PROVINCE OF MANITOBA

BEFORE THE PUBLIC UTILITY BOARD

Manitoba Hydro	**)**	
2010/11 & 2011/12 General Rate	**)**	**Case No. 17/10**
Application	**)**	

DIRECT TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

RESOURCE CONSERVATION MANITOBA

AND

TIME TO RESPECT EARTH'S ECOSYSTEMS

Resource Insight, Inc.

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I. Identification 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, integrated resource planning, 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 (PBR) 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 over two hundred times on utility issues, before regulators in thirty U.S. jurisdictions and five Canadian provinces. My previous testimony is listed in my resume.

Q: Have you testified previously before this Board?

A: Yes. I testified in Manitoba PUB 136-07, the 2008/09 general rate application of Manitoba Hydro ("the Company" or "Hydro"), and Hydro's 2008 Energy-Intensive Industrial Rate proceeding.

II. Introduction

Q: On whose behalf are you testifying?

A: My testimony is sponsored by the Resource Conservation Manitoba ("RCM") and Time to Respect Earth's Ecosystems ("TREE").

Q: What is the purpose of your direct testimony?

A: My sponsors have asked me to evaluate the revenue allocation, rate design and demand-side management ("DSM") proposals of Manitoba Hydro, in light of the Public Utility Board's concern about below-cost pricing and environmental emissions:

> The Board seeks to assure itself that MH's rate design and rates are consistent with the pursuit of the environmental objectives of The Sustainable Development Act (SDA). Energy efficiency presents the potential for a virtuous circle, wherein lower domestic consumption results in reduced customer bills, higher MH aggregate net export revenue and net income, and lower carbon emissions by MH's American export customers. (PUB Order 117/06, p. 3)

Q: What specific issues does your testimony address?

A: I address the following issues:

- the reviewability of Hydro's Cost of Service Study ("COSS") and rate design proposals and proof of revenue calculations;
- the reasonableness of the COSS for use in revenue allocation and rate design;
- inclusion of market prices, T&D costs, losses, and environmental values in the estimate of marginal costs;
- Hydro's rate design proposals in light of the Board's interest in promoting more efficient energy use. The Board's initiatives include the following measures:
  - elimination of declining-block-rate schedules and introduction of inverted rates,
  - introduction of time-of-use rates, initially for large volume non-residential customers,
  - demand-energy rebalancing to move cost recovery from demand to energy charges,
  - implementation of a marginal-cost-based rate for new high consumption firm customers or large expansions.
- Alternative uses of revenues from exports, new-customer marginal rates, and increased tail blocks.
- Evaluation of Manitoba Hydro's efforts to promote DSM.

III. Reviewability of Manitoba Hydro's Workproducts

Q: Has the Company provided adequate documentation of its COS Study and rate design calculations?

A: No. Hydro's submittal was limited in detail. The COS Study documentation did not even provide a table of the allocation factors or the resulting class rates of return. The Company's Proof-of-Revenues tables lacked the calculations and billing unit forecasts. The Company provided all documents as PDF files only in Appendices 10.1, 10.2, 11.1 and 11.2.

My review of the issues relevant to this proceeding has been further complicated by Hydro's refusal to provide materials requested in discovery. For example, Hydro refused to provide the following information in Excel-readable form:

- a working copy of its COSS model, with formulas intact (RCM/TREE/MH I-3a),
- tables of important values, such as external and internal allocators (IR RCM/TREE/MH I-3b-c),
- the derivation of external allocators and direct assignments, which includes the aggregation of load research data and application of reconciliation factors (IR RCM/TREE/MH I-3d),
- the marginal costs and calculations used in deriving the generation allocator (RCM/TREE/MH I-3e),
- the summary load-research schedules in Tab 7 of the Company's filing (RCM/TREE/MH 1-5a),
- estimated loads by time period and revenue class for a six-year period (RCM/TREE/MH 1-6a and b),

- the calculation of bill comparisons presented in Appendices 10.5 and 10.6 of the filing (RCM/TREE/MH 1-8a),
- the calculation of the Proof of Revenues (RCM/TREE/MH 1-9).

Q: Why is access to native Excel versions of data and spreadsheets essential to regulatory review?

A: When data, calculations, and models are provided in Excel format, intervenors are able to check the Company's calculations, confirm their understanding of the Company's methodologies, evaluate the impact of Company proposals on rate classes and bills, and/or develop alternative COS Study methods or rate designs.

Q: Can PDF tables be translated into Excel?

A: Yes, but at an inordinate cost to intervenors. The analyst must not only copy the PDF tables into Excel but also reproduce the formulas. Because of resource limitations, I have attempted this process with only a few tables. I discovered that the PDF documents were worse than I expected, for the following reasons:

- Some tables had to be typed over by hand because they were images that could be only partly read electronically (for example, Appendix 11.1, Schedule D2).
- Some of the PDF tables are internally inconsistent. For example, in the residential-rate proof-of-revenue calculation table, Hydro reports second block Diesel sub-class revenues of $158,107. (MIPUG/MH I-20a, p. 2) Given the 6.3¢/kWh rate and 2,350,911 kW.h specified in that table, the revenues for that class should be $148,107. Indeed, the total Diesel revenue in that table is consistent with the correct $148,017 value, but not with the $158,017 Hydro shows for second-block revenue. Two problems are evident from this single observation: there is an error in Hydro's proof-

of-revenue computation, and the totals in that computation are not derived from the sub-totals shown.

- Some tables cannot be reproduced because essential information is missing. For example, it appears that the forecast of class energy use by period used for the generation allocator is drawn from the five-year historic average load shape for each rate class. However, Hydro provides these historical data for only the major rate classes. For five small classes (residential and general service water heating and seasonal rates, and street lighting), the forecasted time-differentiated energy use by period cannot be checked against historic data. (Appendix 38, Attachments 1 and 4).

Q: What is Hydro's explanation for refusing to provide this information?

A: Hydro contends that limiting intervenor access to Company data and models provides the following benefits:

- promoting regulatory efficiency,
- allowing the Company to protect its work product,
- preventing the release of information that "may" be confidential.

The Company explains its position in detail in response to RCM/TREE/MH I-3a:

> First, the models used by the Corporation are large and complex. Manitoba Hydro expects that an independent analyst, untrained with Manitoba Hydro's models, would need to invest a significant amount of time and effort to be capable of operating the model correctly. Allowing other parties to work in and modify spreadsheets and pose questions in Information Requests and on cross-examination based on the modified schedules, will also require Manitoba Hydro to invest a significant amount of time analyzing the changes made to the spreadsheets and to understanding their potential impacts. This approach is inefficient, would require additional time to be provided within the regulatory process and would make the regulatory process more cumbersome.

> Second, spreadsheets contain metadata, which includes working notes and references made by the staff responsible for the files. In order to remove metadata, the file must be converted to an Adobe Acrobat portable document format (pdf) file.…
>
> Third, Manitoba Hydro notes that some of the Corporation's models may be subject to intellectual property rights reserved by third parties and are not available to be shared in the regulatory process. In addition, some spreadsheets may contain competitive or commercially sensitive information which is not appropriate to be disclosed.

Q: Do Hydro's arguments justify its refusal to provide its models?

A: No. Numbers on pages are not sufficient to support the reliability of the Company's estimates of class rates of return and projected retail revenues. These numbers are based on calculations, projections and judgments on which qualified participants may reasonably disagree. However, Hydro appears to take the position that intervenor review of the Company's rate studies is not worth the time and effort of the Company or of the Board.

The COSS model and revenue proof calculations are straightforward in concept. Utilities have made their COSS models available for review in many other jurisdictions. I cannot recall *any* other utility company that has refused to make its proof-of-revenues calculations available.

Finally, the Company raises only the *possibility* of confidentiality problems. It does not identify any actual problems.

Q: Does Hydro propose an alternative to providing Excel spreadsheets, with or without formulas?

A: Yes. It proposes to rerun its models in response to Intervenor requests:

> it is preferable for Intervenors to propose, through the interrogatory process, that Manitoba Hydro run specific scenarios using its models, changing the assumptions as requested, and providing updated results for all parties to examine. Manitoba Hydro is of the view that this is the most appropriate and efficient approach to test new scenarios. (RCM/TREE/ I-3a)

Q: Will Hydro's proposal provide an adequate substitute for intervenor access to the Company's data, calculations and models?

A: No. Hydro's offer to run its models with intervenor inputs is not a feasible solution.

A proof-of-revenue spreadsheet, which Hydro refuses to provide, includes the assumptions and calculations that are essential to a rate case. As Hydro makes important rate-design changes, such as merging the Small and Medium General Service classes and eliminating the 70% winter demand ratchets, its proof of revenues will grow more complicated and less transparent. Without access to the underlying spreadsheets, the Board cannot confirm that the rates it approves are actually designed to collect the allowed revenues.

In the case of the COSS, refusing access to the model prevents independent evaluation for the following reasons:

- a review of the inputs and formulas, which is required to understand fully the workings of the model, is not possible;
- the derivation of allocators from the raw load research and unit cost data, which uses reconciliation to actuals or forecasts, averages, adjustments, and other calculations, is not documented.

Relying on Hydro to run its COSS model with alternative inputs is not a workable solution, for the following reasons:

- The data needed to develop alternative inputs to the COSS are also in PDF files, and therefore not readily accessible to third parties.
- The discovery process creates long leadtimes between intervenor requests for modifications and receipt of model run results.
- It would be time-consuming, if not impossible, to make sure from PDF documents that Hydro correctly understood and made the desired modifications;

- If the results seem counter-intuitive or incorrect, intervenors would not be able to check the model for a possible explanation.
- To the extent that the number of runs would be limited, it would not be possible to estimate the importance and direction of the effects of changes in the various allocators.
- Intervenors would have to divulge their work product.

Q: In your experience, do other utilities make their COSS models and work papers available in Excel spreadsheets?

A: Yes. For example, in the following projects, the companies provided their data and work papers in Excel spreadsheets either with their filing or on request:

- ATCO Electric, in Alberta EB Application No. 1500878, provided COSS-related files and other requested information in Excel spreadsheets (with formulas intact).
- In its most recent three rate cases before the Utah PSC (Dockets Nos. 07-035-93, 08-035-38, and 09-035-23), Rocky Mountain Power (the Utah subsidiary of PacifiCorp) provided a working copy of its COSS model (both interstate and intrastate), training sessions, and all other exhibits and information responses in Word and Excel;
- Berkshire Gas Company, in Massachusetts DTE Docket No. 01-56 (2001), and Columbia Gas, in Maryland PSC Case No. 9159 (2008/2009), also provided a working copy of the COSS, exhibits, tables and information responses in Excel;
- Baltimore Gas & Electric, in Maryland PSC Case No. 9036 (2005), provided its COS study in Excel format, but without formulas; in its most recent rate proceeding, it provided multiple gas and electric COS studies with all functions operating, including macros.

IV. Use of Cost-of-Service Study in Allocation and Rate Design

Q: What role should the study of embedded costs of service play in revenue allocation and rate design?

A: The study should serve only as a guide to allocation and rate design, not as a determinant. Consideration of marginal cost and incentive effects, not embedded cost, should be the primary basis of rate design.

Q: Do the Board and Manitoba Hydro agree that the COSS should be regarded as a guide, not a determinant, of allocation and rate design?

A: Yes. In the Board's view, the COSS is only one of the many guides to rate design and cost allocation:

> COSS neither determines nor changes rates but serves as an assist in rate setting. The COSS is a tool used to assist in evaluating whether customer classes pay their fair share of costs through rates, and serves as one test of the fairness of rates between customer classes. (PUB Order 117-06, p. 8)

Hydro agrees that the COSS is approximate and judgmental:

> Although the study has the appearance of exactness, it does not disclose the actual cost of serving a particular customer or group of customers within a customer class, it only provides an approximation of such costs. This is because there are many judgements involved in the process of classifying and allocating costs, particularly those costs related to capital investment. (Appendix 11.1 PCOSS 10, p. 1)

Q: Have you identified specific problems with using Manitoba Hydro's COSS as a guide in rate design?

A: Yes. The COSS is based on faulty concepts of cost causality. In particular, Hydro's COSS has the following flaws:

- understating the diversity of load on subtransmission,
- understating the diversity of load on substations,
- overstating he portion of distribution costs that are customer-related, and

- ignoring the effects of energy use on distribution costs.

A. Allocation of Subtransmission

Q: How does the COSS classify and allocate subtransmission?

A: In the PCOSS10 (pp. 6, 67–69), subtransmission is classified as 100% demand-related and allocated based on class Non-Coincident Peak (“NCP”) demands.

Q: How does allocation of subtransmission based on class NCP understate the diversity of load on this equipment?

A: The purpose of subtransmission is to “bring power from the common bus network to specific load centres” (Appendix 11.1, PCOSS10, p. 21). These load centers are likely to include a mix of customers of different sizes, types and load shapes and from various rate classes. Class NCP is appropriate only for allocating specific subtransmission lines that serve customers from a single rate class.

Q: How should subtransmission be allocated?

A: It should be allocated based on transmission factor D14 (Average Winter and Summer Coincident Peak), adjusted to exclude customers that are served at the transmission level.

B. Allocation of Distribution

Q: How does the COSS classify and allocate distribution?

A: The PCOSS treats these costs as follows (Appendix 11.1 PCOSS10, p. 6; RCM/TREE/MH I-2b):

- Substations and line transformers are classified as 100% demand-related and allocated on the basis of class NCP.

- Lines and poles are classified as 60% demand-related and 40% customer related. The demand-related portion is allocated on the basis of NCP.
- The remaining distribution plant (including service and meters) is classified as customer-related and allocated on the basis of weighted customer number.

Q: How did Hydro allocate substation costs?

A: Hydro used the sum of estimated class non-coincident peaks (“NCPs”). Specifically, Hydro determined when in the 2008/2009 power year the peak occurred for each rate class, considered separately, and added up the results.

Q: Is class NCP an appropriate allocator for substation costs?

A: No. This allocator would be appropriate if each substation overwhelmingly served a single class, and if the substation peaks occurred roughly at the time of the class peak. Neither of these conditions actually applies to Hydro’s system, for the following reasons:

- Most substations serve more than one rate class. Residential and various types of general service loads are intermingled geographically and are thus served from the same substations.
- Some 58 of Hydro’s 357 substations, representing 25% of the peak substation loads, and about 30% of installed capacity, are most heavily stressed in the summer, due to a combination of higher summer loads and lower summer capacity (RCM/TREE/MH I-7 (p)). Yet none of the distribution-level classes peak in the summer (RCM/TREE/MH I-5 (e)). Thus, roughly 30% of Hydro’s substation costs are driven by loads ignored in class NCPs.
- Of the five distribution classes (residential, GS non-demand-metered, GS small demand-metered, GS medium, GS large <30 kV), two classes,

representing 61% of the class NCPs, had 2008/2009 NCPs in December, and the other three had January NCPs. But every one of the 29 substations for which Hydro provides 2008/2009 winter peak data experienced that peak in January. Again, the (largely December) NCPs do not match the (entirely January) substation peaks.

- Of the winter substation peaks, 2% of the capacity peaked at 9 am, 9% at 10 AM, 19% at 11 AM, 25% at noon, 21% at 5 PM, and 23% at 6 PM. The residential-class NCP was at 7 PM and the GS non-demand-metered NCP was at 2 PM. The other three classes peaked at 10 and 11 AM. Again, the majority of NCPs did not coincide with any substation peaks, and the majority of substation peaks did not coincide with any NCPs. In particular, the substations peaking in the late morning, when most people who are going to have left home for the day, are probably driven by non-residential loads.[1]

Q: How should Hydro allocate substation costs?

A: Hydro should estimate the contribution of each class to the most constrained loading (i.e., the hours when load on the substation is the highest percentage of its seasonal rating) on each substation, or a representative sample of substations. The resulting allocator should reflect the variety of seasons and times at which substations peak.

Q: What is the basis of Hydro's classification of lines and poles as 40% customer-related?

A: Manitoba Hydro bases this classification on a 1990 evaluation of its COSS prepared by Ernst &Young (Appendix 27) and has been accepted for use in

[1]Similarly, most of the summer substation peaks occur in the mid-afternoon, before most residential customers return home.

revenue allocation since 1991 (Appendix 11.1 PCOSS10, p. 6; RCM/TREE/MH I-2c, Appendix 27, p. IV-1 to 10).

Q: What was the basis of Ernst & Young's evaluation of Hydro's distribution classification?

A: The study surveyed classification approaches from the following sources:

- The consultant's experience with other utilities who had, like Hydro, adopted a "fixed proportion" classification without a study of cost-causation. These utilities assumed conductors and poles to be between 30% and 100% demand-related (Appendix 27, p. IV-5).
- A session with Hydro employees on the design of the Company's distribution system. This discussion does not appear to have led to a clear consensus about the drivers of distribution investment:

> our staff was told by Manitoba Hydro employees that the distribution system is sometimes "designed to serve new customers whether the demand is low or high." This design criterion could justify classifying the cost of lines entirely as customer related. However, the same session resulted in notes identifying the general criteria of voltage drop and expected loads on the system over a 20 year period. (Appendix 27, p. IV-5)

- Two "accepted" calculation techniques for classifying distribution: The Minimum-System Method and the Zero-Intercept Method. (Appendix 27, p. IV-9).

Q: Did the 1990 Ernst & Young Study perform any analysis to support Hydro's distribution classification, for example, by using a minimum-system approach?

A: No. Ernst & Young found that Hydro did not have the data required for a cost-causation analysis of its distribution system (Appendix 27, p. IV-10). Instead of a cost analysis, Ernst & Young simply accepted that Hydro's classification of pole and wire was "within acceptable limits on an overall basis," not a difficult standard to meet given that Ernst & Young reported customer-classification factors that ranged from 0% to 100%.

Q: Would a minimum distribution-system analysis provide a reliable basis for classifying distribution investment?

A: No. Both methods are seriously flawed, and overstate the portion of distribution that is customer-related.

1. Minimum-Distribution-System Approaches

Q: Approaches to classifying plant as customer- or demand-related?

A: In concept, the minimum-system approaches separate demand- and customer-related distribution costs according to these simple rules:

- The number of units (feet of line, number of meters) is due to the number of customers.
- The size of units is due to the load.

Q: Are these rules based on a realistic view of an electric distribution system?

A: No. This view is overly simplistic, for three reasons. First, much of the cost of a distribution system is required to cover an area, and is not really sensitive to either load or customer number. For example, serving many customers in one multi-family building is no more expensive than serving one commercial customer of the same size, other than metering. The distribution cost of serving a geographical area for a given load is roughly the same whether that load is from concentrated commercial or dispersed residential customers.

Second, load levels help determine the *number* of units, as well as their size. As load grows, utilities add distribution feeders and transformers in parallel with existing equipment, such as adding a transformer to serve one end of a block, as load grows beyond the capability of the transformer originally serving the block. Indeed, large customers may be served by multiple transformers to increase reliability.

In general, more small electric customers than large customers can be served from one transformer. Higher loads require larger service drops and secondary wires, so more transformers are added to reduce the length of the wires. This multiplication of transformer number is expensive because (1) transformers show large economies of scale in dollars of investment per kVA of capacity and (2) dispersed transformers have lower diversity than transformers serving many customers, increasing the total installed kVA required to meet customer load.

Third, load can determine the type of equipment installed, in addition to size and number. Electric distribution systems are often relocated from overhead to underground (which is more expensive) because the weight of lines required to meet load makes overhead service infeasible. Voltages may also be increased to carry more load, increasing the costs of equipment (e.g., insulation requirements for transformers and lines).

Q: How is the cost of the "minimum distribution system" generally derived?

A: The most common methods used are:

- The Minimum-System Method,
- The Zero-Intercept Method.

Ernst & Young refers to both approaches in its survey.

Q: Please describe the Minimum-System Method.

A: A minimum-system analysis attempts to calculate the cost (in constant dollars) of the utility's installed units (transformers, poles, conductor-feet, etc.), were each of them the minimum-sized unit of that type of equipment that would ever be used on the system. The analysis asks, How much would it have cost to install the same number of units (poles, conductor-feet, transformers), but with the size of the units installed limited to the current minimum unit normally installed? This cost will be customer-related, and the remaining cost will be demand-related.[2]

The ratio of the costs of the minimum system to the actual system (in the same year's dollars) produces a percentage of plant that is claimed to be customer-related.

Q: Please describe the Zero-Intercept Method.

A: The Zero-Intercept Method attempts to extrapolate from the cost of actual equipment (including actual minimum-sized equipment) to the cost of hypothetical equipment that carries zero load, as in 0-kVA transformers, or the smallest units legally allowed (as 25-foot poles), or the smallest units physically feasible (e.g., the thinnest conductors that will support their own weight in overhead spans). The idea is that this procedure identifies the amount of equipment required to connect existing customers, even if they had virtually no load.

Q: Is the first approach, the minimum-system method, successful in separating customer-related from demand-related investment?

A: No, for the following reasons:

[2] Calculating this ratio is not straightforward. The customer-related portion (which is computed in constant dollars) must be compared to the actual installed cost of the entire account (in mixed dollars); translating actual mixed dollars into constant dollars can be difficult, especially under conditions of technical change and different inflation rates for large and small installations (small installations are often more related to labour costs than are large ones, for example).

- The “minimum system” would still meet a large portion of the average customer’s demand requirements.
- Minimum-system analyses tend to use the current minimum unit, not the minimum size ever installed. The current minimum system is sized to carry expected demand. Consequently, as demand has risen over time, so has the minimum size of equipment installed. In fact, utilities usually stop stocking some less-expensive small equipment because rising demand has resulted in very rare use of the small equipment and the cost of maintaining stock became no longer warranted.
- Minimum-system analyses usually ignore the effect of loads on the *number* of units installed, or the *type* of equipment installed. Hence, a portion of the costs allocated to customer number is really driven by demand.
- Minimum systems analyses fundamentally assume that all area-spanning investment is caused by the number of customers. As discussed above, this is not true.

Q: How should the number of units installed be categorized as customer or demand-related?

A: A piece of equipment (e.g., conductor, pole, service drop, or meter) should be considered customer-related only if the removal of one customer eliminates the unit. The number of meters and, for the most part, services (although not the size) are customer-related, while feet of conductor and number of poles should be largely demand-related, especially in non-rural areas.

Reducing the number of customers, without reducing the demand in an area, will only

- sometimes eliminate a span of secondary conductor, if the customer is the furthest one from the transformer on that secondary;

- rarely eliminate a pole, if the customer is at the end of the primary line.

In many situations, additional conductors are added to increase capacity, rather than to reach an additional customer.

Q: Can the zero-intercept method be relied on to determine the customer-related portion of plant?

A: No. The determination of the number of units required for a zero-demand system are far from simple. A system designed to connect customers but provide zero load would look very different from the existing system. A zero-capacity electric system would not use the overlapping primary and secondary systems and line transformers that the real system uses. A system with very low loads would use a single distribution voltage, which eliminates many conductor-feet, reduces the required height of many poles, and eliminates the need for line transformers.

The zero-intercept method is so abstract that it can be interpreted in many ways, and can produce a wide range of results. Any use of this method must be grounded in a firm understanding of the purpose and conceptual framework for defining a zero-intercept.

2. Effect of Energy Use on Distribution Costs

Q: How does energy use affect distribution costs?

A: The sizing of transformers and underground lines is driven by the energy use on the equipment in high-load periods, in addition to maximum hourly loads.

Q: How does energy use in high-load hours affect the cost and sizing of transformers?

A: At least three energy-use factors determine the cost of transformers. The first two—the number of hours in the day in which the transformer operates near its peak period and the load factor on the transformer—affect the maximum load the transformer can tolerate without catastrophic overheating. The third factor is the effect of periodic overloads on useful transformer life.

Short peaks and low off-peak currents allow the transformer to cool between peaks, so that it can tolerate a higher peak current. The limit for very-short-duration loads (e.g., 30 minutes) is generally stated as 200% of rated capacity, while utility practice for high load factors (e.g., 80%) and long peak periods (e.g., 8 hours) often limits loadings to 100%–120% of rated capacity, especially for underground service.

Thus, only about half the installed transformer capacity would be necessary to meet the brief peak loads measured by demand charges, were it not for the neighboring hours of high utilization and the relatively high off-peak loads on peak days. Even considering only system reliability criteria, only 50%–60% of transformer capacity can be attributed to the single-hour peak load.

Energy usage also affects the service life of transformers, due to over-heating of the insulation. For example, a transformer that is overloaded by 20% for eight hours (due to high load, or failure of another transformer in a network) will lose about 0.25% of its useful life. With ten overloads annually at this level, the transformer would last 40 years, by which time accidents, corrosion, and other problems would likely lead to its retirement. Long overloads and higher load levels increase the rate of aging per overload, and frequent overloads lead to rapid failure of the transformer.

In a low-load-factor system, these high loads will occur less frequently, and the heavy loading will not last as long. If the only high-demand hours were the ones on which the peak loads are based, the chances of a first contingency coinciding with the peak would be small, and most transformers would be retired for other reasons before they experienced many overloads. In this situation, larger losses of service life per overload would be acceptable, and the short peak would allow greater overloads for the same loss of service life.

With high load factors, there are many hours of the year when the transformers are at or near full loads.[3] Thus, the size of the transformer must be increased to limit overloads to the small amount that is compatible with acceptable loss of service life per overload for this frequency of overloads, or the transformer will burn out far too rapidly.

Q: Will a higher load factor affect the cost of other components of the T&D system?

A: Yes. Load factor has similar effects on the sizing of underground transmission, primary, and secondary lines. Since heat builds up around the lines, the length of peak loads and the amount of load relief in the off-peak period affects the sizing of underground lines. An underground line may be able to carry twice as much load for a needle peak as for an eight-hour peak with a high daily load factor. To reduce losses and the build-up of heat, utilities must install larger cables, or more cables, than they would to meet shorter loads.[4] Since the number and sizing of underground lines is a function of load factor, a portion of the cost of the lines should be recovered through energy charges, even if demand charges could reasonably measure the contribution of customer loads to peak demands on distribution equipment.

Q: What changes do you recommended to Hydro's COSS methodology?

A: I recommend the following changes to the distribution classification and allocation factors:

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[3]In networks, failure of other transformers or lines will frequently cause overloading at such times.

[4]Both lines and transformers are sized, in part, to reduce the costs of energy losses.

- Allocate subtransmission on the transmission Coincident-Peak allocator D14, adjusted to exclude customers that are served at the transmission level.
- Allocate substation costs according to the contribution of each class to the most constrained loading of all substations (or on a representative sample of substations).
- Eliminate the allocation of conductors and poles on customer number.[5]
- Recognize the effect of high energy use in the allocation of demand-related distribution plant, especially for the summer-peaking portions of the system.

V. Estimate of Marginal Costs for Rate Design and DSM Evaluation

Q: Has the Company provided up-to-date marginal cost data as required by the Board?

A: No (Tab 13–PUB Directives, pp. 16-17).

Q: Why are marginal costs important for Hydro's planning and ratemaking?

A: Marginal costs indicate the value of load reductions and the cost of load increases. Those values are important in both the evaluation of DSM options and the design of rates (e.g. Inclining block rate with tail block charge set at marginal cost).

[5]Initially, conductors and poles would be allocated on the class NCP allocator. As I describe above in reference to substations, the class NCP does not reflect the range of loads that drive the sizing of equipment. Once Hydro has completed the substation analysis described above, it should extend that approach to the distribution feeders and should recognize that some conductor costs are energy-related.

A. *Estimate of Marginal Generation Cost*

Q: What are Hydro's estimates of marginal generation cost?

A: Hydro provides a number of estimates of marginal generation cost, including the following:

- Lost short-term firm export revenues of 5.75 cents per kW.h (including both demand and energy components of 0.9 cents per kW.h and 4.85 cents per kW.h, respectively), for use in a proposed 2010 Energy Intensive Industrial Rate (Application for Approval of EIIR, Tab A, Page 3);
- Short-term time-differentiated estimates of marginal energy costs (for use in deriving the COSS generation cost allocator), as follows:

Hour-Weighted Average Price
Canadian Dollars per kW.h

	Peak	Shoulder	Off-Peak
Spring	$0.059	$0.051	$0.030
Summer	$0.075	$0.054	$0.022
Fall	$0.061	$0.050	$0.031
Winter	$0.084	$0.058	$0.046

Source: Attachment 3 to RCM/TREE/MH I-3(e)(iii)

- A 30-year levelized cost of 6.9 cents per kW.h (which includes 14% total losses at the distribution level), for use in DSM evaluation (OCS IR RCM/TREE/MH II-4b(iii));
- A generation capacity cost of $78 per kW per year (including losses) for use in determining the value of curtailable loads, based on the costs of a new combustion turbine (Appendix 10.8: Curtailable Rate Program, p. 13).

Q: What is the basis of the short-term cost estimate of 5.75 cents per kW.h?

A: The estimate was based on the average price of energy sold under dependable export contracts for fiscal years 2008/09 and 2009/10. The prices after December 1 2009 were forecast (EIIR Application, Tab 1, p. 3).

Q: What sales are included in the "dependable contracts" category?

A: According to the Company, dependable contracts include

> only the Long Term Firm sales including energy sold in both on peak and off peak hours. However, given the terms of the long term contracts, the vast majority of energy sold was in the on peak hours (RCM/TREE/MH II-1c)

Q: What is the basis for the marginal generation cost for used in the COS Study?

A: Hydro estimated marginal generation costs from historical and projected daily prices charged to Surplus Energy Program customers.

Q: If the marginal generation costs are based on projected SEP prices, are they reasonably complete estimates of Hydro's marginal generation costs?

A: No. SEP prices are for interruptible energy, set weekly, without capacity. Marginal generation costs would include the costs of the higher-priced periods in which Manitoba Hydro interrupts SEP supply, as well as firm capacity and other costs of firming supply.

Q: Do you expect the long-run marginal generation cost to exceed the cost estimates used in the EIIR proposal and the COS Study?

A: Yes. It is likely that long-term prices, including the costs of new capacity and carbon allowances, would exceed the near-term prices.

Q: How did Hydro derive a marginal generation cost for DSM evaluation?

A: The Company used a production-costing model "to simulate the operation of its reservoir and generating facilities" (RCM/TREE/MH II-4b(iii)). Hydro ran this model under 94 possible flow conditions

> to determine the value of the small increment of energy and capacity. This value is dependent on the mix of thermal and import energy and the quantity of export energy associated with each of the flow conditions. In low flow conditions, the marginal benefit is derived from the displacement of high-cost thermal and import energy, while in median to high flow conditions the benefit is derived primarily from new export sales. Benefits may be very small or even nonexistent in extremely high flows when tie-lines may be saturated and reservoirs filled to capacity.

In other words, the estimate of marginal generation costs largely depends on Hydro's forecast of future export contracts, for which Hydro has refused to provide any documentation. While Hydro asserts that the marginal-cost value includes the value of generation capacity, Hydro refuses to provide any information about its projections of capacity prices (RCM/TREE/MH II-4b(iv)).

Q: What is the best available set of marginal generation costs for rate design?

A: The marginal-cost estimate for DSM is most appropriate because it is a long-term estimate that includes both generation capacity and energy costs. Since Hydro estimates the DSM marginal energy costs for a constant load, rather than for a typical retail load shape, the DSM marginal energy costs are somewhat understated for rate-design purposes.

B. Estimate of Marginal Transmission and Distribution Cost

Q: Has Hydro estimated marginal T&D?

A: Yes. For purposes of its DSM evaluation, Hydro (RCM/TREE/MH I-7f and II-4b(v)) estimates as follows:

- a marginal transmission cost of is 0.93 cents per kW.h (based on a marginal value of $73.87/kW/year in 2009 dollars and a 91% load factor),
- a marginal distribution cost of 0.56 cents per kW.h (based on a marginal value of $44.78/kW/year in 2009 dollars and a 91% load factor).

Q: What was the basis of these marginal T&D cost estimates?

A: The estimates were taken from a September 23, 2004 report "Marginal Transmission and Distribution Cost Estimates. SPD 04/05" and inflated to 2009 dollars. As this report describes, Hydro applied the "One-Year Deferral Method to the most recent (at the time) ten-year forecast of expenditures: "T&D Capital Expenditure Forecast (CEF03-1), 2003/04–2013/14 (Appendix 49).

Q: Have you identified problems with this analysis?

A: Yes. I have identified the following four flaws. The analysis of costs per kW-year

- eliminated the costs of the transmission and subtransmission projects that were already underway or committed, but did not subtract out the load growth served by these investments;
- excluded overhead transformers and secondary lines as customer-related and unavoidable by DSM. This treatment is inconsistent with the Company's classification of this equipment in its COS Study. (Appendix 49, p. 17, fn. 8);
- excluded operation and maintenance costs, failing to recognize that the O&M associated with load-related projects is also load-related (Appendix 49, p. 20);
- incorrectly considered the Roblin South Station 230-KV Reactor project to be 0% demand-related (Appendix 49, Table B.4). Reactors should be included as 100% load-related, because they are required to prevent the overloading of lines by the combination of real and reactive power.

There may be other projects that Hydro classified as 100% customer-related, which were due to the overloading or premature aging of existing equipment, and therefore demand-related. However, there is not enough detail in

Appendix B to identify the cause of "poor conditions," "operating and maintenance concerns," and "deficiencies."

In addition, the 91% load factor is very high, and thus understates the cost of transmission and distribution per kW.h for most customers and applications.

C. *Estimate of Transmission and Distribution Losses*

Q: What is Hydro's estimate of the distribution loss factors for various classes?

A: Manitoba Hydro (PCOSS10 (Appendix 11.1)) makes the following estimates:

- average distribution energy losses of 5.79% (p. 56),
- peak distribution losses of 7.98% (p. 56),
- peak transmission losses of 8.4% (p. 56),[6]
- transmission energy losses of 5.79% (p. 55).

Hydro further disaggregates the distribution energy and peak demand losses as shown in Table 1. The sales-weighted average of these losses match Hydro's estimates of average losses.

Table 1: Manitoba Hydro Estimates of Distribution Losses

Class	Distribution Energy Losses	Distribution Peak Losses
Residential	7%	10.1%
GS Small—Single Phase	7%	10.1%
GS Small—Three Phase	5.3%	7.7%
GS Medium	5.3%	7.7%
GS Large (less than 30 kV)	4.4%	6.5%
GS Large 30–100 kV	1.5%	2.1%
GS Large (greater than 100 kV)	—%	—%

Source: PCOSS10 (Appendix 11.1), p. 56

Note that all of these loss estimates are for average, rather than marginal deliveries. In other words, they represent Hydro's estimate of total losses in an

[6] I computed this loss factor from the generation and common bus losses.

hour, divided by total deliveries in the hour, rather than the marginal losses of the marginal megawatt-hour delivered. Marginal distribution losses would be considerably greater than these average losses.[7]

D. Estimate of Marginal Cost by Rate Class

Q: Has Hydro provided estimates of total marginal cost for each rate class?

A: No.

Q: Did Manitoba Hydro apply loss factors in computing all marginal cost components?

A: No. The transmission-and-distribution marginal costs, as described in Appendix 49, do not include line losses. On the other hand, line losses of 14% were included in the marginal generation cost of 6.90 cents per kW.h estimated for DSM (RCM/TREE/MH II-4b(xi)).

Q: What are your best estimates of marginal costs, including firm generation supply?

A: I used the sum of the following:

- Hydro's estimate of long-run marginal generation costs of 6.90 cents per kW.h (adjusted for the differences in line loss factors among rate classes).
- A marginal transmission cost of is 0.93 cents per kW.h and a marginal distribution cost of 0.56 cents per kW.h, plus peak losses.

The results of these computations are set forth in Table 2.

[7]The situation for transmission is more complex, and depends on the mix of fixed losses (from transformer cores and AC-DC converters) and variable losses (from lines), as well as the differing generation patterns at various load levels.

Table 2: Marginal Cost by Rate Schedule

Rate Schedule	Generation	Transmission	Distribution	Total
Residential	6.9	1.0	0.6	8.5
GS Small, Non-Demand	6.9	1.0	0.6	8.5
GS Small, Demand-metered	6.8	1.0	0.5	8.3
GS Medium	6.8	1.0	0.5	8.3
GS Large (less than 30Kv)	6.7	1.0	0.4	8.2
GS Large (30–100Kv)	6.5	1.0	0.2	7.7
GS Large (more than 100kV)	6.4	1.0	–	7.5

Q: Do these direct costs include all the costs of domestic consumption of electricity?

A: No. Reducing domestic sales either increases exports, reduces purchases, or reduces Manitoba Hydro's thermal generation. Any of these effects will reduce emissions of conventional pollutants—various combinations of particulates, SO_2, and NO_X, depending on the thermal units turned down—and CO_2. The costs of some of the conventional pollutants are internalized for U.S. utilities through cap-and-trade systems, but the costs of greenhouse gases are currently not internalized. The total social cost of domestic consumption of electricity is thus greater than the direct costs above.

Q: What is the significance of these results for rate design?

A: Hydro's marginal costs exceed proposed tail-block energy rates for all classes, even without including any environmental costs; see Table 3.

Table 3: Comparison of Energy Rates to Hydro's Estimates of Marginal Costs

	Tail-Block Charges (cents per kW.h)			
Class	*2010/11*	*Interim*	*2011/12*	**Marginal Cost**
Residential	6.75	6.57	7.23	8.5
GS Small	3.05	3.05	3.20	8.5
GS Medium	3.05	3.05	3.20	8.3
GS Large (less than 30 kV)	2.88	2.88	3.01	8.3
GS Large 30–100 kV	2.69	2.69	2.81	8.2

GS Large (greater than 100 kV)	2.62	2.62	2.73	7.7

Thus, inclining-block rates are needed to provide customers with appropriate marginal price signals.

E. Estimate of Marginal Cost for Evaluation of Demand-Side Management

Q: What marginal costs did Manitoba Hydro use in evaluating DSM?

A: Hydro says the "marginal value used for the analysis in the 2009 Power Smart Plan was 8.26 cents per kW.h (at meter)" (RCM/TREE/MH I-10(d)(i)).

Q: How did Manitoba Hydro derive this values?

A: Hydro refused to explain the derivation. "The marginal cost contains the expected value of electricity exports, is commercially sensitive and therefore, detailed information on the derivation of the avoided cost can not be provided" (RCM/TREE/MH I-10(d)(i)).

Q: Can you review Hydro's economic evaluation of DSM without this information?

A: No.

Q: Do utilities generally release the derivation of their estimates of avoided costs for DSM evaluation?

A: Yes. I cannot recall a similar situation in which a utility has so broadly refused to document its estimates of avoided costs.[8]

[8] In some cases, utilities will request protected status for certain inputs, such as detailed forecasts of market prices, releasing that information only to parties who are not engaged in power trading. In more than 20 years of reviewing avoided-cost estimates, I cannot recall a situation in which the utility has refused to even break out generation energy and capacity costs, transmission costs, distribution costs, and losses.

In New England, the regional avoided costs (excluding losses and T&D, which are added by individual utilities) are derived in a collaborative process (for which I have been one of the consultants in three of the five biennial rounds) of the electric and gas utilities, consumer representatives, environmental interests and regulators.[9] This work shows detailed avoided-cost projections. Similar details on the derivation of avoided costs in California, developed through a public process of comments and workshops, are described at www.ethree.com/cpuc_avoidedcosts.html.

Forecasts of avoided costs, and their derivation, have been publicly available since the early 1980s, when they were used to value non-utility generation.

Q: Is the Company's estimate of 8.26 cents per kW.h an appropriate avoided cost for all DSM at the distribution level?

A: No. Avoided costs vary among end uses and measures, for many of the same reasons that marginal costs vary among classes, particularly energy load shapes and load factors.[10] The 8.26 cents per kWh assumes that the DSM measure has a flat load curve (RCM/TREE/MH II-4); a DSM measure that is load-following or weather-sensitive is more valuable.

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[9]Most recently, Hornby, Rick, Paul Chernick, Carl Swanson, David White, Ian Goodman, Bob Grace, Bruce Biewald, Chris James, Ben Warfield, Jason Gifford, and Max Chang. 2009. "Avoided Energy Supply Costs in New England: 2009 Report." Northborough, Mass.: Avoided-Energy-Supply-Component Study Group, c/o National Grid < http://www.resourceinsight.com/work/aesc-09.pdf>. This report provides detailed avoided-cost projections.

[10]Unlike marginal costs for rate-design purposes, which end at the customer meter, avoided costs include costs all the way to the end use, which is almost always at secondary voltage. Hence, even for customers metered at primary or transmission voltage, losses and avoided T&D should be computed to secondary distribution.

F. Estimate of Environmental Costs

Q: How did Manitoba Hydro treat environmental costs in its DSM valuation?

A: Hydro assumes that emissions costs are reflected in the export prices on which its marginal cost estimates are based:

> The marginal cost estimate of 8.26 cents per kW.h does not include an explicit environmental cost component. The avoided GHG and other emissions are implicitly valued in the determination of marginal cost because the forecast of export prices includes consideration of potential environmental costs that may be associated with electricity production in Manitoba Hydro's export markets. (RCM/TREE/MH II-4(b)(vii))

Q: Has Hydro provided an estimate of CO_2 values?

A: No. The Company refused to discuss its consideration of the impact of CO_2 legislation (RCM/TREE/MH II-4(b)(vii)).

VI. Changes to Rate Structure

Q: What rate-design changes do you address in this section of your testimony?

A: In several past Orders, the Board has called for the promotion of efficient energy use through sweeping changes in rate design, including phasing out of declining block rates and introduction of inverted rates, rebalancing of demand and energy charges, elimination of winter demand ratchets, implementation of time-of-use (TOU) rates, introduction of a marginal-cost-based rate for new large energy-intensive customers, and preparation of a marginal cost study for use in the COS Study (Tab 13: PUB Directives; Order 150/08). Hydro has eliminated the winter demand ratchets from its proposed rates. I address the Board's other rate design initiatives in the following sections of my testimony.

A. *Inverted or Inclining-Block Rate Design*

Q: Please provide a brief description of the Board's inverted-rate initiative.

A: In Directive 4(d) in PUB Order 117/06 (as well as previous Orders), the Board directed the Company to introduce inverted rates, initially for large non-residential customers, with the tail block energy charges set at marginal cost. In PUB Order 116/08, the Board extended the inverted-rate initiative to all classes:

> The Board encourages MH to develop plans to employ an inverted rate structure for all customer classes, initially to be designed on a revenue neutral (to MH) basis and to send a "price signal" for every kilowatt hour of energy used, to promote conservation. (Order 116/08 at 306)

Q: What is Manitoba Hydro's proposal for the residential class?

A: Manitoba Hydro proposes to collect the residential rate increase solely through the energy charges, to reduce customer charges by shifting revenue recovery from the customer charge to the energy charges and to raise the tail block more than the first block, as follows:

	Basic Monthly	First-Block Energy	Tail-Block Energy	Incline
Base	$6.85	$0.0625	$0.0630	0.8%
Interim	$6.85	$0.0638	$0.0657	3.0%
2010/11	$5.85	$0.0637	$0.0675	6.0%
2011/12	$4.85	$0.0647	$0.0723	11.7%

Q: What is your evaluation of the Company's basic residential-class rate proposal?

A: The Company's residential rate proposal provides significant improvement both in economic efficiency and low-income customer rate impacts. In future cases, the Company should continue to shift revenue recovery into the tail block charge, bringing it closer to marginal cost.

Q: What has Hydro's response been to the Board's recent inverted-rate directives?

A: Manitoba Hydro has proposed an inclining-block rate only for the residential class. It has not presented any proposals or plans for inverting the rates of General Service customers.

Q: How might inclining-block general-service rates be structured?

A: Designing inclining general-service rates is complicated by the fact that Hydro (like most utilities) has several such rates, for customers of different sizes. If the bills for a large customer in one class (e.g., GS Small) are larger than they would be if it became a small customer in the next higher schedule (in this example, GS Medium), that customer will have an incentive to increase usage to move up to the more favourable schedule. Similarly, a small GS Medium customer would have an incentive to maintain its usage level to avoid being reclassified as a GS Small customer. The same effects would occur at the interface between GS Medium and GS Large.

One approach to getting around this problem is to charge each customer traditional embedded costs based on that customer's use in an historical base period, such as 2005–2010. For any deviation from the historical baseline, the customer would pay or be credited at marginal-cost-based rates. Thus, any saving of energy, whether through investments that might be encouraged by an enhanced Power Smart program or through improvements in maintenance or operation, would be rewarded at marginal cost. The increased benefit from efficiency investments would allow Power Smart to pay much lower incentives for the same energy savings. Similarly, any waste of energy would be charged at marginal cost. In making any decision to increase power use, the customer would face the full cost of that usage (as it faces the full costs of labour, materials, and equipment) and would have incentives to make the choice with the lowest total cost.

Under this approach, customers with stable consumption would pay embedded-cost rates, customers with falling consumption (including hard-pressed companies with declining operations) would receive lower bills, and only customers with booming operations would pay greater-than-embedded costs.

If the larger general-service schedule rates are modified in this manner, the smallest general-service schedule can be converted to an inclining-block energy structure without the interface problems described above.

Q: Has this approach been used elsewhere?

A: British Columbia Hydro has implemented a limited version of this approach for large distribution customers (BCUC Order G-110-10, June 29, 2010).

Q: What details need to be resolved before Hydro can implement these marginal-cost-based rates?

A: The important issues are as follows:

- Whether the initial baseline will be revised to reflect changes in usage over time, and if so, how. Revision might include setting the baseline from a long-term (e.g., ten-year) rolling average consumption.
- How baselines will be set for new customers. These baselines can be based on the usage for efficient customers of the same type.
- How "new customer" will be defined in this context.
- Whether major expansion of existing facilities will be treated differently from other causes of increased consumption, perhaps as partly new customers.

- How the rate design will treat customers who reduce operations dramatically or go out of business, potentially resulting in negative bills.
- Whether the rate design will be phased in.

Q: How should the Board proceed with the design of marginal-cost-based rates for the general-service schedules?

A: The Board should require that Hydro consult with customers and other stakeholders (including RCM/TREE) on the design of marginal-cost-based general-service rates and file a specific proposal in its next rate proceeding, with implementation of the initial steps of transition to marginal-cost-based general-service rates occurring in 2013.

B. Demand-Energy Rebalancing

Q: What is the purpose of the Board's Demand-Energy Rebalancing Directive?

A: The Board's Order 116/08 explains the purpose of demand-energy rebalancing as follows:

> Energy and demand balancing is a policy issue that speaks to the fairness of rates to individual customers within a class. The argument for reducing demand charges, and increasing energy charges, is that it does send an improved price signal and thus promotes conservation. As the change occurs, Demand and Energy Cost recoveries will be brought more into line with cost causation principles. (Order 116/08, p. 308)

Q: What energy-demand rebalancing does Manitoba Hydro propose in this case?

A: Hydro proposes that 100% of the revenue increase be recovered in the energy charges. The Company considers this to represent significant progress in rebalancing energy and demand charges, at least compared to the energy and demand costs indicated in the 2008 COSS (Appendix 13-7, pp. 4–5).

Q: What is the basis of Manitoba Hydro's claim?

A: Hydro compares the demand and energy revenues of each class to the results of the filed 2008 COS Study and finds that the energy charge in every General Service rate exceeds embedded generation cost (Appendix 13.7, pp. 4-5).

Q: If Manitoba Hydro adjusts the balance to be consistent with its COSS, will the "appropriate" balance be achieved?

A: No, for the following reasons:

- Hydro's COSS classification factors ignore the effect of energy on distribution costs, as discussed in detail above.
- Embedded costs do not provide efficient pricing signals. Rate design should be based on marginal, not embedded, cost considerations. As shown above, the energy charges of General Service customers do not even cover marginal generation costs. As a result, customers may make inefficient consumption decisions.[11]
- Embedded costs are based on coincident or non-coincident peak, not individual maximum demand.
- Demand charges do not provide appropriate incentives to conserve, even during high load hours.
- Demand charges can be burdensome and inequitable.

Q: Please explain why demand charges do not provide the appropriate incentives.

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[11]For example, the MTS Centre recently converted from all-gas heating to a system in which it will use electricity for most of its heating and switch to gas only to avoid demand charges at the time of the building's maximum loads ("MTS Centre Switches to Green Heating," Wiebe, L, *Winnipeg Free Press,* Oct 30 2007). The low rates for electric energy encourage the MTS Centre to use electricity rather than gas (for which it pays prices much closer to marginal cost), even on the peak hours for the generation, transmission, and local distribution systems.

A: Demand charges are a particularly ineffective means for giving price signals, for the following reasons:

- The demand-charge portion of the electric bill is determined by the customer's individual maximum demand. Capacity costs are driven by coincident loads at the times of the peak loads, not by the non-coincident maximum demands of individual customers. The customer's individual peak hour is not likely to coincide with the peak hours of the other customers sharing a piece of equipment, especially since the peaks on the secondary system, line transformer, primary tap, feeder, substations, sub-transmission lines, and transmission lines occur at varying times.[12] In fact, Hydro acknowledges that T&D capacity is driven by diversified demand, not by billing demand (RCM/TREE/MH I-12(k)).
- Demand charges provide little or no incentive to control or shift load from those times that are off the customers' peak hours but that are very much on the generation and T&D peak hours. Customers can avoid demand charges merely by redistributing load within the peak period. Some of those customers will be shifting loads from their own peak to the peak hour on the local distribution system, on the transmission peak, or on the peak load hour of Manitoba Hydro. This will cause customers to increase their contribution to maximum or critical loads on the local distribution system, the transmission system, or the regional generation system.
- Demand charges are difficult to avoid; even a single failure to control load results in the same demand charge as if the same demand had been reached in every day or every hour.

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[12] This diversity is demonstrated for substations in RCM/TREE/MH I-7(p)); substations peak at different times, on different days, in different months, and in different seasons.

- Rather than promoting conservation at high-cost times, or shifting of load from system peak periods, demand charges encourage customers to waste resources on the arbitrary tasks of flattening their personal maximum loads, even if those occur at low-cost times. For instance, in order to respond to demand charges effectively, customers will need to install equipment to monitor loads, interrupt discretionary load, and schedule deferrable loads. Moreover, lower energy charges will encourage increased electric use, some of which will likely occur in the peak period.

Q: What pricing signals do demand charges give to customers?

A: Not only are demand charges ineffective in shifting loads off high-cost hours, they may cause some customers to shift loads in ways that increase costs.

Q: Should demand charges be eliminated entirely from rates?

A: Yes. When time-of-use energy charges are introduced, demand charges should be eliminated, and the revenues currently collected through demand charges instead collected through peak-period energy charges. In other words, all system and regional transmission, substation, and feeder costs should be recovered through on-peak energy charges. This time-of-use rate design will encourage reduction of usage in high-load periods, when transmission-and-distribution equipment is heavily loaded.

Q: Has Manitoba acknowledged that TOU rates could effectively replace demand charges?

A: Yes. Hydro "accepts in principle the rationale that some costs, which are demand-related, could be collected in a peak period energy charge…." (Appendix 13.7, p. 5).

C. Introduction of Time-of-Use Rates

Q: Has the Board required Manitoba Hydro to submit proposals for Time-of-Use rates in this proceeding?

A: Yes. Board Order 117/06 (p. 24) directed Manitoba Hydro to

> file proposals for the appropriate implementations of Time of Use Rates for non-residential customers….

Q: Has Hydro provided any TOU rate plans in response to the Board's requirement?

A: No. Hydro has failed to pursue any analysis of TOU rates since the Board issued its directive, even though the Company acknowledges that TOU rates can provide efficient pricing signals and that peak energy charges can substitute for demand charges in energy-demand rebalancing (Appendix 13.7, pp. 1, 6).

Q: Does Hydro explain why it has not filed a TOU rate plan in this proceeding?

A: No. Nothing has been filed in this case. The Company's response to the Directive has only been the following:

> Manitoba Hydro intends to bring a proposal to its Board of Directors at the January 21, 2010, meeting. Such a proposal will address, in an integrated fashion, the role of TOU Rates and/or Inverted Rates in conjunction with any Energy Intensive Rate proposal and any revisions to Service Extension Policy for General Service Large customers served at higher than 30 kV. As soon thereafter as practicable, Manitoba Hydro will file same with the PUB. (Tab 13, p. 17)

Q: Is it feasible to design a TOU rate that signals the highest cost hours?

A: Yes. A three-period (peak, shoulder, and off-peak), seasonally differentiated rate, with a narrow "critical peak" period, for example, would provide a useful price signal.

Q: Do all TOU pricing systems use fixed-pricing approaches?

A: Not all TOU pricing systems use fixed periods or fixed on-peak prices. Some pricing systems for large customers flow prices through in real time, with the price of power in each hour determined in that hour. Another approach, which California is currently exploring, charges a premium price during certain critical hours, which may be defined based on energy prices, load levels, or reliability of the supply and delivery systems. The timing of those critical hours is determined based on short-term (hour-ahead or day-ahead) conditions, but the premium price is fixed in advance.

VII. Use of Revenues from Exports and Marginal-Cost-Based Rates

Q: How would marginal-cost-based rate designs increase revenues?

A: Since Hydro's rates are well below marginal costs, raising the tail-block energy rates towards marginal costs would increase revenues, all else equal. Similarly, charging marginal costs for the energy used by new large General Service loads and for net increases in sales to other General Service customers would increase revenues.

In addition, higher tail-block rates should encourage customers to use energy more efficiently and more carefully, increasing the energy available for export and the resulting revenues.

Q: How should Manitoba Hydro use the export revenues and the additional revenues from higher tail blocks and marginal-cost pricing of new large loads?

A: Appropriate uses for the additional revenues include the following:

- reducing or eliminating customer charges;

- reducing or eliminating demand charges, especially as Manitoba Hydro phases in time-of-use energy rates;
- reducing inner blocks;
- funding assistance to low-income customers and aboriginal communities;
- funding economic-development activities (including potentially infra-marginal discounts on power charges);
- funding expanded energy-efficiency and fuel-switching programs, especially for low-income and electric-heating customers;
- improving Hydro's financial structure;
- reducing tax burdens on Manitoba businesses and households.

In any case, the redistribution of revenue should not promote additional usage.

VIII. Evaluation of Hydro's Efforts in Promoting Demand-Side Management

Q: How have you reviewed the aggressiveness of Hydro's efforts in promoting DSM?

A: I looked at the following two ratios:

- the savings rate, computed as the ratio of annual incremental DSM energy savings from energy efficiency, divided by total retail sales;
- the spending rate, computed as the ratio of annual utility energy-efficiency expenditures, divided by total retail sales.

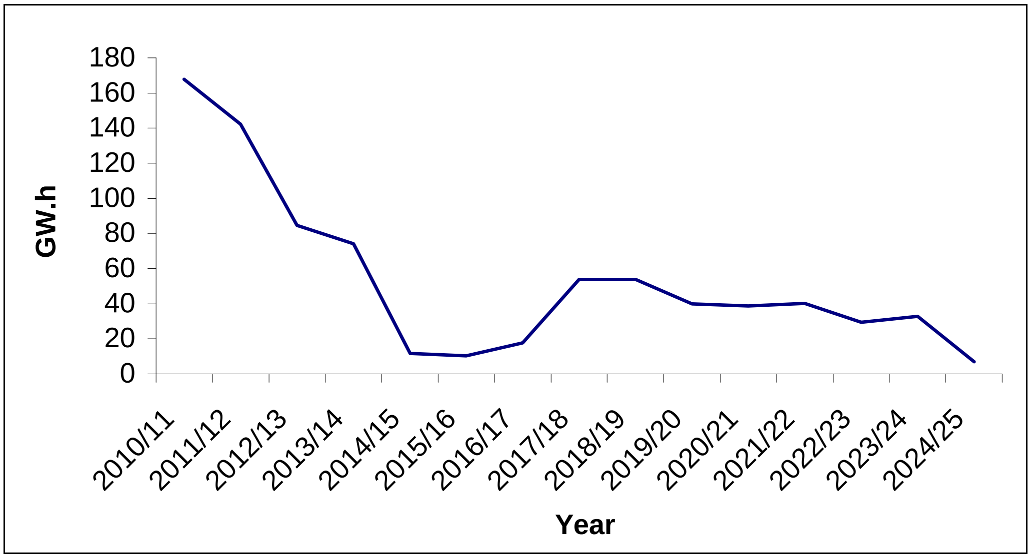
Q: What did you conclude from your review?

A: Manitoba projects a precipitous decline in its DSM efforts and annual incremental savings.

Q: What is Manitoba's projected savings rate?

A: According to Hydro's 2009 PowerSmart Plan (Appendix 9.1), Appendix A.3, Manitoba Hydro expects to increase its annual conservation savings by about 150 GW.h (at the meter) in the years 2010/11 and 2011/12, but only by 30 GW.h on average in the years 2013/14 through 2024/25. These projections are shown in Figure 1.

Figure 1: Manitoba Hydro's Planned DSM Savings



Source: 2009 Power Smart Plan (Appendix 9.1), Appendix A.3

Manitoba's 2009 load forecast (Appendix 7.1, Table 1) projects sales of 24,600 GW.h in 2010/11 and 25,159 in 2011/12. Hydro's planned savings rate is thus 0.7% in 2010/11, 0.6% in 2011/12, and much less (closer to 0.1%) in later years.

Q: What is Hydro's current rate of spending on DSM?

A: The 2009 PowerSmart Plan (Appendix 9.1), Appendix A.5, indicates that Manitoba Hydro expected to spend $27.7 million on conservation in 2009/10, rising to $30.7 million in 2010/11, falling to $29 million in 2011/12, and then declining rapidly to $15.9 million in 2014/15 and $4.4 million in 2024/25.

Hydro's planned spending rate is thus $1.25/MW.h of sales in 2010/11, $1.15/MW.h in 2011/12, and much less thereafter.

Q: How does the Company's savings ratios compare to those of other energy-efficiency programs in North America?

A: Hydro's savings plans are modest compared to those of many other North American jurisdictions, including some with long histories of extensive savings (e.g., California, Massachusetts, Vermont) as well as others with little DSM experience (e.g., Illinois and Indiana). Table 4 shows the ratio of target energy-efficiency savings to retail sales for twenty U.S. states and Manitoba Hydro. Most of these states are targetting savings in excess of 1% in at least some years, and several have annual targets over 2%, far more aggressive than Hydro's plan, which averages 0.6% over the first three years and 0.2% for the next eight years.

Table 4: Comparison of DSM Target Savings Ratios

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
AZ		1.03%	1.02%	1.20%	1.58%	1.56%	1.54%	1.51%	1.49%	1.47%	1.45%	1.43%
CA	1.31%	1.26%	1.27%	1.28%	1.41%	0.92%	0.88%	0.90%	0.90%	0.91%	0.90%	0.89%
CO	0.53%	0.76%	0.80%	0.85%	0.90%	0.95%	1.00%	1.05%	1.10%	1.15%	1.20%	1.20%
CT	1.0%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%
DE	0.5%	0.8%	1.3%	2.5%	3.0%	3.0%	4.0%					
HI	0.6%	0.6%	0.8%	0.8%	1.0%	1.0%	1.3%	1.3%	1.5%	1.5%	1.8%	1.8%
IL	0.4%	0.6%	0.8%	1.0%	1.4%	1.8%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
IN		0.3%	0.5%	0.7%	0.9%	1.1%	1.3%	1.5%	1.7%	1.9%	2.0%	2.0%
IA	1.0%	1.2%	1.3%	1.4%	1.4%							
MD	1.0%	1.2%	1.7%	2.2%	2.7%	2.6%	3.1%					
MA	1.0%	1.5%	2.0%	2.4%	2.4%	2.4%	2.4%	2.4%	2.4%	2.4%	2.4%	2.4%
MI	0.3%	0.5%	0.8%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%
MN		1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%
NM		0.9%	0.9%	0.8%	0.8%	0.8%	0.6%	0.6%	0.6%	0.6%	0.8%	0.8%
NY	2.1%	2.1%	2.2%	2.2%	2.2%	2.2%	2.3%					
OH	0.3%	0.5%	0.7%	0.8%	0.9%	1.0%	1.0%	1.0%	1.0%	1.0%	2.0%	2.0%
PA			1.0%	1.0%	1.0%							
RI	1.2%	1.2%	1.1%									
TX	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%
VT	2.6%	2.6%	2.6%									
WA	0.7%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%
MB	0.6%	0.7%	0.6%	0.3%	0.3%	0.0%	0.0%	0.1%	0.2%	0.2%	0.1%	0.1%

Targets have not been set for the years in grey.

Sources: "Advancing Energy Efficiency in Arkansas," M. Neubauer, et al., American Council for an Energy-Efficient Economy, June 2010, Table 14; Manitoba savings from Appendix 9.1, Appendix A.3; Manitoba sales from Appendix 7.1, Table 1.

Q: How does the Company's spending rate compare to those of other energy-efficiency programs in North America?

A: By this measure as well, Hydro is far from a leader in North America. See Table 5, which shows the 2009 budget for energy-efficiency programs for Hydro and for the U.S. states with higher levels of utility funding of efficiency programs.

Table 5: Comparison of 2009 Electric DSM Spending Rates per MW.h

Jurisdiction	Total Sales (MW.h)	2009 Budget ($M)	Budget per MW.h
VT	5,496,513	$30.7	$5.59
RI	7,617,629	$29.5	$3.87
CA	259,583,623	$998.3	$3.85
HI	10,126,185	$35.5	$3.51
MA	54,359,198	$183.8	$3.38
NY	140,034,397	$378.3	$2.70
CT	29,715,764	$73.4	$2.47
ME	11,282,967	$20.8	$1.84
OR	47,566,897	$84.7	$1.78
NJ	75,779,853	$132.3	$1.75
MN	64,004,463	$111.2	$1.74
UT	27,586,700	$45.4	$1.65
WA	90,164,701	$146.5	$1.62
WI	66,286,439	$101.1	$1.53
NH	10,698,493	$15.2	$1.42
ID	22,753,779	$31.5	$1.38
IA	43,641,195	$55.6	$1.27
NV	34,283,654	$41.9	$1.22
MB	24,080,000	$27.7	$1.15

Note: Native dollars (U.S. for U.S. states, Canadian for Manitoba)

Source: "2010 State Energy Efficiency Scorecard," American Council for an Energy-Efficient Economy, October 2010, Report E107, Table 4.; Manitoba Filing Appendix 7-1, Table 1.

Hydro is spending less in total than much smaller jurisdictions, such as Vermont, Rhode Island, and Hawai'i. Eighteen states spent more per megawatt-hour of 2009 sales than did Hydro. Some states not in Table 5 (such as Colorado, at $0.92/MWh in 2009, Arizona and Pennsylvania at $0.67/MWh, Illinois at $0/66/MWh, Maryland at $0.61/MWh) are expecting to increase their program savings considerably in the next few years (as shown in Table 4), and will probably soon be spending more than Hydro did in 2009, while Hydro is forecasting that its DSM activities will decline sharply. Since the U.S. dollar is worth slightly more than the Canadian dollar, the differences are actually somewhat larger than indicated in Table 5.

Q: What do you conclude from these comparison?

A: I believe that Hydro should be able to double or triple its energy-efficiency spending and savings from current levels and maintain those higher levels for the planning period.

My opinion is buttressed by Dunsky et al. (Appendix 25), who note that Hydro lags behind leading jurisdictions in the following areas:

- comprehensiveness of program coverage, especially for small commercial and low-income multi-family retrofit, and new construction (pp. 13, 18);
- use of upstream strategies, turnkey installation and market outreach (Appendix 25, p. 14); the setting of aggressive savings targets (p. 15);
- improvement in industrial-process programs (p. 18).

Dunsky et al. also urge that Hydro abandon the use of the rate-impact measure (RIM) to screen program design and limit program effects (p. 15); Hydro has indicated it will continue using the RIM (Appendix 71, pp. 7–8).

Manitoba Hydro may require more encouragement from the Board if Manitoba is ever to become a leader in energy efficiency. Hydro proposes to benchmark its programs to those of BC Hydro (Appendix 71, p. 7), rather than the "three leading providers" identified by Dunsky et al.: Pacific Gas & Electric (California), Efficiency Vermont, and Xcel Energy (Minnesota). Vermont and PG&E have achieved and are planning much more intensive savings than BC Hydro; Dunsky et al. frequently cite aspects of the leading providers' portfolios that are superior to the Company's programs. Manitoba may have much less to learn from BC Hydro's programs than it could from the leading providers.

Q: What are the benefits of implementation of enhanced DSM programs?

A: Enhancing DSM programs would reduce bills for Manitoba consumers, reduce Manitoba's dependence on local and imported fossil energy, reduce greenhouse gas emissions and other pollution, and reduce the risk of drought for Manitoba Hydro.

IX. Recommendations

Q: Please summarize your recommendations to the Board on cost-allocation issues.

A: The Board should recognize that Hydro's existing cost-of-service methodology overstates the costs of serving residential customers in the following ways:

- The costs of the subtransmission system, driven by the coincident loads of customers of all classes other than GS Large >100kV, are currently allocated on class non-coincident peaks.
- The costs of substations—driven by a mix of peak loadings in different seasons, months, days, and times, resulting from various mixes of class loads on each substation—are currently allocated on class non-coincident peaks, representing entirely winter loads, including class peaks that do not coincide with any identified substation peaks.
- An arbitrary 40% of conductor and pole costs are allocated equally to each distribution customer, regardless of size, even though little if any of these costs are caused by the number of customers.

- Energy usage over many hours of the year contributes to the cost of distribution plant, especially for the summer-peaking portions of the system, but Hydro allocates no distribution costs on energy.

The Board should instruct Hydro to address and correct these problems in its ongoing redesign of its cost-of-service methodology. Until a new cost-of-service methodology is adopted, the Board should not shift cost responsibility onto residential consumers.

Q: What are your recommendations to the Board on rate design issues?

A: The Board should instruct Hydro to modify rates in the following ways over the next several years:

- increase tail-block energy rates to marginal costs, including environmental costs.
- implement marginal-cost-based rates for larger GS customers, using a two-part rate if necessary.
- use the increased revenues from tail-block sales to reduce customer demand and inner-block energy charges; fund enhanced energy-efficiency programs, low-income-customer discounts, and economic development; and improve Hydro's financial structure.
- implement time-of-use energy charges, starting with the largest customers, and move revenue-collection from demand charges to time-of-use energy charges.

Implementation of all of these initiatives—meaning actual changes in retail rates—can start in Hydro's next rate proceeding. Time-of-use rates will require appropriate metering, but even that can be implemented for many large customers in the next proceeding.

If the Board increases funding for DSM, low-income programs, economic development, or strengthening Hydro's balance sheet, the additional costs should be recovered through energy rates and through tail-block energy charges where possible.

In order to make any of these improvements a reality, the Board must be able to compel Hydro to comply with the Board's directives to file studies and implement rate-design changes. Hydro has repeatedly ignored previous Board directives. The Board should consider its alternatives if Hydro continues to stonewall, including the possibility of disallowing some management compensation and of appointing an independent party to conduct analyses and design rates.

Q: Please summarize your recommendations to the Board on DSM issues.

A: Hydro's DSM efforts are modest compared to those of many other North American jurisdictions. The Board should require Hydro to increase its efficiency investments and achievements to reach the 90th percentile of North American jurisdictions. Hydro should start by adopting the recommendations of Dunsky et. al., including expanding program coverage, improving program designs, and abandoning the use of the RIM in program design or screening.

Q: Does this conclude your testimony?

A: Yes.

Exhibit PLC-1

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SUMMARY OF PROFESSIONAL EXPERIENCE

1986–Present **President, Resource Insight, Inc.** Consults and testifies in utility and insurance economics. Reviews utility supply-planning processes and outcomes: assesses prudence of prior power planning investment decisions, identifies excess generating capacity, analyzes effects of power-pool-pricing rules on equity and utility incentives. Reviews electric-utility rate design. Estimates magnitude and cost of future load growth. Designs and evaluates conservation programs for electric, natural-gas, and water utilities, including hook-up charges and conservation cost recovery mechanisms. Determines avoided costs due to cogenerators. Evaluates cogeneration rate risk. Negotiates cogeneration contracts. Reviews management and pricing of district heating systems. Determines fair profit margins for automobile and workers' compensation insurance lines, incorporating reward for risk, return on investments, and tax effects. Determines profitability of transportation services. Advises regulatory commissions in least-cost planning, rate design, and cost allocation.

1981–86 **Research Associate, Analysis and Inference, Inc.** (Consultant, 1980–81). Researched, advised, and testified in various aspects of utility and insurance regulation. Designed self-insurance pool for nuclear decommissioning; estimated probability and cost of insurable events, and rate levels; assessed alternative rate designs. Projected nuclear power plant construction, operation, and decommissioning costs. Assessed reasonableness of earlier estimates of nuclear power plant construction schedules and costs. Reviewed prudence of utility construction decisions. Consulted on utility rate-design issues, including small-power-producer rates; retail natural-gas rates; public-agency electric rates, and comprehensive electric-rate design for a regional power agency. Developed electricity cost allocations between customer classes. Reviewed district-heating-system efficiency. Proposed power-plant performance standards. Analyzed auto-insurance profit requirements. Designed utility-financed, decentralized conservation program. Analyzed cost-effectiveness of transmission lines.

1977–81 **Utility Rate Analyst, Massachusetts Attorney General.** Analyzed utility filings and prepared alternative proposals. Participated in rate negotiations, discovery, cross-examination, and briefing. Provided extensive expert testimony before various regulatory agencies. Topics included demand forecasting, rate design, marginal costs, time-of-use rates, reliability issues, power-pool operations, nuclear-power cost projections, power-plant cost-benefit analysis, energy conservation, and alternative-energy development.

EDUCATION

SM, Technology and Policy Program, Massachusetts Institute of Technology, February 1978.

SB, Civil Engineering Department, Massachusetts Institute of Technology, June 1974.

HONORS

Chi Epsilon (Civil Engineering)

Tau Beta Pi (Engineering)

Sigma Xi (Research)

Institute Award, Institute of Public Utilities, 1981.

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“Using the Costs of Required Controls to Incorporate the Costs of Environmental Externalities in Non-Environmental Decision-Making.” Presentation at the American Planning Association 1992 National Planning Conference; presentation cosponsored by the Edison Electric Institute. May 1992.

“Cost Recovery and Decoupling” and “The Clean Air Act and Externalities in Utility Resource Planning” panels (session leader), DSM Advocacy Workshop; April 15 1992.

“Overview of Integrated Resources Planning Procedures in South Carolina and Critique of South Carolina Demand Side Management Programs,” Energy Planning Workshops; Columbia, S.C.; October 21 1991;

“Least Cost Planning and Gas Utilities.” Conservation Law Foundation Utility Energy Efficiency Advocacy Workshop; Boston, February 28 1991.

“Least-Cost Planning in a Multi-Fuel Context,” NARUC Forum on Gas Integrated Resource Planning; Washington, D.C., February 24 1991.

“Accounting for Externalities: Why, Which and How?” Understanding Massachusetts’ New Integrated Resource Management Rules; Needham, Massachusetts, November 9 1990.

“Increasing Market Share Through Energy Efficiency.” New England Gas Association Gas Utility Managers’ Conference; Woodstock, Vermont, September 10 1990.

“Quantifying and Valuing Environmental Externalities.” Presentation at the Lawrence Berkeley Laboratory Training Program for Regulatory Staff, sponsored by the U.S. Department of Energy’s Least-Cost Utility Planning Program; Berkeley, California, February 2 1990;

“Conservation in the Future of Natural Gas Local Distribution Companies,” District of Columbia Natural Gas Seminar; Washington, D.C., May 23 1989.

“Conservation and Load Management for Natural Gas Utilities,” Massachusetts Natural Gas Council; Newton, Massachusetts, April 3 1989.

New England Conference of Public Utilities Commissioners, Environmental Externalities Workshop; Portsmouth, New Hampshire, January 22–23 1989.

“Assessment and Valuation of External Environmental Damages,” New England Utility Rate Forum; Plymouth, Massachusetts, October 11 1985; “Lessons from Massachusetts on Long Term Rates for QFs”.

“Reviewing Utility Supply Plans,” Massachusetts Energy Facilities Siting Council; Boston, Massachusetts, May 30 1985.

“Power Plant Performance,” National Association of State Utility Consumer Advocates; Williamstown, Massachusetts, August 13 1984.

"Utility Rate Shock," National Conference of State Legislatures; Boston, Massachusetts, August 6 1984.

"Review and Modification of Regulatory and Rate Making Policy," National Governors' Association Working Group on Nuclear Power Cost Overruns; Washington, D.C., June 20 1984.

"Review and Modification of Regulatory and Rate Making Policy," Annual Meeting of the American Association for the Advancement of Science, Session on Monitoring for Risk Management; Detroit, Michigan, May 27 1983.

ADVISORY ASSIGNMENTS TO REGULATORY COMMISSIONS

District of Columbia Public Service Commission, Docket No. 834, Phase II; Least-cost planning procedures and goals; August 1987 to March 1988.

Connecticut Department of Public Utility Control, Docket No. 87-07-01, Phase 2; Rate design and cost allocations; March 1988 to June 1989.

EXPERT TESTIMONY

1. **MEFSC** 78-12/MDPU 19494, Phase I; Boston Edison 1978 forecast; Massachusetts Attorney General; June 12 1978.

   Appliance penetration projections, price elasticity, econometric commercial forecast, peak demand forecast. Joint testimony with Susan C. Geller.

2. **MEFSC** 78-17; Northeast Utilities 1978 forecast; Massachusetts Attorney General; September 29 1978.

   Specification of economic/demographic and industrial models, appliance efficiency, commercial model structure and estimation.

3. **MEFSC** 78-33; Eastern Utilities Associates 1978 forecast; Massachusetts Attorney General; November 27 1978.

   Household size, appliance efficiency, appliance penetration, price elasticity, commercial forecast, industrial trending, peak demand forecast.

4. **MDPU** 19494; Phase II; Boston Edison Company Construction Program; Massachusetts Attorney General; April 1 1979.

   Review of numerous aspects of the 1978 demand forecasts of nine New England electric utilities, constituting 92% of projected regional demand growth, and of the NEPOOL demand forecast. Joint testimony with S.C. Geller.

5. **MDPU** 19494; Phase II; Boston Edison Company Construction Program; Massachusetts Attorney General; April 1 1979.

Reliability, capacity planning, capability responsibility allocation, customer generation, co-generation rates, reserve margins, operating reserve allocation. Joint testimony with S. Finger.

6. **ASLB, NRC** 50-471; Pilgrim Unit 2, Boston Edison Company; Commonwealth of Massachusetts; June 29 1979.

   Review of the Oak Ridge National Laboratory and NEPOOL demand forecast models; cost-effectiveness of oil displacement; nuclear economics. Joint testimony with S.C. Geller.

7. **MDPU** 19845; Boston Edison Time-of-Use Rate Case; Massachusetts Attorney General; December 4 1979.

   Critique of utility marginal cost study and proposed rates; principles of marginal cost principles, cost derivation, and rate design; options for reconciling costs and revenues. Joint testimony with S.C. Geller. Testimony eventually withdrawn due to delay in case.

8. **MDPU** 20055; Petition of Eastern Utilities Associates, New Bedford G. & E., and Fitchburg G. & E. to purchase additional shares of Seabrook Nuclear Plant; Massachusetts Attorney General; January 23 1980.

   Review of demand forecasts of three utilities purchasing Seabrook shares; Seabrook power costs, including construction cost, completion date, capacity factor, O&M expenses, interim replacements, reserves and uncertainties; alternative energy sources, including conservation, cogeneration, rate reform, solar, wood and coal conversion.

9. **MDPU** 20248; Petition of MMWEC to Purchase Additional Share of Seabrook Nuclear Plant; Massachusetts Attorney General; June 2 1980.

   Nuclear power costs; update and extension of MDPU 20055 testimony.

10. **MDPU** 200; Massachusetts Electric Company Rate Case; Massachusetts Attorney General; June 16 1980.

    Rate design; declining blocks, promotional rates, alternative energy, demand charges, demand ratchets; conservation: master metering, storage heating, efficiency standards, restricting resistance heating.

11. **MEFSC** 79-33; Eastern Utilities Associates 1979 Forecast; Massachusetts Attorney General; July 16 1980.

    Customer projections, consistency issues, appliance efficiency, new appliance types, commercial specifications, industrial data manipulation and trending, sales and resale.

12. **MDPU** 243; Eastern Edison Company Rate Case; Massachusetts Attorney General; August 19 1980.

Rate design: declining blocks, promotional rates, alternative energy, master metering.

13. **Texas PUC** 3298; Gulf States Utilities Rate Case; East Texas Legal Services; August 25 1980.

Inter-class revenue allocations, including production plant in-service, O&M, CWIP, nuclear fuel in progress, amortization of canceled plant residential rate design; interruptible rates; off-peak rates. Joint testimony with M. B. Meyer.

14. **MEFSC** 79-1; Massachusetts Municipal Wholesale Electric Company Forecast; Massachusetts Attorney General; November 5 1980.

Cost comparison methodology; nuclear cost estimates; cost of conservation, cogeneration, and solar.

15. **MDPU** 472; Recovery of Residential Conservation Service Expenses; Massachusetts Attorney General; December 12 1980.

Conservation as an energy source; advantages of per-kWh allocation over per-customer-month allocation.

16. **MDPU** 535; Regulations to Carry Out Section 210 of PURPA; Massachusetts Attorney General; January 26 1981 and February 13 1981.

Filing requirements, certification, qualifying facility (QF) status, extent of coverage, review of contracts; energy rates; capacity rates; extra benefits of QFs in specific areas; wheeling; standardization of fees and charges.

17. **MEFSC** 80-17; Northeast Utilities 1980 Forecast; Massachusetts Attorney General; March 12 1981 (not presented).

Specification process, employment, electric heating promotion and penetration, commercial sales model, industrial model specification, documentation of price forecasts and wholesale forecast.

18. **MDPU** 558; Western Massachusetts Electric Company Rate Case; Massachusetts Attorney General; May 1981.

Rate design including declining blocks, marginal cost conservation impacts, and promotional rates. Conservation, including terms and conditions limiting renewable, cogeneration, small power production; scope of current conservation program; efficient insulation levels; additional conservation opportunities.

19. **MDPU** 1048; Boston Edison Plant Performance Standards; Massachusetts Attorney General; May 7 1982.

Critique of company approach, data, and statistical analysis; description of comparative and absolute approaches to standard-setting; proposals for standards and reporting requirements.

20. **DCPSC** FC785; Potomac Electric Power Rate Case; DC People's Counsel; July 29 1982.

    Inter-class revenue allocations, including generation, transmission, and distribution plant classification; fuel and O&M classification; distribution and service allocators. Marginal cost estimation, including losses.

21. **NHPUC** DE1-312; Public Service of New Hampshire-Supply and Demand; Conservation Law Foundation, et al.; October 8 1982.

    Conservation program design, ratemaking, and effectiveness. Cost of power from Seabrook nuclear plant, including construction cost and duration, capacity factor, O&M, replacements, insurance, and decommissioning.

22. **Massachusetts Division of Insurance;** Hearing to Fix and Establish 1983 Automobile Insurance Rates; Massachusetts Attorney General; October 1982.

    Profit margin calculations, including methodology, interest rates, surplus flow, tax flows, tax rates, and risk premium.

23. **Illinois Commerce Commission** 82-0026; Commonwealth Edison Rate Case; Illinois Attorney General; October 15 1982.

    Review of Cost-Benefit Analysis for nuclear plant. Nuclear cost parameters (construction cost, O&M, capital additions, useful like, capacity factor), risks, discount rates, evaluation techniques.

24. **New Mexico PSC** 1794; Public Service of New Mexico Application for Certification; New Mexico Attorney General; May 10 1983.

    Review of Cost-Benefit Analysis for transmission line. Review of electricity price forecast, nuclear capacity factors, load forecast. Critique of company ratemaking proposals; development of alternative ratemaking proposal.

25. **Connecticut Public Utility Control Authority** 830301; United Illuminating Rate Case; Connecticut Consumers Counsel; June 17 1983.

    Cost of Seabrook nuclear power plants, including construction cost and duration, capacity factor, O&M, capital additions, insurance and decommissioning.

26. **MDPU** 1509; Boston Edison Plant Performance Standards; Massachusetts Attorney General; July 15 1983.

    Critique of company approach and statistical analysis; regression model of nuclear capacity factor; proposals for standards and for standard-setting methodologies.

27. **Massachusetts Division of Insurance;** Hearing to Fix and Establish 1984 Automobile Insurance Rates; Massachusetts Attorney General; October 1983.

    Profit margin calculations, including methodology, interest rates.

28. **Connecticut Public Utility Control Authority** 83-07-15; Connecticut Light and Power Rate Case; Alloy Foundry; October 3 1983.

    Industrial rate design. Marginal and embedded costs; classification of generation, transmission, and distribution expenses; demand versus energy charges.

29. **MEFSC** 83-24; New England Electric System Forecast of Electric Resources and Requirements; Massachusetts Attorney General; November 14 1983, Rebuttal, February 2 1984.

    Need for transmission line. Status of supply plan, especially Seabrook 2. Review of interconnection requirements. Analysis of cost-effectiveness for power transfer, line losses, generation assumptions.

30. **Michigan PSC** U-7775; Detroit Edison Fuel Cost Recovery Plan; Public Interest Research Group in Michigan; February 21 1984.

    Review of proposed performance target for new nuclear power plant. Formulation of alternative proposals.

31. **MDPU** 84-25; Western Massachusetts Electric Company Rate Case; Massachusetts Attorney General; April 6 1984.

    Need for Millstone 3. Cost of completing and operating unit, cost-effectiveness compared to alternatives, and its effect on rates. Equity and incentive problems created by CWIP. Design of Millstone 3 phase-in proposals to protect ratepayers: limitation of base-rate treatment to fuel savings benefit of unit.

32. **MDPU** 84-49 and 84-50; Fitchburg Gas & Electric Financing Case; Massachusetts Attorney General; April 13 1984.

    Cost of completing and operating Seabrook nuclear units. Probability of completing Seabrook 2. Recommendations regarding FG&E and MDPU actions with respect to Seabrook.

33. **Michigan PSC** U-7785; Consumers Power Fuel Cost Recovery Plan; Public Interest Research Group in Michigan; April 16 1984.

    Review of proposed performance targets for two existing and two new nuclear power plants. Formulation of alternative policy.

34. **FERC** ER81-749-000 and ER82-325-000; Montaup Electric Rate Cases; Massachusetts Attorney General; April 27 1984.

    Prudence of Montaup and Boston Edison in decisions regarding Pilgrim 2 construction: Montaup's decision to participate, the Utilities' failure to review their earlier analyses and assumptions, Montaup's failure to question Edison's decisions, and the utilities' delay in canceling the unit.

35. **Maine PUC** 84-113; Seabrook 1 Investigation; Maine Public Advocate; September 13 1984.

Cost of completing and operating Seabrook Unit 1. Probability of completing Seabrook 1. Comparison of Seabrook to alternatives. Rate effects. Recommendations regarding utility and PUC actions with respect to Seabrook.

36. **MDPU** 84-145; Fitchburg Gas and Electric Rate Case; Massachusetts Attorney General; November 6 1984.

    Prudence of Fitchburg and Public Service of New Hampshire in decision regarding Seabrook 2 construction: FGE's decision to participate, the utilities' failure to review their earlier analyses and assumptions, FGE's failure to question PSNH's decisions, and utilities' delay in halting construction and canceling the unit. Review of literature, cost and schedule estimate histories, cost-benefit analyses, and financial feasibility.

37. **Pennsylvania PUC** R-842651; Pennsylvania Power and Light Rate Case; Pennsylvania Consumer Advocate; November 1984.

    Need for Susquehanna 2. Cost of operating unit, power output, cost-effectiveness compared to alternatives, and its effect on rates. Design of phase-in and excess capacity proposals to protect ratepayers: limitation of base-rate treatment to fuel savings benefit of unit.

38. **NHPUC** 84-200; Seabrook Unit 1 Investigation; New Hampshire Public Advocate; November 15 1984.

    Cost of completing and operating Seabrook Unit 1. Probability of completing Seabrook 1. Comparison of Seabrook to alternatives. Rate and financial effects.

39. **Massachusetts Division of Insurance;** Hearing to Fix and Establish 1985 Automobile Insurance Rates; Massachusetts Attorney General; November 1984.

    Profit margin calculations, including methodology and implementation.

40. **MDPU** 84-152; Seabrook Unit 1 Investigation; Massachusetts Attorney General; December 12 1984.

    Cost of completing and operating Seabrook. Probability of completing Seabrook 1. Seabrook capacity factors.

41. **Maine PUC** 84-120; Central Maine Power Rate Case; Maine PUC Staff; December 11 1984.

    Prudence of Central Maine Power and Boston Edison in decisions regarding Pilgrim 2 construction: CMP's decision to participate, the utilities' failure to review their earlier analyses and assumptions, CMP's failure to question Edison's decisions, and the utilities' delay in canceling the unit. Prudence of CMP in the planning and investment in Sears Island nuclear and coal plants. Review of literature, cost and schedule estimate histories, cost-benefit analyses, and financial feasibility.

42. **Maine PUC** 84-113; Seabrook 2 Investigation; Maine PUC Staff; December 14 1984.

Prudence of Maine utilities and Public Service of New Hampshire in decisions regarding Seabrook 2 construction: decisions to participate and to increase ownership share, the utilities' failure to review their earlier analyses and assumptions, failure to question PSNH's decisions, and the utilities' delay in halting construction and canceling the unit. Review of literature, cost and schedule estimate histories, cost-benefit analyses, and financial feasibility.

43. **MDPU** 1627; Massachusetts Municipal Wholesale Electric Company Financing Case; Massachusetts Executive Office of Energy Resources; January 14 1985.

    Cost of completing and operating Seabrook nuclear unit 1. Cost of conservation and other alternatives to completing Seabrook. Comparison of Seabrook to alternatives.

44. **Vermont PSB** 4936; Millstone 3; Costs and In-Service Date; Vermont Department of Public Service; January 21 1985.

    Construction schedule and cost of completing Millstone Unit 3.

45. **MDPU** 84-276; Rules Governing Rates for Utility Purchases of Power from Qualifying Facilities; Massachusetts Attorney General; March 25 1985, and October 18 1985.

    Institutional and technological advantages of Qualifying Facilities. Potential for QF development. Goals of QF rate design. Parity with other power sources. Security requirements. Projecting avoided costs. Capacity credits. Pricing options. Line loss corrections.

46. **MDPU** 85-121; Investigation of the Reading Municipal Light Department; Wilmington (MA) Chamber of Commerce; November 12 1985.

    Calculation on return on investment for municipal utility. Treatment of depreciation and debt for ratemaking. Geographical discrimination in street-lighting rates. Relative size of voluntary payments to Reading and other towns. Surplus and disinvestment. Revenue allocation.

47. **Massachusetts Division of Insurance;** Hearing to Fix and Establish 1986 Automobile Insurance Rates; Massachusetts Attorney General and State Rating Bureau; November 1985.

    Profit margin calculations, including methodology, implementation, modeling of investment balances, income, and return to shareholders.

48. **New Mexico PSC** 1833, Phase II; El Paso Electric Rate Case; New Mexico Attorney General; December 23 1985.

    Nuclear decommissioning fund design. Internal and external funds; risk and return; fund accumulation, recommendations. Interim performance standard for Palo Verde nuclear plant.

49. **Pennsylvania PUC** R-850152; Philadelphia Electric Rate Case; Utility Users Committee and University of Pennsylvania; January 14 1986.

    Limerick 1 rate effects. Capacity benefits, fuel savings, operating costs, capacity factors, and net benefits to ratepayers. Design of phase-in proposals.

50. **MDPU** 85-270; Western Massachusetts Electric Rate Case; Massachusetts Attorney General; March 19 1986.

    Prudence of Northeast Utilities in generation planning related to Millstone 3 construction: decisions to start and continue construction, failure to reduce ownership share, failure to pursue alternatives. Review of industry literature, cost and schedule histories, and retrospective cost-benefit analyses.

51. **Pennsylvania PUC** R-850290; Philadelphia Electric Auxiliary Service Rates; Albert Einstein Medical Center, University of Pennsylvania and AMTRAK; March 24 1986.

    Review of utility proposals for supplementary and backup rates for small power producers and cogenerators. Load diversity, cost of peaking capacity, value of generation, price signals, and incentives. Formulation of alternative supplementary rate.

52. **New Mexico PSC** 2004; Public Service of New Mexico, Palo Verde Issues; New Mexico Attorney General; May 7 1986.

    Recommendations for Power Plant Performance Standards for Palo Verde nuclear units 1, 2, and 3.

53. **Illinois Commerce Commission** 86-0325; Iowa-Illinois Gas and Electric Co. Rate Investigation; Illinois Office of Public Counsel; August 13 1986.

    Determination of excess capacity based on reliability and economic concerns. Identification of specific units associated with excess capacity. Required reserve margins.

54. **New Mexico PSC** 2009; El Paso Electric Rate Moderation Program; New Mexico Attorney General; August 18 1986. (Not presented).

    Prudence of EPE in generation planning related to Palo Verde nuclear construction, including failure to reduce ownership share and failure to pursue alternatives. Review of industry literature, cost and schedule histories, and retrospective cost-benefit analyses.

    Recommendation for rate-base treatment; proposal of power plant performance standards.

55. **City of Boston, Public Improvements Commission;** Transfer of Boston Edison District Heating Steam System to Boston Thermal Corporation; Boston Housing Authority; December 18 1986.

History and economics of steam system; possible motives of Boston Edison in seeking sale; problems facing Boston Thermal; information and assurances required prior to Commission approval of transfer.

56. **Massachusetts Division of Insurance;** Hearing to Fix and Establish 1987 Automobile Insurance Rates; Massachusetts Attorney General and State Rating Bureau; December 1986 and January 1987.

    Profit margin calculations, including methodology, implementation, derivation of cash flows, installment income, income tax status, and return to shareholders.

57. **MDPU** 87-19; Petition for Adjudication of Development Facilitation Program; Hull (MA) Municipal Light Plant; January 21 1987.

    Estimation of potential load growth; cost of generation, transmission, and distribution additions. Determination of hook-up charges. Development of residential load estimation procedure reflecting appliance ownership, dwelling size.

58. **New Mexico PSC** 2004; Public Service of New Mexico Nuclear Decommissioning Fund; New Mexico Attorney General; February 19 1987.

    Decommissioning cost and likely operating life of nuclear plants. Review of utility funding proposal. Development of alternative proposal. Ratemaking treatment.

59. **MDPU** 86-280; Western Massachusetts Electric Rate Case; Massachusetts Energy Office; March 9 1987.

    Marginal cost rate design issues. Superiority of long-run marginal cost over short-run marginal cost as basis for rate design. Relationship of consumer reaction, utility planning process, and regulatory structure to rate design approach. Implementation of short-run and long-run rate designs. Demand versus energy charges, economic development rates, spot pricing.

60. **Massachusetts Division of Insurance** 87-9; 1987 Workers' Compensation Rate Filing; State Rating Bureau; May 1987.

    Profit margin calculations, including methodology, implementation, surplus requirements, investment income, and effects of 1986 Tax Reform Act.

61. **Texas PUC** 6184; Economic Viability of South Texas Nuclear Plant #2; Committee for Consumer Rate Relief; August 17 1987.

    STNP operating parameter projections; capacity factor, O&M, capital additions, decommissioning, useful life. STNP 2 cost and schedule projections. Potential for conservation.

62. **Minnesota PUC** ER-015/GR-87-223; Minnesota Power Rate Case; Minnesota Department of Public Service; August 17 1987.

Excess capacity on MP system; historical, current, and projected. Review of MP planning prudence prior to and during excess; efforts to sell capacity. Cost of excess capacity. Recommendations for ratemaking treatment.

63. **Massachusetts Division of Insurance** 87-27; 1988 Automobile Insurance Rates; Massachusetts Attorney General and State Rating Bureau; September 2 1987. Rebuttal October 8 1987.

    Underwriting profit margins. Effect of 1986 Tax Reform Act. Biases in calculation of average margins.

64. **MDPU** 88-19; Power Sales Contract from Riverside Steam and Electric to Western Massachusetts Electric; Riverside Steam and Electric; November 4 1987.

    Comparison of risk from QF contract and utility avoided cost sources. Risk of oil dependence. Discounting cash flows to reflect risk.

65. **Massachusetts Division of Insurance** 87-53; 1987 Workers' Compensation Rate Refiling; State Rating Bureau; December 14 1987.

    Profit margin calculations, including updating of data, compliance with Commissioner's order, treatment of surplus and risk, interest rate calculation, and investment tax rate calculation.

66. **Massachusetts Division of Insurance;** 1987 and 1988 Automobile Insurance Remand Rates; Massachusetts Attorney General and State Rating Bureau; February 5 1988.

    Underwriting profit margins. Provisions for income taxes on finance charges. Relationships between allowed and achieved margins, between statewide and nationwide data, and between profit allowances and cost projections.

67. **MDPU** 86-36; Investigation into the Pricing and Ratemaking Treatment to be Afforded New Electric Generating Facilities which are not Qualifying Facilities; Conservation Law Foundation; May 2 1988.

    Cost recovery for utility conservation programs. Compensating for lost revenues. Utility incentive structures.

68. **MDPU** 88-123; Petition of Riverside Steam & Electric Company; Riverside Steam and Electric Company; May 18 1988, and November 8 1988.

    Estimation of avoided costs of Western Massachusetts Electric Company. Nuclear capacity factor projections and effects on avoided costs. Avoided cost of energy interchange and power plant life extensions. Differences between median and expected oil prices. Salvage value of cogeneration facility. Off-system energy purchase projections. Reconciliation of avoided cost projection.

69. **MDPU** 88-67; Boston Gas Company; Boston Housing Authority; June 17 1988.

Estimation of annual avoidable costs, 1988 to 2005, and levelized avoided costs. Determination of cost recovery and carrying costs for conservation investments. Standards for assessing conservation cost-effectiveness. Evaluation of cost-effectiveness of utility funding of proposed natural gas conservation measures.

70. **Rhode Island PUC** Docket 1900; Providence Water Supply Board Tariff Filing; Conservation Law Foundation, Audubon Society of Rhode Island, and League of Women Voters of Rhode Island; June 24 1988.

    Estimation of avoidable water supply costs. Determination of costs of water conservation. Conservation cost-benefit analysis.

71. **Massachusetts Division of Insurance** 88-22; 1989 Automobile Insurance Rates; Massachusetts Attorney General and State Rating Bureau; Profit Issues, August 12 1988, supplemented August 19 1988; Losses and Expenses, September 16 1988.

    Underwriting profit margins. Effects of 1986 Tax Reform Act. Taxation of common stocks. Lag in tax payments. Modeling risk and return over time. Treatment of finance charges. Comparison of projected and achieved investment returns.

72. **Vermont PSB** 5270, Module 6; Investigation into Least-Cost Investments, Energy Efficiency, Conservation, and the Management of Demand for Energy; Conservation Law Foundation, Vermont Natural Resources Council, and Vermont Public Interest Research Group; September 26 1988.

    Cost recovery for utility conservation programs. Compensation of utilities for revenue losses and timing differences. Incentive for utility participation.

73. **Vermont House of Representatives, Natural Resources Committee;** House Act 130; "Economic Analysis of Vermont Yankee Retirement"; Vermont Public Interest Research Group; February 21 1989.

    Projection of capacity factors, operating and maintenance expense, capital additions, overhead, replacement power costs, and net costs of Vermont Yankee.

74. **MDPU** 88-67, Phase II; Boston Gas Company Conservation Program and Rate Design; Boston Gas Company; March 6 1989.

    Estimation of avoided gas cost; treatment of non-price factors; estimation of externalities; identification of cost-effective conservation.

75. **Vermont PSB** 5270; Status Conference on Conservation and Load Management Policy Settlement; Central Vermont Public Service, Conservation Law Foundation, Vermont Natural Resources Council, Vermont Public Interest Research Group, and Vermont Department of Public Service; May 1 1989.

    Cost-benefit test for utility conservation programs. Role of externalities. Cost recovery concepts and mechanisms. Resource allocations, cost allocations, and equity considerations. Guidelines for conservation preapproval mechanisms. Incentive mechanisms and recovery of lost revenues.

76. **Boston Housing Authority Court** 05099; Gallivan Boulevard Task Force vs. Boston Housing Authority, et al.; Boston Housing Authority; June 16 1989.

Effect of master-metering on consumption of natural gas and electricity. Legislative and regulatory mandates regarding conservation.

77. **MDPU** 89-100; Boston Edison Rate Case; Massachusetts Energy Office; June 30 1989.

Prudence of BECo's decision to spend $400 million from 1986–88 on returning the Pilgrim nuclear power plant to service. Projections of nuclear capacity factors, O&M, capital additions, and overhead. Review of decommissioning cost, tax effect of abandonment, replacement power cost, and plant useful life estimates. Requirements for prudence and used-and-useful analyses.

78. **MDPU** 88-123; Petition of Riverside Steam and Electric Company; Riverside Steam and Electric; July 24 1989. Rebuttal, October 3 1989.

Reasonableness of Northeast Utilities' 1987 avoided cost estimates. Projections of nuclear capacity factors, economy purchases, and power plant operating life. Treatment of avoidable energy and capacity costs and of off-system sales. Expected versus reference fuel prices.

79. **MDPU** 89-72; Statewide Towing Association, Police-Ordered Towing Rates; Massachusetts Automobile Rating Bureau; September 13 1989.

Review of study supporting proposed increase in towing rates. Critique of study sample and methodology. Comparison to competitive rates. Supply of towing services. Effects of joint products and joint sales on profitability of police-ordered towing. Joint testimony with I. Goodman.

80. **Vermont PSB** 5330; Application of Vermont Utilities for Approval of a Firm Power and Energy Contract with Hydro-Quebec; Conservation Law Foundation, Vermont Natural Resources Council, Vermont Public Interest Research Group; December 19 1989. Surrebuttal February 6 1990.

Analysis of a proposed 450-MW, 20 year purchase of Hydro-Quebec power by twenty-four Vermont utilities. Comparison to efficiency investment in Vermont, including potential for efficiency savings. Analysis of Vermont electric energy supply. Identification of possible improvements to proposed contract.

Critique of conservation potential analysis. Planning risk of large supply additions. Valuation of environmental externalities.

81. **MDPU** 89-239; Inclusion of Externalities in Energy Supply Planning, Acquisition and Dispatch for Massachusetts Utilities; December 1989; April 1990; May 1990.

Critique of Division of Energy Resources report on externalities. Methodology for evaluating external costs. Proposed values for environmental and economic externalities of fuel supply and use.

82. **California PUC**; Incorporation of Environmental Externalities in Utility Planning and Pricing; Coalition of Energy Efficient and Renewable Technologies; February 21 1990.

    Approaches for valuing externalities for inclusion in setting power purchase rates. Effect of uncertainty on assessing externality values.

83. **Illinois Commerce Commission** Docket 90-0038; Proceeding to Adopt a Least Cost Electric Energy Plan for Commonwealth Edison Company; City of Chicago; May 25 1990. Joint rebuttal testimony with David Birr, August 14 1990.

    Problems in Commonwealth Edison's approach to demand-side management. Potential for cost-effective conservation. Valuing externalities in least-cost planning.

84. **Maryland PSC** 8278; Adequacy of Baltimore Gas & Electric's Integrated Resource Plan; Maryland Office of People's Counsel; September 18 1990.

    Rationale for demand-side management, and BG&E's problems in approach to DSM planning. Potential for cost-effective conservation. Valuation of environmental externalities. Recommendations for short-term DSM program priorities.

85. **Indiana Utility Regulatory Commission;** Integrated Resource Planning Docket; Indiana Office of Utility Consumer Counselor; November 1 1990.

    Integrated resource planning process and methodology, including externalities and screening tools. Incentives, screening, and evaluation of demand-side management. Potential of resource bidding in Indiana.

86. **MDPU** 89-141, 90-73, 90-141, 90-194, and 90-270; Preliminary Review of Utility Treatment of Environmental Externalities in October QF Filings; Boston Gas Company; November 5 1990.

    Generic and specific problems in Massachusetts utilities' RFPs with regard to externality valuation requirements. Recommendations for corrections.

87. **MEFSC** 90-12/90-12A; Adequacy of Boston Edison Proposal to Build Combined-Cycle Plant; Conservation Law Foundation; December 14 1990.

    Problems in Boston Edison's treatment of demand-side management, supply option analysis, and resource planning. Recommendations of mitigation options.

88. **Maine PUC** 90-286; Adequacy of Conservation Program of Bangor Hydro Electric; Penobscot River Coalition; February 19 1991.

    Role of utility-sponsored DSM in least-cost planning. Bangor Hydro's potential for cost-effective conservation. Problems with Bangor Hydro's assumptions about customer investment in energy efficiency measures.

89. **Virginia State Corporation Commission** PUE900070; Order Establishing Commission Investigation; Southern Environmental Law Center; March 6 1991.

Role of utilities in promoting energy efficiency. Least-cost planning objectives of and resource acquisition guidelines for DSM. Ratemaking considerations for DSM investments.

90. **MDPU** 90-261-A; Economics and Role of Fuel-Switching in the DSM Program of the Massachusetts Electric Company; Boston Gas Company; April 17 1991.

    Role of fuel-switching in utility DSM programs and specifically in Massachusetts Electric's. Establishing comparable avoided costs and comparison of electric and gas system costs. Updated externality values.

91. **Private arbitration;** Massachusetts Refusetech Contractual Request for Adjustment to Service Fee; Massachusetts Refusetech; May 13 1991.

    NEPCo rates for power purchases from the NESWC plant. Fuel price and avoided cost projections vs. realities.

92. **Vermont PSB** 5491; Cost-Effectiveness of Central Vermont's Commitment to Hydro Quebec Purchases; Conservation Law Foundation; July 19 1991.

    Changes in load forecasts and resale markets since approval of HQ purchases. Effect of HQ purchase on DSM.

93. **South Carolina PSC** 91-216-E; Cost Recovery of Duke Power's DSM Expenditures; South Carolina Department of Consumer Affairs; September 13 1991. Surrebuttal October 2 1991.

    Problems with conservation plans of Duke Power, including load building, cream skimming, and inappropriate rate designs.

94. **Maryland PSC** 8241, Phase II; Review of Baltimore Gas & Electric's Avoided Costs; Maryland Office of People's Counsel; September 19 1991.

    Development of direct avoided costs for DSM. Problems with BG&E's avoided costs and DSM screening. Incorporation of environmental externalities.

95. **Bucksport Planning Board;** AES/Harriman Cove Shoreland Zoning Application; Conservation Law Foundation and Natural Resources Council of Maine; October 1 1991.

    New England's power surplus. Costs of bringing AES/Harriman Cove on line to back out existing generation. Alternatives to AES.

96. **MDPU** 91-131; Update of Externalities Values Adopted in Docket 89-239; Boston Gas Company; October 4 1991. Rebuttal, December 13 1991.

    Updates on pollutant externality values. Addition of values for chlorofluorocarbons, air toxics, thermal pollution, and oil import premium. Review of state regulatory actions regarding externalities.

97. **Florida PSC** 910759; Petition of Florida Power Corporation for Determination of Need for Proposed Electrical Power Plant and Related Facilities; Floridians for Responsible Utility Growth; October 21 1991.

    Florida Power's obligation to pursue integrated resource planning and failure to establish need for proposed facility. Methods to increase scope and scale of demand-side investment.

98. **Florida PSC** 910833-EI; Petition of Tampa Electric Company for a Determination of Need for Proposed Electrical Power Plant and Related Facilities; Floridians for Responsible Utility Growth; October 31 1991.

    Tampa Electric's obligation to pursue integrated resource planning and failure to establish need for proposed facility. Methods to increase scope and scale of demand-side investment.

99. **Pennsylvania PUC** I-900005, R-901880; Investigation into Demand Side Management by Electric Utilities; Pennsylvania Energy Office; January 10 1992.

    Appropriate cost recovery mechanism for Pennsylvania utilities. Purpose and scope of direct cost recovery, lost revenue recovery, and incentives.

100. **South Carolina PSC** 91-606-E; Petition of South Carolina Electric and Gas for a Certificate of Public Convenience and Necessity for a Coal-Fired Plant; South Carolina Department of Consumer Affairs; January 20 1992.

    Justification of plant certification under integrated resource planning. Failures in SCE&G's DSM planning and company potential for demand-side savings.

101. **MDPU** 92-92; Adequacy of Boston Edison's Street-Lighting Options; Town of Lexington; June 22 1992.

    Efficiency and quality of street-lighting options. Boston Edison's treatment of high-quality street lighting. Corrected rate proposal for the Daylux lamp. Ownership of public street lighting.

102. **South Carolina PSC** 92-208-E; Integrated Resource Plan of Duke Power Company; South Carolina Department of Consumer Affairs; August 4 1992.

    Problems with Duke Power's DSM screening process, estimation of avoided cost, DSM program design, and integration of demand-side and supply-side planning.

103. **North Carolina Utilities Commission** E-100, Sub 64; Integrated Resource Planning Docket; Southern Environmental Law Center; September 29 1992.

    General principles of integrated resource planning, DSM screening, and program design. Review of the IRPs of Duke Power Company, Carolina Power & Light Company, and North Carolina Power.

104. **Ontario Environmental Assessment Board** Ontario Hydro Demand/Supply Plan Hearings; *Environmental Externalities Valuation and Ontario Hydro's Resource Planning* (3 vols.); October 1992.

Valuation of environmental externalities from fossil fuel combustion and the nuclear fuel cycle. Application to Ontario Hydro's supply and demand planning.

105. **Texas PUC** 110000; Application of Houston Lighting and Power Company for a Certificate of Convenience and Necessity for the DuPont Project; Destec Energy, Inc.; September 28 1992.

Valuation of environmental externalities from fossil fuel combustion and the application to the evaluation of proposed cogeneration facility.

106. **Maine Board of Environmental Protection;** In the Matter of the Basin Mills Hydroelectric Project Application; Conservation Intervenors; November 16 1992.

Economic and environmental effects of generation by proposed hydro-electric project.

107. **Maryland PSC** 8473; Review of the Power Sales Agreement of Baltimore Gas and Electric with AES Northside; Maryland Office of People's Counsel; November 16 1992.

Non-price scoring and unquantified benefits; DSM potential as alternative; environmental costs; cost and benefit estimates.

108. **North Carolina Utilities Commission** E-100, Sub 64; Analysis and Investigation of Least Cost Integrated Resource Planning in North Carolina; Southern Environmental Law Center; November 18 1992.

Demand-side management cost recovery and incentive mechanisms.

109. **South Carolina PSC** 92-209-E; In Re Carolina Power & Light Company; South Carolina Department of Consumer Affairs; November 24 1992.

DSM planning: objectives, process, cost-effectiveness test, comprehensiveness, lost opportunities. Deficiencies in CP&L's portfolio. Need for economic evaluation of load building.

110 **Florida Department of Environmental Regulation** hearings on the Power Plant Siting Act; Legal Environmental Assistance Foundation, December 1992.

Externality valuation and application in power-plant siting. DSM potential, cost-benefit test, and program designs.

111. **Maryland PSC** 8487; Baltimore Gas and Electric Company, Electric Rate Case; January 13 1993. Rebuttal Testimony: February 4 1993.

Class allocation of production plant and O&M; transmission, distribution, and general plant; administrative and general expenses. Marginal cost and rate design.

112. **Maryland PSC** 8179; for Approval of Amendment No. 2 to Potomac Edison Purchase Agreement with AES Warrior Run; Maryland Office of People's Counsel; January 29 1993.

Economic analysis of proposed coal-fired cogeneration facility.

113. A. **Michigan PSC** U-10102; Detroit Edison Rate Case; Michigan United Conservation Clubs; February 17 1993.

Least-cost planning; energy efficiency planning, potential, screening, avoided costs, cost recovery, and shareholder incentives.

114. **Ohio PUC** 91-635-EL-FOR, 92-312-EL-FOR, 92-1172-EL-ECP; Cincinnati Gas and Electric demand-management programs; City of Cincinnati. April 1993.

DSM planning, program designs, potential savings, and avoided costs.

115. **Michigan PSC** U-10335; Consumers Power Rate Case; Michigan United Conservation Clubs; October 1993.

Least-cost planning; energy efficiency planning, potential, screening, avoided costs, cost recovery, and shareholder incentives.

116. **Illinois Commerce Commission** 92-0268, Electric-Energy Plan for Commonwealth Edison; City of Chicago. Direct testimony, February 1 1994; rebuttal, September 1994.

Cost-effectiveness screening of demand-side management programs and measures; estimates by Commonwealth Edison of costs avoided by DSM and of future cost, capacity, and performance of supply resources.

117. **FERC** 2422 et al., Application of James River–New Hampshire Electric, Public Service of New Hampshire, for Licensing of Hydro Power; Conservation Law Foundation; 1993.

Cost-effective energy conservation available to the Public Service of New Hampshire; power-supply options; affidavit.

118. **Vermont PSB** 5270-CV-1,-3, and 5686; Central Vermont Public Service Fuel-Switching and DSM Program Design, on behalf of the Vermont Department of Public Service. Direct, April 1994; rebuttal, June 1994.

Avoided costs and screening of controlled water-heating measures; risk, rate impacts, participant costs, externalities, space- and water-heating load, benefit-cost tests.

119. **Florida PSC** 930548-EG–930551–EG, Conservation goals for Florida electric utilities; Legal Environmental Assistance Foundation, Inc. April 1994.

Integrated resource planning, avoided costs, rate impacts, analysis of conservation goals of Florida electric utilities.

120. **Vermont PSB** 5724, Central Vermont Public Service Corporation rate request; Vermont Department of Public Service. Joint surrebuttal testimony with John Plunkett. August 1994.

Costs avoided by DSM programs; Costs and benefits of deferring DSM programs.

121. **MDPU** 94-49, Boston Edison integrated resource-management plan; Massachusetts Attorney General. August 1994.

Least-cost planning, modeling, and treatment of risk.

122. **Michigan PSC** U-10554, Consumers Power Company DSM Program and Incentive; Michigan Conservation Clubs. November 1994.

Critique of proposed reductions in DSM programs; discussion of appropriate measurements of cost-effectiveness, role of DSM in competitive power markets.

123. **Michigan PSC** U-10702, Detroit Edison Company Cost Recovery, on behalf of the Residential Ratepayers Consortium. December 1994.

Impact of proposed changes to DSM plan on energy costs and power-supply-cost-recovery charges. Critique of proposed DSM changes; discussion of appropriate measurements of cost-effectiveness, role of DSM in competitive power markets.

124. **New Jersey Board of Regulatory Commissioners** EM92030359, Environmental costs of proposed cogeneration; Freehold Cogeneration Associates. November 1994.

Comparison of potential externalities from the Freehold cogeneration project with that from three coal technologies; support for the study "The Externalities of Four Power Plants."

125. **Michigan PSC** U-10671, Detroit Edison Company DSM Programs; Michigan United Conservation Clubs. January 1995.

Critique of proposal to scale back DSM efforts in light of potential for competition. Loss of savings, increase of customer costs, and decrease of competitiveness. Discussion of appropriate measurements of cost-effectiveness, role of DSM in competitive power markets.

126. **Michigan PSC** U-10710, Power-supply-cost-recovery plan of Consumers Power Company; Residential Ratepayers Consortium. January 1995.

Impact of proposed changes to DSM plan on energy costs and power-supply-cost-recovery charges. Critique of proposed DSM changes; discussion of appropriate measurements of cost-effectiveness, role of DSM in competitive power markets.

127. **FERC** 2458 and 2572, Bowater–Great Northern Paper hydropower licensing; Conservation Law Foundation. February 1995.

Comments on draft environmental impact statement relating to new licenses for two hydropower projects in Maine. Applicant has not adequately considered how energy conservation can replace energy lost due to habitat-protection or -enhancement measures.

128. **North Carolina Utilities Commission** E-100, Sub 74, Duke Power and Carolina Power & Light avoided costs; Hydro-Electric–Power Producer's Group. February 1995.

Critique and proposed revision of avoided costs offered to small hydro-power producers by Duke Power and Carolina Power and Light.

129. **New Orleans City Council** UD-92-2A and -2B, Least-cost IRP for New Orleans Public Service and Louisiana Power & Light; Alliance for Affordable Energy. Direct, February 1995; rebuttal, April 1995.

Critique of proposal to scale back DSM efforts in light of potential competition.

130. **DCPSC** Formal 917, II, Prudence of DSM expenditures of Potomac Electric Power Company; Potomac Electric Power Company. Rebuttal testimony, February 1995.

Prudence of utility DSM investment; prudence standards for DSM programs of the Potomac Electric Power Company.

131. **Ontario Energy Board** EBRO 490, DSM cost recovery and lost-revenue–adjustment mechanism for Consumers Gas Company; Green Energy Coalition. April 1995.

DSM cost recovery. Lost-revenue–adjustment mechanism for Consumers Gas Company.

132. **New Orleans City Council** CD-85-1, New Orleans Public Service rate increase; Alliance for Affordable Energy. Rebuttal, May 1995.

Allocation of costs and benefits to rate classes.

133. **MDPU** Docket DPU-95-40, Mass. Electric cost-allocation; Massachusetts Attorney General. June 1995.

Allocation of costs to rate classes. Critique of cost-of-service study. Implications for industry restructuring.

134. **Maryland PSC** 8697, Baltimore Gas & Electric gas rate increase; Maryland Office of People's Counsel. July 1995

Rate design, cost-of-service study, and revenue allocation.

135. **North Carolina Utilities Commission** E-2, Sub 669. December 1995.

Need for new capacity. Energy-conservation potential and model programs.

136. **Arizona Commerce Commission** U-1933-95-317, Tucson Electric Power rate increase; Residential Utility Consumer Office. January 1996.

Review of proposed rate settlement. Used-and-usefulness of plant. Rate design. DSM potential.

137. **Ohio PUC** 95-203-EL-FOR; Campaign for an Energy-Efficient Ohio. February 1996

Long-term forecast of Cincinnati Gas and Electric Company, especially its DSM portfolio. Opportunities for further cost-effective DSM savings. Tests of cost effectiveness. Role of DSM in light of industry restructuring; alternatives to traditional utility DSM.

138 **Vermont PSB** 5835; Vermont Department of Public Service. February 1996.

Design of load-management rates of Central Vermont Public Service Company.

139. **Maryland PSC** 8720, Washington Gas Light DSM; Maryland Office of People's Counsel. May 1996.

Avoided costs of Washington Gas Light Company; integrated least-cost planning.

140. A. **MDPU** DPU 96-100; Massachusetts Utilities' Stranded Costs; Massachusetts Attorney General. Oral testimony in support of "estimation of Market Value, Stranded Investment, and Restructuring Gains for Major Massachusetts Utilities," July 1996.

Stranded costs. Calculation of loss or gain. Valuation of utility assets.

141. **MDPU** DPU 96-70; Massachusetts Attorney General. July 1996.

Market-based allocation of gas-supply costs of Essex County Gas Company.

142. **MDPU** DPU 96-60; Massachusetts Attorney General. Direct testimony, July 1996; surrebuttal, August 1996.

Market-based allocation of gas-supply costs of Fall River Gas Company.

143. **Maryland PSC** 8725; Maryland Office of People's Counsel. July 1996.

Proposed merger of Baltimore Gas & Electric Company, Potomac Electric Power Company, and Constellation Energy. Cost allocation of merger benefits and rate reductions.

144. **New Hampshire PUC** DR 96-150, Public Service Company of New Hampshire stranded costs; New Hampshire Office of Consumer Advocate. December 1996.

Market price of capacity and energy; value of generation plant; restructuring gain and stranded investment; legal status of PSNH acquisition premium; interim stranded-cost charges.

145. **Ontario Energy Board** EBRO 495, LRAM and shared-savings incentive for DSM performance of Consumers Gas; Green Energy Coalition. March 1997.

LRAM and shared-savings incentive mechanisms in rates for the Consumers Gas Company Ltd.

146. **New York PSC** Case 96-E-0897, Consolidated Edison restructuring plan; City of New York. April 1997.

Electric-utility competition and restructuring; critique of proposed settlement of Consolidated Edison Company; stranded costs; market power; rates; market access.

147. **Vermont PSB** 5980, proposed statewide energy plan; Vermont Department of Public Service. Direct, August 1997; rebuttal, December 1997.

Justification for and estimation of statewide avoided costs; guidelines for distributed IRP.

148. **MDPU** 96-23, Boston Edison restructuring settlement; Utility Workers Union of America. September 1997.

Performance incentives proposed for the Boston Edison company.

149. **Vermont PSB** 5983, Green Mountain Power rate increase; Vermont Department of Public Service. Direct, October 1997; rebuttal, December 1997.

In three separate pieces of prefiled testimony, addressed the Green Mountain Power Corporation's (1) distributed-utility-planning efforts, (2) avoided costs, and (3) prudence of decisions relating to a power purchase from Hydro-Quebec.

150. **MDPU** 97-63, Boston Edison proposed reorganization; Utility Workers Union of America. October 1997.

Increased costs and risks to ratepayers and shareholders from proposed reorganization; risks of diversification; diversion of capital from regulated to unregulated affiliates; reduction in Commission authority.

151. **MDTE** 97-111, Commonwealth Energy proposed restructuring; Cape Cod Light Compact. Joint testimony with Jonathan Wallach, January 1998.

Critique of proposed restructuring plan filed to satisfy requirements of the electric-utility restructuring act of 1997. Failure of the plan to foster competition and promote the public interest.

152. **NH PUC** Docket DR 97-241, Connecticut Valley Electric fuel and purchased-power adjustments; City of Claremont, N.H. February 1998.

Prudence of continued power purchase from affiliate; market cost of power; prudence disallowances and cost-of-service ratemaking.

153. **Maryland PSC** 8774; APS-DQE merger; Maryland Office of People's Counsel. February 1998.

Power-supply arrangements between APS's operating subsidiaries; power-supply savings; market power.

154. **Vermont PSB** 6018, Central Vermont Public Service Co. rate increase; Vermont Department of Public Service. February 1998.

Prudence of decisions relating to a power purchase from Hydro-Quebec. Reasonableness of avoided-cost estimates. Quality of DU planning.

155. **Maine PUC** 97-580, Central Maine Power restructuring and rates; Maine Office of Public Advocate. May 1998; Surrebuttal, August 1998.

Determination of stranded costs; gains from sales of fossil, hydro, and biomass plant; treatment of deferred taxes; incentives for stranded-cost mitigation; rate design.

156. **MDTE** 98-89, purchase of Boston Edison municipal streetlighting, Towns of Lexington and Acton. Affidavit, August 1998.

Valuation of municipal streetlighting; depreciation; applicability of unbundled rate.

157. **Vermont PSB** 6107, Green Mountain Power rate increase, Vermont Department of Public Service. Direct, September 1998; Surrebuttal drafted but not filed, November 2000.

Prudence of decisions relating to a power purchase from Hydro-Quebec. Least-cost planning and prudence. Quality of DU planning.

158. **MDTE** 97-120, Western Massachusetts Electric Company proposed restructuring; Massachusetts Attorney General. Joint testimony with Jonathan Wallach, October 1998. Joint surrebuttal with Jonathan Wallach, January 1999.

Market value of the three Millstone nuclear units under varying assumptions of plant performance and market prices. Independent forecast of wholesale market prices. Value of Pilgrim and TMI-1 asset sales.

159. **Maryland PSC** 8794 and 8804; BG&E restructuring and rates; Maryland Office of People's Counsel. Direct, December 1998; rebuttal, March 1999.

Implementation of restructuring. Valuation of generation assets from comparable-sales and cash-flow analyses. Determination of stranded cost or gain.

160. **Maryland PSC** 8795; Delmarva Power & Light restructuring and rates; Maryland Office of People's Counsel. December 1998.

Implementation of restructuring. Valuation of generation assets and purchases from comparable-sales and cash-flow analyses. Determination of stranded cost or gain.

161. **Maryland PSC** 8797; Potomac Edison Company restructuring and rates; Maryland Office of People's Counsel. Direct, January 1999; rebuttal, March 1999.

Implementation of restructuring. Valuation of generation assets and purchases from comparable-sales and cash-flow analyses. Determination of stranded cost or gain.

162. **Connecticut DPUC** 99-02-05; Connecticut Light and Power Company stranded costs; Connecticut Office of Consumer Counsel. April 1999.

Projections of market price. Valuation of purchase agreements and nuclear and non-nuclear assets from comparable-sales and cash-flow analyses.

163. **Connecticut DPUC** 99-03-04; United Illuminating Company stranded costs; Connecticut Office of Consumer Counsel. April 1999.

Projections of market price. Valuation of purchase agreements and nuclear assets from comparable-sales and cash-flow analyses.

164. **Washington UTC** UE-981627; PacifiCorp–Scottish Power Merger, Office of the Attorney General. June 1999.

Review of proposed performance standards and valuation of performance. Review of proposed low-income assistance.

165. **Utah PSC** 98-2035-04; PacifiCorp–Scottish Power Merger, Utah Committee of Consumer Services. June 1999.

Review of proposed performance standards and valuation of performance.

166. **Connecticut DPUC** 99-03-35; United Illuminating Company proposed standard offer; Connecticut Office of Consumer Counsel. July 1999.

Design of standard offer by rate class. Design of price adjustments to preserve rate decrease. Market valuations of nuclear plants. Short-term stranded cost

167. **Connecticut DPUC** 99-03-36; Connecticut Light and Power Company proposed standard offer; Connecticut Office of Consumer Counsel. Direct, July 1999; Supplemental, July 1999.

Design of standard offer by rate class. Design of price adjustments to preserve rate decrease. Market valuations of nuclear plants. Short-term stranded cost.

168. **W. Virginia PSC** 98-0452-E-GI; electric-industry restructuring, West Virginia Consumer Advocate. July 1999.

Market value of generating assets of, and restructuring gain for, Potomac Edison, Monongahela Power, and Appalachian Power. Comparable-sales and cash-flow analyses.

169. **Ontario Energy Board** RP-1999-0034; Ontario Performance-Based Rates; Green Energy Coalition. September 1999.

Rate design. Recovery of demand-side-management costs under PBR. Incremental costs.

170. **Connecticut DPUC** 99-08-01; standards for utility restructuring; Connecticut Office of Consumer Counsel. Direct, November 1999; Supplemental January 2000.

Appropriate role of regulation. T&D reliability and service quality. Performance standards and customer guarantees. Assessing generation adequacy in a competitive market.

171. **Connecticut Superior Court** CV 99-049-7239; Connecticut Light and Power Company stranded costs; Connecticut Office of Consumer Counsel. Affidavit, December 1999.

Errors of the CDPUC in deriving discounted-cash-flow valuations for Millstone and Seabrook, and in setting minimum bid price.

172. **Connecticut Superior Court** CV 99-049-7597; United Illuminating Company stranded costs; Connecticut Office of Consumer Counsel. December 1999.

Errors of the CDPUC, in its discounted-cash-flow computations, in selecting performance assumptions for Seabrook, and in setting minimum bid price.

173. **Ontario Energy Board** RP-1999-0044; Ontario Hydro transmission-cost allocation and rate design; Green Energy Coalition. January 2000.

Cost allocation and rate design. Net vs. gross load billing. Export and wheeling-through transactions. Environmental implications of utility proposals.

174. **Utah PSC** 99-2035-03; PacifiCorp Sale of Centralia plant, mine, and related facilities; Utah Committee of Consumer Services. January 2000.

Prudence of sale and management of auction. Benefits to ratepayers. Allocation and rate treatment of gain.

175. **Connecticut DPUC** 99-09-12; Nuclear Divestiture by Connecticut Light & Power and United Illuminating; Connecticut Office of Consumer Counsel. January 2000.

Market for nuclear assets. Optimal structure of auctions. Value of minority rights. Timing of divestiture.

176. **Ontario Energy Board** RP-1999-0017; Union Gas PBR proposal; Green Energy Coalition. March 2000.

Lost-revenue-adjustment and shared-savings incentive mechanisms for Union Gas DSM programs. Standards for review of targets and achievements, computation of lost revenues. Need for DSM expenditure true-up mechanism.

177. **NY PSC** 99-S-1621; Consolidated Edison steam rates; City of New York. April 2000.

Allocation of costs of former cogeneration plants, and of net proceeds of asset sale. Economic justification for steam-supply plans. Depreciation rates. Weather normalization and other rate adjustments.

178. **Maine PUC** 99-666; Central Maine Power alternative rate plan; Maine Public Advocate. Direct, May 2000; Surrebuttal, August 2000.

Likely merger savings. Savings and rate reductions from recent mergers. Implications for rates.

179. **MEFSB** 97-4; MMWEC gas-pipeline proposal; Town of Wilbraham, Mass. June 2000.

Economic justification for natural-gas pipeline. Role and jurisdiction of EFSB.

180. **Connecticut DPUC** 99-09-03; Connecticut Natural Gas Corporation Merger and Rate Plan; Connecticut office of Consumer Counsel. September 2000.

Performance-based ratemaking in light of mergers. Allocation of savings from merger. Earnings-sharing mechanism.

181. **Connecticut DPUC** 99-09-12RE01; Proposed Millstone Sale; Connecticut Office of Consumer Counsel. November 2000.

Requirements for review of auction of generation assets. Allocation of proceeds between units.

182. **MDTE** 01-25; Purchase of Streetlights from Commonwealth Electric; Cape Light Compact. January 2001

Municipal purchase of streetlights; Calculation of purchase price under state law; Determination of accumulated depreciation by asset.

183. **Connecticut DPUC** 00-12-01 and 99-09-12RE03; Connecticut Light & Power rate design and standard offer; Connecticut Office of Consumer Counsel. March 2001.

Rate design and standard offer under restructuring law; Future rate impacts; Transition to restructured regime; Comparison of Connecticut and California restructuring challenges.

184. **Vermont PSB** 6460 & 6120; Central Vermont Public Service rates; Vermont Department of Public Service. Direct, March 2001; Surrebuttal, April 2001.

Review of decision in early 1990s to commit to long-term uneconomic purchase from Hydro Québec. Calculation of present damages from imprudence.

185. **New Jersey BPU** EM00020106; Atlantic City Electric Company sale of fossil plants; New Jersey Ratepayer Advocate. Affidavit, May 2001.

Comparison of power-supply contracts. Comparison of plant costs to replacement power cost. Allocation of sales proceeds between subsidiaries.

186. **New Jersey BPU** GM00080564; Public Service Electric and Gas transfer of gas supply contracts; New Jersey Ratepayer Advocate. Direct, May 2001.

Transfer of gas transportation contracts to unregulated affiliate. Potential for market power in wholesale gas supply and electric generation. Importance of reliable gas supply. Valuation of contracts. Effect of proposed requirements contract on rates. Regulation and design of standard-offer service.

187. **Connecticut DPUC** 99-04-18 Phase 3, 99-09-03 Phase 2; Southern Connecticut Natural Gas and Connecticut Natural Gas rates and charges; Connecticut Office of Consumer Counsel. Direct, June 2001; Supplemental, July 2001.

Identifying, quantifying, and allocating merger-related gas-supply savings between ratepayers and shareholders. Establishing baselines. Allocations between affiliates. Unaccounted-for gas.

188. **New Jersey BPU** EX01050303; New Jersey electric companies' procurement of basic supply; New Jersey Ratepayer Advocate. August 2001.

Review of proposed statewide auction for purchase of power requirements. Market power. Risks to ratepayers of proposed auction.

189. **NY PSC** 00-E-1208; Consolidated Edison rates; City of New York. October 2001.

Geographic allocation of stranded costs. Locational and postage-stamp rates. Causation of stranded costs. Relationship between market prices for power and stranded costs.

190. **MDTE** 01-56, Berkshire Gas Company; Massachusetts Attorney General. October 2001.

Allocation of gas costs by load shape and season. Competition and cost allocation.

191. **New Jersey BPU** EM00020106; Atlantic City Electric proposed sale of fossil plants; New Jersey Ratepayer Advocate. December 2001.

Current market value of generating plants vs. proposed purchase price.

192. **Vermont PSB** 6545; Vermont Yankee proposed sale; Vermont Department of Public Service. Direct, January 2002.

Comparison of sales price to other nuclear sales. Evaluation of auction design and implementation. Review of auction manager's valuation of bids.

193. **Connecticut Siting Council** 217; Connecticut Light & Power proposed transmission line from Plumtree to Norwalk; Connecticut Office of Consumer Counsel. March 2002.

Nature of transmission problems. Potential for conservation and distributed resources to defer, reduce or avoid transmission investment. CL&P transmission planning process. Joint testimony with John Plunkett.

194. **Vermont PSB** 6596; Citizens Utilities Rates; Vermont Department of Public Service. Direct, March 2002; Rebuttal, May 2002.

Review of 1991 decision to commit to long-term uneconomic purchase from Hydro Québec. Alternatives; role of transmission constraints. Calculation of present damages from imprudence.

195. **Connecticut DPUC** 01-10-10; United Illuminating rate plan; Connecticut Office of Consumer Counsel. April 2002

Allocation of excess earnings between shareholders and ratepayers. Asymmetry in treatment of over- and under-earning. Accelerated amortization of stranded costs. Effects of power-supply developments on ratepayer risks. Effect of proposed rate plan on utility risks and required return.

196. **Connecticut DPUC** 01-12-13RE01; Seabrook proposed sale; Connecticut Office of Consumer Counsel. July 2002

Comparison of sales price to other nuclear sales. Evaluation of auction design and implementation. Assessment of valuation of purchased-power contracts.

197. **Ontario EB** RP-2002-0120; Review of transmission-system code; Green Energy Coalition. October 2002.

Cost allocation. Transmission charges. Societal cost-effectiveness. Environmental externalities.

198. **New Jersey BPU** ER02080507; Jersey Central Power & Light rates; N.J. Division of the Ratepayer Advocate. Phase I December 2002; Phase II (oral) July 2003.

Prudence of procurement of electrical supply. Documentation of procurement decisions. Comparison of costs for subsidiaries with fixed versus flow-through cost recovery.

199. **Connecticut DPUC** 03-07-02; CL&P rates; AARP. October 2003

Proposed distribution investments, including prudence of prior management of distribution system and utility's failure to make investments previously funded in rates. Cost controls. Application of rate cap. Legislative intent.

200. **Connecticut DPUC** 03-07-01; CL&P transitional standard offer; AARP. November 2003.

Application of rate cap. Legislative intent.

201. **Vermont PSB** 6596; Vermont Electric Power Company and Green Mountain Power Northwest Reliability transmission plan; Conservation Law Foundation. December 2003.

Inadequacies of proposed transmission plan. Failure of to perform least-cost planning. Distributed resources.

202. **Ohio PUC** Case 03-2144-EL-ATA; Ohio Edison , Cleveland Electric, and Toledo Edison Cos. rates and transition charges; Green Mountain Energy Co. Direct February 2004.

Pricing of standard-offer service in competitive markets. Critique of anticompetitive features of proposed standard-offer supply, including non-bypassable charges.

203. **NY PSC** Cases 03-G-1671 & 03-S-1672; Consolidated Edison Company Steam and Gas Rates; City of New York. Direct March 2004; Rebuttal April 2004; Settlement June 2004.

Prudence and cost allocation for the East River Repowering Project. Gas and steam energy conservation. Opportunities for cogeneration at existing steam plants.

204. **NY PSC** 04-E-0572; Consolidated Edison rates and performance; City of New York. Direct, September 2004; rebuttal, October 2004.

Consolidated Edison's role in promoting adequate supply and demand resources. Integrated resource and T&D planning. Performance-based ratemaking and streetlighting.

205. **Ontario EB** RP 2004-0188; cost recovery and DSM for Ontario electric-distribution utilities; Green Energy Coalition. Exhibit, December 2004.

Differences in ratemaking requirements for customer-side conservation and demand management versus utility-side efficiency improvements. Recovery of lost revenues or incentives. Reconciliation mechanism.

206. **MDTE** 04-65; Cambridge Electric Light Co. streetlighting; City of Cambridge. Direct, October 2004; Supplemental January 2005.

Calculation of purchase price of street lights by the City of Cambridge.

207. **NY PSC** 04-W-1221; rates, rules, charges, and regulations of United Water New Rochelle; Town of Eastchester and City of New Rochelle. Direct, February 2005.

Size and financing of proposed interconnection. Rate design. Water-mains replacement and related cost recovery. Lost and unaccounted-for water.

208. **NY PSC** 05-M-0090; system-benefits charge; City of New York. Comments, March 2005.

Assessment and scope of, and potential for, New York system-benefits charges.

209. **Maryland PSC** 9036; Baltimore Gas & Electric rates; Maryland Office of People's Counsel. Direct, August 2005.

Allocation of costs. Design of rates. Interruptible and firm rates.

210. **British Columbia Utilities Commission** Project No. 3698388, British Columbia Hydro resource-acquisition plan; British Columbia Sustainable Energy Association and Sierra Club of Canada BC Chapter. Direct, September 2005.

Renewable energy and DSM. Economic tests of cost-effectiveness. Costs avoided by DSM.

211. **Connecticut DPUC** 05-07-18; financial effect of long-term power contracts; Connecticut Office of Consumer Counsel. Direct September 2005.

Assessment of effect of DSM, distributed generation, and capacity purchases on financial condition of utilities.

212. **Connecticut DPUC** 03-07-01RE03 & 03-07-15RE02; incentives for power procurement; Connecticut Office of Consumer Counsel. Direct, September 2005. Additional Testimony, April 2006.

Utility obligations for generation procurement. Application of standards for utility incentives. Identification and quantification of effects of timing, load characteristics, and product definition.

213. **Connecticut DPUC** Docket 05-10-03; Connecticut L&P; time-of-use, interruptible and seasonal rates; Connecticut Office of Consumer Counsel. Direct and Supplemental Testimony February 2006.

Seasonal and time-of-use differentiation of generation, congestion, transmission and distribution costs; fixed and variable peak-period timing; identification of pricing seasons and seasonal peak periods; cost-effectiveness of time-of-use rates.

214. **Ontario Energy Board** Case EB-2005-0520; Union Gas rates; School Energy Coalition. Evidence, April 2006.

Rate design related to splitting commercial rate class into two classes: new break point, cost allocation, customer charges, commodity rate blocks.

215. **Ontario Energy Board** Case EB-2006-0021; natural gas demand-side-management generic issues proceeding; School Energy Coalition. Evidence, June 2006.

Multi-year planning and budgeting; lost-revenue adjustment mechanism; determining savings for incentives; oversight; program screening.

216. **Indiana Utility Regulatory Commission** Cause Nos. 42943 and 43046; Vectren Energy DSM proceedings; Citizens Action Coalition. Direct, June 2006.

Rate decoupling and energy-efficiency goals.

217. **Pennsylvania PUC** Docket No. 00061346; Duquesne Lighting; Real-time pricing; PennFuture. Direct, July 2006; surrebuttal August 2006.

Real-time and time-dependent pricing; benefits of time-dependent pricing; appropriate metering technology; real-time rate design and customer information

218. **Pennsylvania PUC** Docket No. R-00061366, et al.; rate-transition-plan proceedings of Metropolitan Edison and Pennsylvania Electric; Real-time pricing; PennFuture. Direct, July 2006; surrebuttal August 2006.

Real-time and time-dependent pricing; appropriate metering technology; real-time rate design and customer information.

219. **Connecticut DPUC** 06-01-08; Connecticut L&P procurement of power for standard service and last-resort service; Connecticut Office of Consumer Counsel. Reports and technical hearings September and October 2006.

Conduct of auction; review of bids; comparison to market prices; selection of winning bidders.

220. **Connecticut DPUC** 06-01-08; United Illuminating procurement of power for standard service and last-resort service; Connecticut Office of Consumer Counsel. Reports and technical hearings August and November 2006; March, September, October, and November 2007; February, April, and May 2008.

Conduct of auction; review of bids; comparison to market prices; selection of winning bidders.

221. **NY PSC** Case No. 06-M-1017; policies, practices, and procedures for utility commodity supply service; City of New York. Comments, November and December 2006.

Multi-year contracts, long-term planning, new resources, procurement by utilities and other entities, cost recovery.

222. **Connecticut DPUC** 06-01-08; procurement of power for standard service and last-resort service, lessons learned; Connecticut Office Of Consumer Counsel. Comments and Technical Conferences December 2006 and January 2007.

Sharing of data and sources; benchmark prices; need for predictability, transparency and adequate review; utility-owned resources; long-term firm contracts.

223. **PUCO** Case No. 05-1444-GA-UNC; recovery of conservation costs, decoupling, and rate-adjustment mechanisms for Vectren Energy Delivery of Ohio; Ohio Consumers' Counsel. Direct, February 2007.

Assessing cost-effectiveness of natural-gas energy-efficiency programs. Calculation of avoided costs. Impact on rates. System benefits of DSM.

224. **NY PSC** Case 06-G-1332, Consolidated Edison Rates and Regulations; City of New York. Direct, March 2007.

Gas energy efficiency: benefits to customers, scope of cost-effective programs, revenue decoupling, shareholder incentives.

225. **Alberta EUB** 1500878; ATCO Electric rates; Association of Municipal Districts & Counties and Alberta Federation of Rural Electrical Associations. Direct, May 2007

Direct assignment of distribution costs to streetlighting. Cost causation and cost allocation. Minimum-system and zero-intercept classification.

226. **Connecticut DPUC** Docket 07-04-24, Review of capacity contracts under Energy Independence Act; Connecticut Office of Consumer Counsel, Joint Direct Testimony June 2007.

Assessment of proposed capacity contracts for new combined-cycle, peakers and DSM. Evaluation of contracts for differences, modeling of energy, capacity and forward-reserve markets. Corrections of errors in computation of costs, valuation of energy-price effects of peakers, market-driven expansion plans and retirements, market response to contracted resource additions, DSM proposal evaluation.

227. **NY PSC** Case 07-E-0524, Consolidated Edison electric rates; City of New York. Direct, September 2007.

Energy-efficiency planning. Recovery of DSM costs. Decoupling of rates from sales. Company incentives for DSM. Advanced metering. Resource planning.

228. **Manitoba PUB** 136-07, Manitoba Hydro rates; Resource Conservation Manitoba and Time to Respect Earth's Ecosystem. Direct, February 2008.

Revenue allocation, rate design, and demand-side management. Estimation of marginal costs and export revenues.

229. **Mass. EFSB** 07-7, DPU 07-58 & -59, proposed Brockton Power Company plant; Alliance Against Power Plant Location. Direct, March 2008

Regional supply and demand conditions. Effects of plant construction and operation on regional power supply and emissions.

230. **CDPUC 08-01-01**, peaking generation projects; Connecticut Office of Consumer Counsel. Direct (with Jonathan Wallach), April 2008.

Assessment of proposed peaking projects. Valuation of peaking capacity. Modeling of energy margin, forward reserves, other project benefits.

231. **Ontario EB-2007-0905,** Ontario Power Generation payments; Green Energy Coalition. Direct, April 2008.

Cost of capital for Hydro and nuclear investments. Financial risks of nuclear power.

232. **Utah PSC 07-035-93,** Rocky Mountain Power Rates; Utah Committee of Consumer Services. Direct, July 2008

Cost allocation and rate design. Cost of service. Correct classification of generation, transmission, and purchases.

233. **Ontario EB-2007-0707,** Ontario Power Authority integrated system plan; Green Energy Coalition, Penimba Institute, and Ontario Sustainable Energy Association. Evidence (with Jonathan Wallach and Richard Mazzini), August 2008.

Critique of integrated system plan. Resource cost and characteristics; finance cost. Development of least-cost green-energy portfolio.

234. **NY PSC** Case 08-E-0596, Consolidated Edison electric rates; City of New York. Direct, September 2008.

Estimated bills, automated meter reading, and advanced metering. Aggregation of building data. Targeted DSM program design. Using distributed generation to defer T&D investments.

235. **CDPUC 08-07-01**, integrated resource plan; Connecticut Office of Consumer Counsel. Direct, September 2008.

Integrated resource planning scope and purpose. Review of modeling and assumptions. Review of energy efficiency, peakers, demand response, nuclear, and renewables. Structuring of procurement contracts.

236. **Manitoba PUB** 2008 MH EIIR, Manitoba Hydro intensive industrial rates; Resource Conservation Manitoba and Time to Respect Earth's Ecosystem. Direct, November 2008.

Marginal costs. Rate design. Time-of-use rates.

237. **Maryland PSC** 9036; Columbia Gas rates; Maryland Office of People's Counsel. Direct, January 2009.

Cost allocation and rate design. Critique of cost-of-service studies.

238. **Vermont PSB** 7440; extension of authority to operate Vermont Yankee; Conservation Law Foundation and Vermont Public Interest Research Group. Direct, February 2009; Surrebuttal, May 2009.

Adequacy of decommissioning funding. Potential benefits to Vermont of revenue-sharing provision. Risks to Vermont of underfunding decommissioning fund.

239. **Nova Scotia Review Board** P-884(2), Nova Scotia Power DSM and cost recovery, Nova Scotia Consumer Advocate. May 2009.

Recovery of demand-side-management costs and lost revenue.

240. **Nova Scotia Review Board** P-172, proposed biomass project, Nova Scotia Consumer Advocate. June 2009.

Procedural, planning, and risk issues with proposed power-purchase contract. Biomass price index. Nova Scotia Power's management of other renewable contracts.

241. **Connecticut Siting Council** 370A, Connecticut Light & Power transmission projects; Connecticut Office of Consumer Counsel. Direct, July 2009.

Need for transmission projects. Modeling of transmission system. Realistic modeling of operator responses to contingencies

242. **Mass. DPU** 09-39, NGrid rates, Mass. Department of Energy Resources. August 2009.

Revenue-decoupling mechanism. Automatic rate adjustments.

243. **Utah PSC** Docket No. 09-035-23, Rocky Mountain Power rates; Utah Office of Consumer Services. Direct, October 2009. Rebuttal, November 2009.

Cost-of-service study. Cost allocators for generation, transmission, and substation.

244. **Utah PSC** Docket No. 09-035-15, Rocky Mountain Power energy-cost-adjustment mechanism; Utah Office of Consumer Services. Direct, November 2009; Surrebuttal, January 2010.

Automatic cost-adjustment mechanisms. Net power costs and related risks. Effects of energy-cost-adjustment mechanisms on utility performance.

245. **Penn. PUC** Docket No. R-2009-2139884, Philadelphia Gas Works energy efficiency and cost recovery; Philadelphia Gas Works. Direct, December 2009.

Avoided gas costs. Recovery of efficiency-program costs and lost revenues. Rate impacts of DSM.

246. **Ark. PSC** Docket No. 09-084-U, Entergy Arkansas rates; National Audubon Society and Audubon Arkansas. Direct, February 2010; Surrebuttal, April 2010.

Recovery of revenues lost to efficiency programs. Determination of lost revenues. Incentive and recovery mechanisms.

247. **Ark. PSC** Docket No. 10-010-U, Energy efficiency; National Audubon Society and Audubon Arkansas. Direct, March 2010; Reply, April 2010.

Regulatory framework for utility energy-efficiency programs. Fuel-switching programs. Program administration, oversight, and coordination. Rationale for commercial and industrial efficiency programs. Benefit of energy efficiency.

248. **Ark. PSC** Docket No. 08-137-U, Generic rate-making; National Audubon Society and Audubon Arkansas. Direct, March 2010.

Calculation of avoided costs. Recovery of utility energy-efficiency-program costs and lost revenues. Shareholder incentives for efficiency-program performance.

249. **Plymouth, Mass., Superior Court** Civil Action No. PLCV2006-00651-B (Hingham Municipal Lighting Plant v. Gas Recovery Systems LLC et al.) breach of agreement; defendants. Affidavit, May 2010.

Contract interpretation. Meaning of capacity measures. Standard practices in capacity agreements. Power-pool rules and practices. Power planning and procurement.

250. **Mass. DPU** 10-54, NGrid purchase of long-term power from Cape Wind; Natural Resources Defense Council et al. Direct, July 2010.

Effects of renewable-energy projects on gas and electric market prices. Impacts on system reliability and peak loads. Importance of PPAs to renewable development. Effectiveness of proposed contracts as price edges.

251. Maryland PSC 9230, Baltimore Gas & Electric rates; Maryland Office of People's Counsel. Direct, Direct, July 2010; Rebuttal, Surrebuttal, August 2010.

Allocation of gas- and electric-distribution costs. Critique of minimum-system analyses and direct assignment of shared plant. Allocation of environmental compliance costs. Allocation of revenue increases among rate classes.

252. Ontario EB-2010-0008, Ontario Power Generation facilities charges; Green Energy Coalition. Evidence August 2010.

Critique of including a return on CWIP in current rates. Setting cost of capital by business segment.

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