the utility. Typically the savings amount to be shared is based on the total resource-cost net-benefits calculation. Shared savings mechanisms usually specify a minimum threshold that must be achieved by the utility before any benefits are retained. Penalties also can be included for performance that fails to achieve the minimum threshold.

Nevertheless, disputes can arise over the choice of method to calculate or estimate both net benefits and avoided costs. Are savings achieved on a deemed approach (predetermined), or an evaluated approach (actual measurement)? Are avoided costs higher or lower than the level that was forecast at the time of implementation?

The second category, bonus payments for performance targets, rewards the utility for meeting certain DSM program goals. The mechanisms vary greatly in their structure but typically set a minimum threshold that must be achieved before any incentive is awarded. In some cases penalties are also meted if minimum thresholds aren't achieved.

The incentives can be a percentage of spending, a fixed amount per unit of energy saved, or a percentage of net benefits. For example, California's incentive mechanism metes out a per-unit savings penalty for failure to achieve 65 percent or more of the DSM target, no reward for 65 percent to 85 percent of target, and tiered awards of 1 percent to 12 percent of net benefits for up to 125 percent of the DSM target. The mechanism also has a total dollar cap.

In Colorado, the natural gas performance bonus is a combination of achieving the performance targets and minimizing the cost per unit saved. A bonus factor is calculated by multiplying 50 percent of the difference between the percentage of the performance target and a threshold level of 80 percent times the ratio of the actual cost per therm saved and the budgeted cost per therm saved. The bonus factor is multiplied times the cost of the program with the final bonus capped at the lesser of 20 percent of expenditures or 25 percent of net benefits. The mechanism thus strives to encourage increased savings and reduced program costs.

Lost revenue adjustment appears straightforward—but only on the surface.

Under the third category, regulators might authorize an enhanced rate of return on the deferred balance remaining after the utility chooses to defer and amortize its DSM expenditures. Until 2010, when the state moved to a tariff rider approach, Nevada authorized an additional 5 percent equity return on deferred balance of DSM expenditures. Legislation authorizes enhanced returns as a performance mechanism in several jurisdictions, but currently no state is employing the enhanced ROE shareholder incentive mechanism.

A Balanced Future

An optimal energy system contains a mix of demand- and supply-side resources. Such a mix should produce the most cost-effective, reliable, and environmentally responsible portfolio—but only if regulators ensure that utilities will remain indifferent in choosing between supply-and demand-side options.

This indifference can best be guaranteed, however, if regulators pursue a combination of policies: reasonable cost recovery, effective compensation for revenues lost to falling sales, and viable incentives for shareholders—incentives commensurate with earnings opportunities on the supply side.