PROVINCE OF ONTARIO

BEFORE THE ONTARIO ENERGY BOARD

Natural Gas Demand-Side	)	
Management Generic Issues	)	**Case EB-2006-0021**
Proceeding	)	
________________________________	)	

EVIDENCE OF

PAUL CHERNICK

ON BEHALF OF

THE SCHOOL ENERGY COALITION

RESOURCE INSIGHT, INC.

JUNE 2, 2006

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I. Introduction and Qualifications

Q: Mr. Chernick, please state your name, occupation and business address.

A: I am Paul L. Chernick. I am the president of Resource Insight, Inc., 5 Water Street, Arlington, Massachusetts.

Q: Summarize your professional education and experience.

A: I received an SB degree from the Massachusetts Institute of Technology in June 1974 from the Civil Engineering Department, and an SM degree from the Massachusetts Institute of Technology in February 1978 in technology and policy. I have been elected to membership in the civil engineering honorary society Chi Epsilon, and the engineering honor society Tau Beta Pi, and to associate membership in the research honorary society Sigma Xi.

I was a utility analyst for the Massachusetts Attorney General for more than three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power supply options. Since 1981, I have been a consultant in utility regulation and planning, first as a research associate at Analysis and Inference, after 1986 as president of PLC, Inc., and in my current position at Resource Insight. In these capacities, I have advised a variety of clients on utility matters.

My work has considered, among other things, the cost-effectiveness of prospective new generation plants and transmission lines, retrospective review of generation-planning decisions, ratemaking for plant under construction, ratemaking for excess and/or uneconomical plant entering service, conservation program design, cost recovery for utility efficiency programs, the valuation of environmental externalities from energy production and use, allocation of costs of service between rate classes and jurisdictions, design of retail and wholesale rates, and performance-based ratemaking and cost recovery in restructured gas and electric industries. My professional qualifications are further summarized in Schedule A.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified approximately two hundred times on utility issues before various regulatory, legislative, and judicial bodies in the United States and Canada.

Q: Have you previously presented evidence before the Ontario Energy Board?

A: Yes. I filed evidence and/or testified before the Ontario Environmental Assessment Board in Ontario Hydro's Demand/Supply Plan hearings in 1992, and before the OEB in the following dockets:

- EBRO 490, DSM cost recovery and lost-revenue adjustment mechanism for Consumers Gas Company
- EBRO 495, LRAM and shared-savings incentive for DSM performance of Consumers Gas
- RP-1999-0034; Ontario Performance-Based Rates for electric distribution utilities
- RP-1999-0044; Ontario Hydro transmission-cost allocation and rate design
- RP-1999-0017; Union Gas proposal for performance-based rates
- RP-2002-0120; Ontario transmission-system code
- RP 2004-0188; cost recovery and DSM for electric-distribution utilities
- EB-2005-0520; rate design and cost allocation for Union Gas firm customers.

II. Introduction

Q: On whose behalf are you testifying?

A: My testimony is sponsored by the School Energy Coalition.

Q: What is the purpose of your direct testimony?

A: The School Energy Coalition has asked me to review a number of the issues raised in the evidence of Union Gas and Enbridge Gas Distribution, including the following:

- multi-year DSM planning and budgeting;
- cost recovery for DSM, including the DSM variance account;
- the operation of the lost-revenue adjustment mechanism;
- treatment of any payments or credits the utilities may receive for the climate-change mitigation effects of the DSM programs;
- the role of the DSM Consultative process;
- auditing and verification of program revenue requirements;
- screening of programs.

I have not been asked to review the utilities' SSM proposal, but my silence on that issue should not be interpreted as agreement with what they have proposed.

Q: Please summarize your recommendations.

A: My principal recommendations are as follows:

- DSM planning and budgeting should operate on a multi-year basis, generally matching the term of the rate plan.
- DSM costs in rates (including direct costs, lost revenues and shareholder incentives) should not normally vary during the rate plan. Deviations from the amounts embedded in rates should be accumulated in a DSM variance account and deferred to the subsequent rate plan.

- Any payments or credits the utilities may receive for the climate-change mitigation effects of the DSM programs should be credited to the DSM budget.
- The utilities' lost-revenue adjustment mechanism (LRAM) should be continued, and should use the best available data on lost revenues.
- The utilities should be encouraged to use the DSM consultative process to improve their programs and increase the certainty of cost recovery.
- All components of program revenue requirements, and especially LRAM and incentives, must be audited by a technically-competent independent party selected and managed by or on behalf of the ratepayers, whose interests are being protected by the audit.

III. Multi-Year Planning and Budgeting

Q: Do you support the utilities' proposal to implement multi-year DSM plans?

A: Yes.

Q: For what period should the DSM plan be established?

A: A three-year DSM plan and budget would be long enough to allow the utility to plan and implement programs in a logical and methodical manner, while not too long a period to go without review of the plan.

If the utilities are put on three-year rate plans, or even a four-year cycle, the DSM plan can coincide with the rate plan. Synchronizing the rate plan and the DSM plan has administrative advantages, and ties the DSM plan into the rate-case review of capital expansion plans and load forecasts. If the rate plans are set for much longer periods, some sort of mid-term review might be required. For the purpose of this testimony, I assume three-year rate and DSM cycles.

In any case, the utility should file with the Board regular (e.g., quarterly) reports on commitments and expenditures. If program spending falls significantly below the level in the plan, the Board (on its own motion or at the request of a party) should be willing to investigate the reason for the shortfall.

A. Cost Recovery

Q: How do you propose that the utilities should recover their direct expenditures on DSM?

A: The three-year budget for the three-year plan should be reviewed by the Board and the revenue requirement should be included in the rates approved for the rate plan. Since I assume the rate plan will be for three years, one third of the budget would be included as an expense in each year.

Differences between the budget and actual spending would be accumulated in a DSM variance account (DSMVA). At the end of the rate plan years, the positive or negative value of the DSMVA would be rolled into rates for the next rate plan.

To avoid run-away spending without oversight, and to protect the utilities and ratepayers from unpleasant surprises, the maximum positive DSMVA should be limited to a relatively small expansion of spending, such as one-half of the average annual spending (or one sixth of the three-year budget). If the utility expects its spending to exceed that level, it should file with the Board explaining the cause of the expanded spending, demonstrating the prudence and cost-effectiveness of the incremental expenditures, and seeking approval of the budget change. While there are many good reasons to revise budgets upward (increased demand from customers, new technological opportunities), spending can also rise due to inefficiency or imprudence.

Q: When should the incentive be computed and recovered in rates?

A: As with the DSMVA and LRAM, incentives should be reviewed and recovered in the next rate plan, based on comparison of the aggregate target and achievements for the entire period of the current rate plan.[1] To increase the utility's peace of mind, the incentive can be computed annually. After the first year, the utility could compare its achievements to one third of the rate-plan target (with similar scaling of thresholds and other parameters). After the second year, the utility could compare its cumulative achievements to two thirds of the target, and the utility could identify the increment or decrement between the first year incentive and the two-year incentive. In the last year, estimated achievements over the DSM plan would be compared to the total goal, and the incremental incentive would be identified. This final value would be audited and reviewed by the Board, and the resulting incentive would be rolled into rates in next rate plan.

B. Integrating Gas and Electric Demand-Side Management

Q: How should electricity savings be reflected in gas DSM planning?

A: Gas DSM programs, funded by gas customers, should primarily be directed to save gas, rather than electricity. Nonetheless, savings of electricity (and other resources, such as water) are real benefits to customers and the province, and the gas utilities should reflect electric savings in the screening of programs, measures and projects. For the same reason, electric savings and other resource savings incidental to the gas DSM program should be included in the

[1]Results for the final year will be estimated, and some reconciliation may be deferred and recovered in the second rate-plan following.

computation of TRC for the shared-savings mechanism. The same is true for any increases in electricity usage, such as for high-efficiency furnaces.

Q: How should the gas utilities work with the electric utilities in the delivery of DSM?

A: The gas utilities should offer to coordinate with the electric utilities in delivery of programs in which there is substantial overlap of such joint costs as the following:

- Coordination with and training of builders, and modeling of building efficiency for new-construction programs.
- The cost of site visits for direct-installation programs in the residential and small commercial retrofit markets.

Coordinated gas and electricity programs should be able to reach the customer at a cost well below the cost of two separate programs. Giving customers a single point of contact for services and incentive payments from both utilities would likely increase participation and reduce confusion, as well.

These coordinated programs can be implemented by either utility, or by a contractor paid by both utilities. The joint program costs should be split between the two utilities roughly in proportion to the net benefits produced for each fuel. The electric portion of these coordinated programs would be paid for by the electric utility, and none of the electric savings would be attributed to the gas utility for SSM purposes. However, since the gas system's share of the program cost would decrease (as some costs are shifted to the electric utility), the TRC net benefits from the program should increase, potentially increasing the gas utility's SSM incentive.

Q: Do you support the gas utilities' proposal to retain for shareholders half of the net revenues from DSM services provided to electric utilities?

A: No. The Electric Program Earnings Sharing Deferral Account proposed by the gas utilities would give shareholders far too large an incentive for an activity made possible by ratepayer funding for the underlying gas-utility capability and infrastructure. To the extent that the piggybacking of electric DSM on gas DSM reduces gas program costs, it will increase the gas utility's SSM incentive by increasing TRC net benefits per dollar spent and freeing up more dollars for gas DSM. That incentive should be sufficient.

Even determining the "net revenues" from the electric DSM activities under the Electric Program Earnings Sharing Deferral Account would be problematic. The gas utilities would retain 50% of electric DSM revenues net of costs, but only a few percent of gas DSM TRC benefits net of costs. Hence, the gas utilities would have every incentive to hide joint costs in the gas DSM budget, rather than split them with the electric operations. Under the joint-implementation approach, both the electric utility and the gas utility have incentives to negotiate cost-allocation rules that are fair to their customers.

At some point, administration of electric and/or gas programs may be put out to bid. At that time, the utilities, or their affiliates, might be allowed to bid on providing electric and/or joint programs, if appropriate ratepayer safeguards can be developed. In the meantime, the gas utilities should work with the electric utilities as partners, rather than clients.

C. Climate-Change Mitigation Credits

Q: If the utility receives any payments for the climate-change mitigation effects of the DSM programs, how should those payments be treated?

A: I recommend that any such payments be treated as additions to the DSM budget, allowing the utility to pursue more DSM without increasing the DSMVA, or achieving the same DSM with a lower DSMVA. Since the payments would result from a ratepayer-financed activities, the benefits should flow to the ratepayers.

IV. Lost-Revenue Adjustment Mechanism

Q: Should each gas utility continue to recover the revenues they lose due to DSM through an LRAM?

A: Yes.

A. LRAM in a Multi-year DSM Plan

Q: How should the LRAM function in the context of a multi-year DSM plan?

A: The utilities may be nervous about waiting until the end of the rate plan to recover their lost revenues. To mitigate this concern, some allowance for lost revenues from the planned DSM program should be incorporated in rates, as a reduction in projected sales. That amount should reflect the timing of the planned load reductions, which will start small and grow over the plan period (with seasonal variation for weather-sensitive measures). The amount reflected in rates might be the average expected reduction over the rate plan, or somewhat less, if the Board prefers to avoid over-collections of lost revenues and the need to refund those excess funds. The difference between lost revenues in rates and the estimated revenues lost from DSM measures implemented since the beginning of the plan would be included in the LRAM. This computation must be performed monthly, to reflecting the accumulation of installed measures and the seasonality in lost revenues, but it is the aggregate value of the incremental (or decremental) lost revenues over the DSM plan that will be rolled into rates for the next plan.

The utilities should be allowed to estimate the value of the LRAM for interim financial reporting, but the LRAM should be cleared and included in rates only after it is subject to an independent audit and Board review.

B. Inputs

Q: Should the LRAM be computed from the assumptions about average unit savings, free ridership, rate class, rate block and other parameters used in preparing the DSM plan?

A: No. The LRAM should be based on the most current information on actual revenues lost during the rate plan. The purpose of the LRAM is to make the utility whole for its delivery revenues actually lost due to DSM. If the utility assumes a 20% free-ridership rate in planning the program, but subsequent studies indicate that the free-ridership rate was 40%, the utility should be made whole for what it actually lost, not what was assumed *ex ante*.

Q: Are there any special problems in estimating the lost revenues from custom projects?

A: Yes. Since custom projects are distinct, by their very nature, it is difficult to conceptualize a free-ridership rate for a project. Either the utility made the project happen, with incentives and other assistance, or the project would have happened anyway. To get around this problem, a free-ridership rate should be developed and applied to the entire set of custom projects in a program, or even in the entire utility portfolio.

Q: Are free-ridership rates for a measure or program identical for all purposes?

A: No. The free-ridership rates for the LRAM computation will often be lower than for the TRC computation in screening, or in the computation of incentives. The question for LRAM is whether the efficiency would have occurred during the rate plan, while for screening and incentives the issue is whether the efficiency investment would have occurred at all. Whether a measure installed under a DSM program in 2007 would otherwise have been installed in 2011 or never installed at all makes no difference in the lost revenues for 2007–2010, but makes large a difference in the present value of the TRC benefits over the life of the measure. While a similar free-rider rate must be developed for SSM, as well, the value many be different (and larger) than for the LRAM.

Q: In determining whether the utility is responsible for savings, either in computing the LRAM or incentives, what standard should the Board apply?

A: In general, the Board standard should be that the utility program has a central role in the decision to install the high-efficiency equipment. If a program is delivered and/or paid for jointly by electric and gas utilities, the savings should be allocated between them (probably with the electric utility paying for and getting credit for the electric savings), since each dollar of savings can only be caused once. The allocation rules can be negotiated between the utilities, for review and approval (or amendment) by the Board.

V. Determining Savings for Incentives

Q: Should the measure of savings for incentives be the same as that used in the LRAM?

A: No. Unlike the LRAM, incentives should use the best information available at the time the utility is implementing the program. The purpose of the incentive is to encourage the utility to strive to do more of the things that are identified as its objectives. For the incentive to be effective, and not frustrate or confuse utility management, the utility must have a fairly clear idea of the incentives related to various levels of activity. If a particular program appears to have TRC net benefits of $500 per installation, the utility should be able to count on that value in estimating the incentive it will earn. Changing the assumptions after the fact is likely to give inconsistent signals and undermine the relationship between the utility's achievements and its rewards.

Q: Do you recommend that the assumptions used in computing incentives remain fixed for the entire DSM plan, or for an entire year?

A: No. Management should implement the DSM plan on the basis of the best available information from time to time during the plan implementation period. As soon as new information becomes available, the incentives for future commitments should be based on the improved information, and the utility should determine whether any modifications to the program are appropriate.

Nor should the utility be allowed to insulate itself from new information. There must be mechanisms—a vigorous consultative process would be perfect—for stakeholders to provide the utility with evidence that an assumption is wrong. The utility should retain the responsibility for determining how to review the evidence and whether to change its assumptions. If the utility does not respond appropriately to the evidence (seriously reviewing it and revising assumptions as appropriate), the utility should be at risk for disallowance of incentives that depend on the unexamined assumptions. In addition, the utility should be at risk for expenditures that appeared to be cost-effective with the utility inputs, but not with ex-post estimates that correspond to the ignored suggestions.

VI. Oversight

A. The Consultative Process

Q: What position should the Board take with respect to the process of consultation among each utility and interested parties?

A: The Board should encourage the utilities to continue and expand their use of the consultations. In particular, utility DSM plans, budgets and cost claims should be viewed more favorably if they have been reviewed and endorsed by well-informed and adequately funded parties. The utility retains the responsibility for running its own program and effectively using outside resources, including the consultations. Failure to use those resources effectively may leave the utility vulnerable to prudence disallowances.

B. Auditing and Verification of Program Revenue Requirements

Q: How should the Board ensure that the various revenue requirements in the DSM program are properly computed?

A: Independent auditing is essential to public and regulatory confidence in the utilities' cost claims. A consultant hired by and reporting to the utility is not really an auditor, in this sense. To be effective, the auditor must be hired by and report to some other entity, such as a committee of the parties or the Board.

It is also important that the auditor not just be qualified to confirm the utility's direct costs (which is a standard accounting problem), but also to critically examine the assumptions that determine the LRAM and incentives, such as measure life, free ridership, participant costs, and savings per installation. The auditor should also be empowered to instruct the utility to perform analyses (such as the distribution of savings across rate classes or blocks) that would be essential for determining lost revenues or incentives.

C. Research

Q: How should the level and type of research funding within the DSM budget be determined?

A: The utilities have the responsibility to respond to Board directives and to manage their research efforts prudently and efficiently. Research initiatives may be triggered in at least four ways.

First, the Board may require specific studies, including an updated market potential study with each new multi-year plan.

Second, the consultative group may request studies to refine inputs about which the parties have not reached consensus. While the utility retains the responsibility to manage its research budget, along with other portions of its DSM efforts, the inability to verify inputs may leave the utility vulnerable to cost disallowances. In the longer term, a utility's willful failure to resolve uncertainties may prompt the Board or the government to reconsider the use of the gas utilities as DSM program administrators, potentially cutting the utility off from all incentives. In short, ignoring a reasonable request for a study of DSM evaluation inputs would expose the utility to significant risks.

Third, the auditor should recommend research projects that are necessary to improve the estimates of lost revenues, TRC benefits, or other inputs to the incentive computation. The utilities should respond to those recommendations in a timely fashion, to produce the necessary data or explain to the Board why the studies are not feasible or warranted.

Fourth, the utilities should be free to identify additional research needs. To ensure that the DSM budget is not consumed by research, the utilities should propose and the Board should set a soft research budget ceiling for the DSM plan period. If the utility proposes to spend more than the soft ceiling, it should file an explanation and request for approval with the Board.

VII. Program Screening

Q: Do you have any recommendations regarding program screening?

A: Yes. It is important that the utilities have the best possible data on critical inputs, including measure life, free ridership, customer costs, and average savings.[2] Misestimates of these parameters can result in the utilities misallocating their budgets among programs, over-recovering lost revenues, and receiving incentives that are disproportionately large compared to the actual savings.

The expected life of every measure should reflect the period of time that the measure is likely to be used, which is generally less than its full engineering life. Energy-efficient equipment may not operate for its full engineering life due to vacancy or change of use in the building, loss or demolition of the building, remodeling (removing insulated walls or roof, for example) and other factors. The Board should be able to determine that the inputs are unbiased.

Q: Does this conclude your testimony?

A: Yes.

[2] Unlike avoided costs, which are projections for the future and inherently uncertain, there are specific correct values for these parameters, at least in principle.