TRANSMISSION PLANNING & DESIGN DIVISION

SYSTEM PLANNING
DEPARTMENT

REPORT ON

MARGINAL TRANSMISSION & DISTRIBUTION COST ESTIMATES

SPD 04/05

This report is intended for internal use by Manitoba Hydro only.

Contents

Executive Summary

Objectives

This report has the following two objectives:

1) To develop a methodology for estimating marginal (or avoided) T&D costs.
2) To update the existing marginal (or avoided) T&D costs that were originally produced in the 1990 avoided cost study [4,5,7].

Recommendations

1) **The one year deferral (OYD) method should be used for marginal (or avoided) T&D cost estimates.**

   This method is developed on the basis of the deferral value of load-growth related capital costs due to a reduction in the forecasted system peak load (demand). In this method, the deferral time is restricted to one year, while the size of load reduction can be anywhere between 0 and one year's worth of load growth. The restriction on the deferral time is consistent with the planning practice that T&D capital investments are planned to meet the forecast annual peak load.

2) **The values in Table A should be used as long-term marginal (or avoided) T&D cost components.**

TABLE A

LEVELIZED MARGINAL (OR AVOIDED) T&D COSTS ($/KW/YEAR)*

	Transmission	Distribution	
		Subtransmission	Distribution-Circuit
Average (Mean)	45.44	22.09	40.93
Standard Deviation	6.19	2.12	1.60

***Notes:**

a) The values are levelized over the study period of 2004/05 to 2013/14.

b) The values are expressed in 2004 constant dollars and escalate at the inflation rate.

c) The averages (means) are considered as the generic marginal T&D cost components. The probability that the marginal cost falls within 1, 2, and 3 standard deviations from the average is 84.1%, 97.7% and 99.9%, respectively.

d) The values are valid for a winter peak system.

e) The values are non-area-specific (i.e., do not vary by area).

f) The values do not include the replacement costs associated with the capital investments.

g) The values can be assumed to continue into the future beyond the planning horizon of 2013/14.

h) Although the values are derived for load reductions between 0 and 1 year's worth of load growth, it has been shown that their application can be extended to the case of larger load reductions (say, up to two times the annual load growth).

i) The values are valid for a real discount rate of 6.0% (without the inflation rate component). If the real discount rate is significantly different from 6.0%, they should be modified using the information provided in this report.

j) The values are valid only for transmission, subtransmission and distribution-circuit defined in this report.

The costs are based on the "T&D Capital Expenditure Forecast (CEF03-1)" for the period of 2003/04 to 2013/14 and the Corporate "Electric Load Forecast" for the same period. They are derived using the OYD method and a random load reduction stream that is defined as $\{\delta L_k\}=\{\lambda_k \Delta L_k\}$, where ΔL_k ($k=1,2,3,\cdots$) is the forecasted load growth in year k and λ_k ($k=1,2,3,\cdots$) is a random number uniformly distributed between 0 and 1.

3) **The marginal costs should be updated 5 years from now or earlier as needed.**

Results of Pevious Study

The last avoided T&D cost study was conducted in 1990. The avoided cost components produced in that study are $11/kW/Year and $11/kW/Year (in 1990 constant dollars) for transmission and distribution, respectively. They are significantly lower than those recommended in the present study. This is mainly attributed to the differences in the methods, assumptions and data used for the avoided cost estimates.

1. Introduction

For various purposes such as the evaluation of demand side management (DSM) programs and equipment losses, etc. [4,7], we need to estimate the additional (incremental) cost incurred by an increase in capacity and energy requirements, or equivalently the cost that can be avoided if not having to increase capacity and energy requirements. Such an incremental cost is labeled “marginal cost” or “avoided cost”. The marginal cost for a power system is usually split into three system levels: generation, transmission and distribution (T&D). The marginal generation costs include both capacity and energy components; while the marginal T&D costs are capacity related only.

The term “avoided cost” was replaced by “marginal cost” in the report on “1996/97 Update to Marginal Costs”, PP&O Report 97-5, prepared by Resource Planning & Market Analysis because the latter was judged to be more descriptive and useful for the Manitoba Hydro situation [7]. To be consistent with the current marginal costing practices, the term “marginal cost” was adopted in this report. The term “avoided cost”, however, will occasionally be used for convenience, bearing the same meaning as “marginal cost”.

In this report, we will first propose a methodology for marginal T&D costs, and then provide marginal (or avoided) T&D cost estimates for the Manitoba Hydro system. The results will supercede the existing avoided T&D costs originally produced in the 1990 avoided cost study [4].

2. Methodology

Marginal T&D cost seems to be a simple concept, but its detailed definitions and calculation procedures vary widely in practice depending upon the way it is perceived [1,2,4,6,8,9,10]. The marginal (or avoided)

T&D costs currently used in Manitoba Hydro are based on the deferral values, i.e. the savings from capital cost deferrals in response to a reduction in the forecasted system peak load (demand). A similar definition has been used by other utilities/organizations such as PG&E, Energy and Environmental Economics, Inc., San Francisco, CA, etc. [8,9,10] as well. In this study, we will use the deferral concept and seek a methodology for marginal T&D costs with respect to small load reductions, say, close to the average annual load growth or smaller.[1]

2.1. Notations

For convenience, the notations to be used in this report are summarized below:

k — fiscal year with $k = 0$ representing the current one.

N — study period in years based on which the marginal costs are estimated, which covers the future years within the T&D planning horizon (about 10 years) if not otherwise indicated.

j — inflation rate or escalation rate.[2]

i — real discount rate, i.e., discount rate without the effect of inflation.[3]

d — discount rate with the effect of inflation,[4] which is determined as

$$d = (1+i)(1+j) - 1 = i + j + ij \tag{1}$$

I_k — load-growth related investments (capital expenditures) for year k expressed in terms of "constant-worth" dollars, which do not

[1] In the existing Manitoba Hydro avoided costing method [4], load reductions are required to be significant enough to cause capital deferrals.

[2] j is taken to be the inflation or escalation rate in the document "Projected Escalation, Interest and Exchange Rates — G911-1", issued 2004 05 27.

[3] i is taken to be the real weighted average cost of capital in G911-1, issued 2004 05 27.

[4] d is taken to be the weighted average cost of capital in G911-1, issued 2004 05 27.

escalate with time. Note that "load-growth related" is used to describe the investments driven by the needs for capacity expansion to accommodate the forecasted load growth.

$\tilde{I}_k$ — load-growth related investments for year k expressed in terms of "then-current" dollars (including the effect of inflation). $\tilde{I}_k$ and I_k are related to each other as

$$\tilde{I}_k = I_k (1 + j)^k \quad (2)$$

I_{eq} — equivalent uniform annual investments expressed in "constant-worth" dollars over the study period, i.e.

$$I_{eq} = [\sum_{k=1}^{N} \frac{I_k}{(1+i)^k}] \bigg/ \sum_{k=1}^{N} \frac{1}{(1+i)^k} \quad (3)$$

L_k — forecasted system peak load (demand) for year k.

ΔL_k — load growth in year k, which is defined as

$$\Delta L_k = L_k - L_{k-1} \quad (4)$$

ΔL_{ave} — average annual load growth over the study period, i.e.

$$\Delta L_{ave} = \frac{1}{N} \sum_{k=1}^{N} \Delta L_k \quad (5)$$

δL_k — expected reduction in the peak load in year k.

Δt_k — deferral time, i.e. a time period by which the capital expenditures for year k are deferred.

Δt — deferral time that does not vary from year to year.

I_{incr} — levelized incremental investment per unit of load growth (\$/kW/Year).

C_{avoid} — levelized marginal (or avoided) cost (\$/kW/Year).

2.2. General Deferral Concept

The deferral concept to be presented below is similar as the one used in the previous avoided cost study [4], which is on the basis that the load-growth related capital expenditures can be deferred if there is a reduction in the forecasted system peak load (demand).

Suppose the capital expenditures for year k, denoted by $\tilde{I}_k$, can be deferred by a time period, Δt_k, due to a load reduction, δL_k. The capital expenditures deferred to year $k+\Delta t_k$, after being adjusted for inflation, are equal to

$$\tilde{I}_k(1+j)^{\Delta t_k}$$

This amount of dollars is discounted back to year k as

$$\frac{\tilde{I}_k(1+j)^{\Delta t_k}}{(1+d)^{\Delta t_k}}$$

This indicates that the deferring of $\tilde{I}_k$ to year $k+\Delta t_k$ is equivalent to the spending of $\tilde{I}_k(1+j)^{\Delta t_k}\big/(1+d)^{\Delta t_k}$ in year k. Obviously, the saving (i.e. cost avoided) in year k is

$$\tilde{I}_k - \tilde{I}_k\frac{(1+j)^{\Delta t_k}}{(1+d)^{\Delta t_k}} = [1-\frac{(1+j)^{\Delta t_k}}{(1+d)^{\Delta t_k}}]\tilde{I}_k$$

The deferral value, i.e., the present value of all savings over the study period, is

$$\Delta PV = \sum_{k=1}^{N}[1-\frac{(1+j)^{\Delta t_k}}{(1+d)^{\Delta t_k}}]\frac{\tilde{I}_k}{(1+d)^k} \tag{6}$$

Such a deferral value is also used in the Present Worth (PW) method [2,8,10].

Considering the relations $(d+1)=(1+i)(1+j)$ and $\tilde{I}_k = I_k(1+j)^k$, we can rewrite Eq. (6) as

$$\Delta PV = \sum_{k=1}^{N}[1-\frac{1}{(1+i)^{\Delta t_k}}]\frac{I_k}{(1+i)^k} \tag{7}$$

The deferral value, ΔPV, can be levelized over the study period to yield the marginal (or avoided) cost, as described below.

When the effect of inflation is not accounted for, the marginal (or avoided) cost ($/kW/Year), denoted by C_{avoid}, can be assumed to be constant over the study period. The present value of the costs avoided due to load reductions is

$$\sum_{k=1}^{N}\frac{C_{avoid}\delta L_k}{(1+i)^k}$$

This value should exactly match the deferral value, ΔPV, determined by Eq. (6) or (7). Therefore, the levelized marginal cost is

$$C_{avoid} = \{\sum_{k=1}^{N}[1-\frac{(1+j)^{\Delta t_k}}{(1+d)^{\Delta t_k}}]\frac{\tilde{I}_k}{(1+d)^k}\} \Big/ \sum_{k=1}^{N}\frac{\delta L_k}{(1+i)^k} \tag{8}$$

or equivalently

$$C_{avoid} = \{\sum_{k=1}^{N}[1-\frac{1}{(1+i)^{\Delta t_k}}]\frac{I_k}{(1+i)^k}\} \Big/ \sum_{k=1}^{N}\frac{\delta L_k}{(1+i)^k} \tag{9}$$

Equations (8) and (9) provide two equivalent approaches to arrive at the marginal cost, i.e., the “then-current” dollar approach and the “constant-worth” dollar approach.[5] In both equations, the load reduction is discounted at the real discount rate, i. Equation (9) is easier to handle and therefore will be used hereafter in this report.

The levelized marginal costs (or avoided) cost C_{avoid} determined by Eq. (8) or (9) is measured in constant-worth dollars. It can be converted to the "then-current" dollar value in year k as $C_{avoid}(1+j)^k$.

The two methods to be presented in the following sections are derived from the above concept. Their difference lies mainly in the restrictions imposed on the deferral time.

2.3. Load Reduction Streams

In the context of this report, a load reduction stream refers to a series of reductions in peak load (demand), which is represented mathematically as $\{\delta L_1, \delta L_2, \cdots, \delta L_N\}$. The marginal cost is affected by the type (shape) of load reduction stream. In this study, the following three types of load reduction streams will be considered:

- *Uniform load reduction stream*: It is defined such that the reduction in peak load is the same from year to year, i.e. $\delta L_k = \delta L$ for $k = 1, 2, 3, \cdots, N$.
- *Near-uniform load reduction stream*: It is defined such that its shape is similar to that of the annual load growth stream, i.e. $\delta L_k = \lambda \Delta L_k$ ($k = 1, 2, 3, \cdots, N$), where λ is a number between 0 and 1. Since the annual load growth usually does not deviate significantly from the average, this type of load reduction stream is referred to as near-uniform load reduction stream in this report.
- *Random load reduction stream*: It is defined such that the reduction in peak load varies from year to year in a random fashion. It is mathematically represented as $\{\delta L_k\} = \{\lambda_k \Delta L_k\}$ where λ_k ($k = 1, 2, 3, \cdots, N$) is a random number uniformly distributed between α and 1 with α being

5 The "then-current" dollars include the effect of inflation, but the "constant-worth" dollars don't. The constant dollar cash flows can be brought forward or deferred without adjustment for inflation. For more detailed information, see Section 3.8.6 Inflationary Effects in "Principles of Engineering Economic Analysis" by A.J. Szonyi, et al. [3]. In Manitoba Hydro, "constant-worth dollar" is usually referred to as "constant dollar".

a fixed positive number smaller than 1. It covers all the possible types of load reduction streams in practice, including the above two types.

2.4. One-Year Deferral (OYD) Method

The method to be presented below may be viewed as a probability-based one. In this method, the deferral time is restricted to one year, while the size of load reduction can be anywhere between 0 and one year's worth of load growth.[6] The restriction on the deferral time is consistent with the planning practice that T&D capital investments are planned to meet the forecasted annual peak load.

Let us start with an example. Suppose the capacity of a substation is 40 MWA, the power factor is 1.0, and the expected peak loads of the station are 38.5 MW and 41.2 MW for 2010/11 and 2011/12, respectively. The expected load growth in 2011/12 at this station is 2.7 MW. The existing station capacity can meet the 2010/11 peak load but can not meet the 2011/12 one. The shortage or scarcity of capacity for 2011/12 is 1.2 MW, as shown in Fig. 1. Based on the above information, a new transformer has been planned for service in 2011/12. Now, a reduction of 1.5 MW in the peak load, for instance, is expected for 2011/12. Considering that the load reduction of 1.5 MW exceeds the capacity shortage of 1.2 MW for 2011/12, we can defer the installation of the new transformer from 2011/12 to 2012/13. This suggests that the load reduction needs not to reach at least one year's worth of load growth of 2.7 MW in order to cause a capital deferral*!*

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[6] In the approach used in the previous avoided cost study [4,5], it is assumed that a reduction in load can not cause capital deferrals until it approaches a significant level. "Significant" is defined such that the size of load reduction reaches at least one-year load growth. Under such an assumption, we can not estimate the avoided costs due to small load increments. Besides, it is hard to obtain accurate avoided cost estimates unless the load reductions are chosen such that they are just "significant". As shown in this section, the "significant level" requirement is inconsistent with the practical situation.

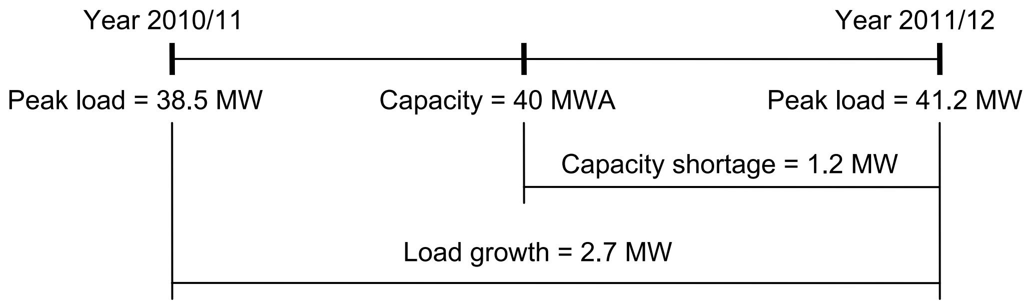

Fig. 1. Illustration of capacity shortage of a substation that is unable to accommodate the peak load in the year of 2011/12, assuming that the power factor is 1.0.

From a system-wide standpoint, the investments for year k are associated with capacity expansion of many facilities (e.g. lines, stations, etc.). The capacity shortage of each one could be anywhere between 0 and the annual load growth, ΔL_k. In other words, the capacity shortage is randomly distributed between 0 and ΔL_k. According to what has been observed from the above example, any load reduction, δL_k, even if it is less than ΔL_k, could possibly cause a capital deferral. Now the question is: What is the probability of capital deferral due to a load reduction of δL_k? To answer this question, we would like to look at the following three situations:

- For $\delta L_k / \Delta L_k = 0$ (no load reduction), the probability of capital deferral is 0%.
- For $\delta L_k / \Delta L_k = 1$ (the load reduction equal to the annual load growth ΔL_k), the probability of capital deferral is 100%.
- For $\delta L_k / \Delta L_k = 0.5$ (the load reduction is halfway between 0 and ΔL_k), the probability of capital deferral is 50%, which is based on the judgment that there is an equal chance for the capacity shortage to be above or below $0.5\Delta L_k$.

The above observations suggest that the probability of capital deferral is $\delta L_k / \Delta L_k$, which is a linear function of δL_k.

Thus, out of the investments for year k, the portion that would be deferred by one year due to a load reduction, δL_k, is equal to $\frac{\delta L_k}{\Delta L_k} \times 100\%$.

The remaining portion is equal to $(1 - \frac{\delta L_k}{\Delta L_k}) \times 100\%$, which would not be deferred and therefore would not contribute to any savings. Replacing I_k and Δt_k in Eq. (9) with $I_k \, \delta L_k / \Delta L_k$ and 1, respectively, we immediately get

$$C_{avoid} = (1 - \frac{1}{1+i})[\sum_{k=1}^{N} \frac{\delta L_k}{\Delta L_k} \frac{I_k}{(1+i)^k}] \Big/ \sum_{k=1}^{N} \frac{\delta L_k}{(1+i)^k} \tag{10}$$

where δL_k is between 0 and ΔL_k.

If δL_k in Eq. (10) is replaced with $\delta L_k \beta$ with β being an arbitrary number, the marginal cost C_{avoid} remains unchanged. This means that the marginal cost determined by Eq. (10) is not sensitive to the size of load reduction for a similar shape of load reduction stream.

Below we would like to briefly analyze the marginal costs for uniform and near-uniform load reduction streams. The situation for the random load reduction will be examined later in this report.

For a uniform load reduction stream (i.e., $\delta L_k = \delta L$), Eq. (10) reduces to

$$C_{avoid} = (1 - \frac{1}{1+i})[\sum_{k=1}^{N} \frac{I_k}{\Delta L_k} \frac{1}{(1+i)^k}] \Big/ \sum_{k=1}^{N} \frac{1}{(1+i)^k} \tag{11}$$

For a near-uniform load reduction stream (i.e., $\delta L_k = \lambda \Delta L_k$), Eq. (10) becomes

$$C_{avoid} = [(1-\frac{1}{1+i})\sum_{k=1}^{N}\frac{I_k}{(1+i)^k}] \Big/ \sum_{k=1}^{N}\frac{\Delta L_k}{(1+i)^k} \quad (12)$$

Numerical results presented later in this report show that the differences between the avoided costs for uniform and near-uniform load reduction streams are so small that they are interchangeable. Equations (11) and (12) do not contain δL_k. This means that the marginal costs for uniform and near-uniform load reduction streams do not vary with the size of load reduction.

From the Corporate "Electric Load Forecast", it is seen that the annual load growth usually does not deviate significantly from the average. For this reason, the denominator in Eq. (12) can be approximated by $\sum_{k=1}^{N}\Delta L_{ave}\big/(1+i)^k$, that is,

$$\sum_{k=1}^{N}\frac{\Delta L_k}{(1+i)^k} \approx \Delta L_{ave}\sum_{k=1}^{N}\frac{1}{(1+i)^k} \quad (13)$$

For the data provided in Table 1 for example, $\sum_{k=1}^{9}\Delta L_k\big/(1+i)^k = 202.45$ and $\sum_{k=1}^{9}\Delta L_{ave}\big/(1+i)^k = 202.72$, noting that a discount rate of $i = 6.0\%$ is used for the calculations. The two numbers, 202.45 and 202.72, are almost identical. Thus, a good approximation of Eq. (12) is

$$C_{avoid} = (1-\frac{1}{1+i})[\sum_{k=1}^{N}\frac{I_k}{(1+i)^k}] \Big/ [\Delta L_{ave}\sum_{k=1}^{N}\frac{1}{(1+i)^k}] \quad (14)$$

The above facts suggest that a uniform load reduction stream equal to the average annual load growth can be assumed to cause the entire investment plan to shift by one year. This is the very assumption adopted in the PG&E's PW method [9].

2.5. Arbitrary Deferral Time (ADT) Method

In the PW method [2,10], the deferral time, Δt_k, is defined as the ratio of peak load reduction to peak load growth, i.e., $\Delta t_k = \delta L_k / \Delta L_k$. If the deferral time is not restricted to integer values in years, it can be used to obtain the marginal cost for any small size of load reduction [8]. The PW method with such a relaxed definition of deferral time is renamed the arbitrary deferral time (ADT) method in this report for convenience. However, the justification of using a non-integer deferral time seems still to be in question. Below we attempt to explore the meaning of such a deferral time.

In Section 2.4 it has been shown that $\frac{\delta L_k}{\Delta L_k} \times 100\%$ of the investments, I_k, for year k would be deferred by one year ($\Delta t_k = 1$) due to a load reduction $\delta L_k \le \Delta L$, and $(1 - \frac{\delta L_k}{\Delta L_k}) \times 100\%$ of the investments would not be deferred ($\Delta t_k = 0$). The weighted average deferral time is

$$\Delta t_k = 0 \times (1 - \frac{\delta L_k}{\Delta L_k}) + 1 \times \frac{\delta L_k}{\Delta L_k} = \frac{\delta L_k}{\Delta L_k} \tag{15}$$

Thus, the effect of deferring $\frac{\delta L_k}{\Delta L_k} \times 100\%$ of the investment, I_k, by one year is equivalent to that of deferring 100% of the investments by a period of Δt_k with $\Delta t_k = \delta L_k / \Delta L_k$. The non-integer deferral time can therefore be interpreted as the weight average deferral time. Substituting $\Delta t_k = \delta L_k / \Delta L_k$ in Eq. (9) yields

$$C_{avoid} = \{\sum_{k=1}^{N} [1 - \frac{1}{(1+i)^{\delta L_k / \Delta L_k}}] \frac{I_k}{(1+i)^k}\} \Big/ \sum_{k=1}^{N} \frac{\delta L_k}{(1+i)^k} \tag{16}$$

where δL_k is between 0 and ΔL_k.

Numerical tests later in this report show that Eq. (16) and (10) give practically the same results.

2.6. Incremental Investment per Unit of Load Growth

The present value of the annual investments over the study period is calculated as follows:

$$PV = \sum_{k=1}^{N} \frac{\tilde{I}_k}{(1+d)^k} = \sum_{k=1}^{N} \frac{I_k}{(1+i)^k} \tag{17}$$

When not considering the effect of inflation, we may assume that the incremental investment per unit of load growth, denoted by I_{incr}, is constant over the study period. The present value of the annual investments driven by the load growth can be expressed as

$$PV = \sum_{k=1}^{N} \frac{I_{incr}\Delta L_k}{(1+i)^k} \tag{18}$$

This value should exactly match the one determined by Eq. (17). Thus, we have

$$I_{incr} = [\sum_{k=1}^{N} \frac{I_k}{(1+i)^k}] \Big/ \sum_{k=1}^{N} \frac{\Delta L_k}{(1+i)^k} \tag{19}$$

This is the levelized incremental investment per unit of load growth.

There exists an interesting relation between I_{incr} and C_{avoid} for uniform and near-uniform load reduction streams. Comparing Eq. (19) with (12), we have

$$C_{avoid} = (1 - \frac{1}{1+i}) I_{incr} \approx i I_{incr} \tag{20}$$

This equation indicates that the marginal cost is approximately equal to the carrying charge or opportunity cost of the incremental investment per unit of load growth for a uniform or near-uniform load reduction stream. This may be used as an alternative approach to estimate the marginal cost.

3. Data Preparation

The task of this section is to prepare the data for marginal T&D cost estimates, which include annual load growth rates, annual load-growth related capital expenditures, etc.

3.1. Assumptions

Summarized below are the assumptions used for the marginal T&D cost estimates:

- T&D facilities are sized to meet the winter peak load (demand).
- T&D marginal costs are not area-specific (i.e., do not vary by area).
- T&D marginal costs expressed in constant dollars will continue into the future beyond the 10 year planning horizon.
- The entire T&D system is equally affected by a load reduction on a percentage basis.
- The load-growth related investment plan contained in “T&D Capital Expenditure Forecast (CEF03-1), 2003/04 – 2013/14” [11] is assumed to meet winter system peak loads which are considered to be the net total peaks (MW) in the base-case scenario in “Electric Load Forecast, 2003/04 to 2023/24” [12].[7]

[7] The net total peak is defined as the maximum hourly demand in a given year, required to meet the needs of Manitoba customers on the integrated system. It does not include diesel generation, industrial self-generation, exports, losses associated with exports/imports, and station service loads.

- The Customer Service Orders are not relevant to the T&D avoided costs.[8]

Note that an item is said to be "capacity-related", "load-growth related" or "load-related" if it is driven by the needs for capacity expansion in order to accommodate the forecasted system load growth or to meet the forecasted system peak loads.

It is assumed that load-growth related capital costs can not be deferred due to a reduction in the forecast load in the following situations:

- They are already committed.
- Their in-service dates are dictated by factors other than load growth such as safety, etc.

3.2. Split of Marginal T&D Cost

The marginal T&D cost was split into transmission and distribution components in the last avoided cost study [4,5]. Transmission and distribution are defined as follows:

- *Transmission*: It includes assets for bulk transmission of power. Specifically, it consists of transmission lines and terminal stations.[9] Assets providing connections between generation and transmission are excluded because they are included in the evaluation of marginal generation costs.
- *Distribution*: It includes assets for delivering power from terminal stations to customers. In this report, distribution is further split into two components:

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8 Overhead transformers and secondary services (i.e. the portion of distribution from distribution transformers to customer meters, which are typically 347/600 V, 120/208 V, etc.) are for individual customers and the associated costs are usually covered by the Customer Service Orders (previously called District Work Orders). It is assumed that these costs can not be deferred by a DSM program, etc. and is not relevant to the avoided distribution cost.

9 Terminal stations are defined as those providing connections between major transmission voltage levels (115 kV and above) or between major transmission and subtransmission voltage levels (66 kV, 33 kV).

- Subtransmission: It includes subtransmission lines and distribution stations.
- Distribution-circuit: It includes assets between distribution stations (exclusive) and customer meters (e.g. overhead lines, underground cables, pad-mounted transformers, etc.).

These cost components are additive.

3.3. Study Period

The latest T&D Capital Expenditure Forecast (CEF03-1) was issued in November 2003, and it covers the years 2003/04 to 2013/14. The fiscal year of 2003/04 has passed and therefore the capital costs for that year are “sunk”, i.e. irrelevant to the marginal costs. So we will look at the fiscal years 2004/05 to 2013/14. Each fiscal year is identified by a number k ($k = 0, 1, 2, 3, \cdots, N$) with $N = 9$. The number $k = 0$ represents the current fiscal year of 2004/05. Considering that the capital expenditures for the current fiscal year can barely be deferred in practice, we will determine the marginal costs based on the study period of year 1 to 9 (i.e. 2005/06 to 2013/14).

It is recommended that the marginal T&D cost estimates based on the 9 year study period be updated in 5 years or earlier as needed.

3.4. Forecasted System Peak Loads

The forecasted total system peak loads for the years 2004/05 to 2013/14 are given in the Manitoba Hydro Electric Load Forecast 2003/04 to 2023/24 (referring to [11] or Appendix A). They are reproduced in Table 1 for convenience.

The average annual load growth over the study period 2005/06 to 2013/14) is 30 MW. In the context of this study, the total system peak load beyond 2013/14 is assumed to grow at 30 MW per year.

TABLE 1

FORECASTED SYSTEM PEAK LOADS

K	Fiscal Year	Total System Peak Load (MW)	Load Growth per Year (MW)*
0	2004/05 (current year)	4028	
1	2005/06	4053	25
2	2006/07	4088	35
3	2007/08	4126	38
4	2008/09	4153	27
5	2009/10	4180	27
6	2010/11	4201	21
7	2011/12	4228	27
8	2012/12	4258	30
9	2013/14	4296	38
Average			29.778
k > 9	Beyond 2013/14		30

*Note: 29.778 MW/Year is the 9-year average load growth rate.

3.5. Annual T&D Capital Expenditures

3.5.1. A Quick Look at T&D Capital Budget

The T&D capital budget is divided into major and domestic items. The major items are typically over $2,000,000 and each of them has a Capital Project Justification (CPJ) and a Capital Expenditure Revision (CER). Domestic items consist of many smaller projects, which are usually grouped into the following areas:

- Transmission Planning & Design (TP&D)
- Distribution Planning & Design (DP&D)
- Construction and Line Maintenance
- Distribution Construction
- System Operations
- Apparatus Maintenance

- VP Transmission & Distribution

Domestic items are further split into blanket and non-blanket categories. Blanket projects are typically smaller than $300,000 and not required to have a CPJ or CER. Non-blanket projects are typically between $300,000 and $2,000,000, and each of them has a CPJ and CER.

Some items in the TP&D and DP&D areas are load-growth related; those in the other five areas, however, are not driven by load growth and therefore are excluded from the marginal cost study.

3.5.2. Analysis of T&D Capital Expenditures

This section is to identify the load-growth related part of the TP&D and DP&D capital expenditures (see Appendix B). A load related capital item may be driven by several factors in addition to load growth. As rules of thumb, the following guidelines are used for splitting a capital item between load-related and non-load-related portions:

- Major item or non-blanket item:
    - 100% load related if it is mainly driven by load growth.
    - 0% load related if it is mainly driven by factors other than load growth.
    - 50% load-related if it is driven by load growth and other factors.
    - Other percentage based on judgment.
- TP&D domestic budget - blanket:
    - Transmission line additions & modifications: 50% load-related.
    - Station site acquisition: 50% load-related.
    - Property land right acquisition: 0% load-related
    - Others: 0% load related.

- DP&D domestic budget – station blanket: 75% load-related.
- DP&D domestic budget – distribution blanket:
  - Subtransmission (S/T) additions & modifications: 50% load-related.
  - S/T system – ice melting: 0% load-related.
  - Street lighting: 0% load-related.
  - Highway changes: 0% load-related.
  - S/T modifications – storm damage: 0% load-related.
  - System improvements: 80% load-related.
  - Customer service: 50% load related.
  - New & upgraded feeders: 50% load-related.
  - Underground residential dist: 50% load-related.
  - Defective cable replacements: 0% load-related.
  - Others: 0% load-related.

Note that the guidelines for splitting the DP&D domestic blanket items are based on the advice from Distribution Planning & Design at Winnipeg, Brandon and Selkirk.

The major items are analyzed on a project-by-project basis and the results are summarized in Appendix B.

Unlike major items, TP&D and DP&D domestic items include many small projects. The annual domestic budgets have been projected for future years within the planning horizon, but are not defined in detail. In such a situation, what we can do is to analyze the 2003/04 domestic budget, and assume that the result (i.e. load-related portion in %) will hold for the future years. The non-blanket items for 2003/04 are analyzed on a project-by-project basis and the blanket budget is analyzed by categories.

According to the "Analysis of Domestic Items" provided in the "Manitoba Hydro Management Report" issued Feb. 2004 (see Appendix A), 76.6% of the T&D domestic budget goes to the TP&D and DP&D categories. So we may reasonably assume that the budget for TP&D and DP&D is 75% of the T&D domestic budget.

Summarized in Appendix B is the analysis of the TP&D and DP&D domestic budgets provided in "2003/04 T&D Domestic Reports" issued by Financing Department, T&D. According to Table B.2 in Appendix B, about 55% of the TP&D and DP&D domestic budget is load related. Thus we assume a 50/50 split between load and non-load related portions. Also according to Table B.2, we assume that the load-related part can be further divided as follows: 5% for transmission, 25% for subtransmission, and 70% for distribution-circuit.

The above results are summarized below:

- Total T&D domestic budget:
  - 75% for TP&D and DP&D categories
  - 25% for other categories (irrelevant to marginal costs)
- Total TP&D and DP&D domestic budget:
  - 50% for capacity-related projects
  - 50% for non-capacity related projects (irrelevant to marginal costs)
- Capacity-related part of TP&D and DP&D domestic budget:
  - 5% for transmission
  - 25% for subtransmission
  - 70% for distribution-circuit

The load-growth related (capacity related) cash flows for the different categories are given in Tables 2 and 3 (referring to Appendix B).

TABLE 2

LOAD-GROWTH RELATED ANNUAL INVESTMENT STREAMS EXPRESSED IN TERMS OF "THEN-CURRENT" DOLLARS* (IN THOUSANDS OF DOLLARS)

K	Fiscal Year	Transmission	Distribution		Transmission & Distribution
			Subtransmission	Distribution-Circuit	
0	2004/05 (current year)	2,050	7,622	21,341	31,014
1	2005/06	4,138	7,791	21,814	33,743
2	2006/07	10,670	9,561	22,339	42,570
3	2007/08	21,811	17,302	22,811	61,925
4	2008/09	33,070	15,932	23,336	72,339
5	2009/10	33,859	28,726	23,835	86,419
6	2010/11	50,040	16,156	24,439	90,635
7	2011/12	50,669	8,775	24,570	84,014
8	2012/12	15,660	8,841	24,754	49,255
9	2013/14	30,697	9,292	25,620	65,609

**Note: The effect of inflation is included and the assumed inflation rate is 2%.*

TABLE 3

LOAD-GROWTH RELATED ANNUAL INVESTMENT STREAMS EXPRESSED IN TERMS OF 2004 CONSTANT DOLLARS* (IN THOUSANDS OF DOLLARS)

K	Fiscal Year	Transmission	Distribution		Transmission & Distribution
			Subtransmission	Distribution-Circuit	
0	2004/05	2,050	7,622	21,341	31,014
1	2005/06	4,057	7,638	21,386	33,081
2	2006/07	10,255	8,856	21,471	40,582
3	2007/08	20,553	14,543	21,496	56,592
4	2008/09	30,551	13,398	21,559	65,509
5	2009/10	30,667	22,870	21,588	75,125
6	2010/11	44,434	13,321	21,701	79,456
7	2011/12	44,110	7,639	21,390	73,139
8	2012/12	13,366	7,545	21,127	42,038
9	2013/14	25,686	7,763	21,438	54,886
Equivalent		23,755	11,586	21,467	56,808
> 9	Beyond 2013/14	23,755	11,586	21,467	56,808

**Note: The values do not include the effect of inflation and the assumed inflation rate is 2%.*

3.6. Interest and Inflation Rates

The values for the inflation rate j, real discount rate i (not including the inflation rate component) and discount rate d (including the inflation rate component) are taken to be 2.0%, 6.0% and 8.15%, respectively, according to the document "Projected Escalation, Interest and Exchange Rates — G911-1" issued 2004 05 27. Note that (1+2.0%)×(1+6.0%) – 1 = 8.15%.

4. Results of Marginal T&D Costs

This section presents the results of marginal T&D costs calculated using the methodology and data in the previously sections. MS Excel and Visual Basic are used to realize the calculations.

4.1. Uniform and Near-Uniform Load Reduction Streams

The calculated marginal costs for uniform and near-uniform load reduction streams are shown in Tables 4 and 5, noting that for a near-uniform load reduction stream, the OYD and ADT methods become identical.

TABLE 4
MARGINAL COSTS ($/KW/YEAR, 2004 CONSTANT DOLLARS) GIVEN BY THE OYD METHOD

	Transmission	Distribution	
		Subtransmission	Distribution-Circuit
Uniform Load Reduction Stream	48.86	23.09	42.35
Near-Uniform Load Reduction Stream	45.21	22.05	40.86

TABLE 5
MARGINAL COSTS ($/KW/YEAR, 2004 CONSTANT DOLLARS) GIVEN BY THE ADT METHOD FOR UNIFORM LOAD REDUCTION STREAM

	Transmission	Distribution	
		Subtransmission	Distribution-Circuit
Load Reduction Equal to Average Annual Load Growth	48.69	23.04	42.26
Load Reduction Equal to 0.1 Times Average Annual Load Growth	50.13	23.70	43.46

From Tables 4 and 5, the following observations can be made:

- The marginal costs for uniform and near-uniform load reduction streams are very close so that they are interchangeable.
- The marginal costs given by the two methods are very close so that they are interchangeable.
- The marginal costs are practically insensitive to the size of load reduction.

4.2. Random Load Reduction Stream

Consider a random load reduction stream $\{\delta L_k\} = \{\lambda_k \Delta L_k\}$ where λ_k is uniformly distributed between α and 1 with $\alpha = 0$. Results are produced for one million (1,000,000) samples of such a random load reduction stream. Each sample is obtained using the following algorithm:

Randomize
For k =1 to N
$\lambda_k \Leftarrow$ Rnd()
$\delta L_k \Leftarrow \lambda_k \Delta L_k$
Next k

The function Rnd() is a random-number generator in MS Visual Basic which returns a random number between 0 and 1. The Randomize statement is used to initialize the random-number generator so that each random-number sequence does not repeat the previous ones. The load reduction streams thus obtained are different from each other. An instance of them might look like {0.0277×25, 0.3086×35, 0.4042×38, 0.2399×27, 0.5535×27, 0.5878×21, 0.2465×27, 0.9231×30, 0.1233×38}.

The cumulative frequency distributions (CFD) of the marginal costs calculated using the OYD method are plotted in Figs. 2 to 4. The CFD, $F(x)$, is defined as the ratio of the number of data values smaller than x to the total number of data entries (i.e. 1,000,000).

Figures 2 to 4 indicate that the marginal costs are governed by the normal distribution. Thus, the probability that the marginal cost falls within 1, 2 and 3 standard deviations from the average is 84.1%, 97.7% and 99.9%, respectively. The same is also true for the marginal costs obtained using the ADT method.

The averages (mean) and standard deviations of the marginal costs calculated using the two methods are shown in Tables 6 and 7. The values provided in the two tables are almost identical. Thus, we may conclude that the OYD and ADT methods are equivalent or interchangeable.

In addition, upon comparing Table 6 or 7 with Table 4 it is found that the average (mean) of the marginal cost is very close to the marginal cost for a uniform or near-uniform load reduction stream.

Based on the above discussions, we recommend using the values provided in Table 6 as the generic marginal costs. The range of 1, 2 or 3 standard deviations from the average may be chosen for sensitivity study.

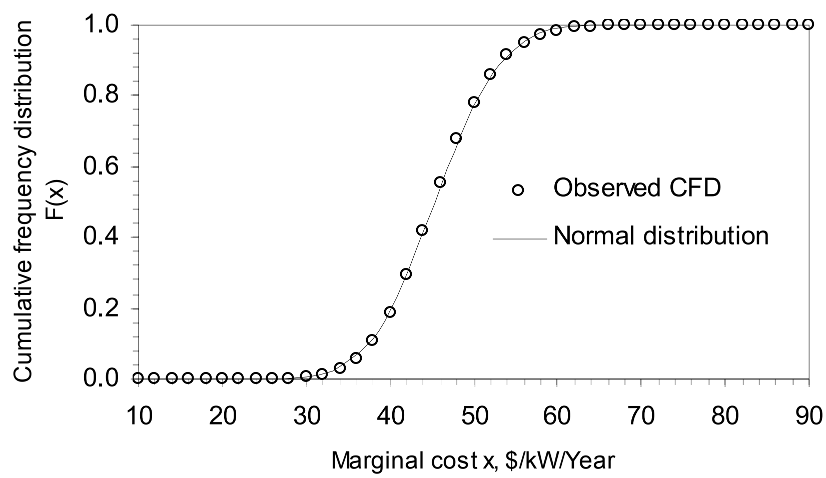

Fig. 2. The cumulative frequency distribution (CFD) of transmission marginal costs. The mean = 45.44 $/kW/Year; the standard deviation = 6.19 $/kW/Year.

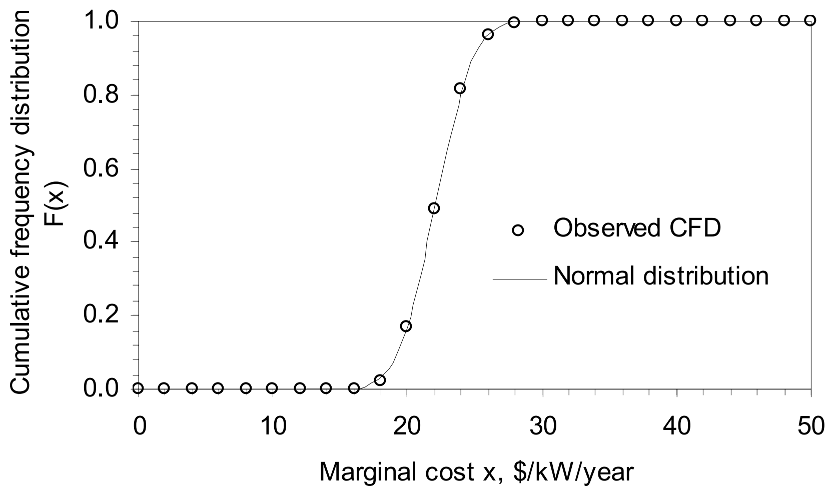

Fig. 3. The cumulative frequency distribution (CFD) of subtransmission marginal costs. The mean = 22.09 $/kW/Year; the standard deviation = 2.12 $/kW/Year.

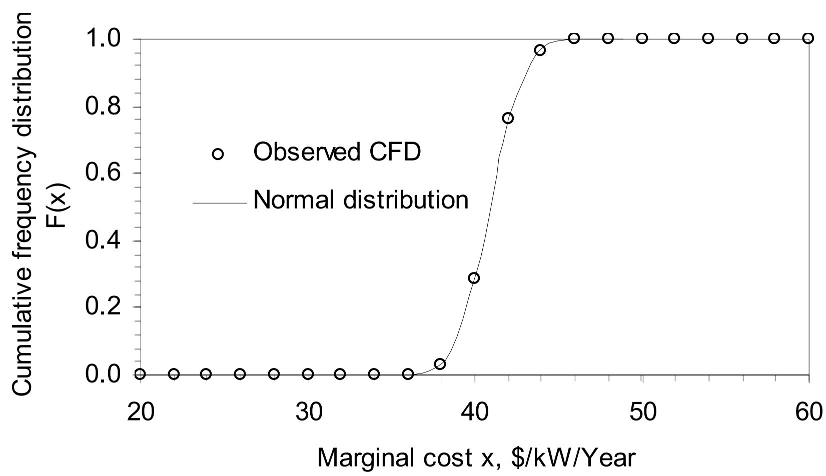

Fig. 4. The cumulative frequency distribution (CFD) of distribution marginal costs. The mean = 40.93 $/kW/Year; the standard deviation = 1.60 $/kW/Year.

TABLE 6
MARGINAL T&D COSTS ($/KW/YEAR, 2004 CONSTANT DOLLARS) GIVEN BY THE OYD METHOD FOR A RANDOM LOAD REDUCTION STREAM

	Transmission	Distribution	
		Subtransmission	Distribution-Circuit
Average	45.44	22.09	40.93
Standard Deviation	6.19	2.12	1.60

TABLE 7
MARGINAL T&D COSTS ($/KW/YEAR, 2004 CONSTANT DOLLARS) GIVEN BY THE ADT METHOD FOR A RANDOM LOAD REDUCTION STREAM

	Transmission	Distribution	
		Subtransmission	Distribution-Circuit
Average	45.90	22.31	41.35
Standard Deviation	6.21	2.13	1.62

4.3. Comparison with Existing Avoided Costs

The transmission and distribution avoided costs (in 1990 dollars) recommended in the 1990 avoided cost study [4,5] are $11/kW/Year and $11/kW/Year, respectively (see Appendix C). They escalate to $15/kW/Year and $15/kW/Year (in 2004 dollars), respectively, assuming an escalation rate of 2%. These values are much lower than those provided in the present study, which is attributed to the following factors:

- The increment transmission and distribution investments per kW of load growth were $130/kW/Year and $286/kW/Year (1990 dollars), respectively, as estimated in Appendix C, which are much lower than those in the present study. The lower values are due to lower capital investments and higher load growth (see Appendix C).

- Because of the “significance level” requirement, the load reductions associated with the 100 MW DSM program were not considered to cause capital deferrals until after 1998/99. That is, the capital costs for the first 7 years (between 1990/91 to 1998/99) were treated as “sunk” costs in the avoided cost estimates. The avoided costs derived from the capital expenditures in the distant future (from 1998/99 to 1014/15) were heavily discounted. For example, $1 in 1997 was discounted to $0.665 in 1990 assuming a real discount rate of 6%.

- The residual values of the capital investments at the end of the study period were treated as actual cash flows and accounted for in the

1990 avoided cost estimates. This lowers the transmission and distribution deferral values (i.e. savings from capital deferrals) by 29% and 57%, respectively (see Appendix C).

5. Related Subjects

5.1. Predicting Marginal Costs beyond Planning Horizon

The marginal (or avoided) cost C_{avoid} is calculated over the planning horizon that is 10 years in the current T&D planning practice. There is no approved investment plan available for us to calculate the marginal cost beyond the planning horizon. On the other hand, the marginal cost is often used for evaluating alternatives spanning across a period much longer than 10 years. Therefore we need to project the marginal cost beyond the planning horizon. One way of doing it is simply to assume that the levelized marginal cost in constant-worth dollars will continue into the future beyond the planning horizon. Another way is to assume that the 10 year T&D constant-worth dollar investment stream will repeat itself every 10 years and apply the methods previously presented to estimate the marginal cost for a longer period.

5.2. Effect of Discount Rate

The marginal costs in the previous sections are obtained for a real discount rate of 6% (without the inflation rate component). For a different real discount rate, we will have different marginal costs. Because the marginal costs reflect the savings from capital cost deferrals, a larger discount rate will lead to larger marginal cost values. The marginal costs calculated for a number of different real discount rates are plotted in Fig. 5 where the factor f_d is the ratio of the marginal cost for a discount rate of 6% to that for a discount rate of i. An approximate mathematical expression for the relationship is found through curving fitting as follows:

$$f_d = -67.8i^2 + 19.7i + 0.057 \tag{21}$$

The f_d v.s. i curve can be used to modify the marginal cost values provided in this report if the projected real discount rate is significantly different from 6.0%. For example, the results in Tables 6 and 7 can be multiplied by a factor of 1.2 to obtain those for a real discount rate of 8.0%. It is noted that the factor f_d is not only applicable to the average, but also to the standard deviation.

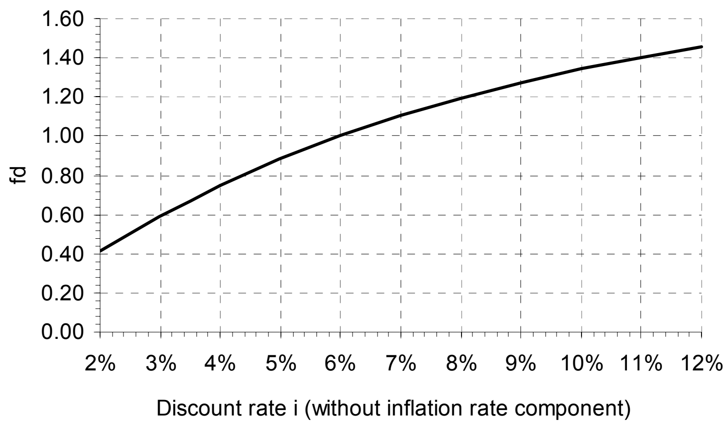

Fig. 5. Marginal cost v.s. real discount rate.

5.3. Marginal Cost with Respect to Larger Load Reduction

In the previous sections, we focus on the marginal cost associated with small load reductions, i.e. from 0 to the amount of one-year load growth. It has been shown that a variation in the size of load reduction within this range would cause a negligible change in the marginal cost for uniform and near-uniform load reduction streams. Now we would like to examine the situation with respect to larger load reductions, say, close to two times the average annual load growth.

As discussed in Section 2.4, a uniform load reduction stream equal to the average annual load growth ΔL_{ave} over the study period can be assumed to cause the entire load growth related investment plan to shift by one year and the resultant error is negligible. This assumption can actually be extended to the situation where load reductions are equal to $m\Delta L_{ave}$ ($m = 2, 3$) by changing the deferral time from one year to m years. Thus, the marginal cost can be approximately determined as

$$C_{avoid\_m} = \frac{1}{m}[1 - \frac{1}{(1+i)^m}][\sum_{k=1}^{N} \frac{I_k}{(1+i)^k}] \Big/ [\Delta L_{ave} \sum_{k=1}^{N} \frac{1}{(1+i)^k}] \qquad (22)$$

From this equation, we have

$$C_{avoid\_m} \Big/ C_{avoid\_1} = \frac{1}{m}[1 - \frac{1}{(1+i)^m}]/(1 - \frac{1}{1+i}) \qquad (23)$$

For $m = 2$,

$$C_{avoid\_2} \Big/ C_{avoid\_1} = \frac{1}{2}[1 - \frac{1}{(1+i)^2}]/(1 - \frac{1}{1+i}) \approx 1 - i/2 \qquad (24)$$

This indicates that as the size of load reduction is increased from one to two year load growth, the marginal cost varies by about $0.5i \times 100\%$, which is 3% for $i = 6.0\%$ for example. Therefore, the marginal costs given by the OYD method and the ADT method can be applied in the situation where the size of load reduction is between zero and two times the average annual load growth.

6. Concluding Summary

A rigorous method for estimating marginal T&D costs has been developed in this report on the basis of the deferral value of future load-growth related capital expenditures due to a reduction in the forecasted system peak load (demand). It is named the one-year deferral (OYD) method. Another deferral value based method has been presented as well, which is essentially the Present Worth method proposed in [2,8,10] and renamed the arbitrary deferral time (ADT) method in this report. The OYD and ADT methods differ mainly in the restrictions imposed on the deferral time. In the OYD method, the deferral time is restricted to one year, and only part of the load-growth related annual investments are deferred; in the other one, all the load-growth related annual investments are deferred by a period Δt_k that is defined as $\Delta t_k = \delta L_k / \Delta L_k$ and not restricted to integer values in years.

The marginal cost estimates in this report are based on the "T&D Capital Expenditure Forecast (CEF03-1)" for the years 2003/04 – 2013/14 and the Corporate "Electric Load Forecast" for the years 2003/04 to 2013/14. The marginal costs are split into transmission, subtransmission, and distribution-circuit components. The inflation rate, j, and the real discount rate, i (without the inflation rate component), are taken to be 2.0% and 6.0%, respectively, according to the document "Projected Escalation, Interest and Exchange Rates — G911-1", issued 2004 05 27.

Numerical tests on the two methods are conducted for three types of load reduction streams: uniform, near-uniform and random. The followings observations have been made:

- The marginal costs for uniform and near-uniform load reduction streams are very close so that they are interchangeable.
- The marginal cost for a random load reduction stream is governed by the normal distribution. The probability that the marginal cost is within 1, 2 and 3 standard deviations from the average is 84.1%, 97.7% and 99.9%, respectively.
- The OYD and ADT methods give practically the same marginal costs.
- The average (mean) of the marginal cost for a random load reduction stream is practically equal to that for a uniform or near-uniform load reduction stream.

Several related issues have been discussed, which includes the marginal costs beyond the 10 planning horizon, the effect of the discount rate on the marginal cost, etc.

The marginal costs presented in the report are non-area specific and winter-peak-load related. The values in Table 6 are recommended as the generic marginal T&D costs. The range of 1, 2 or 3 standard deviations from the average may be chosen for sensitivity study.

It should be borne in mind that the marginal costs provided in this report may not be applicable in the situations where there is a very large load change (say, much larger than two times the annual load growth), or where the capacity expansion is based on the summer system peak load (demand).

Recommended future work is summarized below (but not limited to):

- To develop more sophisticated guidelines for extracting the load-growth related capital costs from the T&D Capital Expenditure Forecast;
- To update the marginal T&D costs every 5 years or on an as-needed basis;
- To develop an area-specific marginal T&D costing method if needed;
- To develop marginal costs for summer peaking distribution systems if needed.

7. References

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[11] "Capital Expenditure Forecast (CEF03-1), 2003/04 – 2013/14", Volume 2 of 2, Transmission & Distribution, Manitoba Hydro, November, 2003.

[12] "Electrical Load Forecast, 2003/04 to 2023/24", Market Forecast, Manitoba Hydro, May, 2003.

Appendix A

- **Manitoba Hydro Net Electric Load Forecast, 2003/04 to 2023/2024**
- **Projected Escalation, Interest and Exchange Rates – G911-1, Issued 2004 05 27**
- **Analysis of Domestic Items, Manitoba Hydro Management Report, Feb. 2004**

Table 1

MANITOBA HYDRO NET ELECTRIC LOAD FORECAST
2002/03 - 2023/24

Fiscal Year	Net Firm Energy (GW.h)	%	Net Total Peak (MW)	%	Load Factor %
2002/03 Actual	21940	7.1%	3916	4.1%	64.0%
Weather	-272		14		
2002/03 Adjusted	21668	4.5%	3930	4.3%	62.9%
2003/04	22171	2.3%	3956	0.7%	64.0%
2004/05	22690	2.3%	4028	1.8%	64.3%
2005/06	22976	1.3%	4053	0.6%	64.7%
2006/07	23262	1.2%	4088	0.9%	65.0%
2007/08	23554	1.3%	4126	0.9%	65.2%
2008/09	23783	1.0%	4153	0.7%	65.4%
2009/10	24009	1.0%	4180	0.7%	65.6%
2010/11	24203	0.8%	4201	0.5%	65.8%
2011/12	24430	0.9%	4228	0.6%	66.0%
2012/13	24680	1.0%	4258	0.7%	66.2%
10 Year Avg.		1.3%		0.8%	
2013/14	24927	1.0%	4296	0.9%	66.2%
2014/15	25191	1.1%	4338	1.0%	66.3%
2015/16	25458	1.1%	4380	1.0%	66.4%
2016/17	25729	1.1%	4422	1.0%	66.4%
2017/18	26001	1.1%	4465	1.0%	66.5%
2018/19	26274	1.1%	4508	1.0%	66.5%
2019/20	26576	1.1%	4556	1.1%	66.6%
2020/21	26847	1.0%	4599	0.9%	66.6%
2021/22	27143	1.1%	4646	1.0%	66.7%
2022/23	27436	1.1%	4692	1.0%	66.8%
2023/24	27675	0.9%	4730	0.8%	66.8%
21 Year Avg.		1.2%		0.9%	

- See the Glossary of Terms for a definition of Net Firm Energy and Net Total Peak.

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Note: This page is part of the Manitoba Hydro Management Report, Feb. 2004.

ANALYSIS OF DOMESTIC ITEMS
(IN THOUSANDS OF DOLLARS)
FOR THE ELEVEN MONTH PERIOD ENDED FEBRUARY 29, 2004

	BLANKETS			NON-BLANKETS					
	FORECAST	RELEASES	ACTUAL	FORECAST	RELEASES	ACTUAL	FORECAST	RELEASES	ACTUAL
CORPORATE	4 922 *						4 922 *		
PUBLIC AFFAIRS	--	--	--	--	--	--	--	--	--
GAS SUPPLY & SERVICES	--	--	--	--	--	--	--	--	--
HUMAN RESOURCE	301	--	160	--	--	--	301	--	160
RATES & REGULATORY AFFAIRS	--	--	--	500	500	225	500	500	225
INFORMATION TECHNOLOGY	8 946	8 800	6 170	4 626	4 626	7 264	13 572	13 426	13 434
CORPORATE PLANNING	--	--	--	--	--	--	--	--	--
CORPORATE CONTROLLER	--	--	--	--	--	--	--	--	--
PRESIDENT & CEO	--	--	--	5	5	11	5	5	11
	14 169	8 800	6 330	5 131	5 131	7 500	19 300	13 931	13 830
POWER SUPPLY	919 *						919 *		
POWER PLANNING	70	--	15	603	603	56	672	603	71
HVDC	565	209	280	2 590	2 591	2 209	3 155	2 800	2 489
GENERATION NORTH	769	--	887	2 258	2 257	1 432	3 026	2 257	2 318
GENERATION SOUTH	1 856	710	1 407	5 974	5 974	7 292	7 830	6 684	8 698
ENGINEERING SERVICES	250	--	19	1 248	1 247	546	1 498	1 247	565
POWER SUPPLY ADMINISTRATION	100	--	1	--	--	--	100	--	1
	4 528	919	2 609	12 672	12 673	11 534	17 200	13 592	14 142
TRANSMISSION & DISTRIBUTION	1 533 *						1 533 *		
TRANSMISSION PLANNING & DESIGN	2 313	910	1 693	9 495	9 494	6 896	11 808	10 403	8 589
DISTRIBUTION PLANNING & DESIGN	26 990	24 343	30 597	14 942	14 973	13 626	41 932	39 316	44 223
CONSTRUCTION & LINE MAINTENANCE	2 000	--	1 632	6	6	2	2 006	6	1 634
DISTRIBUTION CONSTRUCTION	325	--	190	365	365	324	690	365	514
SYSTEM OPERATIONS	3 636	--	1 923	2 572	2 571	2 912	6 208	2 571	4 835
APPARATUS MAINTENANCE	5 090	3 844	4 436	774	887	610	5 864	4 731	5 046
VP TRANSMISSION & DISTRIBUTION	942	482	461	672	(345)	467	1 614	137	928
	42 829	29 579	40 933	28 826	27 950	24 838	71 655	57 530	65 769
CUSTOMER SERVICE & MARKETING	(148) *						(148) *		
CUSTOMER SERVICE OPERATIONS	52 596	47 576	47 402	--	--	507	52 596	47 576	47 909
SUPPORT SERVICES	2 273	--	2 442	--	--	--	2 273	--	2 442
CUSTOMER SERVICE & MARKETING ADMINISTRATION	--	--	--	18	18	55	18	18	55
	54 721	47 576	49 844	18	18	562	54 739	47 595	50 406
TOTAL	116 248	86 873	99 716	46 647	45 773	44 435	162 894	132 647	144 147

* BALANCE OF ALLOCATED FORECAST

04 03 16

Appendix B

- **Summary of T&D Capital Expenditure Forecast (CEF03-1)**
- **Analysis of TP&D and DP&D Major and Domestic Items**
- **Load-Growth Related T&D Annual Investment Streams**

CAPITAL EXPENDITURE FORECAST (CEF03-1)
(IN MILLIONS OF DOLLARS)
FOR THE YEARS 2003/04 TO 2013/14

	PROJECT TOTAL	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
TRANSMISSION & DISTRIBUTION												
GLENBORO-RUGBY 230KV T/L	30 5	0.9	0 4									
HERBLET LAKE - THE PAS 230kV TRANSMISSION	57.3			1 1	4 8	15 4	18 4	16 6	0 9			
WINNIPEG to BRANDON TRANSMISSION SYSTEM IMPROVEMENTS	34.9						1.9	1 1	3 1	3 0	4 7	21 1
RIDGEWAY 230-66KV TRANSFORMER ADDITION	9.3			0 2	0 5	0 7	4.4	3.5				
DORSEY-ROSSER 230KV TRANSMISSION IMPROVEMENT	2 5	0 1	0 4									
DORSEY - LaVERENDRYE - ST. VITAL 230kV TRANSMISSION	28 1										5 6	7 7
ROSSER - SILVER 230KV TRANSMISSION	30 4	2 4	7 6	13 9								
NEEPAWA 230-66KV STATION	20 9	0 0	0 0	0 0	0 0	0 0	0 2	1.1	9 2	10 3		
ROSSER - MCPHILLIPS 115KV TRANSMISSION IMPROVEMENTS	2 8	2 5	0 2									
RICHER SOUTH 230-66KV TRANSFORMER ADDITION	5 3	0 0	0 5	0 6	2 3	1 8						
PINE FALLS - BLOODVEIN 115kV TRANSMISSION	32 3				0 2	0 3	1 1	2 9	7 1	17 1	3 6	
ST. VITAL - STIEBACH 230kV TRANSMISSION	24 7			0 6	0 6	1.0	3 8	4.9	13 8			
RIDGEWAY - SELKIRK 230KV TRANSMISSION	27 1		1 0	2 6	4 0	4 4	5.0	10 0				
SOURIS - PEMBINA VALLEY 230kV TRANSMISSION	34.0	0 0	0 0	0 0	0 7	0 9	1 6	1 9	12.2	16 8		
WINNIPEG AREA TRANSMISSION REFURBISHMENT	8.4	0 5	0.9									
DORSEY - US D602F 500KV AC T/L INSULATOR REPL	7 4	0 2	0 0									
DORSEY 230KV BUS ENHANCEMENTS	17.5	4 8	2 0									
FLIN FLON AREA TRANSMISSION IMPROVEMENTS PHASE 2	13 1	1 9	7 9	1.5	0 0							
PINE FALLS - GREAT FALLS 115-66KV SUPPLY	10 3	5 7	0 0	0 0	0 0	0.0	0.0	0 2	1.9	1.7	0.0	
RUTTAN - SOUTH INDIAN LAKE 66KV LINE	13.7	2 8	1 1									
CENTRAL SUPPLY PIKWITONEI & THICKET PORTAGE	5.4	0 3										
BIRTLE SOUTH - ROSSBURN 66KV LINE	4 9											0.1
ST. BONIFACE PLESSIS RD 115-25KV STATION	18.3	0 3	0 5									
ST. BONIFACE PLESSIS RD BK2 ADDITION	2.1	0.4	0 2									
ROSSER OAK POINT 115-24kV STATION	22.1	0 0	0 0	0 0	0 0	1 6	2.3	13 5	4.6			
ROSSER OAK POINT BANK 2 ADDITION	10.3						1.0	6 4	2 8			
BRANDON CROCUS PLAINS 115-24KV BANK ADDITION	8.6	0 0	0 0	0 0	0 8	4 6	2 9	0 3				
FT GARRY PERIMETER SOUTH BANK REPL	5.1				0 7	3 0	1.4					
ROVER SUB STATION REPLACE 4KV SWITCHGEAR	5.6	0 2	4.2	1.3								
PORTAGE SOUTH 230-66kV 2nd TRANSFORMER ADDITION	7.9	0.2	5.4	2 2								
VIRDEN AREA DISTRIBUTION CHANGES	17.2	0 8	1 0	1.7								
DEFECTIVE RINJ CABLE REPLACEMENT	8.6	1 0	1 4	1 4	1.5							
BRERETON LAKE STATION AREA	8 6	5 3	0 7	0 8	0 6	0 1						
SHAMATTAWA NEW DIESEL GS & TANK FARM	16.4	1 8	0.4	1.7	0 7							
HARROW STATION BANK 3 INSTALLATION	2.6	0.0	1 9	0.7								
STONY MOUNTAIN NEW 115-12KV STATION	3.3	0.0	0 5	1 3	0 3	1 2						
COMMUNICATIONS	158 2	39 8	16 2	23 9	22 8	10 2	1 0					
MAPINFO IMPLEMENTATION	30.5	1 0										
INTEGRATION OF SYSTEM CONTROL CENTRES	3 8	0 7	1 9	1 2								
SITE REMEDIATION	10 9	0.7	3 1	1 0	0 1							
OIL CONTAINMENT	7.5	0 6	1 1	1 1	1 2	1 1	1 4					
DOMESTIC ITEM		71.7	81 3	83 1	85 1	86 9	88 9	90 8	93.1	93.6	94.3	97 6
TRANSMISSION & DISTRIBUTION TOTAL		**146.7**	**141.5**	**142.2**	**127.1**	**133.3**	**135.4**	**153.2**	**148.9**	**142.5**	**108.1**	**126.6**

Table B.1. Analysis of T&D Major Items for Years 2003/04 To 2013/14 (Including Effect of Inflation)

Items	Justification	Comments	03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14
Transmission -- major items:		100% load related											
Herblet Lake - The Pas 230 kV Transmission	Load and reliability	To provide firm supply for increasing Flin-Flon and The-Pas loads			1,147	4,785	15,398	18,378	16,607	945			
Winnipeg to Brandon Transmission System Improvement	Load and reliability	To accommodate West MB area future load growth						1,889	1,065	3,110	2,974	4,726	21,119
Ridgeway 230-66 kV Transformer Addition	Load and reliability	To supply increased Wpg load			244	453	727	4,410	3,487				
Dorsey - LaVerendrye - St. Vital 230 kV Transmission	Load and reliability	To provide firm supply for East MB loads										5,576	7,748
Neepawa 230-66 kV Station	Load and reliability	To supply Neepawa and related Western region future load growth						195	1,126	9,219	10,326		
Richer South 230-66 kV Transformer Addition	Load and reliability	To provide firm supply to Richer area loads	1	516	602	2,294	1,836						
Pine Falls - Bloodvein 115 kV Transmission	Load and reliability	To accommodate Lake Wpg East area load increases				241	266	1,135	2,880	7,134	17,103	3,554	
St. Vital - Steinbach 230 kV Transmission	Load and reliability	To accommodate load growth in South-eastern MB			576	632	1,017	3,819	4,883	13,769			
Souris - Pembina Valley 230 kV Transmission	Load and reliability	To support load growth in South-western MB	1	1	1	658	926	1,564	1,858	12,217	16,801		
Pine Falls - Great Falls 115-66 kV Supply	Load and reliability	To provide contingency capacity for Paine Falls 66 kV system that will run short due to load growth	5,713	9	10	11	12	13	250	1,900	1,710	36	
Subtotal			**5,715**	**526**	**2,580**	**9,074**	**20,182**	**31,403**	**32,156**	**48,294**	**48,914**	**13,892**	**28,867**
Subtransmission -- major items:		100% load related											
Birtle South - Rossburn 66 kV Line	Load and reliability	To support Rossburn and Shoal Lake area load growth											142
Rosser Oak Point 115-24 kV Station	Load and reliability	To support load growth in the area				37	1,592	2,310	13,494	4,631			
Rosser Oak Point Bank #2 Addition	Load and reliability	To support load growth in the area						1,019	6,449	2,797			
Brandon Crocus Plains 115-24 kV Bank Addition	Load, reliability, etc.	To support load growth in the area		-1	-1	830	4,600	2,875	270				
Ft. Garry Perimeter South Bank Replacement (66-12 kV)	Load	To supply load growth in South Brandon area				716	2,963	1,394					
Subtotal			**0**	**-1**	**-1**	**1,583**	**9,155**	**7,598**	**20,213**	**7,428**	**0**	**0**	**142**
Other major items:		0% load related or 0% of costs can be deferred due to a load reduction											
Dorsey - Rosser 230 kV Transmission Improvements	Load and reliability	To refurbish 230 kV line DR5. Costs should be considered as partially load-related. $1.953 millions has been spent.	132	368									
Rosser - McPhillips 115 kV Transmission Improvements	Load and reliability	To increase transmission capacity for load support. ISD is the current year and costs can not be deferred.	2,536	174									

Ridgeway - Selkirk 230 kV Transmission	Load and reliability	To provide supply to Selkirk area to alleviate flicker problems and to support Parkdale area. The flicker problems will be resolved by installing an SVC and this item will be deferred beyond the 10 planning horizon		965	2,648	3,959	4,433	5,046	10,038				
Winnipeg Area Transmission Refurbishment	Load and reliability	To refurbish the lines to insure safe operating ground clearances. $6.139 millions have been spent.	536	935									
Flin Flon Area Transmission Improvements (Phase 2)	Load, safety, reliability and efficiency	Mainly due to factors other than load growth.	1,873	7,915	1,539	37							
Rosser - Silver 230 kV Transmission	Load and reliability	To provide firm supply to Silver Station to accommodate load growth in Interlake area. Project has already started.	2,417	7,581	13,880								
Ruttan - South Indian Lake 66 kV Line	Load	To support increased South Indian Lake load. ISD is the current year and can not be deferred	2,765	1,076									
St. Boniface Plessis Road 115-25 kV Station	Load and reliability	ISD is the current year and can not be deferred	289	465									
St. Boniface Plessis Road Bank #2 Addition	Load and reliability	ISD is the current year and can not be deferred	363	200									
Portage South 230-66 kV 2nd Transformer Addition	Load and reliability	Costs have been committed	206	5,382	2,222								
Virden Area Distribution Changes	Load, safety, etc.	The project was mainly driven by factors other than load growth	762	993	1,744								
Horrow Station Bank #3 Installation (115-24 kV)	Load and reliability	To provide addition 24 capacity for high load growth. ISD is one year away and can not be deferred		1,906	716								
Stony Mountain New 115-12 kV Station	Load, reliability and efficiency	Existing station equipment and their supply line are in a deteriorated condition and must be replaced. Cost can not be deferred		470	1,342	298	1,232						
Glenboro - Rugby 230 kV T/L	Reliability and other		877	383									
Dorsey - US D602F 500 kV AC T/L Insulator Replacement	Reliability	Replace defective ones	234	24									
Dorsey 230 kV Bus Enhancements	Safety, reliability and efficiency		4,786	1,963									
Central Supply Pikwitonei & Thicket Portage	Salvage diesel units and remediate sites		292										
Rover Substation Replace 4 kV Switchgear	Safety and reliability		159	4,154	1,320								
Defective Rinj (Red Jacket) Cable Replacement	Reliability and service		1,021	1,395	1,445	1,542							
Brereton Lake Station Area	Safety, reliability service and efficiency		5,330	696	751	607	101						
Shamattawa New Diesel GS & Tank Farm	Load and service	Generation related	1,843	358	1,675	673							
Communications	Reliability and service		39,828	16,249	23,908	22,829	10,178	1,038					
MapInfo Implementation	Efficiency		1,041										
Integration of System Control Centers	Reliability and service		721	1,861	1,222								

Site Remediation	Safety and other		656	3,055	1,009	144							
Oil Containment	Safety and other		644	1,075	1,122	1,244	1,138	1,385					
Subtotal			**69,311**	**59,643**	**56,543**	**31,333**	**17,082**	**7,469**	**10,038**	**0**	**0**	**0**	**0**
Domestic items	Part of the costs is load related and to be identified		**71,700**	**81,300**	**83,100**	**85,100**	**86,900**	**88,900**	**90,800**	**93,100**	**93,600**	**94,300**	**97,600**
Total			***146,726***	***141,468***	***142,222***	***127,090***	***133,319***	***135,370***	***153,207***	***148,822***	***142,514***	***108,192***	***126,609***

Table B.2. Split of 2003/04 TP&D and DP&D Domestic Budget (Including Effect of Inflation) Based on Tables B.3 to B.6

		Approved Domestic Budget (in $1,000)			Capacity-Related Portion (in $1,000)		
		Blanket	Non-blanket	Blanket & Non-blanket	Blanket	Non-blanket	Blanket & Non-blanket
				(A) + (B)			(D) + (E)
		(A)	(B)	(C)	(D)	(E)	(F)
(R1)	Transmission	1,132	6,825	7,957	0	1,784	1,784
(R2)	Subtransmission - TP&D	1,132	2,319	3,451	0	2,213	2,213
(R3)	Subtransmission - DP&D	2,761	3,898	6,659	2,071	1,846	3,917
(R4)	Subtransmission (R2+R3)	3,893	6,217	10,110	2,071	4,059	6,130
(R5)	Distribution-circuit	22,087	8,805	30,892	15,150	4,045	19,195
(R6)	Total approved T&D domestic budget (R1+R4+R5)			48,959			
(R7)	Total capacity-related T&D domestic budget (R1+R4+R5)						27,109
(R8)	Capacity-related portion (R7/R6)						55.4%
Split of capacity-related domestic budget:							
	Transmission (R1/R7)						6.6%
	Subtransmission (R4/R7)						22.6%
	Distribution-circuit (R4/R7)						70.8%

Notes:

1). The balances of targets are not included in the analysis

2). The following assumptions may be made according to the above results:

a). The domestic budget may be split between capacity and non-capacity related portions at a ratio of 50/50

b). Capacity-related domestic budget may be split as follows:

5% for transmission,

25% for subtransmission,

70% distribution-circuit.

3). Effect of inflation is included

Table B.3. Analysis of 2003/04 TP&D Domestic Budget -- Blankets (Including Effect of Inflation)

Projects	Approved Forecast (in $1,000)	Capacity-Related Portion		Comments
			in $1,000	
Transmission Lines - Additions & Modifications	125	50%	63	50% load-related (Note: This is an arbitrary assumption)
Station Site Acquisition	85	50%	43	50% load-related based on the assumption that it is for expanding station (or station capacity)
Station Supervisory Control & Automation Modifications	50	0%	0	
Protection & Metering	301	0%	0	
Surveys & Mapping Equipment	123	0%	0	
Property Survey Equipment	20	0%	0	
Property Land Rights Acquisition	650	0%	0	Not used for the purchase of additional land to expand capacity (according to comments from Doreen Devloo, Property Dept.)
TP&D Preliminary Engineering - Stations	784	0%	0	
TP&D Preliminary Engineering - Transmission Lines	125	0%	0	
Total TP&D Blankets -- Transmission	**1,132**		**53**	50/50 split between transmission and subtransmission
Total TP&D Blankets -- Subtransmission	**1,132**		**53**	
Total TP&D Blankets	**2,263**		**105**	TP&D blanket budget is about 7% capacity-related

Notes:

1). The total TP&D blanket of $105,000 is tiny compared to the total of TP&D major items, and therefore will be ignored.

Table B.4. Analysis of 2003/04 TP&D Domestic Budget -- Non-Blankets (Including Effect of Inflation)

Projects	Approved Forecast (in $1,000)	Capacity-Related Portion		Justifications or Comments
			in $,1000	
Transmission				
Dorsey-Neepawa-Cornwallis 230kV T/L	220	100%	220	To provide initial ac system improvements required to transmit power to Brandon area to supply future load growth.
Dorsey-Riel (South Loop) Property Requirements	296	100%	296	Right-of-way for all future contemplated EHV lines in the Winnipeg area
Dorsey West Property Requirements	66	100%	66	Right-of-way for all future contemplated EHV lines in the Winnipeg area.
Dorsey - St. Vital 230kV T/L	42	100%	42	To provide for part of system changes to transmit power from Dorsey to east half of Winnipeg.
William River Stn - G8P Line Switches	-272	0%	0	To provide supply flexibility to Norway House and minimize extended customers outages.
St. Vital 230-115 kV Transformer Addition	178	100%	178	Install a 230-115 kV transformer to meet increased Winnipeg area load
St. Vital 230-115 kV Transformer Addition	4	100%	4	To accommodate Winnipeg area load growth, etc.
500kV Line D602F 'A' Protection Replacement	156	0%	0	Because it is obsolete and requires extensive annual maintenance.
500kV Line 602F 'B' Protection Replacement	0	0%	0	Because it is obsolete and requires extensive annual maintenance.
Flin Flon Border new 115kV Station	17	100%	17	To provides necessary facilities to terminate 115 kV lines from Cliff Lake and Ross Lake stations and from Island Falls (SaskPower).
Pine Fall Protection Changes for Lines PA1 and PA2	29	0%	0	The relay system is obsolete and there are no spares available.
Roblin South Station 230 KV Reactor Addition	1,816	0%	0	To maintain 230 kV voltage limits within 95-105% during normal and contingency conditions.
T/L Thermal Rating Verification (W.I.R.E. Services)	1,018	0%	0	To complete missing information on the "conductor thermal rating" list issued by Transmission Line Design to System Performance.
Transmission System Metering	1,215	0%	0	To replace obsolete strip chart recorders and indicating demand meters with digital meters, and install them at 11 new sites to complete the metering system for transmission tariff purposes.
Transmission Line Vibration Study	51	0%	0	To monitor aeolian and motion arising from extreme weather events on the sky wire of line D54C.

Rosser-St.James 115kV TL Property Acquisition	465	0%	0	To allow MH to control the use of the land encumbered by the St. James 115 kV T/L. Ownership allows MH to benefit under its secondary land use program from the potential for parking revenue.
Target transferred from VP:				
Dorsey 500kV Spare Transformer Cold Standby	777	100%	777	To allow for design and construction of pad foundation for a single phase spare transformer at Dorsey.
Nelson River Crossing Strobe Light Replacement	478	0%	0	To replace antiquated strobe light system.
St. Vital Battery Banks	184	100%	184	Larger battery banks are required due to recent additions to St. Vital station.
Star Lake SK1-1 vacrupter switch	84	0%	0	To maintain short customer interruptions during switching.
Subtotal	**6,825**		**1,784**	
Subtransmission				
Jenpeg Terminal 66 kV Changes	40	100%	40	Required for operation and protection of a new line to Norway house.
Glenboro South Station Bank 3 Addition	105	100%	105	In stall a 230-66 kV transformer to deal with load growth in Glenboro South 66 kV system
Richer South 230-66kV Emergency Transformer	0	100%	0	To provide a second contingency backup to all 230-66 kV transformers on the MH system.
Target transferred from VP:				
Assiniboine Wilkes Ave - 115-24kV Transformer Addition	261	100%	261	To support load growth in the area and provide backup to other 24 kV stations nearby.
Portage South Station 66kV Breaker Addition	258	100%	258	Associated with the 66 kV line from Portage South to Portage Westco Drive which deals with load growth
Portage South-Portage Westco Drive 66kV Line	164	100%	164	Construction of the new 16 km, 66 kV line will off-load the line 84 whose limit is being approached.
Selkirk MRM Primary Metering	55	0%	0	
Selkirk MRM Protection	51	0%	0	
Portage South Station Hot Standby	1,385	100%	1,385	To replace the 230-66 kV bank #1 in the event of its failure in order to quickly restore supply to large customers including new loads.
Subtotal	**2,319**		**2,213**	
TP&D Non-blanket -- Transmission	**6,825**		**1,784**	
TP&D Non-blanket -- Subtransmission	**2,319**		**2,213**	
TP&D Non-blanket -- Transmission + Subtransmission	**9,144**		**3,997**	TP&D non-blanket budget is about 44% capacity-related

Table B.5. Analysis of 2003/04 DP&D Domestic Budget -- Blankets (Including Effect of Inflation)

Projects	Approved Forecast (in $1,000)	Capacity-Related Portion		Comments
			in $1,000	
1) Brandon				
Station	**736**	75%	552	
Distribution				
S/T Adds & Mods	0	75%	0	
S/T System - Ice Melting	0	0%	0	
Street Lighting	156	0%	0	
Highway Changes	669	0%	0	
S/T Mods - Storm Damage	0	0%	0	
System Improvements	2,892	80%	2,314	
Customer Service	1,978	50%	989	Arbitrary assumption
New & Upgrd Feeders	0	80%	0	
Underground Residential Dist	192	100%	192	
Adjustment made to Dist Const Activity Rate	0	0%	0	
Defective Cable Replacements	0	0%	0	
Subtotal	**5,887**		**4,047**	
2) Selkirk				
Station	**1,200**	75%	900	
Distribution				
S/T Adds & Mods	400	63%	250	
S/T System - Ice Melting	250	0%	0	
Street Lighting	500	0%	0	
Highway Changes	800	0%	0	
S/T Mods - Storm Damage	0	0%	0	
System Improvements	3,900	75%	2,925	
Customer Service	2,150	50%	1,075	Arbitrary assumption
New & Upgrd Feeders	0	75%	0	
Underground Residential Dist	50	100%	50	
Duct Systems	0	0%	0	
Defective Cable Replacements	500	0%	0	
Subtotal	**8,550**		**5,200**	
3) Winnipeg				
Station	**825**	75%	619	

Distribution				
S/T Adds & Mods	100	10%	10	
S/T System - Ice Melting	0	0%	0	
Street Lighting	350	0%	0	
Highway Changes	0	0%	0	
S/T Mods - Storm Damage	0	0%	0	
System Improvements	4,500	85%	3,825	
Customer Service	1,500	50%	750	Arbitrary assumption
New & Upgrd Feeders	0	85%	0	
Underground Residential Dist	700	100%	700	
Carryover and Unreleased Projects	0	0%	0	
Defective Cable Replacements	500	0%	0	
Subtotal	**7,650**		**5,904**	
Total DP&D Blankets -- Station*	**2,761**		**2,071**	Station blanket budget is about 75% capacity-related
Total DP&D Blankets -- Distribution*	**22,087**		**15,150**	Distribution blanket budget is about 69% capacity-related
Total DP&D Blankets	**24,848**		**17,221**	DP&D blanket budget is about 69% capacity-related

***Notes:**

1) "Station" is part of "subtransmission" in this marginal cost study (Report SPD 04/05).
2) "Distribution" is interpreted as "distribution-circuit" in this marginal cost study (Report SPD 04/05).

Table B.6. Analysis of 2003/04 DP&D Domestic Items -- Approved Non-Blankets (Including Effect of Inflation)

Projects	Approved Forecast (in $1000)	Capacity-Related Portion		Justifications or Comments
			in $1000	
1) Bdn Distribution Planning & Design Non-Blankets				
Station				
Benito Station Rebuild	0	0%	0	Due to poor conditions
Holland 66-8.32kv Stn 03-833	0	0%	0	Due to poor conditions
Gladstone Stn Salvage	52	50%	26	A new station has been built. Existing station is old, and inadequate in space for adding larger transformers.
Boissevain Stn 66kV Rebuilt	1	0%	0	Due to its poor conditions
Rorketon 66-24.9/14.4 kV Station	795	0%	0	Construct a new single banks station near the existing site due to various operating and maintenance concerns
Brandon 65th St East Bank Add	0	100%	0	Addition of a 115-24.9 kV bank will address the inadequate capacity concern
74437 - Flin Flon Ross L. Neut Reactor	0	0%	0	For equipment and operator safety concerns
Holland 66-8.32kv Stn	-13	0%	0	Existing station is in poor condition
Dauphin Vermillion Stn Bk Sal & Mobile	45	100%	45	To serve more load
Dauphin Second St Stn Convert to 12 KV	9	50%	4	Existing switchgear is in poor condition, etc. Better spare bank locations for future load growth
Brandon Highland Mobile Provision	0	100%	0	To provide for mobile connection
Subtotal	**887**		**75**	
Distribution				
DAUPHIN 2ND ST. CONVERSION	8	0%	0	Part of two year plan to convert Dauphin to 12 kV
L74 Rebuild Killarney - Ninette	-12	0%	0	L74 is old and is in poor condition. A new 66 kV line will address all old-age related issues
Prospector Corner 66-24.9kv Dist. Supply	525	100%	525	To reduce feeder losses
Stage 2 - Dauphin Second St. Conversion	3	50%	2	Existing switchgear is in poor condition, etc. Better spare bank locations for future load growth
66kV Line 85 Rebuild and GE12-1	-72	0%	0	Due to poor condition with old poles, etc.
MacGregor S.I. Fdr MR12-4 & New MR12-3	-15	50%	-8	New feeder will improve voltage and losses

FLIN FLON ROSS LAKE NEW FEEDER	-2	100%	-2	To meet a demand of 1500 kVA (new load)
L52 66kV Rebuild Pilot Mound - Swan Lake	143	0%	0	Due to rotten arms, rottens poles, etc.
66kV TAP PELICAN RAPIDS CORNER DSC	479	100%	479	To deal with load increase at Pelican Rapids
MAFEKING TO PELICAN RAPIDS CORNER 66 KV	917	100%	917	To deal with load increase at Pelican Rapids
SHOAL LAKE RURAL REBUILD	1,576	50%	788	Existing 33-8 kV station is in poor condition. As a result of upgrading 8 kV distribution to 12 kV and subtransmission to 66 kV, load capability will be increased
Subtotal	**3,549**		**2,701**	
Total Bdn Distribution Planning & Design Non-Blankets	**4,436**		**2,775**	
2) Selkirk Distribution Planning & Design Non-Blankets				
Station				
Parkdale Stn-Bnk Add'n	0	100%	0	To deal with load growth
038374 NIVERVILL STN CON NEW 66-12KV STN	8	0%	0	Deficiencies and condition of the existing station results in need for a new station
Ilford Station	0	0%	0	Many deficiencies cause serious operating problems and safety concerns
Vivian Stn-Improvement	15	50%	7	To address safety concerns and also provide for mobile connection
Sarto Station Bank Replacement	1	100%	1	For higher station capacity to accommodate load growth
WINKLER NORTH STATION BANK ADDITIO	-202	100%	-202	To handle load growth
Winkler Market Bank Replacement	0	100%	0	To insolate harmonics produced at Monarch industries, and also provide transformer redundancy
East Selkirk Stn.-Disconnects Repl	-54	0%	0	For safety concerns
Cross Lake Station ISD 2003-09-30	962	100%	962	Install a 3rd transformer
Gimli Station - New Station	305	50%	153	The existing station is too old. The 2nd bank in new station provides one level of redundancy into the system
Gillam Station-New Station	481	50%	240	The existing station is too old. The 2nd bank in new station provides one level of redundancy into the system
06458 STEINBACH 1st AVE ACR REPLACEMENT	413	0%	0	
Stony Mountain Stn - Site acquisition/Eng	102	100%	102	For new 115-12 kV station to deal with load growth

Subtotal	**2,031**		**1,264**	
Distribution				
Rebuild Line 64 Fort Alexander	591	50%	295	Wpg River caused erosion of river banks that results in distributed soil and leaning poles. A new school requires feeder extension and line modification as well.
Brokenhead-Beausejour N 33kV	0	0%	0	For safety concerns
KOMARNO FDR KO08-2 CONVER INWOOD	0	0%	0	To address the low voltage problem
NORWAY HOUSE SCHOOL	1,359	0%	0	This project is customer service for Norway House Cree Nation.
STAR LAKE FDR STL12-1 RELOCATION	-7	0%	0	To improve reliability, service and power quality.
Inwood Conversion - Stage 2 N/B	141	0%	0	To address the low voltage problem
04326 INWOOD CONVERSION - STAGE 3 N/B	432	0%	0	To address the low voltage problem
L#20 Stuartb-Vita S/T	669	50%	334	To increase reliability and also reduce losses.
THOMPSON WESTWOOD ACRs	-59	0%	0	
WINKLER MARKET 8kV CONVERSION WM8-	0	0%	0	To maintain operating and safety standards
06200 WABOWDEN DSC'S NON-BLANKET	511	100%	511	Install 2 new 66-12 kV distribution supply centers to replace existing Wabowden station
PINEY SUPPLY CENTRE - NON-BLANKET	683	0%	0	For safety concerns
06989 HADISHVILLE DSC INSTALLATION	0	0%	0	For safety concerns
06990 MEDIKA DSC INSTALLATION	0	100%	0	Construct new distribution supply center
Subtotal	**4,319**		**1,141**	
Total Selkirk Distribution Planning & Design Non-Blankets	**6,351**		**2,405**	
3) Winnipeg Distribution Planning & Design Non-Blankets				
Station				
Court - Install 115 12kV Bank	0	100%	0	Installation of a 2nd bank provides firm capacity
Augier 115-12kV Bus Rebild	489	0%	0	For safety concerns
Birds Hill Station Property	-17	0%	0	
Transcona RAVELSTONE STN - PROPERTY ACQUISITION	507	100%	507	For the future Ravelstone Station to accommodate load growth
Subtotal	**979**		**507**	
Distribution				
12kV Padmount Feeder Capacitors	45	0%	0	To complete outstanding work and deficiencies related to installation of various feeder capacitors
EK Spgfld Add 66-12kV Bank #2	-10	100%	-10	Provides for additional 12 kV capacity for north-east Winnipeg

Winnipeg 63.5kV Network T/L Refurbish	-42	0%	0	To ensure safe operating ground clearances
Oak Bluff 12kv S.I.	-1	100%	-1	Facilities are required to integrate the new Oak Bluff station into the distribution system
Kitchen Craft 1180 Springfield	0	100%	0	To meet the increased load requirement
Pembina Station Rebuild	312	0%	0	Transformer replacement to maintain reliability standards
MAPLES SILICONE CABLE INJECTION	418	0%	0	To revitalize existing cables in Maples area using a technique of cable injection
Dakota-Upgrade 731DK Feeder	214	100%	214	To relieve heavily loaded feeders DK731, etc.
Subtotal	**937**		**203**	
Total Winnipeg Distribution Planning & Design Non-Blankets	**1,916**		**710**	
Total DP&D Non-Blankets -- Station*	**3,898**		**1,846**	
Total DP&D Non-Blankets -- Distribution*	**8,805**		**4,045**	
Total DP&D Non-Blankets -- (Station + Distribution)	**12,703**		**5,891**	DP&D non-blanket budget is about 46% capacity-related

***Notes:**

1) "Station" is part of "subtransmission" in this marginal cost study (Report SPD 04/05).
2) "Distribution" is interpreted as "distribution-circuit" in this marginal cost study (Report SPD 04/05).

Table B.7. T&D Expansion Plan — Load Growth Related Expenditures in $1,000 (Including Effect of Inflation)

k	Fiscal Year	T&D Domestic Budget	TP&D and DP&D Domestic Budget	Capacity-Related Domestic Budget	Transmission			Distribution: Subtransmission			Distribution: Distribution-circuit			Total T&D
					Major	Domestic	Total Capacity-Related	Major	Domestic	Total Capacity-Related	Major	Domestic	Total Capacity-Related	
			(A)×(75%)	(B)×(50%)		(C)×(5%)	(D)+(E)		(C)×(25%)	(G)+(H)		(C)×(70%)	(J)+(K)	(F)+(I)+(L)
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
0	2004/05	81,300	60,975	30,488	526	1,524	2,050	0	7,622	7,622	0	21,341	21,341	31,014
1	2005/06	83,100	62,325	31,163	2,580	1,558	4,138	0	7,791	7,791	0	21,814	21,814	33,743
2	2006/07	85,100	63,825	31,913	9,074	1,596	10,670	1,583	7,978	9,561	0	22,339	22,339	42,570
3	2007/08	86,900	65,175	32,588	20,182	1,629	21,811	9,155	8,147	17,302	0	22,811	22,811	61,925
4	2008/09	88,900	66,675	33,338	31,403	1,667	33,070	7,598	8,334	15,932	0	23,336	23,336	72,339
5	2009/10	90,800	68,100	34,050	32,156	1,703	33,859	20,213	8,513	28,726	0	23,835	23,835	86,419
6	2010/11	93,100	69,825	34,913	48,294	1,746	50,040	7,428	8,728	16,156	0	24,439	24,439	90,635
7	2011/12	93,600	70,200	35,100	48,914	1,755	50,669	0	8,775	8,775	0	24,570	24,570	84,014
8	2012/13	94,300	70,725	35,363	13,892	1,768	15,660	0	8,841	8,841	0	24,754	24,754	49,255
9	2013/14	97,600	73,200	36,600	28,867	1,830	30,697	142	9,150	9,292	0	25,620	25,620	65,609

Table B.8. T&D Expansion Plan — Load Growth Related Expenditures in $1,000 (Not Including Effect of Inflation)

					Transmission			Distribution						
								Subtransmission			Distribution-circuit			
k	Fiscal Year	T&D Domestic Budget	TP&D and DP&D Domestic Budget	Capacity-Related Domestic Budget	Major	Domestic	Total Capacity-Related	Major	Domestic	Total Capacity-Related	Major	Domestic	Total Capacity-Related	Total T&D
			(A)×(75%)	(B)×(50%)		(C)×(5%)	(D)+(E)		(C)×(25%)	(G)+(H)		(C)×(70%)	(J)+(K)	(F)+(I)+(L)
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
0	2004/05	81,300	60,975	30,488	526	1,524	2,050	0	7,622	7,622	0	21,341	21,341	31,014
1	2005/06	81,471	61,103	30,551	2,529	1,528	4,057	0	7,638	7,638	0	21,386	21,386	33,081
2	2006/07	81,795	61,347	30,673	8,722	1,534	10,255	1,187	7,668	8,856	0	21,471	21,471	40,582
3	2007/08	81,888	61,416	30,708	19,018	1,535	20,553	6,866	7,677	14,543	0	21,496	21,496	56,592
4	2008/09	82,130	61,597	30,799	29,012	1,540	30,551	5,699	7,700	13,398	0	21,559	21,559	65,509
5	2009/10	82,240	61,680	30,840	29,125	1,542	30,667	15,160	7,710	22,870	0	21,588	21,588	75,125
6	2010/11	82,670	62,003	31,001	42,884	1,550	44,434	5,571	7,750	13,321	0	21,701	21,701	79,456
7	2011/12	81,484	61,113	30,557	42,583	1,528	44,110	0	7,639	7,639	0	21,390	21,390	73,139
8	2012/13	80,484	60,363	30,182	11,857	1,509	13,366	0	7,545	7,545	0	21,127	21,127	42,038
9	2013/14	81,667	61,250	30,625	24,155	1,531	25,686	107	7,656	7,763	0	21,438	21,438	54,886

Notes:

1). Inflation or escalation rate j = 2%

Appendix C

— Existing Avoided T&D Costs

5.5 Conclusions

- The significant variation in Transmission Cumulative Savings (Table 1 of Appendices G and I) is due to the discrete nature of the Major Items included in the analysis. If a forecast of future Major Transmission Items Capital requirements was used, a more consistent result would be expected. Such a forecast does not exist at the present time.

- Transmission and Distribution capital requirements are generally well determined for the initial 10 year budget period. Beyond 10 years, few specific plans are formalized in the budget. For this reason, T&D Avoided Costs were determined for only a maximum 25 year period.

- In terms of levelized cost savings, the results are consistent between the two D.S.M. programs which were evaluated.

- Considering the variation between the 100 MW and 200 MW DSM programs, it is recommended that the following costs be used as representative of T&D Avoided Costs.

Distribution	$11/kW/YR ($1990)
Transmission	$11/kW/YR ($1990)
TOTAL	$22/kW/YR ($1990)

- NUG's or DSM programs which are located in or targetted to specific areas of the system may have significantly different T&D Avoided Costs than those determined in this report.

  Specific programs will require specific determinations of potential savings.

APPENDIX 1: DISTRIBUTION SYSTEM AVOIDED COSTS FOR THE 100MW DSM PROGRAM

TABLE 6: CALCULATION OF LEVELIZED AVOIDED COSTS DUE TO D.S.M.

YEAR	CAPITAL REQUIREMENTS WITHOUT D.S.M. 1995 PRESENT VALUE	CAPITAL REQUIREMENTS WITH D.S.M. 1995 PRESENT VALUE	DIFFERENCE IN PRESENT VALUE	CUMULATIVE PRESENT VALUE SAVING ($M)	LEVELIZING FACTORS (MW)	LEVELIZED AVOIDED COST ($/KW/YR 1995)
1995/96	$27.25	$27.25	$0.00	$0.00	32.00	
1996/97	$26.02	$26.02	$0.00	$0.00	46.56	
1997/98	$24.81	$24.81	$0.00	$0.00	62.29	
1998/99	$23.67	$21.18	$2.49	$2.49	71.19	
1999/00	$22.63	$20.25	$2.38	$4.87	74.16	
2000/01	$21.51	$19.24	$2.26	$7.14	74.33	
2001/02	$20.50	$18.34	$2.16	$9.30	73.56	
2002/03	$19.52	$17.47	$2.05	$11.35	71.99	
2003/04	$18.56	$16.61	$1.95	$13.30	70.39	
2004/05	$17.73	$15.87	$1.87	$15.17	69.41	
2005/06	$16.89	$15.11	$1.78	$16.95	68.34	
2006/07	$16.12	$14.42	$1.70	$18.65	67.21	
2007/08	$15.34	$13.72	$1.61	$20.26	66.02	
2008/09	$14.62	$13.08	$1.54	$21.80	64.79	
2009/10	$13.89	$12.42	$1.46	$23.26	63.51	
2010/11	$13.19	$11.81	$1.39	$24.65	62.20	
2011/12	$12.54	$11.22	$1.32	$25.97	60.86	
2012/13	$11.91	$10.66	$1.25	$27.22	59.50	
2013/14	$11.32	$10.13	$1.19	$28.41	58.12	
2014/15	$10.75	$9.62	$1.13	$29.55	56.74	
RESIDUAL VALUE AT THE END OF THE STUDY PERIOD	($182.82)	($165.85)	($16.97)	$12.58		$9.88

APPENDIX 2: TRANSMISSION SYSTEM AVOIDED COSTS FOR THE 100MW DSM PROGRAM

TABLE 6: CALCULATION OF LEVELIZED AVOIDED COSTS DUE TO D.S.M.

YEAR	CAPITAL REQUIREMENTS WITHOUT D.S.M. 1995 PRESENT VALUE	CAPITAL REQUIREMENTS WITH D.S.M. 1995 PRESENT VALUE	DIFFERENCE IN PRESENT VALUE	CUMULATIVE PRESENT VALUE SAVING ($M)	LEVELIZING FACTORS (MW)	LEVELIZED AVOIDED COST ($/KW/YR 1995)
1995/96	$14.95	$12.75	$2.20	$2.20	32.00	
1996/97	$14.70	$14.17	$0.53	$2.73	46.56	
1997/98	$32.34	$13.96	$18.39	$21.12	62.29	
1998/99	$46.05	$29.55	$16.50	$37.62	71.19	
1999/00	$46.29	$42.71	$3.59	$41.21	74.16	
2000/01	$9.80	$42.91	($33.11)	$8.09	74.33	
2001/02	$9.36	$8.37	$0.99	$9.08	73.56	
2002/03	$9.34	$7.91	$1.43	$10.51	71.99	
2003/04	$11.60	$7.52	$4.08	$14.58	70.39	
2004/05	$13.79	$7.58	$6.21	$20.79	69.41	
2005/06	$11.22	$9.66	$1.56	$22.35	68.34	
2006/07	$16.72	$11.69	$5.03	$27.38	67.21	
2007/08	$26.37	$9.41	$16.96	$44.34	66.02	
2008/09	$16.44	$14.40	$2.04	$46.38	64.79	
2009/10	$6.17	$23.14	($16.98)	$29.40	63.51	
2010/11	$5.86	$14.23	($8.37)	$21.03	62.20	
2011/12	$5.57	$4.98	$0.59	$21.62	60.86	
2012/13	$5.29	$4.73	$0.56	$22.17	59.50	
2013/14	$5.02	$4.50	$0.53	$22.70	58.12	
2014/15	$4.77	$4.27	$0.50	$23.21	56.74	
RESIDUAL VALUE AT THE END OF THE STUDY PERIOD	($155.53)	($148.91)	($6.63)	$16.58		$13.02

Table C.1. A Brief Look at Capital Cost v.s. Load Growth in 1990 Voided Cost Study

k	Fiscal Year	Peak (MW)	Load Growth (MW/Year)	Load Growth Discounted @6%	Distribution Capital Costs (Base 1995 Dollars) (in Millions of Dollars)	Present Value of Distribution Capital Costs @6%	Transmission Capital Costs (Base 1995 Dollars) (in Millions of Dollars)	Present Value of Transmission Capital Costs @6%
0	1995/96	3,988			27.25		12.75	
1	1996/97	4,055	67	63	27.38	26	12.71	12
2	1997/98	4,161	106	94	27.48	24	12.70	11
3	1998/99	4,236	75	63	27.60	23	12.66	11
4	1999/00	4,296	60	48	27.77	22	12.71	10
5	2000/01	4,365	69	52	27.78	21	12.65	9
6	2001/02	4,441	76	54	27.78	20	12.72	9
7	2002/03	4,509	68	45	27.93	19	12.65	8
8	2003/04	4,578	69	43	27.95	18	12.66	8
9	2004/05	4,645	67	40	28.10	17	12.63	7
10	2005/06	4,714	69	39	28.18	16	12.65	7
11	2006/07	4,783	69	36	28.30	15	12.63	7

(R1)	Average load growth rate (MW/Year) =	72			
(R2)			576		
(R3)				219	
(R4)					100
	Incremental Distribution Cost per kW of Load Growth ($/kW/Year, 1995 dollars) (1000×R3/R2) =			380	
	Incremental Distribution Cost per kW of Load Growth ($/kW/Year, 1990 dollars) =			284	
	Incremental Transmission Cost per kW of Load Growth ($/kW/Year, 1995 dollars) (1000×R4/R2) =				173
	Incremental Transmission Cost per kW of Load Growth ($/kW/Year, 1990 dollars) =				130

References:

[D-1]   W. Pyl, "Transmission and Distribution System Avoided Costs", Memo to File, File 2-14-1, AC Transmission Planning Division, Manitoba Hydro, March 20, 1990.