Overview of C&DM practices in North America and potential alternatives for Ontario

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LONDON ECONOMICS

London Economics International LLC ("LEI") was retained by the Ontario Energy Board to assist the Board in identifying options for a ratemaking framework that will account for electricity distributor conservation and demand management (C&DM) in 2006 electricity distribution rates. Our mandate was to present alternatives; recommending which alternative is most appropriate is not within the scope of work which we were assigned. This memo presents four hypothetical models for regulating C&DM. Each model varies by degree of administrative complexity and cost-benefit efficiency. We compare the models on the basis of five key criteria: administration, rate impact, regulatory consistency, incentive compatibility, and universality. Our hypothetical C&DM models are based on our experience designing innovative ratemaking methods, a survey of existing C&DM frameworks, and the literature surrounding best practices. We have included some practical examples of how the different mechanisms function, the benefits and drawbacks of each, and the issues that need to be addressed.

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717 Atlantic Avenue, Unit 1A
Boston, MA 02111
www.londoneconomics.com

AJ Goulding/Gilan Sabatier
617-494-8200
ajg@londoneconomics.com

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1 Executive summary

The Ontario Energy Board issued a Request for Proposal ("RFP") to assist the Board in identifying options for a ratemaking framework that will account for electricity distributor conservation and demand management (C&DM) in 2006 electricity distribution rates. In accordance with the terms of the RFP, our report has focused on addressing specific ratemaking matters that impact the distribution sector as a whole such as regulatory treatment of operating and capital expenditures, revenue protection, and distributor incentives for loss mitigation for efficient distribution and for customer side of the meter initiatives. We were not asked to make any recommendations regarding which alternatives were most appropriate for Ontario.

Conservation and demand management (C&DM) programs encourage consumers to modify their levels and patterns of electricity consumption. These types of programs typically reduce total annual energy consumption or target load reductions during peak periods. Consequently, they erode utility revenues. Thus, utilities need to be provided with the proper revenue recovery mechanisms and incentives to implement cost-effective C&DM programs. After reviewing C&DM practice across North America, we introduce four prototype models that cover a range of possibilities. Each of these models incorporates an incentive mechanism. Program costs are treated either as an expense or rolled into ratebase.

Model 1 (pay as you go) provides an example of a C&DM framework that offers a fairly low administrative burden to the regulator. It uses a timely prospective surcharge mechanism to ensure lost revenue recovery and a bonus incentive that rewards the utility in proportion to energy savings. This model's simplicity is attractive to the regulator.

Model 2 (pay over time) provides an example of a C&DM framework that presents a median level of administrative effort by the regulator depending on the size of the sector. It uses a deferral account to ensure lost revenue recovery and a shared savings incentive that splits energy savings with the consumer. This model is commonly applied and offers benefits to both the utility and the consumer.

Model 3 (SSM only) provides an example of a C&DM framework that presents a high level of complexity. It uses a prospective shared savings mechanism (SSM), but no lost revenue adjustment mechanism (LRAM). Revenues from the SSM are subject to true-up based on actual utility performance. Model 3 provides companies with upfront revenues, but could benefit the consumer by ensuring that incentives actually lead to bill reductions. Model 3 is the most administratively complex of those we examine.

Model 4 (flat rate pricing plus SSM) restructures Ontario rates to be calculated on a flat rate basis. This eliminates the need for an LRAM. The model incorporates an SSM calculated using a retrospective surcharge, meaning this model is also results oriented based on reductions in customer bills. We recognize that such a redesign of Ontario ratemaking procedures may not be feasible before 2008; however it is presented here as one important hypothetical alternative.

Ultimately, the model chosen in Ontario may be one of these or some hybrid that contains elements of all our hypothetical models. The appropriate model will depend largely on two factors: the OEB's regulatory objective and the expectations regarding wholesale and retail electricity market outcomes in Ontario. The OEB must decide to what extent it wants to trade off on the total cost of electricity versus the price of electricity. This will determine the method of evaluation. The choice is between the Total Resource Cost Test which measures the net costs of a C&DM program based on the total costs of the program, including both participant and utility costs and the Rate Impact Measure Test which measures the direction and magnitude of the expected changes in rates for all customers when a utility implements a C&DM program.

The uncertainty surrounding the Ontario electricity market makes selection of the appropriate C&DM model difficult because the value of C&DM is predicated on the opportunity cost of electricity. Given that wholesale market outcomes are uncertain, cost-benefit analysis of C&DM programs will also be challenging. Ontario does benefit from the fact that its utility system is fully unbundled, meaning C&DM mechanisms do not need to take into account the impact on generation revenues. Other issues to account for in C&DM design include the large number of Ontario utilities, the diversity of service territories and ownership structures, uncertain institutional roles and responsibilities, and the interaction between C&DM design and other elements of rate design such as default supply.

2 Regulatory accounting and treatment of C&DM

There are three regulatory accounting issues to be dealt with regarding C&DM initiatives: how to treat the expenses, how to deal with revenue loss, and how to structure incentives. The first question turns on whether the actual costs of the program are expensed or capitalized, and if capitalized, whether the utility earns a return on them. The second issue revolves around how to assure that a utility meets its revenue requirement if its rates include a volumetric component, and if volumes are reduced by C&DM initiatives. The final issue relates to the design of incentives for utilities, both to encourage innovation and also to assure that C&DM programs are efficient – effectively, how to assure that C&DM budgets are not merely spent, but are spent well. Treatment of expenses is examined in this section; lost revenues are discussed in Section 3, and incentives in Section 4.

C&DM programs have historically been evaluated on the basis of standardized cost-benefit tests. North American and other regulators worldwide have used several tests to identify cost-effective C&DM programs with the Total Resource Cost Test and the Rate Impact Measure Test being the most important. For each test, the net present value and cost-benefit ratio is determined so that the C&DM programs can be ranked.

The Total Resource Cost Test measures the net costs of a C&DM program based on the total costs of the program, including both participant and utility costs. This test measures benefits as reductions to energy and demand costs and all program costs including installation, operation, maintenance, and administration, irrespective of who pays for them.

The Rate Impact Measure Test measures the direction and magnitude of the expected changes in rates for all customers when a utility implements a C&DM program. This test also measures C&DM's revenue-shifting effect where costs must be spread over a smaller sales volume. Allocation of allowed revenues over lower volumes results in an increase in rates on a cents per kilowatthour basis. If a utility has excess capacity and its average costs exceed its marginal costs, a C&DM program will likely increase rates. The opposite is true when marginal costs are forecasted to exceed average costs.[1]

The selection of a C&DM cost-benefit test has an impact on whether the C&DM program chosen will minimize the total cost of electricity to the consumer or minimize the price of electricity paid by consumers. For instance, those who favor minimizing the total cost of electricity consumed (including generation costs) will favor the Total Resource Cost test while those concerned about minimizing electricity prices tend to favor the Rate Impact Measure. Furthermore, the cost-benefit analysis for non-integrated utilities is somewhat different from

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[1] Put another way, the question becomes: does a utility become more efficient or less efficient as volumes increase? If lost volumes result in a loss of economies of scale, rates will rise; if the utility actually becomes more efficient at lower volumes, the efficiency benefit may outweigh the effect of lost volumes on the revenue requirement.

that of integrated utilities. When evaluating the cost-benefit of implementing C&DM, integrated utilities can compare the cost of C&DM to the cost of new supply. Non-integrated distribution utilities should actually be performing the test in a similar fashion, even though they do not control generation resources themselves. Section 2.1 will discuss the tradeoff between total cost and price.

C&DM resources may provide benefits over a long period of time (anywhere from 5 to 30 years). Under traditional cost-of-service ratemaking, the cost of resources that provide long term benefits are typically capitalized over the expected life of the resource. Some utilities, however, have been allowed to expense the program cost of C&DM as discussed in Section 2.2.

Section 2.3 addresses cost allocation among customer classes and the need to balance issues of equity with revenue maximization.

Finally, Section 2.4 discusses the timeline for implementation of a C&DM program and the regulator's data needs.

2.1 Impact of C&DM on electricity cost and prices

C&DM programs result in a tradeoff between total electricity cost (i.e. utility revenue requirement) and electricity prices. If utilities run an aggressive C&DM program, electricity prices will likely increase as utility costs are spread over a smaller amount of electricity delivered. On the other hand, the total cost of electricity should be lower as the cost of energy saved through C&DM should be less than the cost of future capacity expansion. For customers, C&DM will likely increase the price of electricity but will ultimately lower their bill as they are likely to consume less. Thus, the question of whether it is appropriate for distribution rates to increase depends on how the regulator values reductions in electricity costs versus reductions in electricity prices.

A 1991 study conducted by the Oak Ridge National Laboratory (ORNL) for the US Department of Energy examined this tradeoff between cost and price.[2] This study utilized a utility planning model to assess the effects of C&DM programs on utility revenues, total resource costs, electricity prices, and electricity consumption for the period 1990 to 2010. The study produced the following key findings:

- C&DM programs generally reduce electricity costs and raise electricity prices. Utilities and regulators must make tradeoffs between the total resource cost test and the rate impact measure;

[2] Hirst, E. "*The Effects of Utility C&DM Programs on Electricity Costs and Prices*". Oak Ridge National Laboratory. November 1991.

- The percentage reduction in electricity cost is often much greater than the percentage increase in electricity price caused by C&DM programs;

- Even if C&DM is very inexpensive or the utility faces very high avoided costs, the tradeoff between costs and prices remains. In special cases where the cost per kWh of C&DM programs is very low, both prices and costs can be reduced;

- C&DM programs are cost effective even if the utility has excess capacity and slow load growth. This occurs because C&DM programs offset not just the operating costs of existing assets, but also reduce the other costs of operating the utility system, defer construction of new transmission and distribution facilities, and, in the long term, defer the construction and operation of new power plants (even if those power plants would have been built by another entity);

- Having customers share in the costs of the C&DM program implemented by the utility reduces the size of the tradeoff between costs and prices by reducing the maximum cost of conserved electricity paid by the utility. Such an approach, however, would reduce the value of savings to customers achieved by the programs.

Other studies have confirmed to some extent the findings of the ORNL report. Steven Nadel and Miriam Pye reviewed data from ten existing studies on the rate impacts of C&DM programs and found that C&DM program rate impacts varied between -2.8% and 9.4% with a median rate impact of 1.7%.[3] Such studies, however, should never be taken as universal. Other factors may serve to alter the impact on rates. One factor is the relative size of the C&DM program and its cost-effectiveness. Another is the relative energy/peak load impact of the particular C&DM programs being implemented. Many of today's C&DM programs are relatively small and taking these factors into account will provide a more detailed picture of the magnitude of the impact of any particular C&DM program on a utility.

2.2 Treatment of operating and capital costs

There are generally two different treatments for operating and capital costs associated with C&DM programs. Utilities can choose to either capitalize or expense these costs. The main difference between the methods is in their impact of rates. Typically, when a utility decides to expense these costs, they are immediately reflected in rates and rates therefore increase immediately as well. On the other hand, when a utility decides to capitalize these costs over a number of years, the general tendency is that the costs will not affect rates as dramatically as if they were expensed. Figure 1 and
Figure 2 present examples of C&DM spending by utilities across North America. CD&M spending as a proportion of revenue is a function of whether the utility is integrated or not;

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[3] Aspects of Nadel and Pye's research can be found in "*Partnerships: Redefining the Relationship between Utilities and Industry C&DM Program Design*." American Council for an Energy Efficient Economy. 1996.

those which are have larger revenues due to the inclusion of the generation business unit. This in turn can make C&DM spending appear proportionately smaller.

Capitalizing operating and capital costs allows the utility to spread costs over the period of time that matches that of the C&DM program that is being implemented. FortisBC is a good example of how a utility capitalizes C&DM costs. The BCUC requires FortisBC to capitalize all expenditures associated with C&DM. FortisBC is also required to amortize these expenditures at the straight-line rate of 12.5% subject to certain conditions:

- That C&DM costs capitalized be net of income taxes
- That FortisBC file semi-annual demand side management reports
- That C&DM projects be evaluated economically, where the customer and FortisBC's cost components are added together and tested using TRC

Other utilities have been allowed to expense the cost of their C&DM programs such as NSTAR Gas & Electric. In Ontario, the approach traditionally used in the gas industry has been to determine an approved budget for C&DM spending, and then to track variance around that amount. Variance accounts have the advantage of allowing for precise tracking of expenditure; however, they can be administratively burdensome for the utility. Generally speaking, it is sensible for regulators to allow for overspending of such accounts if the impact of the overspending leads to TRC benefits; underspending, however, should result in refunds to ratepayers of unspent amounts.

Figure 1. Examples of integrated utility C&DM spending in 2002/2003

	DSM Spending	Gross Revenue	DSM Spending (% of Gross Revenue)
AEP Texas Central Company(2002)	$ 2,339,000	$ 1,605,334,000	0.15%
Alabama Power Co(2002)	$ 25,828,000	$ 3,710,533,000	0.70%
BC Hydro(2003)	$ 63,000,000	$ 2,553,000,000	2.47%
Consolidated Edison Co-NY Inc (2002)	$ 5,547,000	$ 6,390,560,000	0.09%
Florida Power & Light(2003)	$ 150,000,000	$ 8,293,000,000	1.81%
Florida Power Corp(2002)	$ 62,046,000	$ 3,082,733,000	2.01%
Fortis BC(2003)	$ 2,455,000	$ 245,500,000	1.00%
Idaho Power(2003)	$ 1,208,036	$ 780,382,000	0.15%
Northern States Power Co(2002)	$ 38,920,000	$ 2,391,345,000	1.63%
Public Service Co of Colorado(2002)	$ 10,885,000	$ 3,385,176,000	0.32%
Tampa Electric Co(2002)	$ 16,717,000	$ 1,582,937,000	1.06%
Virginia Electric & Power Co(2002)	$ 6,684,000	$ 4,888,033,000	0.14%
Wisconsin Power & Light Co(2002)	$ 25,878,000	$ 782,837,000	3.31%

Figure 2. Examples of distribution companies C&DM spending in 2002/2003

	DSM Spending	Gross Revenue	DSM Spending (% of Gross Revenue)
Baltimore Gas & Electric Co(2002)	$ 16,679,000	$ 1,966,013,000	0.85%
Connecticut Light & Power Co(2002)	$ 56,695,000	$ 2,507,036,000	2.26%
Fitchburg Gas & Electric(2003)	$ 1,600,000	$ 60,500,000	2.64%
Hydro-Quebec Distribution*(2003)	$ 41,000,000	$ 8,700,000,000	0.47%
Jersey Central Power & Lt Co(2002)	$ 27,002,000	$ 2,304,832,000	1.17%
Massachusetts Electric Co(2002)	$ 50,852,000	$ 1,682,499,000	3.02%
Nstar(2003)	$ 63,219,000	$ 2,914,131,000	2.17%
Oncor Electric Delivery Company(2002)	$ 21,643,000	$ 1,994,434,000	1.09%
Public Service Elec & Gas Co(2002)	$ 146,554,000	$ 3,959,033,000	3.70%
Unitil Energy Systems(2003)	$ 2,700,000	$ 130,400,000	2.07%

*assuming the $123 million budgeted over 3 years will be spent evenly over that period

Source: Idaho Power, Nstar, HQ, Fortis BC, BC Hydro, FPL, EIA

The accounting treatment of C&DM program costs has consequences for utility revenue requirements and electricity prices. The ORNL study cited in Section 2.1 modeled the impact of the accounting treatment on rates and costs. These results are summarized in Figure 3.

Figure 3. Summary of results for cases with C&DM resources purchased up to 4.5c/kWh for the base utility and different financial treatment of C&DM expenses

Summary Statistics, 1990-2010	Percentage change relative to the supply-only case:		
	Expense	10-year depreciation	15-year depreciation
Net present value (million $)			
Revenue requirements	-4.7	-5.3	-5.6
Environmental costs	-2.4	-2.3	-2.2
Average electricity price (c/kWh)	1.1	1.1	0.7
Average electric bill ($/customer)	-5.9	-6.6	-7.1

Source: ORNL

The modeling was done in 1991 and projected the impacts of various cost allocation scenarios over 20 years. It showed that expensing C&DM program costs rather than capitalizing them, reduces the cost and price benefits of these programs (for both the TRC and RIM tests). In other words expensing the costs of C&DM programs raises electricity prices in the short term, whereas capitalizing these costs over 15 years defers the price increase for several years.

2.3 Rate design and cost allocation

The allocation of C&DM costs to customers can be a difficult issue. While C&DM has the potential to lower electricity costs for all customers, there is some concern over non-participant rate impacts. This is particularly true for certain large industrial customers who are relatively sophisticated about energy efficiency and have consequently undergone significant cost-effective investments in C&DM. Utility C&DM has little to offer for these customers. Meanwhile, other less efficient customers (who may be competitors to the efficient industrial customers) stand to gain from utility C&DM programs. If the more efficient customers must pay higher rates due to implementation of utility C&DM, then they may perceive themselves to be subsidizing potential competitors and others who are less efficient.

It is important to recognize, however, that the point of C&DM initiatives by distribution utilities is that those who support utility C&DM argue that there are strong positive externalities in C&DM investments. Thus, even an industrial consumer which has exhausted its C&DM opportunities it can still expect to benefit from economic C&DM efforts by others if such efforts help to reduce overall wholesale generation market prices to lower levels than would otherwise have been experienced. As such, those consumers who argue that they are paying for C&DM initiatives for which they receive no benefit may be taking an overly narrow view of C&DM potential.

The industrial customers' argument raises the issue of cost causation and allocation. A study conducted by the National Association of Regulatory Utility Commissioners (NARUC) noted that cost causation "… is generally not related to participation in, eligibility to participate in, or the receipt of benefits from such programs. Such expenditures would not have been incurred except for their contribution to meeting system-wide or regional kW and kWh requirements."[4] In other words, C&DM costs do not arise from participation in the program, but rather from the demand and energy consumption causing the need.

Cost causation, however, is just one concept of equity. The NARUC study outlined four concepts of equity that can be applied to the allocation of C&DM costs:

1. Cost causation;
2. Equal opportunities to participate in C&DM programs;
3. Direct allocation to actual participants; and
4. Allocation to participating customer classes.

There are several different ways that costs can be allocated based on these concepts. Costs can be allocated on the basis of demand (per kW), energy (kWh), or some combination of both. They can also be allocated on the basis of C&DM savings by class or by the C&DM budgets allocated for each class. All of these methods, however, cause differential impacts of one sort or another. Demand allocations, for instance, could impose costs disproportionately on industrial load. Allocation to participating customers would serve as a disincentive to program participation.

[4] "*Cost Allocation for Electric Utility Conservation and Load Management Programs*". NARUC. March 1993.

The NARUC study concluded that the marginal cost approach was the preferred method. This approach allocates C&DM costs in proportion to each class's marginal cost revenues, which is consistent with the principles of cost causation. It is also simply administered as these costs are simply rolled into the reconciliation of marginal cost revenues and revenue requirements. There are, however, a number of utilities that allocate C&DM costs to participating classes. This is generally done to protect certain other (non-participant) customer classes.

Rate cases sometimes result in adjustments to existing rate design to better reflect C&DM demand and energy impacts at the class level. Any reduction in the demand and energy allocators for C&DM participants would result in an increase in the fixed cost responsibility of non-participants. Some argue that such adjustments ignore the long term benefits that program participants receive from C&DM. Supporters of this argument advocate the assignment of direct costs to participant classes or that class allocators be developed based on pre-C&DM class demand.

Existing C&DM rate design shows that regulators have a range of cost allocation strategies available to them. The appropriate strategy depends on the regulator's determination of the relative weight that should be given to efficiency and equity considerations. We note that in Ontario a significant cost allocation exercise with regards to distributors will be carried out in 2007.

2.4 Data needs

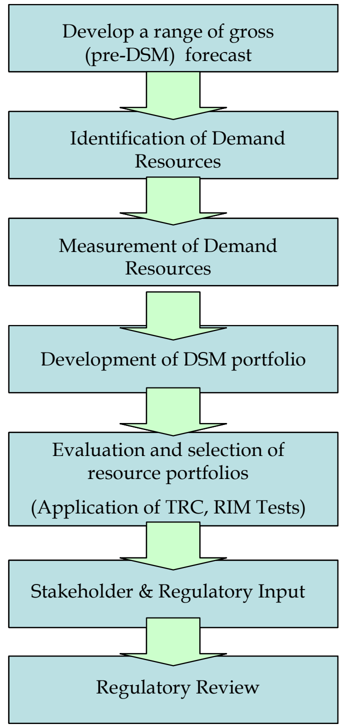
In engaging in C&DM, the regulator requires utilities to file a C&DM Plan. This plan may require the utility to go through a preparation process like the one illustrated in Figure 4. In this process, the utilities are required to include various data which are detailed on the following page.

The essential part of preparing a C&DM plan to submit to the regulator is developing a range of gross demand forecasts excluding C&DM programs. The range of forecasts should address various uncertainties about the future and for example provide a low-end, moderate and high-end estimate. The forecast should be structured in terms of end-use categories (i.e. residential, commercial & industrial) so that the C&DM impact in each category can be better assessed further in the process.

The next step is identifying and evaluating various C&DM resources. In other words, in this process utilities come up with the C&DM programs they wish to engage in and measure their impact on demand, their cost, and the result of the standardized cost-benefit tests (i.e. TRC). These measurements should be done for the lifetime of the C&DM program.

This will allow the utility to come up with several C&DM portfolios that they can present to the regulator. These portfolios may then be subjected to stakeholder as well as regulatory input prior to a formal regulatory review. The utility may seek stakeholder input prior to filing by engaging in focus groups or other consultative processes internal to the utility. Ultimately, one C&DM portfolio may be selected and put forth for regulatory approval.

Figure 4. C&DM planning process



This process differs slightly for subsequent years after the first regulatory filing. Once a C&DM program is approved by the regulator, the subsequent filings for the distribution companies do not need to be as comprehensive as the initial submission. The content and frequency of the subsequent submissions would depend on the C&DM mechanism in place.

Annual reports are likely required from utilities which use a prospective or a retrospective surcharge to recover C&DM costs. These reports would include data such as program costs and other costs associated with the C&DM programs. Additionally, the utilities would need to provide actual demand and energy data in order to determine the appropriate level of loss revenue adjustment. Utilities using a prospective surcharge could be required to submit quarterly or semi-annual C&DM reports in order to allow the regulator to monitor the application of the surcharge. These reports would allow for the true up of lost revenues. Utilities using a deferral account mechanism would only need to provide a periodic statement of their account.

Incentive mechanisms also produce certain data needs. Prior to implementation of any C&DM program, incentive rates being used and how net benefits should be quantified (e.g. should environmental benefits be factored in) would have to be determined. Some incentive mechanisms are more data-intensive than others. Hybrid mechanisms, for example, require a wide range of information on program costs. Once the programs are implemented, the utilities may have to submit annual reports to evaluate the effectiveness of their C&DM programs and the incentives. The report should include information on actual energy saved, the level of incentive payments to be received, actual program costs, and participation.

3 Lost revenue adjustment mechanisms (LRAM)[5]

When utilities engage in C&DM, they not only incur the cost of those programs, but they are also subject to a potential loss in revenues. Utilities therefore need mechanisms in place that address those issues in order to remove the financial disincentive of implementing C&DM.

Because it decreases the amount of energy needed to satisfy a given level of energy service or comfort, C&DM reduces the volume of energy sold by the utility. Lost revenues occur when actual electricity sales are less than the electricity sales level used to set electricity prices. It therefore may represent the un-recovered fixed costs to the utility. Whereas some portion of the resulting lost revenue is offset by a reduction or avoidance of variable costs (e.g., the cost of fuel for power plants), the remaining portion of lost revenue not offset by variable cost reductions is a direct loss to the utility.

Lost revenue mechanisms allow utilities to recover all of the revenues that they would have recovered had they not promoted sales reductions through energy efficiency. Their principal purpose is to compensate for the fact that utility costs are spread over a smaller sales base as a result of C&DM activities. These mechanisms are designed to make C&DM a revenue-neutral activity and eliminate the disincentive to minimize savings from C&DM. This leaves the utility financially indifferent to the level of C&DM that is achieved.

There are two main types of lost revenue adjustment mechanisms: a surcharge account and a deferral account. Surcharges are reflected on customer's bills as rate adjustments that are generally rolled into an overall C&DM surcharge. Deferral accounts allow the utility to track net lost revenue and recover it at the next rate case.

3.1 Surcharges

There are two types of surcharges: prospective and retrospective. A prospective surcharge mechanism recovers the lost revenue as a result of the current year's C&DM activities. In other words, this means that net lost revenue is recovered in the same period the utility incurs these losses. Under a prospective surcharge mechanism, the utility files a forecast of C&DM savings and associated net loss revenue for the upcoming program year. Usually these filings are on an annual basis, although some utilities file on a quarterly basis. The prospective surcharge mechanism provides for greater cash flow to the utility then either the retrospective surcharge or the deferral account.

The projected C&DM savings and consequent net loss revenue forecast are translated into a surcharge. The surcharge may be levied on all customers, or allocated across customer classes. A subsequent reconciliation between the initial net lost revenue forecast and a subsequent

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[5] The LRAMs discussed here are addressed in Baxter, L. "Understanding net lost revenue adjustment mechanisms and their effects on utility finances". *Utilities Policy* Vol. 5, No. 3/4, pp. 175-184. 1995.

assessment of C&DM program performance is then needed. With this mechanism, a utility will typically include net lost revenue reconciliation from earlier program years with its forecast of net lost revenue for the upcoming program year. The reconciliation may result in either an increase or decrease in the surcharge for the upcoming program year, depending upon whether the outcome of the reconciliation indicates an under-recovery or over-recovery of net loss revenue from the earlier program year. Alternatively, the surcharge may also be designed to amortize net lost revenue recovery for the current program year over a series of years. A typical time period in use is the estimated average life of the measures installed that year. This allows for more flexibility. An example might be mechanisms that concentrate net lost revenue from a new C&DM program later in the program year to reflect the lower C&DM savings associated with program start-up early in the program year.

A retrospective surcharge, on the other hand, is designed to recover revenue lost from C&DM activity in a previous year or years. In all other respects, the retrospective and prospective surcharges are very similar. A retrospective surcharge is also similar to a deferral account, except that the retrospective surcharge does not require waiting until the next rate case before recovery can begin, increasing certainty of recovery for the utility.

3.1.1 Electric utilities in Maryland

A good example of a surcharge and the impact it has on rates is illustrated in a filing by the Maryland Public Utility Commission on C&DM funding mechanisms. Until 2000, the large majority of utilities in Maryland used a public benefits charge (PBC) to recover lost revenue. The surcharge is expressed in mils/kWh terms. The estimated revenues associated with this surcharge in Maryland in 1998 are summarized in Figure 5. This table indicates that a 1 mil surcharge collected from all ratepayers results in approximately $57 million of revenues.

Figure 5. Total Annual Revenues of Alternative PBCs in 1998

	1998 Sales (GWh)	3 mils/kWh	2 mils/kWh	1mil/kWh	0.5mil/kWh	0.1/kWh	Total 1998 Retail Sales
Residential	22,444	$ 67,332,000	$ 44,888,000	$ 22,444,000	$ 11,222,000	$ 2,244,400	$ 1,877,000,000
Commercial	25,222	$ 75,666,000	$ 50,444,000	$ 25,222,000	$ 12,611,000	$ 2,522,200	$ 904,000,000
Industrial	9,733	$ 29,199,000	$ 19,466,000	$ 9,733,000	$ 4,866,500	$ 973,300	$ 1,225,000,000
Total	**57,399**	**$ 172,197,000**	**$ 114,798,000**	**$ 57,399,000**	**$ 28,699,500**	**$ 5,739,900**	**$ 4,006,000,000**

Source: Maryland PUC

The rate impact of the surcharge is further explored in Figure 6 which compares the impact of a 1 mil/kWh surcharge on typical monthly bills of the four largest investor-owned utilities in Maryland.

Figure 6. Bill Impact of 1 mil PBC for Typical Customers by Utility in 1998[6]

Monthly Bill (Without PBC)	Usage (kWh)	BGE	DPL	PE	Pepco	Simple Average Maryland
Residential	750	$ 78	$ 71	$ 55	$ 79	$ 72
Commercial	12,500	$ 1,173	$ 1,244	$ 955	$ 1,351	$ 1,208
Industrial	200,000	$ 16,047	$ 12,448	$ 11,352	$ 16,268	$ 14,364
Bill Impact of 1 mil PBC	PBC/month	% Change	% Change	% Change	% Change	% Change
Residential	$ 2.25	1.0%	1.1%	1.4%	0.9%	1.0%
Commercial	$ 37.50	1.1%	1.0%	1.3%	0.9%	1.0%
Industrial	$ 600.00	1.2%	1.6%	1.2%	1.2%	1.4%

Source: Maryland PUC

This table indicates that a 1 mil/kWh surcharge has the effect of increasing average bills by approximately 1-1.4% depending on the customer class.

3.1.2 Massachusetts utilities

Distribution utilities in Massachusetts also have a surcharge mechanism in place. Each year, they submit their C&DM plan to the Department of Trade and Energy which, based on calculations for lost revenue, energy savings and total cost, assigns a surcharge to be applied to customer rates. Figure 7 illustrates the average surcharge for residential customers in Massachusetts.

Figure 7. Average Surcharge for Residential Customers in Massachusetts

Year	DSM Surcharge (c/kWh)	Average Residential Price (c/kWh)	Surcharge (% of avg. price)
1998	0.33	10.64	3.10%
1999	0.31	9.71	3.19%
2000	0.285	10.53	2.71%
2001	0.27	12.16	2.22%
2002	0.25	11.17	2.24%

Source: DTE

Other example of utilities using a surcharge include Bonneville Power Administration, Buckeye Power, Madison Gas & Electric, Northeast Utilities, Portland General Electric, and various municipal utilities including the City of Austin, Texas and the City of Phoenix, Arizona.

3.2 Deferral account mechanism

The most common LRAM used to compensate for lost revenues is the deferral account. It works as follows. In a given year the utility calculates the amount of volume or kWh losses due to its own C&DM initiatives. (This must be calculated net of any efficiency trends occurring

[6] The typical bill was calculated for each utility according to load and consumption parameters developed by Edison Electric Institute.

independently of C&DM, since sales losses due to other factors would have been experienced anyway.) Under either cost-of-service (COS) or performance-based-ratemaking (PBR) regulation, rates are generally set by summing all costs and then dividing by the volumes delivered. If volume delivered goes down as a result of C&DM activities, all other things being equal, rates will go up so that costs may be recovered.

Actual differences in forecast revenues are recovered through the deferral account that the utility can claim from ratepayers at a later date. These deferral accounts, for approved amounts, are internal record-keeping tools that the company uses to keep track of claims to be recovered from, or refunded to, ratepayers. A deferral account therefore uses a tracking system that records monthly net lost revenue estimates. The utility then receives authorization to recover this estimated net lost revenue at its next rate case. Typically, a utility files an estimate of the net lost revenue incurred between rate cases as part of its general rate case filing.

Deferral accounts have an unfavorable impact on cash flow for the utility as lost revenues will not be recovered until the next regulatory cycle. Moreover, funds tend to accumulate in these accounts, providing some uncertainty to the utility as to whether they will be recovered. Consideration for the utility's cost of capital is crucial in the design of deferral accounts, particularly if the deferral is for long periods.

3.2.1 Otter Tail Power

Otter Tail Power Company is an investor-owned utility that provides electric service to over 250,000 customers throughout Minnesota, North Dakota and South Dakota. Otter Tail Power owns generation assets in addition to the transmission and distribution infrastructure. As part of the integrated resource plan (IRP) rules adopted in Minnesota in 1990, each of the state's utilities with more than 1,000 retail customers is required to file biennial resource plans. These biennial C&DM resource plans, referred to as Conservation Improvement Plans (CIP), have tracker accounts (deferral accounts) that are used for C&DM program cost recovery. The CIP tracker accounts record actual CIP collections and expenditures to ensure a dollar-for-dollar recovery at ratemaking time. Thus, over-and under-expenditures are reconciled at the time of the next rate case. At each rate case, the Minnesota Public Utilities Commission (PUC) will evaluate the C&DM programs expenditure and will adjust the deferred account by assessing the account balance to rates. Additionally, the PUC allows Otter Tail Power (OTP) to accrue carrying charges on the balance of its CIP account. This means that OTP is able to recover interest (or cost of capital) from its ratepayers for the balance in the CIP tracker account.

3.3 Key aspects of lost revenue adjustment mechanisms

Each of the three mechanisms described above have different affects on utility finances, more specifically on cash flows and rates. Applying a prospective surcharge to rates would allow the utilities to recover the costs associated with the implementation of their C&DM program as they are incurred. This would naturally have a minimal affect on cash flow as the surcharge mechanism would have a neutralizing affect on cash flow. With regards to rates however, a prospective surcharge would have an immediate adverse effect on rates. Through a surcharge mechanism, the ratepayers would bear the cost of C&DM programs immediately. However it should be noted that an increase in cost for the ratepayer could be offset by an increase in energy efficiency as a result of the C&DM program.

A retrospective surcharge and a deferral account can have the same effect on utility finances. Both involve utilities incurring the costs of C&DM programs and then recovering them at the end of the year or at the next rate filing. In other words, these two mechanisms delay the rate impact of C&DM program costs. This delay depends on the recovery timetable set by the regulator. However, both these mechanisms have an adverse effect on utility cash flows, as utilities incur the costs of C&DM programs over an extended period of time and then recoup them all at once. This delay between the time when utilities incur the costs and then recover them causes an increase in volatility of the utilities' cash flow, which may also have an impact on the utility's cost of capital and credit rating.

4 Shareholder incentive mechanisms[7]

C&DM shareholder incentives can be used to motivate utilities to implement energy efficiency measures. Through the 1980s and early 1990s, utilities implemented C&DM programs through an integrated resource planning (IRP) approach in which these programs were treated as supply resources that could defer the need for capacity expansion. The deregulation of the energy industry has altered the landscape for C&DM due to the unbundling of generation, transmission, and distribution. Without generating capacity, distribution utilities have less incentive to invest in C&DM from an avoided cost of new generation perspective, unless the TRC is appropriately structured such that the cost-benefit analysis incorporates generation costs even though generation is no longer controlled by the distribution utility. Many jurisdictions have shown that properly designed incentives can produce results in the restructured marketplace.

The ultimate objective of these mechanisms is to provide the utility with the incentive to maximize resource savings per dollar spent on energy efficiency measures. There are three basic incentive mechanisms employed for C&DM programs: shared savings, bonuses, and markups. There are also hybrid mechanisms that combine elements of the above. The effectiveness of any mechanism is based on its effectiveness in aligning government policy, regulatory objectives, and utility financial self-interest.

4.1 Shared savings mechanism (SSM)

The shared savings mechanism uses an incentive payment equal to a percentage share of the net avoided cost of energy and capacity (i.e. avoided energy cost minus program and participant costs) minus fixed costs. This is the most common type of incentive mechanism as it provides the best link between a policy objective of maximizing benefits to society and the utility's objective of maximizing profit. The basic formula for the shared savings incentive is as follows:

$$I = \lambda (AQ - C_U - C_P) - F$$

Where I = incentive payment;
λ = incentive rate;
A = per unit avoided energy and capacity cost;
Q = quantity of energy and capacity saved;
C_U = utility program costs;
C_P = participant costs;
F = fixed payment

[7] The incentive mechanisms discussed here are addressed in Eto, J., Stoft, S., Kito, S. "*C&DM shareholder incentives: recent designs and economic theory*". Utilities Policy 7 pp. 47-62. 1998.

The fixed payment, F, is a way of setting a minimum savings target for the C&DM program. For example, if F is set at $1 million, then the utility would have to achieve savings equal to or greater than that amount or pay a penalty of up to $1 million.

In this type of mechanism, defining the net benefits is important and contributes to the overall effectiveness of the program. A definition of net benefits based solely on utility costs, for instance, may maximize energy savings, but not societal benefits. Some utilities are required to include the cost of environmental benefits as part of the shared savings calculation, but estimating the cost of environmental externalities is difficult.

On the opposite end of the spectrum is the selection of the appropriate program costs to include in the calculation of shared savings. Program costs typically fall into four categories: administration costs, evaluation costs, rebate costs, and incremental participant costs. Many utilities exclude monitoring and evaluation costs because those activities take place after the conclusion of the C&DM program. Incremental customer costs are also frequently omitted because they are difficult to measure or estimate. The type of costs included in the shared savings formula can increase or decrease the net benefits.

Most importantly, the omission of certain benefits and costs can skew incentives and produce results that are antithetical to policy objectives. Excluding environmental benefits, for example, could lead the utility to protect its financial interests at the expense of incremental benefits to society. Depending on the type of analysis used to quantify such externalities, the additional benefit could be significant. Similarly, the omission of certain costs could also serve to inflate payments to the utility without a corresponding benefit to the consumer.

4.1.1 FortisBC (formerly Aquila Networks Canada)

FortisBC operates under a performance based regulation (PBR) framework in which multi-year C&DM targets are set. FortisBC adopted its SSM in 1999 and derives incentive payments following the basic formula listed above. The utility receives a share of net benefits from C&DM which is defined as the difference between program benefits and program costs. Fortis BC defines benefits as the value of avoided energy and capacity costs and deferred capital expenditures. Penalties are incurred for not achieving a threshold level of net benefits.

The benefits are calculated over the lifetimes of the C&DM measures put into place. FortisBC receives a share of the total net present value of these life-cycle benefits with the typical lifespan being between 5 and 20 years. As of August 2004, the avoided cost at FortisBC was valued at 2.6 cents for each kWh of energy savings, $29.68 for each annual kW of capacity savings, and $36 for each annual kW saved from peak (deferred capital expenditures).

FortisBC receives a share of the net present value of the C&DM net benefits annually in the form of a rate adjustment. Various incentives or penalties are assessed based on FortisBC's actual performance in each of the three customer sectors – residential, general service, and industrial. Incentive payments are made for performances of 100 percent to 150 percent of the planned net benefits. No incentive payment is made for performance between 90 percent and 100 percent of planned net benefits. Varying penalties are levied for performance of less than 90 percent with the maximum penalty applied to performances of less than 50 percent of planned net benefits. If the sum of the incentives and penalties across customer sectors is greater than zero, then that sum is the C&DM incentive (if less than zero, total penalty) for FortisBC for the year. If the sum is less than zero, then there is no C&DM incentive for FortisBC for the year and a penalty is charged. The range of C&DM-related incentives and penalties are set out in Figure 8.

Figure 8. FortisBC C&DM incentive and penalty schedule

% of Target Net Benefits	<50%	<70%	<90%	90-100%	>100%	>110%	>120%
Residential	-6.0%	-4.5%	-3.0%	0.0%	3.0%	4.5%	6.0%
General Service	-4.0%	-3.0%	-2.0%	0.0%	2.0%	3.0%	4.0%
Industrial	-3.0%	-2.0%	-1.0%	0.0%	1.0%	2.0%	3.0%

Source: FortisBC

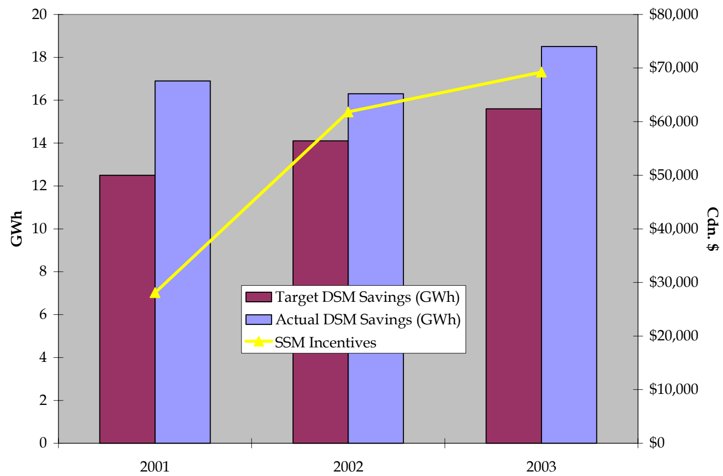
Actual C&DM savings from 2001 through 2003 were above targeted figures. Incentive payments in 2002 and 2003 were much larger than 2001 because most of the savings occurred in the residential sector in those years (where the incentive payment is higher[8]) (see Figure 9). Actual C&DM net benefits from 2001 through 2003 ranged from $2,143,000 to $2,301,000. This was about 13% to 20% above targeted levels.

While the SSM payments have increased, the associated savings have not necessarily increased commensurately. In 2002, incentive payments increased 120%, but overall C&DM savings actually declined 4%. In 2003, however, incentive payments increased 12% while actual C&DM savings increased 13%.

The relative size of the incentive payments to FortisBC are extremely small when compared to total revenue. In 2001, incentive payments represented 0.2% of revenue from all customers and in 2003 and 2004 they represented 0.4%.

[8] The incentive payment is higher in the residential sector because Fortis/Aquila's earlier attempts at C&DM focused primarily on the industrial sector rather than residential customers. This is an example of how regulators can fine tune incentives to influence utility behavior.

Figure 9. Historical SSM payments



4.1.2 San Diego Gas & Electric

San Diego Gas and Electric was the first of California's four large investor-owned utilities to be able to formally receive incentives for C&DM in 1989. Initially, the California Division of Ratepayer Advocates urged the commission to penalize SDG&E should it not meet the target set forth in its 1989 rate case. SDG&E argued that if they were to be penalized for underperforming, they should be rewarded for overperforming.

Under the C&DM mechanism devised in 1993, SDG&E is subject to a penalty if net benefits fall below 50% of the forecast. They are awarded positive incentives when they achieve benefits in excess of 50% of the forecast. At higher benefit levels, the savings share increases steeply at first, then at a slower rate, finally leveling off when benefits reach 130% of forecast. There is no cap on the total amount SDG&E can earn.

SDG&E's share of the savings varies with the performance in an S-shaped pattern (S-curve). The S-curve for each program is uniquely determined by its projected cost effectiveness. The curves are calculated so that if the company reaches 100% of its savings goal for a particular program, its savings share is the percentage that will yield the company an amount equal to its program cost times the authorized rate of return on rate base.

4.2 Bonuses

Under the bonus mechanism, an incentive payment is made equal to the incentive rate times the quantity of energy and capacity saved. This is the second most common mechanism used and the basic formula is as follows:

$I = \lambda Q - F$
Where I = incentive payment;
λ = incentive rate;
Q = quantity of energy and capacity saved;
F = fixed payment

Thus, this formula is similar to SSM with the exception that program and participant costs are excluded. This leads the utility to maximize its own benefits and not total benefits to society. Consequently, the bonus incentive does not perform well when C&DM measures are expensive (i.e. measures that cost more than the avoided cost benefits). Thus this type of incentive generally must pass the Total Resource Cost test to be approved (which would essentially transform it into a shared savings mechanism by taking into account marginal net benefits).

Bonus mechanisms generally work when the regulator seeks the simplest method of calculating incentives and the utility has access to inexpensive C&DM measures. By not taking into account net benefits, however, the utility has an incentive to increase spending on C&DM program until it receives the maximum incentive payment available. For instance, if the utility receives a bonus of 1 cent/kWh, it will seek to maximize that payment even if the cost of implementing the C&DM measure is more expensive than actually supplying power because the utility is guaranteed cost recovery for its C&DM program.

4.2.1 Northern States Power (Xcel Energy)

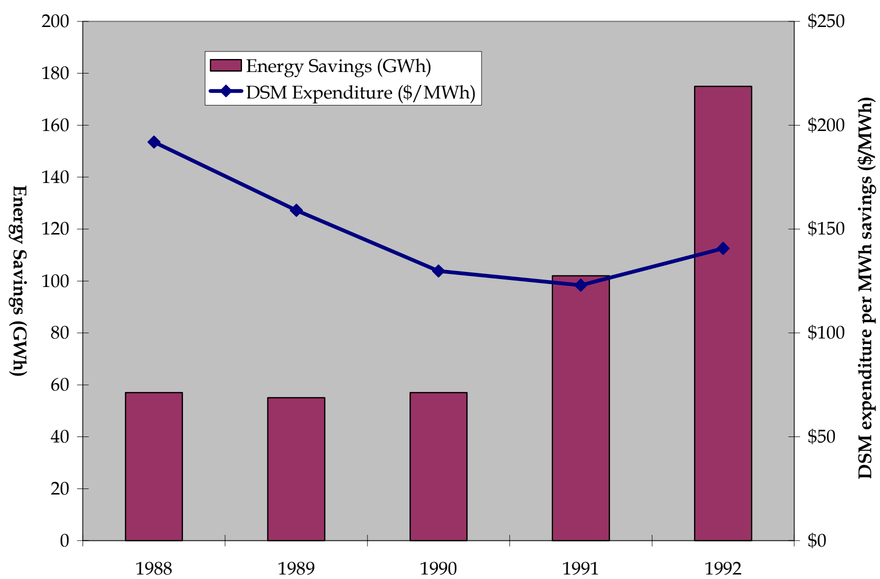
Northern States Power (NSP) of Minnesota is an investor-owned utility that provides gas and electric service to 1.3 million customers throughout five states in the Midwest. NSP owns generation assets in addition to the transmission and distribution infrastructure. The utility operates in a state that has yet to deregulate its power sector and continues to operate under a cost of service regime. In the early 1990's, NSP ran a bonus-based C&DM program targeted towards commercial and industrial customers.

NSP's bonus rate of return mechanism allowed the utility to capitalize and amortize over a five-year period almost all C&DM project expenditures with the exception of research and load management. NSP was allowed to earn a 5% bonus rate of return on the unamortized portion of the capitalized expenditures. This amount was deemed by the Minnesota Public Utilities Commission (MPUC) to be high enough to provide an incentive without giving excessive reward to the utility. Moreover, lost revenue recovery was not allowed as the 5% bonus was viewed as a means of offsetting such losses. The MPUC also retained the right to adjust the incentive based on C&DM activity and performance over time.

In order to receive the incentive payment, NSP had to show cost effectiveness results equal to at least 50% of its target net avoided revenue requirement, a concept similar to avoided cost. If that threshold was met, then the utility would have to meet either savings goals for direct impact projects or weighted participation goals for indirect impact projects. The actual bonus payment was scaled linearly from 0% at 50% of goal achievement to 5% for 100% or more of goal achievement.

NSP's expenditures on their C&DM programs ranged from about $7 million in 1990 to about $13 million in 1991. In 1992, expenditures increased significantly to $24.6 million. These are relatively large amounts when compared to other utilities. In 2003, for example, FortisBC expended an average of US$66 per MWh saved whereas NSP expended an average of $141/MWh saved in 1992. Figure 10 shows that the efficiency of NSP's C&DM program improved over time. However, if you compare the cost per MWh saved for NSP which is at $141/MWh with the average retail price of electricity in Minnesota which was $55.2/MWh in 1992, it is not clear that the program was cost-effective. It is important to note that without factoring in the opportunity cost of supply, however, it is difficult to determine whether it was truly cost-effective.[9]

Figure 10. Efficiency of NSP bonus-based C&DM program



[9] I.e., if the unused energy would otherwise have been consumed at super-peak periods when the cost of energy may have exceeded $141/MWh, than the program may still have been cost effective.

Figure 11. Annual C&DM expenditure and savings

Year	DSM Expenditure ($ 000)	Energy Savings (GWh)
1988	$10,938	57
1989	$8,748	55
1990	$7,400	57
1991	$12,549	102
1992	$24,621	175

Source: *NSP*

4.2.2 Niagara Mohawk Power Company

Niagara Mohawk, owned by National Grid, provides electric service to approximately 1.5 million customers in upstate New York. They implemented a shared-savings incentive mechanism in 1989 and were one of the first utilities in North America to do so.

Their bonus mechanism works in a similar way to that of Northern States Power in the sense that the mechanism they have in place allows them to earn an incentive equal to 5% of the net resource savings attributable to DSM programs.

The regulator defined the net resource saving as the present value of lifetime avoided costs, plus $0.0157/kWh adjustment for environmental externalities, less utility program's costs inclusive of incentives paid to the customers. As an example, total incentive to Niagara Mohawk Power Company for all its DSM programs was $5.2 million in 1991 and $8 million in 1992.

4.2.3 Connecticut Light and Power (CL&P)

CL&P distributes electricity to more than 1.1 million customers in Connecticut. CL&P has an incentive mechanism as a result of a 1988 state statute. The incentive rewards the utility for minimizing costs and maximizing electricity savings in the implementation of its C&DM programs. The mechanism allow CL&P to recoup its expenditures over a ten-year period at its normal rate of return plus a bonus rate which is based upon the aggregate success of its C&DM programs. There are no penalties for poor performance.

The bonus rate of return is determined by a unique C&DM scoring system. Each of the applicable programs contributes the C&DM performance score which is based on the following factors:

- Planned Cost Rate (PCR) – the expected annual program cost divided by the expected lifetime energy of capacity savings of measures to be installed that year

- Actual Cost Rate (ACR) – the actual annual program cost divided by the committed lifetime energy of capacity savings of actual measures installed that year
- Program Performance Ratio (PPR) – PCR/ACR
- Program Weight – the fourth root of the product of the program budget and the square of the ratio of costs to benefits. The sum of all program weights is 100.
- Program Score – PPR * Program Weight
- Performance Score – the sum of all Program Scores. This value defines the aggregate success of UI's C&DM programs and is used to calculate the bonus rate of return.

In 1991, Performance Score greater than 115 resulted in a 3% bonus rate of return. Scores between 85 and 115 resulted in 2% bonuses and scores less than 85% resulted in a 1% bonus.

4.3 Markups

The markup mechanism involves an incentive payment equal to the incentive rate times the utility program costs. The basic formula is as follows:

$$I = \lambda C_U - F$$

Where I = incentive payment;
λ = incentive rate;
C_U = utility program costs;
F = fixed payment

This type of mechanism is usually applied to a subset of utility programs where energy savings are difficult to measure (e.g. information programs). Markups reward spending and present a significant danger of inefficiency as there is little linkage between net benefits to society and utility spending. When the regulator cannot accurately observe a utility's actions, it may improperly reward the utility for costs incurred. For example, a utility could transform a C&DM education program into a thinly veiled public relations campaign or the regulator may not be able to verify a utility's private estimate of net benefits.

Markups are appropriate when the regulator is able to make an unbiased estimate of the potential net benefits of the C&DM program, but cannot verify the benefits. Verification of the benefits may be costly or the actual benefits may be difficult to quantify. In such cases, the regulator may employ a markup mechanism (essentially a forced contract) where the utility is instructed to carry out a program and will be rewarded for doing so. Under this mechanism, a budget is laid out for the C&DM initiative with guaranteed cost recovery plus a specified markup.

4.3.1 Pacific Gas & Electric

Specific examples of markups are rare due to the fact that they encourage spending without linkage to benefits. In 1994, Pacific Gas & Electric's (PG&E) C&DM programs were grouped into three categories: Resource, Equity, and Demonstration. Resource programs in which the utility directly buys energy resources from its customers were eligible for shareholder incentives. Equity programs, including educational programs, were also eligible for shareholder incentives, but to a lesser degree. Demonstration programs were unproven resource alternatives and thus not eligible for shareholder incentives. Although PG&E's Demonstration programs did not incorporate an incentive payment, they could be viewed as falling into this category (with a zero markup incentive).

PG&E's Pacific Energy Center (PEC) is a leading energy research center housed in a 30,000 square foot building. PEC opened in 1991 and develops technology and advanced techniques for electric and gas efficiency. The impact of such an energy center, however, is difficult to quantify. Thus, PEC was deemed an information program with the costs recovered dollar for dollar rather than capitalized and incorporated into the ratebase as an asset. If the California Public Utilities Commission (CPUC) wished to incent this type of program, however, it could have incorporated a markup payment. This would essentially be some sort of guaranteed return on the utility investment. It is clear that use of such incentives would require a project by project evaluation process with some sort of cap on spending. Effectively, this would be similar to traditional cost of service ratemaking, with C&DM activities simply another regulatory asset on which the utility receives a return.[10]

4.4 Hybrids

Hybrid incentives combine two or more of the basic incentive design elements. The various design elements are weighted. These types of incentive mechanisms generally reflect a policy preference for C&DM programs that accomplish multiple objectives. These objectives could include minimizing rate impacts while maximizing net benefits. While hybrid mechanisms offer the ability to meet different objectives, they are administratively difficult.

4.4.1 New England Electric System (now National Grid)

In the early 1990s, the New England Electric System (NEES) implemented C&DM programs across Rhode Island, New Hampshire, and Massachusetts. These programs utilized hybrid incentive mechanisms that combined elements of shared savings and bonuses. In 1990, Rhode Island and New Hampshire utilized two part incentive mechanisms. The utility companies, Narragansett Electric and Granite State Electric, employed a bonus incentive equal to 5% of the value created (adjusted for customer direct costs and evaluation costs). The shared savings incentive allowed the utilities to earn 10% of the net value of the C&DM program.

Massachusetts Electric used only a bonus incentive in 1990. The Massachusetts Department of Public Utilities (MDPU)[11] established a per kW and kWh payment for each kW and kWh saved

[10] Note that, if the C&DM activity is already being capitalized, it is likely already receiving a mark-up.
[11] The regulator is now known as the Massachusetts Department of Telecommunications and Energy.

above pre-set minimum performance thresholds. For example, Massachusetts Electric Company (MECO) had to meet a target of 50% of projected energy in order to qualify for the bonus incentive payment. In 1992, MECO's C&DM incentive plan was changed to a two-part mechanism in conformity with the other NEES utilities. The bonus was reduced to 50% of the expected value with the remaining 50% achieved through an efficiency incentive based on the target benefit/cost ratio. The incentive mechanisms employed by NEES produced upside for the company, though incentive payments remain small when considering that sales revenue is near $2 billion a year (about 0.5% of sales revenue).

4.5 Key aspects of incentive mechanisms

Each of the three basic mechanisms discussed above – shared savings, bonus, markup– have their merits and their faults. The shared savings mechanism is the most favored by regulators because it takes into account net benefits to society. On the other hand, this is the most difficult mechanism to administer due to the need to appropriately quantify net benefits. The bonus mechanism is closely related to SSM, but does not take into account the cost of the program. This method requires evaluation using Total Resource Cost to ensure that the utility does not maximize incentive payments at customer expense. Finally, the markup incentive mechanism is most appropriate for those C&DM programs with intangible benefits that are difficult to quantify. This mechanism, however, is rarely used because the there is no direct link between benefits and spending.

It is important to note that one of the most challenging aspects of establishing well-functioning incentive mechanisms is determining "what might have been." In an LRAM, we know what the target level of revenues was, can do simple arithmetic calculations to determine the shortfall relative to the revenue requirement, and can design a mechanism for recovery; we are indifferent to why volumes dropped, and indeed, had they dropped for a reason other than C&DM, we would still likely already have a variance mechanism in place to assure that the utility achieves its required return. By contrast, if we are giving a utility an incentive, we want to be sure that the incentive is being earned; as such, some forms of incentive mechanisms require us to perform forecasts of volumes without C&DM measures, and to show how those volumes would change according to patterns of weather, population growth, and economic growth, again in the absence of C&DM. Simply knowing that consumption dropped does not allow us to say that C&DM measures were a success; likewise, an increase in consumption does not necessarily mean that C&DM programs have failed, if without C&DM volumes would otherwise have been higher. The more high-powered the incentive scheme, the more important it is to attempt to measure results; however, the methodology for doing so needs to be clearly established in advance, and the nuances well understood.

The level of the incentive rate is a key factor in whether the C&DM program produces the optimal net benefit to society. In particular, studies have shown that the marginal incentive rate can serve to increase or decrease net benefits. The marginal incentive rate represents the additional incentive achieved for an additional dollar in net benefits.[12] Incentive mechanisms can produce varying marginal incentive rates depending on how complex they are. A utility could have a marginal incentive rate of zero, for example, when achieved net benefits are 50% below forecasted levels and a marginal incentive rate of 10% when achieved benefits exceed forecasted levels.

Figure 12. Examples of incentive rates for various North American utilities

Utility	Marginal Incentive Rate
PG&E (1991)	15%
Con Edison (1994)	23%-30%
Narraganset Electric (1990)	5%-15%
Jersey Central Power & Light Corporation (1993)	25%

Low incentive rates could result in less than optimal investment in C&DM. Despite the inclusion of costs in incentives such as SSM or in the Total Resource Cost test, utilities often have hidden costs that must be overcome in order to provide a true incentive to the utility. These hidden costs are difficult to quantify. Examples include management costs associated with the additional effort and any organizational adaptation required to implement a successful program. These are internal costs that come with the disruption of starting new programs and the potential transfer of employees from one task to another.

In contrast, some argue that high incentive rates could result in a crowding out effect, as utilities capture C&DM opportunities which otherwise would have been performed by unregulated companies.

Consequently, an effective incentive rate will allow the utility to maximize its profit over the hidden cost curve. High marginal incentive rates should provide greater incentive to utilities to maximize the effectiveness of their C&DM programs. Incentive rates, however, can be too high which would lead utilities to underestimate net benefits so they can capture the incremental net benefits at the high incentive rate. Regulators have attempted to counter these pitfalls by introducing fixed charges that decouple the incentive rate from the total incentive payment. Other strategies include penalties for sub-par performance, earnings caps, and decreasing marginal incentive rates.[13]

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[12] See Eto, J., Stoft, S., Kito, S. "C&DM shareholder incentives: recent designs and economic theory". *Utilities Policy* 7 pp. 47-62. 1998. for a more detailed discussion of marginal incentive rates.

[13] The issue of performance measurement is critical in order for regulators to certify that rates are reasonable. Clear guidelines need to be established so that all parties know what to file, how performance will be measured, and how the burden on the regulator is to be managed.

5 Loss factor incentive mechanisms

Loss factor incentives are put in place to incentivize distribution companies to improve the efficiency of their distribution system. C&DM programs serve to reduce demand on the system and thus contribute to wholesale price stability. Minimizing line losses can be considered another form of conservation, though it is usually addressed through other parts of the regulatory proceedings. Distribution companies that operate on strict cost of service have little incentive to reduce line losses as they are compensated for their distribution costs through their rate filing. However provisions for line loss efficiency can be found in utilities operating under a PBR framework.

Our examples for loss factor incentive mechanisms lie outside of North America. This can be attributed to the fact that line losses are not a chronic problem in North America. In some countries, notably developing countries where line loss levels are usually above 10%, there is often some form of loss factor incentive mechanism in place.

The issue has arisen in Ontario because of a desire to have distribution utilities focus on activities on both sides of the customer's meter. Most of the examples below rely on the use of a deemed loss factor times some value for generation; those utilities beating the loss factor earn extra profits, while those that do not see inferior returns. We note, however, that if the incentives mechanisms for C&DM for distribution companies are appropriately structured, this problem disappears. For example, if we were to evaluate distribution company C&DM based on the amount of power delivered to the distribution system bus bar, rather than based on deliveries to final customers, the utility incentive would already incorporate consideration for reduction in losses.

5.1 Britain's PBR mechanisms

In Britain's PBR framework there is a losses adjustment component in the calculation of the distribution price. The losses adjustment formula is as follows:

$$\text{Losses Adjustment} = \frac{PL \times (AL_t - L_t)}{D_t}$$

Where: AL_t = the allowance for losses

L_t = the actual losses total for year t

D_t = the total number of units distributed

PL = Price of losses set at £0.03065

contact:
AJ Goulding/Gilan Sabatier
617-494-8200
ajg@londoneconomics.com

Based on this formula, distribution companies can obtain a financial benefit should their actual losses be lower than their allowance for losses.

5.2 Distribution System in Romania

In Romania, the regulatory framework for distribution is still being worked out as the country continues to corporatize and privatize its distribution companies. One likely feature of the distribution regulatory regime is a loss factor incentive mechanism for distribution. During the course of the privatization of the distribution companies, potential buyers put forth various proposals. One proposal put forth works in the following way: as of the first regulatory period, each distribution operator proposes a methodology to the regulator for calculating that distribution operator's electricity losses. Based on this reporting methodology, the regulator sets a certain level of allowed losses for each regualtory period for that distribution operator, including both commercial and technical losses, taking into account the reported historical distribution losses of the subject distribution utility. The first period's level of losses reduction targeted for each distribution operator is based on the average of actual losses reductions reported by that individual distributor during the previous two years. As the allowed level of losses is based on each distributor's own performance, loss factors and targets will vary for each distributor.

The regulator then agrees with the distribution operators on a program for decreasing the electricity losses, and the distribution operators are allowed to keep the financial spread that they earn from reducing their losses relative to deemed losses which have been incorporated into the regulatory formula during each generation period. At the end of each regulatory period, the regulator analyzes the achieved level of losses and sets up a new target losses reduction level for the next period. Each period's target losses reductions are based on the achieved level of losses reduction in the previous period.

The level for each individual distribution company for the next generation period is based on the average of the actual reported level of losses of that distribution company over the previous regulatory period. In no case is the historical performance of a distribution company other than the one for which the loss factor is being set be taken into account. However, distribution companies which fail to make any losses reductions in a regulatory period will be subject to penalties in a subsequent regulatory period.

5.3 Jamaica Public Service Company Limited

Jamaica Public Service Company (JPSCo) is a vertically integrated utility serving 550,000 customers in Jamaica and is 80% owned by Mirant. System losses, which include electricity theft, have been a major operational challenge and a focus for JPSCo, as 18% of the energy produced is lost[14]. Consequently, the rate design in Jamaica has an indirect form of loss factor incentives. Electricity tariffs in Jamaica are set based, in part, on fuel rates which in turn are set monthly based on fuel consumption, system heat rate, and assumed system losses of 15.8%[15] of total net generation. This means that losses above this value directly impair the company's bottom line, creating an incentive for JPSCo to reduce line losses. Conversely, a reduction in losses below 15.8% means the company earns additional profits. Interestingly, the monthly nature of the reset mechanism means that JPSCo faces greater incentives to reduce losses during periods when fuel prices are high, allowing for it to consider certain seasonal adjustments in operations which may reduce line losses during those periods.

5.4 Application to Ontario

It would be possible to develop a deemed loss factor incentive for Ontario. One approach would be to divide Ontario utility distribution assets into two categories, one consisting of assets with a high customer density per kilometer of line, and the other with assets with a low customer density for kilometer of line. Many utilities would have assets in both categories. Revenue requirements would be based on an average of the previous three years' losses per asset category times the load weighted average hourly Ontario energy price (HOEP) or a successor index for the previous year, adjusted for the load shape of the subject utility. True-up accounts would be established each year so that the ultimate incentive would be based on the actual load weighted average HOEP in the subject year, adjusted for the actual load shape of the subject utility, rather than the HOEP of the previous year.

This is but one of many approaches to line loss reduction incentives. However, this brief description demonstrates how complex such mechanisms can become. As noted in the introduction to this section, it may be much more administratively simple to subsume any loss factor incentives into the overall C&DM incentives mechanism by focusing on volumes going into the distribution system, rather than volumes taken out of it. This approach has the added advantage, from the perspective of the distribution company, of focusing solely on the opportunities which that specific distribution company faces; distribution companies will inevitably argue that their situations are unique and not comparable to those of their cohorts.

[14] JPSCo 2004

[15] Office of Utilities Regulator (Jamaican regulator)

6 Alternate mechanisms

The approaches we have discussed in this paper related to lost revenue adjustment mechanisms (LRAM), shareholder incentives, and loss factor adjustment mechanisms are all procedures which have been implemented in numerous jurisdictions across North America and overseas. However, there are a number of cutting edge approaches to Conservation and Demand Management (C&DM) which Ontario may wish to consider. Two in particular are flat rate access and revealed willingness to pay plans. We describe these conceptually here, and incorporate them into some hypothetical approaches for the province later in the paper. We also discuss the importance of customers being charged the true cost of energy, a concept which goes beyond simply modifying distribution system pricing.

6.1 flat rate access

One of the characteristics of a distribution network is that costs are largely fixed. Once the distribution network is built, costs to the distribution company are largely a function of the network topology, rather than the amount of throughput. As the network grows, the fixed costs may undergo step changes, as additional transformers, substations, and other network equipment are purchased and put into service. However, these additional costs do not arise as a result of hour-by-hour changes in load on the distribution system, but rather are due to load growth over time. Distribution systems are considered natural monopolies precisely because, until the system is operating at maximum capacity, average costs decline with each additional unit delivered.

A ratesetting mechanism which relies on a flat rate for distribution service and a variable rate generation more closely reflects the economic realities of the overall electricity supply chain. Generation costs are very sensitive to changes of load in a particular hour, day, month, or season. For customers to receive appropriate price signals, and to be able to make decisions regarding conservation, the price they are charged for generation needs to volumetric in nature and correlated as much as possible to the wholesale price of power at the time at which the power is used. By contrast, distribution pricing may be more appropriately configured as a flat monthly charge designed to reflect the overall revenue requirement of the distribution company, divided according to cost causation principles by customer class.

Flat rate pricing is becoming an increasingly common feature of network industries, whether we look at high speed internet or cell phone pricing.[16] Customer rates would be set by first attributing distribution system costs across customer classes. Once so attributed, total annual costs per customer class for distribution services are then divided by the number of connections within the customer class to determine the annual fixed charge. The annual fixed charge is then

[16] Cell phone pricing, though retaining elements of volumetric pricing, becomes essentially flat rate as customers optimize their plans to conform to their calling patterns so as to avoid additional volumetric charges.

pro rated across the months based on the number of days per month. Appropriate annual balancing mechanisms are then put in place to account for fluctuations in the number of customers. If substantial differentiation in distribution system impact exists within the customer class, sub-customer classes can be created. The system can also be modified so that a large proportion of distribution system charges are recovered through the fixed charge, say 90%, while a small proportion, say 10%, are recovered through a volumetric charge. As the distribution system grows and new capital investments become necessary, the principles of cost causation by customer class are used to determine how the fixed charge should be adjusted.

The implications of flat rate, per customer or per connection pricing are clear with regards to C&DM initiatives. A distribution utility is no longer at risk of lost revenues if volumes fall.[17] As such, the need for an LRAM disappears. Because Ontario has already separated generation from distribution, there is no possibility that distribution utilities can be harmed by a decline in demand for generation. Thus, under flat rate pricing, any incentive at all to encourage conservation on the part of distribution companies comes without any kind of conflict of interest. For example, a shared savings mechanism (SSM) does not need to be accompanied by an LRAM. Furthermore, if the SSM incorporates a measure for compensating the utility for avoiding the cost of new distribution system investments – costs that would otherwise cause an increase in the flat rate – the distribution company becomes incentivized to engage in C&DM investments which reduce both demand for generation and to configure the system so as to minimize future increases in the flat rate.

6.2 revealed willingness to pay plans

Policymakers across North America have been instituting a number of environmentally friendly or public service benefits related adjustments to rates. Often, these policies are based on a broad understanding of what the public in general, and ratepayers in particular, want. Such policies are reflected in rates through public system benefits surcharges, DSM rate riders, green energy procurement thresholds, and a variety of other mechanisms. In some cases, ratemaking policies allow for customers to "opt-in" to a higher level of spending on these programs, as when customers agree to spend a set amount more per month than they otherwise would have paid so as to assure that a portion of their monthly payments goes to an investment in green energy, or when customers voluntarily add a few dollars to their payments which are then used to pay for energy for low income users.

To date, there has been relatively little exploration of the use of similar mechanisms to encourage C&DM. However, it is not conceptually difficult to devise a scheme which allows for voluntary customer participation in increasing investment in C&DM. Let us imagine a

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[17] We note that the contention that flat rate pricing reduces conservation incentives for customers is somewhat spurious. As described, the customer still experiences volumetric charges for generation, and can experience meaningful savings by avoiding consumption. Furthermore, under volumetric distribution pricing with an LRAM, customers as a whole end up paying precisely what they would have paid under flat rate pricing.

variation on the SSM. In this variant, the utility establishes a trust which invests in C&DM initiatives. The trust is funded by voluntary additional payments from customers, in the form of a "check the box" style commitment to pay an additional $5, $10, or $20 per month for a period of 6 or 12 months over and above their total bill. The utility matches these customer investments, and may make additional investments into the trust as well. The trust manages C&DM investments, for which it receives in return an incentive payment based on 50% of the overall reduction in total system costs attributable to the investments the trust has made. The trust in turn returns these incentive payments to the utility and to those ratepayers which have chosen to contribute towards the investments, in proportion to the amounts which were actually contributed.

While it may appear that such a system may pose administrative challenges, the accounting which would need to take place is well within the capabilities of most computerized billing systems. In fact, several US utilities offer ratepayers the opportunity to invest in the stock of their utility in this fashion; if such utilities can keep track of the small investments of thousands of ratepayers in company stock, it is certainly feasible to do the same for a C&DM trust.

The advantage of allowing ratepayers to contribute to C&DM investments is that it enables policymakers to determine the level of importance that customers attach to the overall C&DM initiative. Furthermore, it provides a sense of equity, in that those customers that choose to participate in C&DM investments receive the same financial incentives as the utilities. In the Ontario context, the concept could be applied either on a utility by utility basis, or by creating a province-wide C&DM utility into which utility and customer C&DM investments would be funneled. However, this would have the effect of breaking the geographic link between the source of the investment and the location of implementation.[18]

6.3 real time energy pricing

While discussions regarding the structure of standard service supply and the wholesale generation market in general are beyond the scope of our brief, it is nonetheless important to mention their importance in the overall context of C&DM initiatives. When customers receive truncated price signals, the impact of those price signals on customer behavior is distorted. When generation prices are above historical levels, but this increase is disguised through deferral accounts, customer calculations of the benefits of conservation will fail to take into account the true cost of power, and underinvestment in C&DM will occur. It is important to understand, however, that in periods when there is ample supply, some forms of C&DM may truly be uneconomic.

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[18] This raises an interesting issue, in that at times such a geographic break may be desirable. If we believe that one feature of C&DM investment is to reduce peak load, and to thereby reduce wholesale power costs province-wide, it may well be desirable for C&DM investments to be widely collected from across the province, but focused on one or two activities in the province which use the most peak energy. Such activities are likely to be geographically concentrated, even though the benefits of modifying their consumption would be felt across the province.

These calculations become more complex when environmental externalities are considered. An ex-post analysis of the benefits from avoided energy consumption should utilize the wholesale spot price of electricity as the benchmark for avoided costs. However, the value of avoided emissions is much more difficult to quantify, particularly in jurisdictions where no traded emissions allowance markets exist. When examining C&DM programs in Ontario, policymakers and analysts will need to make a determination as to whether externalities should simply be excluded from the calculation, or whether proxy values should be developed, possibly based on traded emissions allowance markets elsewhere in the Northeast. However, even if a proxy is agreed upon, there remains the issue of whether the value derived should be incorporated into the estimate of benefits used to calculate C&DM incentive payments. If the value of externalities is not included, we will again see underinvestment in C&DM. However, if it is included, customers end up paying for the elimination of a cost that otherwise would not have been charged to them had the energy been consumed. This issue requires further analysis.

Overall, however, when examining C&DM from a holistic perspective, it is important not to overlook the role of Ontario initiatives to promote the use of real time meters, real time pricing, and load participation in the wholesale market. Indeed, the question of whether pursuing all of these initiatives in parallel, or incorporating at least real time metering into the C&DM framework, also could benefit from further study.[19]

[19] We recognize that current policies on smart meter implementation and regulated price plan development may leave utilities with relatively little discretion in the implementation of real-time metering; as such, the notion of coordinating real-time metering with an incentives scheme may be somewhat academic.

7 Impact of Ontario market structure on applying C&DM

There are several elements which need to be taken into account when designing C&DM mechanisms in Ontario, and in particular for the year 2006. These include the unbundled nature of the Ontario electric industry, the number of utilities, the heterogeneity of the utilities and their service territories, the evolution of the wholesale generation market in Ontario, the role of the Ontario Power Authority and the Conservation Bureau, and the nature of the 2005 and 2006 ratemaking processes. Below, we discuss each issue in turn; these issues are also incorporated in a subsequent section that outlines hypothetical approaches to C&DM which could be applied to Ontario for the 2006 rate year.

7.1 separation of generation and distribution

One of the most important aspects of the Ontario electricity market with regards to C&DM is that generation is not part of ratebase. Effectively, this means that the utilities over which the OEB has jurisdiction will generally not be concerned about lost generation sales and the associated potential for stranded generation assets.[20] This effectively reduces the amount of lost revenues that need to be considered when designing an LRAM. It also has the effect of increasing the power of any SSM, as the distribution utility can retain a portion of the savings associated with reduced consumption of wholesale generation output, without seeing its own revenues reduced by the same magnitude in its traditional business lines as it would were it to be fully integrated.

7.2 the number of distribution utilities

Despite a recent round of consolidation, Ontario continues to have over 90 distribution utilities. From an administrative standpoint, this poses challenges. Any initiative undertaken by the OEB must take into account the potential for data submissions, inquiries, filings, rebuttals, and sur-rebuttals from each of these 90 utilities. Thus, programs which require significant active interaction, either verbally or in writing, between the utilities, their customers, and the OEB must be carefully considered and appropriately resourced. Overall benefits of any program must take into account not only the costs to the utility, but the overall costs of the associated regulatory infrastructure, and the associated transaction costs for interested participants.

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[20] Clearly, the same cannot be said of Ontario Power Generation (OPG) and private generators, who may be adversely affected by a successful C&DM program. OPG may attempt in some way to seek recovery for this in the process of negotiating its heritage contracts. For private generators, it becomes simply another aspect to consider when forecasting load in the province.

7.3 corporate and territorial heterogeneity

The issue of there being a multitude of utilities is exacerbated by the fact that these utilities are highly diverse. Some are older urban utilities serving a densely populated area. Others serve growing suburbs with new infrastructure. Ontario contains both some of the largest and some of the smallest distribution companies in North America. Some have a predominately urban client mix, some are predominately rural, and some a mixture. The utilities also vary greatly by the type of customer; some have few industrial and commercial customers, while others have many. In addition, there is a wide range of ownership arrangements, including private companies, municipal shareholders, and the province.

Heterogeneity among utilities affects their capacity to implement D&SM initiatives, as well as the opportunities they face. Large utilities have entire departments devoted to regulatory affairs, and possibly to C&DM alone; for small utilities, C&DM is only one of many issues facing a senior manager. This has a direct impact on the regulatory burden that C&DM rate design issues place on the utility. The greater the number of potential filings associated with C&DM mechanisms, the greater the burden on smaller utilities. As such any province-wide C&DM initiative needs to be flexible and practical, so that utilities are able to exploit the potential that is available without spending a disproportionate amount of time preparing filings. For example, alternative approaches may incorporate the possibility of smaller utilities banding together to invest their C&DM budgets collectively, and possibly to share benefits on a pro rata basis. We can imagine best practice C&DM exchanges set up, possibly with online resources, to facilitate the exchange of ideas among utilities. Any C&DM initiative will need to be clearly laid out, and account for the diversity of circumstances facing Ontario utilities.

7.4 Ontario wholesale generation market

The Ontario wholesale generation market is evolving rapidly. Generally speaking, the near term benefits from C&DM initiatives are largely due to avoided generation costs. However, as generation costs fall, the benefits from C&DM fall as well. Ontario is moving to a form of heritage contracts for some Ontario Power Generation (OPG) assets, with the intent of stabilizing power prices. It is unclear the impact that this, along with the bidding behavior of those entities which are successful in gaining RFPs, will have on wholesale generation markets. These uncertainties make it difficult to assess wholesale generation costs in Ontario; indeed, it becomes less clear whether the HOEP will continue to be an appropriate benchmark for such costs. Because this makes it more difficult to assess the potential benefits from C&DM, it also makes it more difficult to appropriately perform a TRC, or to calculate an SSM which requires a TRC.

The uncertainty in the generation markets is reflected in the ratemaking process in other ways. Current plans for supply tariffs to small customers and other customer classes who do not choose alternative suppliers suggest a continuation of a quasi-fixed price regime for those without real time meters. This means that for 2006 there may be a dichotomy between the economics of C&DM as perceived by the customer and the economics of C&DM to society as a whole. Customers will perceive savings based on the fixed price they are charged; however, from a social standpoint, it would be more efficient if utility incentives incorporated the actual wholesale market value of generation.

7.5 role of the Ontario Power Authority

The Ontario Power Authority (OPA), though now being formed, has yet to fully develop its mission. This extends to the proposed Conservation Bureau which is expected to be part of the OPA. Until the role of the Conservation Bureau is better defined, there is the risk that any electricity distributor C&DM initiative may either be contrary to the government's long term vision for the Bureau, or if successful could make the Bureau irrelevant. Conversely, failure to coordinate C&DM initiatives with Bureau activities could result in subobtimal investment of resources or in duplication of efforts. Of course, it is possible that the C&DM design could actually be used to shape the Bureau itself, investing it with a role and a purpose, or defining it as an entity that seeks conservation activities which are outside of the capability of distribution utilities.

7.6 nature of the 2005 and 2006 ratemaking process

The design of the 2006 C&DM mechanisms must take into account the nature of 2005 initiatives. The directive that distribution utilities invest a substantial portion of their allowed rate increase which was otherwise intended to allow the distribution utilities to achieve a commercial rate of return will force the utilities to create a body of programs which presumably will be of more than one year's duration. Any C&DM initiative for 2006 should take care not to squelch successful initiatives while avoiding providing inadvertent rewards for inefficient ones.

7.7 implications

The administrative cost of regulating 90+ utilities is a real one which necessitates C&DM rate design to be easily administered and self-sustaining. Some of the rate design mechanisms discussed in this paper are easier to administer than others. In terms of lost revenue adjustment mechanisms, the surcharge mechanism (both prospective and retrospective) is likely to result in a greater administrative burden for the OEB. With over 90 utilities, the OEB could expect to receive as many annual filings in a year as there are utilities to recover lost revenue. If the surcharge mechanism is designed to recover lost revenue over a series of years, the administrative burden would be less onerous. However, standardizing forms, making them electronic, and training utilities in their use may help to alleviate some of this burden. The deferral account method offers the simplest method of administration as the accounting would be managed by the individual utilities with periodic rate filings. However, given that the focus of current attention is on the 2006 rate year, this alternative may not be available.

The incentive mechanisms employed also have varying degrees of complexity that requiring different levels of attention. SSM is the most complex to administer as it requires an accurate assessment of net benefits. Establishing the appropriate incentive rate can also be difficult as discussed in Section 4.5. Once a C&DM program is implemented, verification of actual C&DM program savings can be a time-consuming process and could involve an independent auditor. Again, this process can be simplified through standardization of forms, use of electronic record-keeping, and possibly by staggering filing dates of utilities so as to spread the workload throughout the year.

Ontario currently uses SSM in the gas industry, but there are only two major (and one smaller) gas utilities and only one, Enbridge, is using an SSM. Enbridge utilizes a stakeholder committee consisting of major energy users, environmental and consumer groups, the OEB, and itself to administer the SSM. The committee's task includes providing advice on C&DM programming, setting annual C&DM targets, evaluating savings reports, overseeing the application of the SSM incentive formula, and recommending targets and incentives to the regulator. All of these activities take place outside of official hearings. Applying SSM to all of Ontario's distribution utilities would require designing a different process, possibly a "mini-ADR" (alternative dispute resolution) process in which utility submissions are put before an ombudsman board of local ratepayers and utility representatives approved by the OEB; SSM proposed incentives which pass the local board would be deemed automatically approved by the OEB, subject to substantive challenge by a ratepayer with standing.

8 Prototype C&DM models

To provide a sense of how C&DM adjustment mechanisms might be incorporated into rate designs for 2006, we have developed a range of potential models. The models differ not only in their designs, but also in their impact on utility finances and rates. We then identify the pros and cons of each model against five criteria: administrative simplicity, bill impact, regulatory consistency, incentives compatibility/financial stability, and universality.

8.1 potential models

We have developed four basic models for C&DM in Ontario. In Model 1, the LRAM incorporates a prospective surcharge accompanied by a bonus incentive scheme. Model 2 uses an LRAM, deferral accounts, and a 50/50 SSM. In Model 3, we utilize a high-powered SSM, with no LRAM and with a customer participation option. Model 4 would shift Ontario to flat rate distribution pricing, along with an SSM focused on customer bills. In each case, it is assumed that distribution utilities are required to spend a minimum of 1% of revenues on C&DM initiatives. This figure is near the mid-point of observed practice across North America. It also provides for sufficient revenues to be spent as programs become institutionalized, without requiring spending levels which could overwhelm the capability to effectively manage the outflows.

Although not included in our hypothetical models, one additional alternative would be to simply continue the provisions which have been ordered for 2005. As described in OEB hearing testimony of 7 December 2005, the 2005 approach, which is purely voluntary, incorporates an LRAM based on the formula to be established by the 2006 Electricity Distribution Rates (EDR) panel. It also incorporates an SSM of 5% of demonstrated savings, but with no incentive for those expenses which are going into ratebase. Continuing the 2005 approach into 2006 would certainly provide a measure of administrative simplicity, and has positive elements when evaluated under our other criteria as well.[21]

8.1.1 Model 1—"pay as you go" LRAM

Model 1:

- LRAM recovered through prospective surcharge
- costs expensed
- bonus incentive according to actual savings
- implication: least disruption to utility cashflows

Model 1 seeks to protect cash flow concerns of the utility due to C&DM revenue erosion while providing the utility with the strongest incentive to optimize its C&DM program. Consequently, lost revenues are recovered through a prospective surcharge allowing for quick recovery of lost revenue. The cost of the C&DM program will be treated as an expense. This model employs the bonus incentive payment mechanism which pays the

[21] One alternative that we have not mentioned is the alternative of doing nothing, that is, of having no C&DM incentive at all. While certainly a valid part of the policy alternatives continuum, having no incentive or mechanism does not appear to be consist with current Ontario government policy.

utility on the basis of actual energy savings.

This model exhibits a moderate degree of administrative burden. The incentive payment is simple to administer, but the surcharge recovery mechanism requires an annual true up. The incentive payment design, however, may lead the utility to maximize utility benefits and not total benefits to society. Thus this type of incentive generally must pass the Total Resource Cost test to be approved by regulators. If the utility has access to inexpensive C&DM measures, then this model may be used efficiently.

Expensing the operating and capital costs of the C&DM program means that rates will rise more sharply in the short term. While revenue requirements will decrease over the long term, they will not decrease as rapidly as they would if costs were capitalized.

This model can be applied to all types of utilities. However, the C&DM programs that utilities choose to implement should have quantifiable benefits unlike a C&DM program that is based in consumer information, for instance.

8.1.2 Model 2 – "pay over time" LRAM and SSM

Model 2 gives the utility a moderate level of revenue protection while attempting to maximize net benefits to society. Consequently, lost revenues are recovered through a deferral account. The cost of the C&DM program will be capitalized in the ratebase. This model employs the shared savings incentive payment mechanism which splits the savings from C&DM programs between customers and the utility.

Model 2:
- LRAM recovered through deferral account
- costs capitalized
- SSM splits benefits 50/50 with customers
- Implication: lowers initial rate impact

This model also exhibits a fair degree of administrative burden. SSM is a more complex incentive mechanism that requires calculation of expected net benefits. Moreover, setting the appropriate incentive payment rate is not straight forward. SSM, however, can be simplified should it be implemented as part of a multi-year PBR framework in which net benefits are indexed to a productivity index. Use of a deferral account should provide a low level of administrative burden on the regulator, countering the complexity of the SSM.

Capitalization of the operating and capital costs of the C&DM program means that rates will rise over the long term. The revenue requirement, however, will decrease more rapidly over the long term when compared to the expensing of costs.

This model is applicable to all types of utilities provided they engage in C&DM programs that have quantifiable benefits.

8.1.3 Model 3 – high powered shared savings

In Model 3, we envision an approach in which no LRAM is used. Instead, the utility receives a high proportion (75%) of projected first year shared savings. In this case, each utility is granted a prospective surcharge based on an assumed level of the potential reductions in customer bills over the coming year due to C&DM programs. At the end of the year, the utility is required to demonstrate in a filing that the assumed level of savings was achieved. If it was not, the utility is required to refund a portion of the incentive mechanism through bill credits in the subsequent year. If, however, the utility achieved more than the target level of savings for customers, it is allowed to recover an additional amount in the coming year to "top off" the incentive payment. However, such a "top off" payment is only allowed if the savings achieved in the previous year are projected to continue in the following year, so as to minimize the impact on customer bills from the "top off" payments.

The process would work as follows. In the fourth quarter of 2005, utilities would submit assumptions regarding customer bills for the coming year without a C&DM program. This assumed customer bill baseline would be accompanied by a list of underlying parameters such as heating and cooling degree days, economic growth in the service territory, wholesale generation prices, etc. Many of these baseline parameters could be prescribed for all utilities so as to standardize the calculation process. Utilities would be required to invest at least 1% of expected 2006 revenues on C&DM initiatives. Assuming this level of spending and given the nature of the C&DM initiatives to be undertaken, utilities would be asked to estimate the expected level of total customer savings. The utilities would then be entitled to charge a surcharge equal to 75% of projected savings, spread over the coming year.

Model 3:
- no LRAM
- costs expensed
- SSM in which 75% of benefit goes to utility
- SSM recovered through prospective surcharge
- annual true-up mechanism to assure incentive is earned
- implication: moderate bill impact, but administratively complex

In the first quarter of 2007, the utilities would be asked to calculate actual savings experienced by their customers, based on an adjusted baseline level of demand based on the actual heating and cooling degree days experienced, actual economic growth, and actual wholesale power prices. These submissions would be reviewed by an independent third party, and certified before being filed with the OEB. If the submissions showed that the projected savings had not been achieved, a refund mechanism with interest would be set up so as to reduce the actual incentive received by the utility to 75% of actual savings. If actual savings exceeded the target, an additional incentive would be paid associated with a proportion of the savings expected to endure into 2007.

This mechanism could be coupled with a customer contribution mechanism which would allow customers to add to the utility C&DM investments in return for the same incentives received by the utility. However, the overall mechanism is already complex; it would likely be administratively difficult to add a customer contribution mechanism that would only exist for the 2006 rate year. If the high powered SSM were to be extended for a multi-year period, then a customer contribution mechanism could be considered.

8.1.4 Model 4 – flat rate pricing and customer bill savings[22]

Model 4:

- distribution rates calculated on a fixed connection charge basis
- no need for LRAM
- 50/50 SSM recovered through a retrospective surcharge
- 50% of costs expensed, 50% capitalized
- implication: rate basis aligns distribution company incentives with customers

In Model 4, the basis for distribution pricing is shifted to a flat monthly connection charge per customer. Generation services would continue to be charged volumetrically. Utilities would recalculate rates by customer class to determine the flat monthly charge each would pay in order to fully meet the utility's annual revenue requirement. Flat rates would be based on the projected number of customers per customer class for the coming year. An annual true-up mechanism would be used to calculate a surcharge or a credit for the following year based on the actual number of customers within the customer class for the previous year.

The use of a flat rate pricing mechanism for distribution services should make utilities indifferent to the volumes on their system from a revenue perspective, removing one potential obstacle to C&DM initiatives. However, to overcome inertia, and to provide utilities with some upside from C&DM, Model 4 incorporates a retrospective shared savings mechanism, in which utilities receive a bonus based on 50% of achieved reductions in customer bills in the previous one year period. 50% of C&DM costs are expensed, and 50% are capitalized over 5 years, under the assumption that a portion of the C&DM benefits are immediate and the remainder are realized over five years; thus, the split between expensing and capitalizing the costs matches the timing of the expected benefits.

8.2 evaluative criteria

In conjunction with the OEB we have established the following five parameters (administrative simplicity, bill impact, regulatory consistency, incentives compatibility/financial stability, and universality) by which we compare the relative merits of each of our potential approaches to C&DM in Ontario.

Administration: Ontario's large number of distribution utilities necessitates that administration be fairly simple or it would result in an excessive burden on the utilities and on the OEB. An overly complex mechanism would increase transactional costs. The cost of making the change to the new model, and then maintaining it, becomes an additional charge to users that is not

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[22] Although we include this alternative as one viable approach, we recognize that it is likely not feasible for 2006. Cost allocation issues will begin to be addressed prior to the 2007 rate year.

directly related to increases in energy savings. Moreover, the more complicated a C&DM rate mechanism becomes, the more it is subject to potential manipulation or to regulatory interference. Modifications become layered upon modifications, as changes intended to "improve" the mechanism increase complexity.

Bill impact: Ultimately, customers care most about the impact on the size of their bill. Few know or even care about the minutia of rate setting, or the actual per kWh rate they are charged. All that matters to them is that the total bill be at or below what they were expecting to pay. Customers are highly unlikely to oppose a provision which causes one portion of their rates to go up if by so doing their entire bill falls.

Rate consistency: The C&DM mechanism proposed for 2006 should not be a stand-alone measure. It should be consistent with ratemaking practice in Ontario, flow logically from practice for 2005, and form a springboard for practice in 2007 and beyond. As such, the mechanism needs to not in and of itself prevent future innovations in rate design; it should also be viewed by market participants as part of a continuum of policies designed to encourage long term C&DM.

Incentives compatibility/financial stability: For a mechanism to achieve the desired results, it must reach those actors capable of responding. It also must result in compensation sufficient to actually provide an incentive to change behavior. In this case, the C&DM mechanism must provide some reason beyond the "eat your vegetables it's good for you" logic in order for utilities to engage in it. As such, the mere provision of an LRAM simply makes a utility indifferent to C&DM, it does not actually encourage the utility to go out and do it. A mechanism which aligns the incentives of utilities and customers is most likely to produce meaningful results. In addition, any mechanism which jeopardizes the financial health of the utility, or which produces volatile revenues, is not likely to be embraced by utilties.

Universality: The successful implementation of a C&DM mechanism depends on its applicability to various types of utilities. Not all mechanisms are universally applicable and some might provide a better fit to certain types of utility than others. Though we believe that the capabilities of smaller distribution utilities are often underestimated, such utilities might not be able to implement a fairly complex mechanism. However, one component of universality may be simply flexibility; a C&DM mechanism that avoids a one-size-fits-all mentality may be more appropriate for a province with such a diverse set of utilities.

8.3 comparing the models

Figure 13 compares the four prototype models on the basis of the criteria above. It shows that Model 1 is the most administratively simple framework for C&DM. It uses a very basic incentive formula and protects the utility against lost revenue in timely fashion via a prospective surcharge. Some stakeholder involvement is required to establish how much of an incentive payment should be allowed. The utility must expense C&DM program costs, which means that rates may increase somewhat sharply over the short term. Depending on how the bonus mechanism is set up, program costs are not explicitly factored into the incentive formula. This means that the utility will have an incentive to increase spending on C&DM (given that it produces greater savings) in order to maximize its incentive payment. This mechanism is most effective for those utilities that implement relatively inexpensive C&DM measures.

Figure 13. Comparison of prototype models

	"pay as you go"	"pay over time"	SSM only	flat rate with SSM
administrative simplicity	LRAM true up adds administrative burden	SSM administration most complex part	highly complex	simple after initial transition
bill impact	front loaded; reduces up front savings to consumer	spreads impact over time; allows for greater up front savings	intended to show benefits to customers immediately, otherwise surcharge refunded	should reduce bills if SSM component is effective
regulatory consistency	can be continued year on year	can be continued year on year	may break down if not simplified	can be continued year on year
incentives compatibility	bonus incentive relatively small	provides additional incentive to utility, but with greater potential uncertainty	depends on aligning SSM with lost volumes since no LRAM	aligns customer and company incentives
financial stability	positive cashflow impact for utility	deferral accounts less favorable for utility	SSM must be appropriately configured	time lag in recovery of SSM
universality	can be applied broadly	SSM needs to be designed so as to facilitate participation by small utilities	very difficult for smaller utilities	can be applied broadly

Model 2 is among the most commonly used approaches. Administrative difficulty is moderate as use of the SSM requires shareholder input in setting the level of net benefits desired. The sharing of benefits with consumers provides customers with some upside. While distribution rates may increase, the annual cost of electricity should go down due to capitalization of C&DM costs. Incorporation of program costs into the rate base combined with shared savings should lead to fairly stable and predictable costs.[23] The utilities are also given a return on the program

[23] Note that capitalization means that some costs from 2006 will be recovered in rates in later years, leading to a long term effect.

costs in addition to any incentive payments. The benefit-to-cost ratio, however, is highly dependent on the marginal incentive rate used.

Model 3 is the most complex of the C&DM frameworks presented here. Its complexity is due primarily to the use of a prospective SSM surcharge with ex post true-ups. This type of incentive mechanism also requires that the magnitude of the shared savings exceed any potential lost revenues, as no LRAM is in place. Unfortunately, this requires the use of multiple filings and tracking mechanisms to estimate future benefits, calculate the size of the prospective surcharge, and to monitor actual performance. This can become quite complex in an environment where there are many utilities and stakeholders. The treatment of program costs as an expense also means that customers may be exposed to annual rate changes. The prospective surcharge offers improved cash flow relative to the deferral account, but can also be adapted to a multi-year model. Again, the effectiveness of the incentives is dependent on the appropriateness of the incentive rate relative to program costs. Utilities do have a strong incentive to engage in effective programs, otherwise they risk having to repay the incentive payments already received.

The final model, involving flat rate pricing, involves potentially high transaction costs as utilities transition from volumetric charging to flat rate charging to recover their distribution revenue requirement. However, utilities already have all the information necessary to make the transition, and the calculations themselves are not onerous. Instead, some customers may raise a question of equity if there are wide divergences in volumetric usage within a customer class. Arguably, larger users within a customer class may contribute to system expansion needs deemed to have been "caused" by the customer class, thus leading to higher future fixed rates for the class. However, such issues can be dealt with by adjusting the definitions of the various customer classes, or adding customer classes.

If examined in isolation, the retrospective SSM in Model 4 could present issues of rate and customer bill volatility, in that customers would see their bills fall in 2006, but then have to pay back some of that gain in 2007 as part of the retrospective SSM. However, if we assume that C&DM initiatives are ongoing and successful, the positive impact of 2007 C&DM initiatives should effectively pay for the incentive for 2006, and so on over the subsequent years.

8.4 Concluding remarks

A number of issues need to be addressed when thinking about the appropriate model for C&DM in 2006. Following are among the most important issues we foresee:

- **Continuity:** how does the 2006 C&DM regulatory framework flow from the 2005 C&DM regulatory framework?
- **Rate design interaction:** how does the C&DM regulatory framework interact with pricing for default supply, and with overall long term incentive-based ratemaking structures

- **Institutional responsibilities:** while at this time the C&DM regulatory framework for 2006 will almost certainly need to be designed without full knowledge of the role of the Conservation Bureau, the Bureau when established will need to take the 2006 C&DM regulatory framework into account
- **Financial stability:** Ontario distribution utilities have faced numerous challenges over the past several years, ranging from corporatization to rate freezes to rebasing. C&DM rate design for 2006 should not add to the perceived uncertainty in the Ontario marketplace
- **Geographic concentration:** The issue of whether utilities should be allowed to invest in C&DM initiatives outside of their service territory if those programs produce greater overall savings than the opportunities within their own service territory may need to be explored.
- **Flexibility:** The 2006 C&DM program should encourage, rather than squelch, program creativity. A potential benefit of having over 90 utilities is that this may allow for a greater diversity of program approaches; indeed, small utilities may prove to be more nimble and creative than large ones. The 2006 C&DM process should allow for innovation, possibly even through having an alternative recovery process for high potential programs which do not fit into the mainstream process.
- **Equity:** The question of whether those who pay for C&DM initiatives are also those who benefit from them will also need to be explored.

9 Appendix: Responsiveness to the RFP

The RFP asked the questions listed below. We briefly summarize our response to each after each question, or provide a reference to the pages in the paper where it is discussed.

- Do distributors need revenue protection from C&DM?

Yes – in fact, as the very money to invest in C&DM comes from rates, if revenues are based on volumes and volumes decrease, the utility that is successful at C&DM would ironically find itself with less money to invest in C&DM in the future – surely a perverse result.

- What alternative mechanisms are available, and what are the pros and cons of each?

See p.15.

- Do distribution shareholders need a specific C&DM shareholder incentive?

Yes – utility management would in fact be in breach of fiduciary duty were they to aggressively pursue programs which provided no financial return for their shareholders. Furthermore, it is important to emphasize that any incentive needs to be in addition to the normal allowed return, otherwise it does not serve as an incentive at all.

- What mechanisms are available, and what are the pros and cons of each?

See p. 20.

- What would be an appropriate level for the incentive?

The level of the incentive should be consistent with the risk undertaken, but also of sufficient magnitude for utility management to care. Successful programs should have the potential to improve the utility's profits by as much as 5% if sustainable reductions in customer bills can also be achieved. Note that we are not suggesting that the determination of the incentive be based on the size of a utility's profits – the incentive should be based on the impact of C&DM on customer bills. However, the magnitude of that incentive, in order to matter, should have the potential to increase profits by up to 5% if the company does an extraordinary job of implementing C&DM. We note, however, that the incentives should be carefully crafted so as to avoid "crowding out" profitable C&DM initiatives from non-regulated companies.

- What types of loss factor incentive mechanisms are available and what are the pros and cons of each?

See p. 31.

- What alternative mechanisms are available for C&DM spending in 2006, and what are the pros and cons of each?

See p.42.

- What is the appropriate level of spending?

Our survey of North American utilities found spending in the range of 0.15% of revenues to 3% of revenues. We are inclined to target spending at 1% of revenues in the initial years of the program.

- Should over and underspending be permitted?

We are generally of the view that overspending should be permitted when it can be demonstrated to have reduced customer bills, but that underspending should not be permitted except under extraordinary circumstances, as it effectively may give utilities a "free ride" on money customers have already paid for C&DM initiatives. Underspent funds should be refunded to customers.

- What characteristics of Ontario might impact the mechanism chosen?

See p. 38.

- What might be the economic consequences?

Discussed along with potential models for Ontario, starting on p. 46.

- What might be the appropriate treatment of operating and capital costs?

Generally, we prefer that operating costs be expensed for administrative simplicity, and that capital costs be capitalized over a period of time consistent with the length of time over which the savings associated with those capital costs are expected to be achieved. However, as determining this precisely may be complex, it may be more straightforward to capitalize such costs over a five year period.

- What data must be filed by the distributor and when?

See p. 12.

- How would costs be allocated across the distributor's customer base?

Although the principles of cost causation are important, so is administrative simplicity. As such, unless the costs and the benefits can be clearly isolated to a particular customer class, we prefer that the costs be allocated pro rata by load across customer classes.

- Should distributor C&DM programs that raise distribution rates be permitted?

We believe that the focus should be on customer bills, not on rates. As such, those programs which can be demonstrated to reduce customers' total bills should be allowed, regardless of the impact on rates.

London Economics International LLC
717 Atlantic Avenue, Unit 1A
Boston, MA 02111
www.londoneconomics.com

contact:
AJ Goulding/Gilan Sabatier
617-494-8200
ajg@londoneconomics.com