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 overheating 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).

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[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.

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[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.

[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.

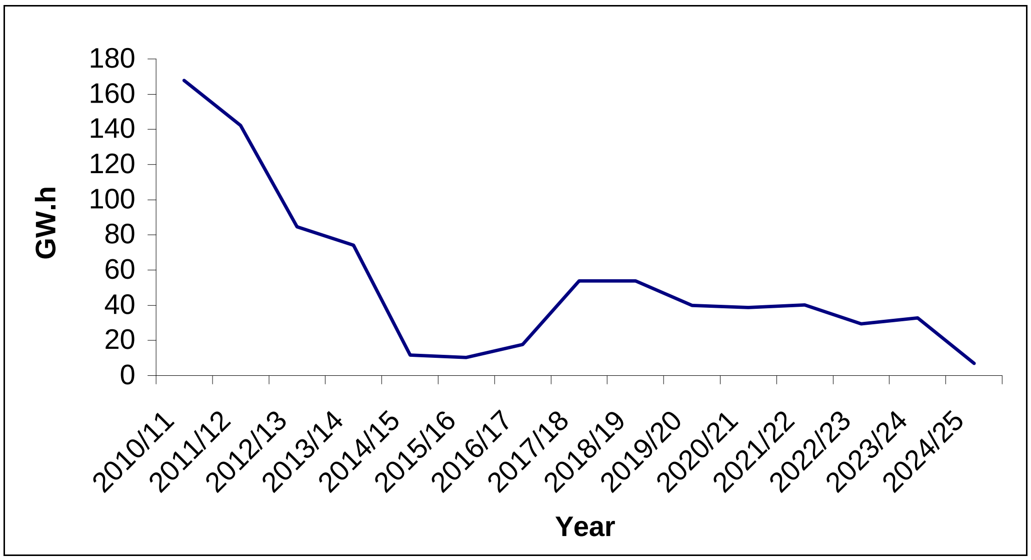
Q: What did you conclude from your review?

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.

S*ources:* "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.