NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF:	The *Public Utilities Act*, R.S.N.S. 1989, c. 380 as amended
	- and -
IN THE MATTER OF:	An Application by Nov Scotia Power Inc. for Approval of its Demand Site Management Plan for 2010 and Demand Site Management Cost Recovery Rider, filed April 7, 2009

DIRECT TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

THE CONSUMER ADVOCATE

Resource Insight, Inc.

MAY 22, 2009

TABLE OF CONTENTS

TABLE OF EXHIBITS

I. Identification & 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 St, 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 electric 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 Exhibit____PLC-1.

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, including utility regulators in 24 states and three Canadian provinces, and two Federal agencies.

Q: Please summarize your experience regarding recovery of utility energy-efficiency program costs and associated revenue losses.

A: I first proposed a combined revenue-stabilization and conservation-funding mechanism in testimony on alternatives to the Seabrook nuclear power plant before the New Hampshire Public Utilities Commission in Docket No. DE1-312 in October 1982. My qualifications list a number of subsequent engagements related to ratemaking for energy-efficiency, including recovery of direct costs and lost revenue.

I have supported broader revenue stabilization than proposed by the utilities in some cases (e.g., in Ontario), and proposed modifications to utility decoupling proposals in other situations (e.g., for Con Edison's electric sales, Vectren's Indiana gas territories). I have also worked on issues of cost recovery in collaborative efforts among utilities, consumer advocates, and other parties, including Con Edison's continuing gas revenue-per-customer decoupling collaborative. I currently work for Philadelphia Gas Works on its lost-revenue-recovery proposal.

II. Introduction

Q: On whose behalf are you testifying?

A: My testimony is sponsored by the Nova Scotia Consumer Advocate.

Q: What is the purpose of your testimony?

A: The Consumer Advocate has asked me to comment on the mechanism proposed by NSPI for recovery of lost contributions to fixed costs (LCFC), in the Demand Side Management Cost Recovery Rider, in the event that the UARB is prepared to approve a mechanism for recovery of lost contributions.

My testimony does not concern the overall mechanism for any allowed recovery of LCFC, such as choices between rate adjustments and deferral for later recovery.

Q: What is the purpose of computing the lost contributions to fixed costs resulting from energy-efficiency programs?

A: The principal purpose of energy-efficiency programs is to reduce costs to customers, including fuel, variable O&M, net purchased power, and new generation, transmission and distribution investments. Since the implementation of the Fuel Adjustment Mechanism, NSPI reconciles its costs for fuel and purchased power. In the short term (e.g., a year or so), load reductions generally have little effect on investment, so every kWh that a customer does not use due to an energy-efficiency program reduces NSPI's earnings. As a result, NSPI will have a financial incentive to delay implementation of DSM, especially measures that have particularly large effects on revenue.

Q: How does NSPI propose to resolve this conflict?

A: The utility proposes to recover its lost contributions to fixed costs through the LCFC component of its DSM Cost Recovery Rider. Specifically, NSPI proposes that

> the estimated reduction in lost kWh sales in each applicable customer class and associated with anticipated program measures, shall be multiplied by the unit fixed costs associated with these lost kWh sales and for each applicable rate class. The unit fixed costs will be derived from the Cost of Service Study approved in the last general rate case. (NSPI Evidence, Appendix E)

Q: Will the rationale for a lost-revenue adjustment mechanism change in the near future?

A: Yes. The adverse incentives of uncompensated lost revenues are particularly important while NSPI is the program administrator and has an opportunity to affect all aspects of program design and implementation. After the independent program administrator is in place, NSPI's role is less important. In jurisdictions with third-party administrators (e.g., Vermont and New York), utilities often do not have lost-revenue recovery mechanisms. Increasing sophistication of the monitoring and review process, such as the Program Development Working Group, may also mitigate the requirement for lost-revenue recovery.

Also, once the effects on sales of full-scale DSM programs are incorporated in ratemaking (after the next rate case), NSPI can be largely compensated for lost revenues in its base rates. The combination of the independent administrator and inclusion of lost revenues in base rates will greatly reduce or eliminate the need for an on-going adjustment mechanism.

If the Board approves recovery of lost contribution to fixed costs as part of the DSM recovery mechanism in this proceeding, that approval should run only until the next rate case, at which time the Board can assess whether changing circumstances have changed or eliminated the need for the mechanism.

Q: How do computations of lost revenues typically work?

A: The basic approach in computing lost revenues comprises the following steps, for each measure covered by an energy-efficiency program:

1. Count the number of measures installed under the program.
2. Estimate the annual sales effects of each measure.
3. Estimate the percentage of the savings that would have occurred without the program, and that therefore do not reflect any program-related revenue loss.[1]
4. Estimate the extent of spillover from the program to non-participants, such as by increasing supply of efficient equipment in warehouses and stores.
5. Determine the types of customers participating in the program, differentiated by rate class and by any other factors that affect lost revenues per kWh saved.
6. Compute when the savings from each measure would start, given both the installation schedule and any seasonality of the affected load (e.g., space-heating efficiency measures installed in May do not save much energy until the next November).

[1]The participants who would have invested in efficiency without the program are often called "free riders." That term incorrectly suggests that they are somehow getting a better deal than other participants.

7. Determine the lost contribution to fixed charges in cents per kWh for each group of customers. This computation requires determination of the customer's bill saving per kWh saved, net of any short-run savings to the utility and net of any costs that will be reallocated through reconciliation mechanisms.

8. Compute the resulting lost contribution to fixed cost as the product of the kWh savings and the lost contribution per kWh, by class.

Q: Has NSPI detailed its methods for computing each step in this process?

A: The utility has not detailed the computation of the kWh savings. I do not consider that to be a problem, so long as the computation of actual savings for the reconciliation is either conducted by the independent administrator or supervised by the collaborative. In any case, the savings estimates must be approved by the Board.

In contrast, NSPI proposes a method for deriving the lost contribution per kWh in its testimony and tariff and apparently seeks Board approval for that method.

Q: Please describe that proposal.

A: For each rate class, NSPI starts with the total revenues in its 2009 Compliance COSS, subtracts the customer-charge revenues (for the three classes that have customer charges) and costs it identifies as variable, and divides the remainder by kWh sales to derive an LCFC per class. All the inputs (customer-charge revenues, variable costs, and kWh sales) are taken from the 2009 Compliance COSS. For ease of discussion, I will refer to the class revenues minus customer-charge revenues as "gross lost revenues."

For this computation, the Company groups together the standard residential rate (Rate Codes 2, 3, and 4) and residential time-of-day rate (Rate Code 6) into a single residential class and the firm and interruptible Large Industrial rates (Rate Codes 23 and 25) into a single class.

Q: Would NSPI's proposed computation of lost contribution per kWh accurately estimate the Company's lost contribution to fixed costs?

A: No, for three reasons. First, NSPI does not account for the DSM-related load reductions embedded in current rates. Second, NSPI's method would not correctly estimate the gross lost revenue for some classes. Third, NSPI fails to net out some costs that are reconciled in the Fuel Adjustment Mechanism (FAM) and are thus not lost to the Company when sales fall.

III. Inclusion of DSM Effects in Current Rates

Q: How are the effects of DSM reflected in current rates?

A: The Company's 2009 General Rate Application states as follows

> **4.4 The DSM Assumption in the Load Forecast**
>
> Consistent with the IRP preferred plan, this Application assumes 77.8 GWh of energy savings in 2009. This assumption will be revised in the Compliance Filing to reflect the Board approved DSM plan resulting from the April 2008 DSM hearing. (NSPI 2009 General Rate Application, May 27, 2008, p. 86)

The Compliance Filing in Rate Case 2009 shows the sales forecast unchanged from NSPI's original proposal (Appendix 2, page 7).

Q: What are the implications for LCFC of the inclusion of DSM savings in the loads used to set existing rates?

A: Since the existing rates are already higher than they would be without DSM, spreading short-term fixed costs over lower sales, the LCFC should be effective only for savings in excess of the amount in rates. That threshold might be set in terms of GWh savings or in dollars of LCFC. To the extent possible, the LCFC embedded in the rates should be allocated to customer classes, so that the customers who are already paying higher rates for the LCFC implicitly assumed in the 2009 Rate Application do not pay twice for the same savings.

IV. Determining Gross Lost Revenue

Q: How does NSPI estimate LCFC per kWh saved, prior to adjustments for variable and reconciled costs?

A: The Company's proposed tariff language is very vague on this point, simply stating that "The unit fixed costs will be derived from the Cost of Service Study approved in the last general rate case." Appendix E, p. 1. The LCFC example in Appendix F (page 9) shows the LCFC being computed by taking total class revenues from the 2009 COSS Compliance Filing, subtracting customer-charge revenues (applicable only to the residential, small-general, and extra-large-industrial programs), and dividing the remaining revenues by class kWh sales assumed in the 2009 COSS Compliance Filing.

Q: Has NSPI properly estimated these gross lost revenue per kWh saved, prior to adjustments for variable and reconciled costs?

A: No. Applying NSPI's approach to the other classes would entail the following problems:

- Assuming that lost revenue per kWh would be the same for standard residential as for residential time-of-day (TOD) customers.
- Assuming that lost revenue will be the same for all periods in the residential TOD class.
- Assuming that the mix of lost sales across the two blocks in the small general class is the same as the mix of sales.
- Assuming that billing demands will decline in proportion to the reduction in sales in the General, Large General, Municipal and Small, Medium and Large Industrial classes.
- Ignoring the effects of demand ratchets.
- Assuming that voltage-related charges and discounts and transformer-ownership discounts are distributed evenly across each class.
- Assuming that lost revenue per kWh would be the same for all industrial load, firm and interruptible.
- Freezing the ratio of demand to energy charges at the level embedded in the 2009 Compliance COSS, rather than updating to reflect changing load patterns.

I discuss the consequences of these assumptions and omissions below.

Q: What is the effect of assuming that lost revenues and hence LCFC are the same for both residential classes?

A: The TOD class has much lower gross lost revenues (averaged over sales) than the standard residential class. From the data in Appendix F, Table 6, I compute average gross lost revenues of 7.85¢/kWh for residential TOD, compared to 11.80¢/kWh for standard residential, while NSPI proposes to use 11.65¢/kWh for both classes. Since NSPI estimates that residential variable costs are 4.45¢/kWh (a number that should be increased slightly, as described in Section V), LCFC should be about 3.4¢/kWh for TOD customers and 7.35¢/kWh for other residential customers, while NSPI would use 7.2¢/kWh for both classes.

The TOD customers, being heating customers, are likely to be particularly good prospects for DSM programs. If savings from TOD customers are proportionately greater than savings from other residential customers, NSPI would over-collect LCFC.

Q: What is wrong with assuming that lost revenue will be the same for all periods in the residential TOD class?

A: The energy charges for the residential TOD class vary from 6.028¢/kWh off-peak to 11.796¢/kWh on-peak and 15.320¢/kWh in the winter super-peak. The Company proposes to use the average energy rate 7.846¢/kWh for all sales reductions.

The residential TOD rate is "only available to customers employing electric-based heating systems utilizing Electric Thermal Storage (ETS) equipment, and electric in-floor radiant heating systems utilizing thermal storage and appropriate timing and controls…" (NSPI Tariffs, January 1, 2009, p. 3). Hence, conservation of space-heating energy will reduce energy use entirely or primarily at the 6.028¢/kWh off-peak rate, and the LCFC mechanism would give NSPI a profit of about 1.8¢/kWh for each heating kWh conserved.

On the other hand, lighting efficiency would reduce sales in the winter peak period and increase sales in the off-peak (to recharge the storage heating to make up for the reduced waste heat from the lighting). No net energy savings occur (although there are winter cost savings from shifting load off-peak, and net energy savings in non-winter months) and NSPI's LCFC mechanism would give the Company no credit for the 7.5 cents of revenue that NSPI would lose with every kWh of lighting conservation.

Q: Why is it incorrect to assume that the mix of lost sales across the two blocks in the small general class is the same as the mix of sales?

A: Most sales in the higher-priced first block are not subject to reduction by DSM programs. The Company estimates that only 2% of total energy sales to the small general class are on bills with only first-block energy (IR CA-7b). For the other 98% of load in the class, all of the energy in the second block must be conserved before DSM can save even a single kWh of first-block energy.

The Company argues that "There may be customers whose energy ordinarily consumed in the second block will be less than their energy savings due to DSM. In such instances the energy savings and lost revenues will pertain to both the second and the first block" (IR CA-7a). That will undoubtedly be true on some occasions; even so, the conservation program would result in the avoidance of 100% of the customer's second-block usage and only some smaller portion of the first-block usage.

Hence, the bulk of energy saved for the small general customers will be in the second block, not the first block. While NSPI assumes that the average small-general energy rate avoided by DSM will be 11.73¢/kWh (about 15.2% in the first block, 84.8% in the second block), the actual value is likely to be closer to 98% in the first block, or 11.52¢/kWh.

Q: Why is it incorrect to assume that billing demands will decline in proportion to the reduction in sales?

A: A customer's billing demand is determined by the highest hourly load during a month, and for the Large General, Large Industrial and Municipal classes, the highest of hourly load in the current month or the previous December, January, or February. I discuss the seasonal ratchet below.

Billing demand is not affected at all by savings that occur at times other than the customer's maximum demand, such as measures that allow the customer to shut down equipment off-peak or to reduce space-conditioning use when the building is unoccupied. Some energy-conservation measures may actually increase maximum load. For example, variable-speed drives may be much more efficient at partial loads, but less efficient at full load, which may be the conditions at which the customer's billing demand occurs. Other measures will have very large effects on billing demand per kWh saved, because the saved kWh are mostly at the time of the customer's maximum load.

The LCFC per kWh can vary widely, depending on how much demand is reduced. For the General Demand class, the energy rate for more than 200 hours use of the maximum demand is 6.781¢/kWh. That is all the gross revenue that NSPI would lose from DSM that affected only energy use of a General Demand customer. But NSPI data in Appendix F, p. 9, indicate the average energy and demand revenue for the General Demand class is 10.795¢/kWh. Since NSPI estimates that 4.9¢/kW of General Demand sales are variable, the LCFC would be about 5.8¢ with the average load shape, and only 1.8¢ for energy-only savings.

Q: What is the problem with ignoring the effects of demand ratchets?

A: There are two such problems. First, the demand ratchets increase the range of measures that do not affect billing demand, and hence result in low LCFC per kWh. The ratchets do not allow the billing demand to be less than the previous winter's demand, so summer efficiency measures (such as chiller improvements) installed for a winter-peaking customer will typically have no effect on demand charges.

Second, even if the measure affects winter billing demand, an efficiency improvement installed in March may have little or no effect on billing demand until the next February, since the billing demand will remain at the winter billing level, regardless of reductions in maximum loads in March through November. Under NSPI's proposal, it would accrue LCFC at roughly three times its actual lost contribution until the billing demand begins to fall.

Q: Does NSPI really propose to use the same lost revenue per kWh for all Large Industrial load, firm and interruptible?

A: Yes.

> Rate code 23 designates those customers served on a firm basis and rate code 25 designates those taking service under the Interruptible Rider of the Large Industrial Tariff. Energy and demand determinants, costs and revenues for both types of customers comprise the class totals shown on page 9 of Appendix F. (IR CA-14)

Q: Are the rates for interruptible Large Industrial customers significantly different from those for firm customers?

A: Yes. The interruptible energy charge is only $0.071¢/kWh less, but the demand charge is $3.43/kVA-month (or about 0.5¢/kWh) less than on the firm rate.

Q: Please describe NSPI's treatment of the transformer-ownership discounts.

A: Customers in the general and industrial rate classes receive credits against their demand charges if they own their own transformers. The Company distributes these discounts across the entire class, effectively assuming that each customer receives a small part of the discount. While NSPI refers to variations in these discounts between customers who own their transformers as "potential effects," they have very real (if small) effects on the LCFC attributable to various customers.

Q: Does NSPI offer any rationale for these errors in its proposed LCFC computation?

A: Only that NSPI prefers simplicity in the lost-revenue mechanism.

> NSPI believes the approach should be simple and transparent. Any perceived gain in the precision of cost recovery by class due to adding complexity is outweighed by the increased administration and information requirements to support such an approach. (IR CA-9)

> …modifications would add unnecessary complexity. (IR CA-10)

> It is not practical to address [transformer ownership discount, the primary-metering credit, and the Large Industrial secondary metering surcharge should] at the individual customer level. (IR CA-15)

The Company refers back to its response to IR CA-9 in four other responses.

Q: Other than the misestimation of LCFC, and in some cases a consistent overestimation of LCFC, do these errors create any other problems?

A: Yes. The Company will profit from any DSM that results in LCFC lower than the assumed value, and lose revenues from any DSM that results in LCFC higher than assumed. Hence, NSPI will have a financial incentive to prefer the following choices

- off-peak savings over on-peak savings for residential TOD customers
- summer over winter savings for residential TOD customers
- savings that do not affect the billing demand for demand-metered customers

These incentives are particularly important while NSPI is the program administrator and has an opportunity to affect all aspects of program design and implementation. Even after the independent program administrator is in place, any role that NSPI retains in the process (e.g., as a member of the collaborative) is inherently suspect if NSPI has known adverse incentives.

Q: Why would the ratio of demand to energy charges change?

A: In a summer with a heat wave or a winter with a severe cold snap, billing demands are likely to be elevated.[2] Total energy use for the year as a whole may not change much from the levels in the 2009 compliance filing. The opposite pattern would occur in a year without extreme weather, but lots of hot summer days and cold winter days. With a recession, energy use may fall as equipment is used less often, but billing demand, driven by the few times that equipment is fully employed, may not decline. Thus, measures that actually affect billing demand may have much larger effects in some years than others.

[2] The cold wave would increase demand charges for the entire next year.

V. Components of Rates Not Lost Due to Reduced Sales

Q: What cost components does NSPI propose to subtract from retail rates in estimating the LCFC?

A: The Company proposes (Evidence, p. 29 and Appendix F, p. 9) to subtract what it calls "variable costs," comprising four cost components derived from the last cost-of-service study. These components (with NSPI's cites to the COSS in parentheses) are as follows:

- fuel costs (line 1, page 3, Exhibit 6)
- the variable cost component of purchased power expenses (lines 4 and 6, page 3, Exhibit 6),
- variable operation and maintenance expenses related to NSPI's production facilities (defined as 16% of O&M—Steam (line 7, page 1, Exhibit 5)), allocated among rate classes using distribution pattern of O&M—Steam Energy-related (line 7, page 3, Exhibit 6)).
- Export revenues (line 14, page 3, Exhibit 6). Since export revenues are a credit, removing them increases LCFC.

Q: Is NSPI correct that all these cost components should be removed from rates before computing the LCFC?

A: Yes.

Q: Has NSPI included all the costs that should be removed from rates before computing the LCFC?

A: No. The Company does not net out fixed purchased-power costs, even though those costs are reconciled in the FAM (IR CA-5). When a customer's load decreases, due to DSM or any other factor, NSPI does not lose the portion of the customer's revenues intended to cover fixed purchased-power costs. The FAM compares the monthly fuel and purchased-power costs to the product of Accrued Sales and the Base Fuel Charge in cents per kWh by class, and reconciles any difference. So if sales decline, the FAM recovery rate increases by the amount of fixed purchased-power costs included in the base rate, and NSPI loses no contribution to fixed costs.

The FAM also reconciles several cost components, such as fuel, that vary with sales level; if sales are lower than forecast, the costs may decline faster or slower than sales. The Company properly removes the base level of all of these components from the LCFC, and the FAM ensures that NSPI will recover the actual costs, regardless of whether the costs decline faster or slower than sales.

Q: Does this conclude your testimony?

A: Yes.