Prospective Cost of Service Study

For Fiscal Year Ending

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Manitoba Hydro

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MANITOBA HYDRO
PROSPECTIVE COST OF SERVICE STUDY 2005/06

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SECTION A - COST OF SERVICE METHODOLOGY REVIEW

A-1 EXECUTIVE SUMMARY

Cost of Service Study History

A Cost of Service Study (COSS) is a method of allocating a utility's cost to the various classes of customer that it serves. Its purpose is to determine a fair sharing of the utility's Revenue Requirement among the customer classes. While there are many allocation methods, the central aim is always to allocate costs to the customer classes on the basis of known customer characteristics. The cost study conducted at Manitoba Hydro is an average (embedded) study in that the unit costs represent the average to serve all customers in a rate class or subclass based upon funds historically invested in plant in service.

Manitoba Hydro's COSS is a Prospective Study. That is, while historic investment has a significant role in determining the costs, the study utilizes forecast costs for the next fiscal year. This provides a basis for testing rates that are proposed for the next fiscal year.

The results of the study indicate the degree to which the rate class/subclass revenue recovers allocated costs. 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. There is no right or wrong way of allocation, as each utility's operating characteristics and reasons for capital investment are not necessarily the same. The objective for the utility is to select a method which best represents cost causation and the equitable sharing of costs among the customer rate classes.

Manitoba Hydro has conducted cost of service studies since the mid 1970s. While significant changes have occurred on an evolutionary basis, the COSS filed with Manitoba Hydro's 2004/05 General Rate Application follows generally the same principles that were adopted with early cost of service studies. The significant changes relate mainly to the ability to better forecast customer loads and load factors and to special treatment of costs such as Demand Side Management (DSM).

The key features of the study that have remained relatively unchanged since the late 1970s are:

- The study deals with embedded costs (although in 1992 the study changed from being historic costs to forecast costs).
- The study functionalizes utility costs into five main groups: Generation; Transmission; Subtransmission; Distribution Plant and Distribution Services (or Customer Service).
- The study classifies Generation and Transmission costs into Energy-related and Demand-related based on the system load factor.
- The study classifies Subtransmission costs on the basis of Non-Coincident Peak Demand only.
- The study allocates Distribution plant costs on the basis of Non-Coincident Peak Demand and Customer Count. The proportion classified on the basis of Demand has been set at 60% since 1991.
- The study classifies Customer Service costs on several ways but all are Customer-related; allocation among classes is based on the number of customers in each class. For some costs customer numbers are weighted differently for each class, reflecting differences among the classes in the cost to provide the service.
- The study allocates Energy-related costs on the basis of annual kW.h including losses back to Generation.
- The study allocates Generation and Transmission Demand-related costs on the basis of both winter peak (top 50 coincident hours) and summer peak (also top 50 coincident hours). Prior to 2004 these costs were allocated on the basis of winter peak only.
- The study allocates a credit for net export revenue to all domestic classes served by the grid, in proportion to each class' share of Generation and Transmission costs. Net export revenue is defined as total revenue received from export customers minus the direct variable costs (water rentals, thermal fuel and import costs) associated with deliveries to export customers.

Section A-6 of this document discusses in detail the changes made within the above general framework, since 1992.

The Key Issue: Export Revenue Allocation

Since at least 1997 Manitoba Hydro has been concerned that the COSS results were becoming distorted as a result of the increasing significance of export revenues. In 1992 net export revenue was sufficient to cover 15% of Manitoba Hydro's total cost of service, in 1997 this coverage had increased to 25% and by 2004 net export revenue was sufficient to cover fully 33% of Manitoba Hydro's costs. Moreover, net export revenue per kW.h sold was also increasing significantly throughout this period, from 1.5 cents per kW.h in 1992 to 4.9 cents per kW.h in the 2004 COSS. Since Manitoba Hydro's COSS credited net export revenue back to customer classes on the basis of their share of Generation and Transmission costs, these increases in export revenue were offsetting a greater and greater percentage of Generation and Transmission costs. In PCOSS 2004 net export revenues covered fully 47% of Generation and Transmission costs while accounting for only 35% of sales from the Transmission system.

In effect, customer classes were receiving export credits based on an ever increasing marginal cost of bulk energy while being allocated costs based on embedded cost of Generation which was relatively stable from year to year. This approach has effectively driven assigned costs and their related prices well below the prices in deregulated wholesale markets into which Manitoba Hydro sells and also well below regulated prices in neighbouring Canadian and US jurisdictions. For customer classes such as General Service Large (for whom Generation and Transmission represents the vast majority of prices) the export credit approach was, in effect, subsidizing almost half their costs. For Residential and Small General Service customers, the subsidy was also substantial, but at 28%, much less than for General Service Large.

In an era in which export revenues were a small portion of total sales, where most sales were opportunity sales priced at a small fraction of average domestic rates, the longstanding method of crediting export revenues to customer classes was appropriate. In the world of the recent past and present, where approximately half of export sales are firm and where average prices exceed, sometimes by a significant margin, average domestic rates, assigning benefits on the basis of customer class usage of Generation and Transmission no longer appears fair or rational.

It was these concerns that prompted the changes proposed by Manitoba Hydro in its 2002 Status Update filing. The PCOSS02 filed in that proceeding allocated net export benefits on the basis of total costs allocated to each class. This method still provided domestic customers with the benefits of net export revenues, but covered an equal percentage of costs for all customer classes. Other changes were also introduced in that study, including revisions to the allocators for Generation Demand-related costs and some changes in how utility costs were functionalized. However, the most significant proposed change, the change to the method of allocation of net export credits, was denied by the Public Utilities Board (PUB) in its subsequent Order 7/03. Subsequently PCOSS04 was prepared incorporating those changes which had been accepted in Order 7/03 but reverted to the allocation of net export credits on the basis of class share of Generation and Transmission costs. The study was submitted as part of the 2004/05 GRA.

Order 7/03 had also directed Manitoba Hydro to carry out a study of Generation classification and file that study with the Board. That study, prepared by National Economic Research Associates (NERA) and titled: "*Classification and Allocation Methods for Generation and Transmission in Cost of Service Studies*" was filed during the course of review of the 2004/05 General Rate Application. The study supported several major changes away from the currently approved methodology. The most significant of these was the creation of an Export Class of customer and the allocation of a share of fixed, as well as operating costs to that class. The excess of revenue over cost from that class was credited to domestic customer classes on the basis of total cost assigned to each of the classes as originally proposed in the 2002 study. A detailed review of the changes proposed in that study and a depiction of the results of those changes, is provided in Section A-4 of this document.

<u>PCOSS06 Key Features and Discussion</u>

The remainder of Section A provides details pertaining to the cost allocation methods reviewed and to the evolution of Cost of Service methods over the period 1992 through 2005.

Section A-2 outlines the methods used to prepare the Base Study (i.e. Current Method) and the results deriving from that method. Section A-2 also provides explicit description as to how each of the following factors is treated in the base study:

a) Winnipeg Hydro cost data;

b) Winnipeg Hydro load information;
c) Uniform Rates;
d) Transmission and Distribution losses;
e) Mitigation costs;
f) Fuel and power purchases;
g) Firm and opportunity export sales;
h) Definition of net export revenue;
i) Allocation of net export revenue;
j) Forecasted water flow conditions; and
k) Development of class loads.

Section A-3 summarizes the Manitoba Hydro's Recommended Method based on the NERA Method with modification to treat firm and opportunity export sales differently. Section A-3 also summarizes the results of these methods and the differences between them and the Current Method. Section A-3 also provides description as to how each of factors listed above is treated differently in the Recommended Method versus that in the Approved Method.

Section A-4 of this document outlines the main features of the two remaining PCOSS06 methods prepared for the document: the original NERA Method and the Generation Vintaging Method which is a variation of the NERA Method.

Section A-5 presents a discussion of the costs that are associated with export sales in both the Current and Recommended Methods. It also includes a more general discussion of which activities at Manitoba Hydro may be associated with export sales and some of the difficulties in identifying specific export-related costs.

Section A-6 summarizes the evolution of Cost of Service Studies at Manitoba Hydro over the period 1992 through 2005. It provides, as well, for each customer class a history of Revenue Cost Coverage results with and without export revenue allocation for the same period.

<u>Alternative Cost of Service Methodologies</u>

The methodology changes recommended in the NERA Report were discussed extensively by all parties involved in the 2004 hearing. However, the PUB was unwilling to accept either the longstanding method or the NERA recommendations without further study and review. Orders 101/04 and 143/04 directed Manitoba Hydro to prepare and submit four versions of its Cost of Service. The required versions were:

1) Manitoba Hydro's current methodology;

2) Manitoba Hydro's preferred or recommended approach and methodology, including supporting rationale.

3) The implementation of the NERA Report recommendations;

4) A Generation Vintaging Method whereby low cost generating resources on the Winnipeg River were dedicated to domestic customers; and

The PUB also directed that the first application of net export revenue shall be used to offset the impact of uniform rates legislation. This adjustment to the revenue of Zones 2 and 3 Residential, General Service Small, General Service Medium and Street Lighting customers has been incorporated into all versions of the COSS methods noted above.

PCOSS06 Base was prepared using the current methodology, comparable to that used in PCOSS04, and determines net export revenue by deducting variable power and water rental costs from gross export revenue. Net export revenue is then allocated on the basis of class Generation and Transmission costs. This method derives Revenue Cost Coverage ratios for all domestic classes of service both before and after allocation of export revenues. During the 2004/05 General Rate Application proceeding Manitoba Hydro suggested that, in considering the results of the COSS prepared using the Current Method, that the PUB give some weight to the RCC results before allocation of export revenue. This suggestion was made on the basis of concern that the magnitude and value of export revenue was distorting the results of an embedded cost study based on the Current Method.

In PCOSS06, the average Revenue Cost Coverage ratio for all domestic classes combined before allocation of net export revenue was 70.7%. If this were adopted as a Revenue Cost Coverage standard, domestic customers would continue to receive the full benefit of export revenues without the need for explicit allocation among the classes. Converting this standard to a base of 100%, the results would be significantly different from the results derived after the allocation of export revenue as depicted below.

Rate Class	Pre Export Revenue Allocation (Base 100)	Post Export Revenue Allocation
Residential	96.6	92.2
General Service Small Non-Demand	109.6	103.1
General Service Small Demand	106.8	106.0
General Service Medium	100.4	102.9
General Service Large <30 kV	87.4	94.0
General Service Large 30 – 100 kV	100.1	109.4
General Service Large >100 kV	100.8	114.7
Area & Roadway Lighting	136.5	105.2
Diesel	85.9	85.9

Manitoba Hydro is not recommending use of the Current Method, either before or after allocation of net export revenue, but provides this information as a basis for comparison with other methods.

The approach recommended in the NERA Report uses marginal cost weighted energy for the allocation of Generation costs. That is, energy in each of four time periods (winter and summer on- and off-peak) is weighted according to the average marginal cost in each of these time periods. Transmission classified as export/import is allocated on the basis of energy at Generation, with all other Transmission costs allocated on 2 CP Demand. This approach also includes an Export customer class to which is allocated Generation and Transmission costs on the same basis as domestic classes. In addition, as originally proposed in the 2002, the NERA method allocates residual net export revenue on the basis of total allocated costs.

The Generation Vintaging Method allocates the lowest cost generation (namely Winnipeg River Generation) only to domestic customers, with remaining domestic load and the Export Class allocated the cost of all other Generation. As in the NERA scenario, the scenario also includes an Export customer class to which is allocated Generation and Transmission costs on the same basis as domestic classes, with the residual net export revenue assigned on the basis of total allocated costs. The Generation Vintaging Method is further discussed, along with the NERA Method, in Section A-4.

Manitoba Hydro filed the results of these scenarios with the Public Utilities Board on February 1, 2005. As its preferred approach, Manitoba Hydro identified in that filing the method recommended by the NERA Report. The primary benefits of using the NERA Method is that its classification and allocation data are more reflective of the export markets into which Manitoba Hydro sells. Manitoba Hydro's marginal cost of electricity supply is often its opportunity value in export markets. Further, it is more internally consistent than the current methodology, which allocates embedded Generation costs but provides offsets on the basis of export revenue derived from selling at marginal cost.

Manitoba Hydro did not, at that time, recommend either retaining the Current Method or adopting the Generation Vintage Method. The Current Method has, as its principal shortcoming, the assignment of net export revenues derived from market prices which are significantly higher than the embedded unit Generation and Transmission costs which they offset. The Generation Vintage Method did not provide results which differ significantly from the NERA Method. Given this and additional complexities this approach was not recommended or adopted by Manitoba Hydro.

Manitoba Hydro continues to support adoption of the recommendation contained in the NERA Report. This method reflects the conditions in which Manitoba Hydro operates more accurately; in addition its overall methodological framework does not represent a significant departure from what has been done in past studies. It is still based upon embedded costs, only the classification and allocation of Generation and Transmission costs have been revised to be more reflective of the marketplace Manitoba Hydro now operates. However, Manitoba Hydro also recommends a modification of the NERA Method beyond what was provided in the February 2005 filing. That modification would provide separate treatment of firm and opportunity exports. Firm exports would attract a full share of embedded Generation and Transmission cost as recommended in the NERA study. Opportunity exports would attract only variable costs (water rentals, thermal fuel and imports) as in the Current Method. Net export revenues after allocation of costs would continue to be allocated among domestic classes on the basis of total costs.

The Revenue Cost Coverage ratios resulting from each of the methods discussed above are as follows:

Class	Current Method	NERA Report	Generation Vintaging	Recommended
Residential	92.2	95.7	95.5	97.0
GSS Non-Demand	103.1	107.1	107.0	107.4
GSS Demand	106.0	106.0	106.1	105.4
GSM	102.9	101.2	101.3	100.6
GSL 0 – 30 kV	94.0	90.1	90.1	90.1
GSL 30 – 100 kV	109.4	103.5	104.0	101.5
GSL >100 kV	114.7	106.3	107.0	103.2
Street Lights	105.2	106.7	106.7	107.1
Diesel	85.9	102.9	102.0	108.1

<u>Class Consolidation</u>

PCOSS06 has been prepared using several alternative methods of cost allocation as described above. All of these variants have specified the domestic class structure which has been in place since 1989 (other than the elimination of zones within classes). Specifically, the structure includes a Residential Class and four General Service Classes. General Service Classes are structured based on several considerations. The General Service Small class is distinguished from the General Service Medium Class on the basis of load size; the demarcation point is 200 kV.A of billing demand. The General Service Small Class is further subdivided into General Service Small Non-Demand (load less than 50 kV.A with no demand billing) and General Service Small Demand (customers are billed for demand on loads between 50 and 200 kV.A but pay lower energy charges on energy usage in excess of 19,590 kW.h per month). Another distinction between General Service Small and General Service Medium is that General Service Small Demand customers are not subject to either the Winter Ratchet of 70% nor the contract ratchet of 25% with respect to the demand portion of the bill.

The distinction between General Service Medium and General Service Large is not, technically, on the basis of load size, but on the basis of transformation. General Service Medium customers are provided transformation by Manitoba Hydro, from the Transmission or primary Distribution voltage to the customer’s utilization voltage. General Service Medium customers therefore pay higher rates than General Service Large customers, because they are receiving more distribution service and because energy losses are higher. There is a load size consideration to the distinction in that

Manitoba Hydro will not provide transformation to loads in excess of 2,500 kV.A. There exist a few General Service Medium loads in excess of that size, because of decisions made many years ago. More common, however, are General Service Large customers with loads considerably smaller than 2,500 kV.A, because these customers have found it advantageous to own their transformation.

Within the General Service Large class, there are further distinctions based on the voltage at which the customer takes service. The majority of General Service Large customers (248 out of 291) are served from the Distribution System (General Service Large <30 kV). A further 43 customers are served from the Subtransmission System (General Service Large 30-100 kV) and the Transmission System (General Service Large >100 kV). Customers served at Subtransmission and Transmission voltages typically have much larger loads than the customers served at Distribution voltages. The average load for General Service Large <30 kV is about 1,200 kV.A, whereas it is 4,600 kV.A for loads served at Subtransmission voltage and 50,000 kV.A for loads served at Transmission voltage.

It is possible and may be desirable to simplify the class structure for both rate schedules and cost allocation. In particular, the General Service Small Demand and General Service Medium classes could be combined. These classes pay the same demand charge and the same charge for run-off energy. They are both served from Corporation-owned transformation and their utilization voltages are similar. If these two classes were to be blended, some changes would need to be made to demand ratchet provisions to address the fact that General Service Small is currently not affected by them. Some changes may be necessary to the rates themselves in order to accommodate similar treatment for the first 50 kV.A of demand and the first 19,590 kW.h per month.

It may also be possible to include the General Service Large class customers served at Distribution voltage into this blended class. The significant difference between many of these customers and the General Service Medium class is the customer ownership of transformation. This could be accommodated by providing a credit, in both the demand and energy charges, for transformer ownership.

The other General Service Large classes are somewhat different in that they do not utilize the Distribution system and the loads are typically much larger. However, these two subclasses could also be incorporated into a single class of high voltage served customers, similar to the “Transmission” class for loads served at 66 kV and above by

BC Hydro. It is arguable that loads served at Transmission voltage, typically 115 kV and higher, could be offered an additional credit for receiving service at the higher voltage.

The impact of consolidating the classes as described above is depicted in the following table.

Customer Class	**Current Method**	**NERA Report**	**Generation Vintaging**	**Recommended**
Residential	92.2	95.7	95.5	97.0
General Service Small Non-Demand	103.1	107.1	107.0	107.4
General Service	101.7	100.0	100.1	99.5
General Service > 30 kV	113.9	105.9	106.6	102.9
Area & Roadway Lighting	105.2	106.7	106.7	107.1
Diesel	85.9	102.9	102.0	108.1

A-2 PCOSS06 STUDY CURRENT METHOD

The current (or base) PCOSS06 reflects the methodology as directed by the PUB in Order 7/03 and filed by Manitoba Hydro with its 2004/05 GRA. The Current Method represents a study that has evolved over time to reflect improved or new technologies and techniques but which is generally consistent with principles that have been in place since the 1970s. In summary, the significant classification and allocation procedures are as listed below:

1) Generation and Transmission costs overall are classified to Energy and Demand on the basis of the system load factor. All Transmission costs are then deemed to be Demand-related with the residual Demand-related costs applying to Generation. This results in a Generation Classification ratio of 82% Energy and 18% Demand in PCOSS06.

2) Generation Energy-related costs are allocated on the basis of annual energy; Demand-related costs are allocated on the average summer and winter peaks (based on top 50 hours) or 2 CP method.

3) Transmission costs are classified as 100% Demand-related and allocated costs on the same basis as Generation, or 2 CP.

4) Subtransmission costs are classified entirely as Demand-related and allocated on the basis of class non-coincident peak demand.

5) Distribution plant costs are classified as either Demand-related or Customer-related. Costs of substations and line transformers are classified as wholly Demand-related and allocated on the basis of class non-coincident demand. Cost of metering equipment and services are classified as wholly Customer-related and allocated on the basis of weighted customer numbers. Costs of poles, wires and related equipment are classified as 60% Demand-related and 40% Customer-related, recognizing that investment in these facilities is related to both the number of customers served and the size of customer loads.

6) Customer Service costs such as direct customer service, billing, marketing and meter reading are all classified as Customer-related and allocated on the basis of weighted or un-weighted customer numbers.

In addition to the above standard features, the following minor changes have been incorporated for the first time into the PCOSS06:

1) An initial allocation of net export revenues is used to fund uniform rates (implemented November 2001). This initial allocation has also been incorporated into the other methods discussed in this document.

2) Complete integration of former Winnipeg Hydro (WH) costs and customer characteristics into the COSS. Prior to this PCOSS06 only partial integration was possible. As noted in PCOSS04, WH assets were integrated but only a preliminary functionalization of them was possible. Similarly, all operating costs and revenues of the former WH operations were incorporated into the study, but only revenues could be precisely assigned to domestic rate classes. Finally, WH class peak load responsibility was assumed to be the same as that of the comparable class in the remaining Manitoba Hydro service territory. All of these deficiencies have been remedied in the current study and the former WH customers are now fully and accurately incorporated into the COSS.

Note as well that at the time of preparation of this study, the status of the two conditional rate increases (April 1, and October 1, 2005) directed by the PUB (Orders 101/04 and 143/04) were not confirmed. The PCOSS06 as a result incorporates both conditional rate increases. On July 5, 2005 Manitoba Hydro President & CEO Bob Brennan wrote a letter to the PUB Chairman Graham Lane indicating the Corporation would not be seeking approval for the second conditional rate increase scheduled for October 1, 2005. While the PCOSS06 includes elevated revenues and costs the results would not be materially different had the second rate increase not been included.

Complete results and supporting tables for the approved method can be found in Sections B-E of this filing organized as follows:

1) Section B – Results – in addition to the Revenue Cost Coverage tables (RCC) tables outlining cost by function and unit cost tables (Energy, Demand and Customer unit costs) can be found;

2) Section C – Functionalization and Classification Methods and Details – contains discussion of the methods as well as all associated tables and supporting documents;

3) Section D – Load Information – discussion and supporting tables as to the derivation of the allocators used in the PCOSS; and

4) Section E – Allocation Methods – this section outlines functional costs to be allocated as well as description as to the various tables used to allocate costs in the PCOSS.

Treatment of Various Items in the Approved PCOSS06

The PUB has requested that Manitoba Hydro address specifically in this document the treatment of a number of issues in PCOSS06, Current Method. The following is a description of the treatment of those issues:

a) Winnipeg Hydro Cost Data – since the acquisition of WH in 2001 all costs associated with the former utility have been integrated into Manitoba Hydro functional costs. Prior to PCOSS06 complete integration of all WH data into the records of Manitoba Hydro was not complete. Prior studies included estimates and/or proxies for key WH data such as functionalization of assets, and load profiles of former WH customers used to develop allocators.

b) Winnipeg Hydro Load Information – the PCOSS06 is the first study where actual load research data from former Winnipeg customers has been incorporated into the study.

c) Uniform Rates – came into effect November 2001, PCOSS02 and future studies only reflected the rate reductions as a result of this legislation. For PCOSS06, as directed by the Board in Order 101/04, uniform rates are to be funded through an initial allocation of net export revenue. With this modification to the study, the first allocation of export revenues was used to fund the class 'cost' of uniform rates. In PCOSS06 the amount removed from net export revenues is $16.7 million and is used to offset uniform rates in the Residential, General Service Small, General Service Medium and Area & Roadway Lighting classes.

d) Generation Costs Weighted on the Basis of Marginal Costs – This method of classification of Generation costs is not used in the Current Method, only in the NERA Method. In the Current Method Generation costs are allocated based on Energy and Demand classified by the system load factor.

e) Transmission and Distribution Losses – these are two separate items in the PCOSS; Transmission losses are an input to the PCOSS (derived as part of the IFF process). Distribution losses are calculated in the PCOSS06 as the difference between deliveries at common bus less sales at the meter. These losses are proportionately allocated back to customer class energies at meter to derive customer class energy at generation.

f) Mitigation costs – as in the financial records of Manitoba Hydro, mitigation costs are treated as a Generation cost in the PCOSS and thus shared by all customer classes. Most mitigation costs are capitalized in the Generation function and therefore appear as depreciation and interest in the Study.

g) Fuel and Power Purchases – in the Current Method, 100% of all import costs and an allocated share of fuel costs and water rentals are deducted from gross export revenues prior to allocation of export revenues (net) among the domestic customer classes.

h) Firm and Opportunity Export Sales – the Current Method does not include the creation of an Export Class of customer; hence the distinction is not relevant in PCOSS06, Current Method – only the total sales revenue from exports and the associated variable cost are needed.

i) Definition of Net Export Revenue – under the Current Method, net export revenue equals gross export revenues less 100% of power purchases and a proportionate share of fuel costs and water rentals. In PCOSS06 gross export revenues are forecast to be $547.4 million. Derivation of net export revenue is as follows:

Allocated Portion of Water Rentals	$31.8 million
Purchased Power Imports	$67.2
Applicable Portion of Fuel Costs	$8.1
Total Variable Costs	$107.1
Gross Exports (above)	$547.4

Export Revenue after Variable Costs	$440.3
Less: Uniform Rate Deductions	$16.7
Net Export Revenue PCOSS06	$423.6

j) Allocation of Net Export Revenue – in the Current Method net export revenues are allocated among domestic classes on the basis of class share of Generation and Transmission costs, the assets that enable export sales.

k) Forecasted Water Flow Conditions – In the Current Method, as well as in any of the other methods reviewed in this document, the PCOSS water flows are those in the second year of Manitoba Hydro's Integrated Financial Forecast and are based on median inflow conditions.

l) Development of Class Loads – development of class loads is required to compute a fair allocator of various costs functionalized in the PCOSS. Although differences exist between the two methods, the differences are at the Generation and Transmission level; Subtransmission, Distribution, and Customer Service allocators are the same in both methods. In the Current Method, Generation costs are allocated on the basis of both Energy (annual) and Demand (average summer and winter peaks or 2 CP). Classification between energy and demand is based on the system load factor. Transmission costs are classified as 100% Demand and as in Generation allocated on the 2 CP method.

m) Use of Surplus Energy Program for Marginal Costing – Marginal cost indicators are not used in the Current Method of the PCOSS06.

A-3 RECOMMENDED METHOD

As noted in Section A-1, Manitoba Hydro is recommending the adoption of the NERA Report Method with one modification. This modification is that the Export Class be further segregated into a firm opportunity sales subclass. Firm exports would be treated as recommended in the NERA Report, that is, as attracting a full share of embedded costs in the same manner as any domestic class. Costs of Generation and Transmission are allocated against firm exports based on their share of Demand and Energy allocators. This is recommended even though firm exports do not have same quality of "firmness" as domestic sales. (For example, Manitoba Hydro is obliged to serve domestic loads as they materialize, while exports are discretionary and are in an amount appropriate to available surpluses.)

On the other hand, opportunity sales rely on water flows which are above dependable and are made only as short-term surpluses allow. It is true that some Manitoba Hydro facilities are designed to permit the use of flows which are above dependable levels to facilitate exports. These include additional generating capability at some Generating Stations as well as additional Transmission capacity. However, these incremental facilities are placed in service at much below average cost of Generation and Transmission facilities and are, in any event, used to serve domestic or other firm loads on a priority basis. Given the difficulty of precise identification of these facilities and their cost, and given that firm exports continue to be costed at a full share of embedded cost, it is not greatly inaccurate to assign opportunity sales only the variable costs such as imports, water rentals and thermal fuel cost.

Manitoba Hydro forecasts firm versus opportunity sales based on the long term average water flow sequences (86 years from 1912 to 1997). While the results are forward looking 18 years into the future only the first five years are used (2006/7 to 2010/11) as it represents a more precise data set that includes firm sales contracts that are currently in place. The percentage resulting from this calculation is 55% of export sales are firm and the remaining 45% represent opportunity sales.

The results of applying this modification to the NERA Report Method are provided in Section B, Schedules B4-B6.

Treatment of Various Items in the Recommended Cost of Service Method

The PUB has requested that this document address specifically the treatment of a number of issues in the Recommended Method. The following is a description as to the treatment of various factors in the modified NERA Report Method, as recommended by Manitoba Hydro. Here, each of the items below highlights the difference between the Current Method and Manitoba Hydro's Recommended Method.

a) Winnipeg Hydro Cost Data – no difference exists between the two methods – the benefits of improved WH data has been incorporated in all scenarios of the PCOSS.

b) Winnipeg Hydro Load Information – no difference exists between the two methods. The improvement of WH data has been incorporated in all methods reviewed herein.

c) Uniform Rates – no difference exists between the two methods.

d) Generation Costs Weighted on the Basis of Marginal Costs – this is done in the recommended methodology only. The marginal cost weightings are derived from the average (inflation adjusted) Surplus Energy Program (SEP) rates from the period January 1, 1999 to October 4, 2004. Marginal cost ratios are multiplied by seasonal energies (winter and summer on- and off-peak) which form the basis for allocation of generation related costs. The marginal cost ratios applied to seasonal energies in the PCOSS06 Recommended Method are:

Winter Off-Peak	1.295
Winter On-Peak	2.101
Summer Off-Peak	1.000
Summer On-Peak	1.923

These values were quite similar to those developed from Platt's data used in PCOSS04.

e) Transmission and Distribution Losses – these are two separate items in the PCOSS; Transmission losses are an input to the PCOSS (derived as part of the IFF process). Distribution losses are calculated in the PCOSS06 as the difference between deliveries at common bus less sales at the meter. These losses are proportionately allocated back to customer class energies at meter to derive customer class energy at Generation. The process is the same in the Current Method.

f) Mitigation Costs – as in the financial records of Manitoba Hydro, mitigation costs are treated as a Generation cost in the PCOSS and thus is shared by all customer classes. Treatment does not differ between the two methods.

g) Fuel and Power Purchases – in the approach recommended by Manitoba Hydro an Export Class of customer is created and some costs allocated to it. Firm export sales normally account for about half the export volume (55% is used representing the average long-term split). These sales attract a full share of Generation and Transmission embedded cost. The remaining export sales are opportunity sales, which are assigned only a share of the cost of water rentals, thermal fuel and power purchases. In the Current Method only variable costs are assigned to all export sales (water rentals, thermal fuel and power purchases).

h) Firm and Opportunity Export Sales – are treated differently in the recommended method, as discussed in (g) above.

i) Definition of Net Export Revenue – net export revenue equals gross export revenues less allocated costs to firm export customers plus variable costs assigned to opportunity sales. For the Recommended Method, which separates the Export Class into two subclasses, the value is $285.9 million (versus $206.2 million in the NERA Method). The derivation of the latter value is (in millions):

	Firm Sales	**Opportunity Sales**	**Total Exports**
Revenue	$254.0	$293.4	$547.4
Allocated Costs	196.3	-	196.3
Variable Costs	-	48.4	48.4
Uniform Rate Adj	7.8	9.0	16.8
Net Exports	$49.9	$236.0	$285.9

j) Allocation of Net Export Revenue – in the Recommended Method net export revenues are allocated to customer classes on the basis of total allocated costs of all functions, not just Generation and Transmission costs.

k) Forecasted Water Flow Conditions – there is no difference between the two methods with regard to water flows. Hydraulic conditions are forecast as one input into the IFF and are forecast based on median water flows.

l) Development of Class Loads – development of class loads is required to compute a fair allocator of various costs functionalized in the PCOSS. Class load data used in the Recommended Method differs from that used in the Current Method only for Generation. Allocation of Generation costs to classes is based on each class' marginal cost weighted energy usage in each of four periods: winter peak, winter off-peak, summer peak and summer off-peak. The marginal cost ratios are based on the rates from Manitoba Hydro's Surplus Energy Program (SEP). In the Current Method the class allocators are annual energy and 2 CP. The Transmission function utilizes the same allocator in both methods, class 2 CP. However, a distinction is made between export lines and other Transmission, with export lines being allocated on the basis of class energy use. Class load data used in the allocation of all remaining costs (Subtransmission, Distribution and Customer Service) are the same in both methods.

m) Use of Surplus Energy Program for Marginal Costing – in PCOSS04 when the NERA results were first published, marginal cost indicators were based on commercially available Platt's data for the MISO service area. However for the PCOSS06 indicators from Manitoba Hydro's own SEP were used. The advantages are that it is based not only on prices pertaining to sales in the interconnected MAPP market, but also reflects Manitoba Hydro's ability to access those prices and the effect of Transmission constraints on the prices Manitoba Hydro can realize. Moreover with the period weighting factors are quite similar to those previously derived using the Platt's data.

Calculation of Export Subclasses – Recommended Method

The following outlines only the modifications as they relate to the Export Class change to firm and opportunity based subclasses.

The table "Calculation of Firm Opportunity Split" shows the calculation between firm and opportunity export sales, while the table "Recommended Method PCOSS06 Model Changes" outlines the changes necessitated in the PCOSS06 model to integrate these changes.

Calculation of Firm Opportunity Split

Recommended Method using Export Subclasses
Calculation of average split between Firm and Opportunity Export Sales

in GW.h

	Firm	Non-Firm	Total	Firm	Non-Firm
2006/07	4,842	3,724	8,566	56.53%	43.47%
2007/08	4,650	3,875	8,525	54.55%	45.45%
2008/09	4,427	4,069	8,496	52.11%	47.89%
2009/10	4,533	3,986	8,519	53.21%	46.79%
2010/11	5,284	3,914	9,198	57.45%	42.55%
				54.77%	45.23%

Recommended Method PCOSS06 Model Changes

Recommended Method
Changes to PCOSS06 Model to account for Firm/Non-Firm Export Subclasses

Percentages Calculated	Cost Components	Export %'age	Firm Allocated	Non-Firm Variable	Total
1) Gross Export Revenue	$ 547,358				$ 547,358
Less: Export funding of Uniform Rates	16,708				16,708
Less: Water Rental, Pwr Purch, Fuel	$ 107,069	45.23%		$ 48,427	48,427
Export Revenue after variable adjustments	$ 423,581				$ 482,223
2) Total Generation Costs					
Table E12 allocation to Firm Exports	$ 828,126	18.8%	$ 155,785		
Table D14 allocation to Firm Exports	$ 8,180	19.3%	$ 1,576		
			$ 157,362		
3) Total Transmission Costs					
Table E10 allocation to Firm Exports	$ 34,995	19.0%	$ 6,649		
Table D14 allocation to Firm Exports	$ 167,738	19.3%	$ 32,323		
Total Allocated Costs			$ 38,972		
			$ 196,334		
					$ 196,334
Net Export Revenue to Allocate to Domestic Customers					**$ 285,889**

A-4 NERA REPORT METHOD AND GENERATION VINTAGING FOR PCOSS06 STUDY

As a result of the 2004/05 General Rate Application (GRA) the PUB issued Board Order 101/04 which among other items, directed Manitoba Hydro to not only file an updated PCOSS based on the current methodology, but file as well two additional studies reflecting different methodologies; these included the approach recommended in the NERA Report and a variant of that method based on high and low cost Generation resources. PUB Order 101/04 noted:

> "*the Board agrees that the cost of service methodology requires further analysis and amendment. This further analysis should include a thorough consideration of the NERA recommendations,*"

The Generation Vintaging Method is similar in all ways but one to the NERA Report Method, with the difference being that Manitoba Hydro's generating resources are split between low cost Generation (i.e. Winnipeg River plants) and high cost Generation (all other Generation stations). Under this method the domestic customer classes receive the exclusive benefit of low cost Generation with the balance of domestic needs and all export requirements coming from the higher cost resources. This method was suggested by TREE/RCM during review of the 2004/05 GRA.

These methods also incorporate the PUB directive regarding the funding of uniform rates through an initial allocation of net export revenues.

The NERA Report was submitted subsequent to filing its 2004 GRA. The report was entitled "*Classification and Allocation Methods for Generation and Transmission in Cost of Service Studies*". This report recommended that significant revisions be made to the COSS methodology; principally that Generation costs be classified and allocated on the basis of time differentiated marginal costs; that costs be separately allocated to an Export Class; and that any remaining net export revenues be credited to domestic customer classes on the basis of total allocated cost, rather than on the basis of only Generation and Transmission cost.

The methodology changes featured in the NERA Report Method relative to the current methodology are as follows:

PCOSS06 – NERA Report Recommendations

The NERA Report recommendations were first submitted during the review of the 2004/05 GRA based on PCOSS04. The methodology used in the PCOSS06 version of the NERA Report recommendations was similar to that submitted in 2004. The major recommendations of the NERA Method incorporated into this iteration of the PCOSS06 include the following:

1) Incorporation of marginal costs (Generation only) as a method of classifying Generation costs;

2) Creation of an Export Class allocated costs in same fashion as domestic customers;

3) Allocation of residual export revenues based on total costs vs. Generation and Transmission only; and

4) Line specific classification of Transmission costs – all export lines allocated on energy, domestic on demand.

The NERA Report methodology incorporated herein differs in two ways from that submitted in 2004. The first is the source data used to calculate the marginal cost indicators for Generation costs. In PCOSS04 marginal cost weighting factors for winter on/off-peak and summer on/off-peak were from commercially available Platt's data within the MISO area. For PCOSS06 the basis of these weightings was from the inflation adjusted Surplus Energy Program (SEP) from the period January 1, 1999 to October 4, 2004. Manitoba Hydro's SEP rate allows customers to choose whether to use an alternate form of energy or to pay market based electricity costs that are sent to these customers on a weekly basis. The advantage of using SEP data is that it is based not only on prices pertaining to sales in the interconnected MAPP market, but also reflects Manitoba Hydro's ability to access those prices and the effect of transmission constraints on the prices Manitoba Hydro can realize. Moreover it correlates reasonably well with the Platt's data which are derived independently. The second change, as mentioned previously, is the uniform rate adjustment.

It should be noted that the marginal cost information is used only to weight energy usage in different time periods; the weighted energy values are applied against embedded cost.

The primary benefits of using the NERA Method in the PCOSS, versus other methodologies, is that its classification and allocation processes with reference to electricity value in interconnected markets and therefore the opportunity value of Manitoba Hydro supply. There have been significant changes in the electricity market which affect the market value of capacity and energy produced and sold by Manitoba Hydro. These changes are occurring principally in the deregulated markets to the south, but also elsewhere in Canada. Manitoba Hydro's marginal cost of electricity supply is often its opportunity value in export markets; this is because an increase in domestic utilization causes Manitoba Hydro to sacrifice the revenue that would have been gained by exporting the incremental usage. Further, it is more internally consistent than the current methodology, which allocates embedded Generation costs, but provides offsets on the basis of export revenue derived from selling at marginal cost.

The current methodology allocates export revenues as a credit to the various classes of service, based on the Generation and Transmission costs allocated to these classes. This method of returning the hydro system benefits to customers recognizes that it is these functions which support the export of surplus capacity and energy. However, this approach effectively uses today's high value of energy to offset lower embedded costs and, consequently, has driven allocated costs and related prices to below marginal cost and also well below regulated prices in neighboring Canadian jurisdictions. Because Generation and Transmission makes up virtually the entire cost of service to General Service Large classes, the potential departure from efficient pricing is greater, on a relative basis, for major industrial and commercial loads than it is for classes which also incur Distribution costs. The NERA Report methodology does not fully address the issue of departure from efficient pricing for Manitoba customer classes overall, but does reduce the degree of disparity among the classes.

PCOSS06 – Generation Vintage (High versus Low Cost Generation)

Order 101/03 also directed Manitoba Hydro to produce a COSS scenario which assigns the lowest cost Generation resources to domestic customers with the higher cost Generation resources allocated to residual domestic consumption and an Export Class:

> *"File an analysis of the impact of allocating less expensive generation costs to domestic classes, with higher cost generation being allocated to domestic and export customers as suggested by TREE/RCM."*

Although not explicit in the directive the reference to the TREE/RCM suggestion implies that "less expensive generation costs" refers to the Winnipeg River (WR) plants. The PCOSS06 Generation Vintage scenario has been prepared using WR as the low cost resource.

The Generation Vintage scenario as presented here incorporates the NERA Method classification and allocation of Generation and Transmission; the creation of an Export Class and the allocation of residual export revenues on the basis of total allocated costs.

The implementation of vintage cost assignment into PCOSS06 was carried out in the following steps:

1) Determine the percentage of WR resources to total Manitoba Hydro energy available in fiscal year 2006, or WR/(total hydraulic + thermal + imports) = WR percentage or approximately 14%;

2) Split total Generation costs between WR and higher cost Generation with allocation of common costs allocated on the percentage determined above;

3) Allocate total Generation costs via two tables: the first, weighted energy produced by WR resources, the second table allocates the higher cost energy production; and

4) The tables differ (versus a single table in the NERA Method) in that energy allocators for WR plant is 14% of total weighted energy, with the high cost table allocating the remaining domestic energy plus the energy forecast for an export customer class. Derivation of the high versus low cost generation can be found on page 27.

The RCC results for the Generation Vintaging scenario, as expected, aligned closely to those results from the scenario based on the NERA Method. The primary driver causing the significant shift of RCC results is the implementation of the NERA methodology including the allocation of excess export revenues on the basis of total allocated costs. The magnitude of the benefits to domestic classes as a result of a two tier Generation costing methodology is not significant relative to the other factors causing the shift in RCC's. Among these causes is the creation of an Export Class, which lowers Generation costs allocated to domestic classes (as the Firm Export Class now picks up their proportionate share of fixed costs) with a corresponding decrease in the amount of export revenue available to distribute among domestic customers. In addition, the allocation of these residual export revenues on total allocated costs equalizes the benefit to domestic customers at all levels of service. The Current Method, by contrast, has no Export Class and only assigns the variable costs (no fixed costs are allocated) of exports against gross export revenue, and allocates this net export revenue on the basis of total Generation and Transmission costs.

Going forward, the Generation Vintage approach presents other difficulties. Currently WR does have the lowest cost Generation resource relative to others in the Manitoba Hydro system; however in the future expenditures will likely have to be made to upgrade these facilities. Hence the definition of what is low cost will shift over time as capital is expended on all Generation facilities within Manitoba Hydro. If the Winnipeg River definition were to be retained over time, this could result in domestic customers exclusively being allocated higher cost Generation. In the end, the Generation Vintaging approach involves significant additional effort without yielding significantly different results.

The table entitled "Separation Generation Costs – Low vs. High Cost" outlines the application of the percentage calculated to the Generation costs to provide the distinction between low cost Generation (Winnipeg River) and high cost Generation. Note that there are two components; direct costs (such as Winnipeg River Generating Stations) and shared costs for all Generation (i.e. – Generation System Control, and Power Resource Planning) that are split based on the percentages calculated.

Low Cost Generation Percentage Calculation

Calculation of Low Cost vs. High Cost %'age split

Gen Plant		GWh
Pine Falls		718
Great Falls		1,061
McArthur Falls		446
Seven Sisters		1,136
Slave Falls		507
Pointe de Bois		637
		4,505
Total Hydraulic	30,177	14.9%
Total Thermal	588	14.6%
Firm Imports	63	
On Peak Imports	34	
Off Peak Imports	1,913	
Total Generation	32,775	32,775
Percentage of Wpg River		**13.7%**

Calculation of Interest and Capital Tax Allocation

Total Generation Interest Expense	413,739,485
Total Generation Capital Tax	21,004,044
Total Interest to Allocate	434,743,529

Book Values of Gen Plants (based on actual 2004 GI)

	2004 NBV
Pine Falls	21,254,791
Great Falls	65,704,197
McArthur Falls	19,161,764
Seven Sisters	58,945,036
Slave Falls	68,620,791
Pointe de Bois	11,722,490
Wpg River Mitigation	2,649,726
Total Wpg River	248,058,795

Total NBV Generation	2,829,397,133	
Total NBV Mitigation	479,967,046	**Wpg River %'age**
Total NBV	3,309,364,179	**7.5%**

Separation Generation Costs – Low vs. High Cost

PCOSS 06
Generation Vintage Analysis

Directive 14.8 (pp 96 of 143 order) - Per PUB orders 101/04 & 143/04 from the 2004/05 GRA hearing TREE/RCM directed Manitoba Hydro to assign lowest cost generation (Wpg River Plants) first to domestic customer with the balance and all exports assigned costs from highest cost generation (Nelson River).

Total Generation Costs per Oper2006 file:

SCC/Node	Depreciation	Operating	Interest	Total
Wpg River Dedicated	7,421,082	33,421,380	32,586,911	73,429,373
High Cost Dedicated	88,836,527	166,324,146	402,156,618	657,317,291
Shared	28,957,359	32,180,510		61,137,868
Total Generation Cost	125,214,968	231,926,035	434,743,529	791,884,532

Allocate Shared Costs to High/Low Cost Generation Plants:

	Wpg River Generation			
	Depreciation	**Operating**	**Interest**	**Total**
Direct Costs	7,421,082	33,421,380	32,586,911	73,429,373
Allocated Shared Cost	3,980,256	4,423,286		8,403,542
Total Cost	11,401,338	37,844,666	32,586,911	81,832,915
			GW.h	4,505
			¢/kW.h	1.82

	High Cost Generation			
	Depreciation	**Operating**	**Interest**	**Total**
Direct Costs	88,836,527	166,324,146	402,156,618	657,317,291
Allocated Shared Cost	24,977,102	27,757,224		52,734,326
Total Cost	113,813,630	194,081,369	402,156,618	710,051,617
			GW.h	28,270
			¢/kW.h	2.51

	Total Cost	% of Cost
Wpg River Generation	81,832,915	10.3%
High Cost Generation	710,051,617	89.7%
	791,884,532	100.0%

A-5 DIRECT AND INDIRECT COSTS OF EXPORTS

It is difficult to definitively assign costs directly to export sales as Manitoba Hydro's system was not built with the explicit purpose of serving export markets: functions that could potentially be deemed as export could, in fact, be used for domestic activities. Simply, the system is reversible in that it can be used to exploit extraprovincial sales, or as was seen during the 2003/04 drought, provide a lifeline to ensure domestic consumption is not interrupted. Previous COSS have not attempted to identify other costs specifically attributable to export sales because of difficulty in assigning costs with the exception of some variable costs. While the drought of 2003/04 is illustrative of the duality of our import/export capability, in the context of the PCOSS such an event is not forecast; the PCOSS is based on median water flows.

That said there are a number of activities tracked in the financial records of Manitoba Hydro that have a significant likelihood of being related to exports. These include departmental activities of staff involved in trading to the external market, power purchases, as well as assets that deliver energy outside the provincial border. Specifically identified export related costs in Manitoba Hydro's financial system include the following settlement cost centres (SCC):

SCC Name	Operating Cost	Depreciation Cost	Total Cost
External Marketing	$2,355.0	$72.1	$2,427.1
Power Purchases	157.4	0	157.4
Transmission Marketing	4,822.5	25.5	4,848.0
Total Export Related Costs	7,334.9	97.6	7,432.5

(in thousands of dollars)

However relative to total Generation and Transmission cost in PCOSS06 (in excess of $1 billion) these "direct" export costs are not significant.

For this document Manitoba Hydro has prepared several different PCOSS06 reports with different methodologies. Among the differences is the treatment of extraprovincial sales. In the Current Method, export sales are netted against power purchases and a proportionate share of water rentals and thermal fuel purchases. In the recommended methodology, Transmission is classified between export lines (allocated on annual energy) and domestic lines (allocated on the basis of Demand) which necessitates the assignment of direct costs to the export function, this includes finance expense (including capital tax), operating and depreciation costs. These costs relative to total transmission are outlined below:

	Finance Expense	**Operating Cost**	**Depreciation Exp**
Total Transmission	$106,839.8	$48,399.7	$47,512.5
Export Transmission	17,287.8	11,814.3	5,893.4
Export Percentage	16.2%	24.4%	12.4%
Transmission Gross Investment (GI)		$973,023,618	
Export GI		145,304,330	
		14.9%	

(in thousands of dollars)

Additionally, a comparison of total costs assigned to the Export Class between the Current and Recommended Methods is shown below.

	Current Method	**Recommended Method**	**Difference**
Power Purchases	$72.9	33.0	39.9
Water Rentals	26.0	11.8	14.2
Thermal Fuel Costs	8.1	3.7	4.4
Allocated Gen. Costs*	0	157.3	(157.3)
Transmission Costs	0	39.0	(39.0)
	$107.0	$244.8	(137.8)

* Note that firm export sales are also allocated a portion of power purchases, water rentals and thermal fuel costs as part of allocating the overall cost of Generation to these sales.

In the recommended methodology the Export Class of service is allocated approximately 21% of total costs, in the current methodology this number is approximately 7%.

A-6 EVOLUTION OF THE COS 1992 TO 2006

This section elaborates the incremental changes that have been made to the COSS methods over the period 1992 through 2006. It should be noted that the following years have been excluded from this review: 1998 and 2005 (no study assembled); 2000 (internal document only); and 2003 (actual retrospective study). For the 2000 and 2003 methodology was carried over from previous studies.

PCOSS92 to 93

- Winnipeg Hydro re-introduced as a customer class.

PCOSS93 to 94

- Introduction of the Interruptible Rate Class.

PCOSS94 to 95

- No significant changes introduced.

PCOSS95 to 96

- Direct assignment of DSM costs to Area & Roadway Lighting Class; and
- Although not a change in methodology per se, the PCOSS reflects the inclusion of the Provincial capital tax levy ($11.9 million additional cost).

PCOSS96 to 97

- Direct assignment of DSM costs extended to GSL >100 kV class.

PCOSS97 to 99

- Coincident peak values of peak demand are reported based on the top 50 peak hours, previously the single hour peak was averaged with the previous two single hour peaks for demand allocation;
- Separate subclass reported for GSL >100 kV Curtailable customers, which is based on separate peak demand for this specific class;
- Area & Roadway Lighting energy allocation is increased to be consistent with Load Research (LR) analysis of this class. Previously energy forecasts were based on 4,075 hours of use per year, with updated LR data the hours of use in the year was increased to 4,252; and

– Although not a change in methodology per se, the PCOSS is based on financial records of the corporation's new financial reporting system SAP, which went online April 1, 1997.

PCOSS99 to 2001

– Direct assignment of all DSM costs to applicable customer classes.

PCOSS01 to 2002

– The PCOSS02 represented a significant departure from previous studies submitted to the Board. The proposed changes to the study were made to address the following; one, satisfy issues arising our of Order 51/96 (revised in Order 91/00) or specifically, that Manitoba Hydro examine "alternative methods of solving the persistent problem of certain subclasses (e.g. Zone 3 Residential and General Service Large) being outside the ZOR", and secondly, to recognize changes in the energy market place and the significant role Manitoba Hydro participates in these external markets. However the original submission of this PCOSS02 was subsequently revised and resubmitted on March 27, 2002 as the original version contained marginal cost indicators that were not supportable due to reasons of commercial sensitivity. In addition, the revised PCOSS02 also removed Winnipeg Hydro as a customer class as it was within this time frame that Manitoba Hydro finalized the purchase of the local utility. The other proposed changes were carried forward and are outlined below:

  - HVDC facilities (excluding Dorsey Converter Station) moved to Generation function from Transmission;
  - Generation and Transmission functions are classified in sum on the basis of system load factor (Transmission Demand netted from total Demand and all remaining Demand-related costs assigned to the Generation function);
  - Generation costs allocated on both Energy (annual) and Demand based on the average of summer and winter demands (2 CP);
  - Transmission costs allocated on the basis 100% demand based on the average of the 12 monthly Transmission peaks (12 CP);
  - Incorporation of uniform rates legislation mandated from the Provincial Government;
  - Winnipeg Hydro removed as a customer class (costs allocated to applicable Manitoba Hydro retail customers, revenue added with export revenues);
  - Net export revenues allocated to retail customers on the basis of total allocated costs (versus Generation and Transmission done previously).

PCOSS02 to 2004

- The PCOSS02 was the COS document submitted as part of the Status Update Hearing before the PUB. Considerable discussion surrounded the proposed changes to the COSS with some of Manitoba Hydro's changes being denied by the PUB. As a result, the PCOSS04 submitted as part of the 2004/05 GRA contained changes that were more in line with methodology submitted prior to the PCOSS02. Specifically these changes include:

  - Generation Energy-related costs allocated on the basis of annual energy versus the average of the summer and winter periods proposed in PCOSS02;
  - Transmission costs, classified as 100% Demand, allocated on the same basis as Generation costs, or the 2 CP method versus the proposed 12 CP in PCOSS02;
  - Net export revenues allocated to retail customers of the basis of Generation and Transmission cost versus allocation of total allocated costs proposed;
  - Although not methodological, the PCOSS04 incorporated rate reductions directed in 07/03 to the General Service Small and Large customer classes.

PCOSS04 to 2006

- As directed in Order 101/04, net export revenues were used to fund the cost of the uniform rates legislation;
- As the integration of Winnipeg Hydro operation into that of Manitoba Hydro was completed, more complete data was available to functionalize, classify and allocate the former operations of WH along with those of Manitoba Hydro. While integration was reflected in PCOSS04, a complete, accurate profile was not available at the time the PCOSS04 was prepared.

The following table outlines the revenue cost coverage ratios (RCC) since 1992 to the results of the PCOSS06. Note the RCC results are given in two ways: pre-export revenue allocation and post export revenue allocation as is the more traditional reporting of results.

Historic RCC Results

RCC Results from 1992 thru 2006^

Class	1992 Pre Export	1992 Post Export	1993 Pre Export	1993 Post Export	1994 Pre Export	1994 Post Export	1995 Pre Export	1995 Post Export	1996 Pre Export	1996 Post Export	1997 Pre Export	1997 Post Export
Residential	73.0	90.8	75.0	88.5	68.0	88.7	68.6	90.2	69.8	91.1	70.1	91.4
GSS ND	87.3	105.9	93.3	107.2	87.3	108.6	85.4	107.8	86.4	108.9	84.3	107.3
GSS Dmd	79.8	101.1	87.2	103.2	80.9	105.6	79.3	105.3	80.1	106.3	78.2	104.5
GSM	87.1	109.3	93.6	110.5	84.4	110.1	79.2	106.1	75.6	102.4	75.3	102.4
GSL	85.7	111.5	92.1	111.8	81.5	111.4	78.3	109.7	75.5	106.8	76.9	108.2
A & R Lights	109.4	118.7	112.5	119.0	106.8	117.0	109.5	119.6	102.9	112.5	99.8	108.8

Class	1999 Pre Export	1999 Post Export	2001 Pre Export	2001 Post Export	2002* Pre Export	2002* Post Export	2003 Actual Pre Export	2003 Actual Post Export	2004 Pre Export	2004 Post Export	2006 Current Pre Export	2006 Current Post Export
Residential	73.3	92.1	66.7	90.7	57.5	96.5	71.3	92.4	63.9	90.6	68.3	92.2
GSS ND	87.1	106.9	79.7	104.4	71.1	109.4	84.5	107.3	76.2	104.9	77.5	103.1
GSS Dmd	83.9	107.7	75.9	105.4	65.7	104.7	81.4	108.4	74.8	109.7	75.5	106.0
GSM	81.1	105.5	77.5	109.4	65.8	104.4	75.2	102.9	68.7	104.8	71.0	102.9
GSL	77.7	107.8	74.0	112.0	61.1	100.0	73.3	107.2	66.2	109.6	68.7	108.6
A & R Lights	87.6	93.4	85.1	92.0	88.3	101.9	101.9	109.9	98.5	108.9	96.5	105.2

^ all results from prospective studies unless noted

* based on March 27/02 revised PCOSS02

SECTION B – SUMMARY RESULTS

Conclusions and Recommendations

The Revenue Cost Coverage (RCC) results of the PCOSS06 are shown for four scenarios: Manitoba Hydro's Recommended Method; Manitoba Hydro's Current Method; the NERA Method; and the Generation Vintaging Method. The RCC results of all four scenarios include the uniform rate adjustment.

As has been typical of past PCOSS, the study has been prepared on the basis of a financial forecast incorporating median water flows, specifically, on the basis of IFF04-1. The level of export earnings forecast in this PCOSS reflects this assumption. At the time of preparation of IFF04-1, the reservoirs in Manitoba were above average and this also has been incorporated into the forecast of export revenues. Consequently, the forecast of export revenues in IFF04-1 and in this PCOSS is greater than what would have been forecast had the reservoirs been at average levels at the time of the forecast. Since the forecast was approved, precipitation has been below average thereby partially offsetting the impact of higher-than-normal storage.

The effect of forecasting export revenues which are greater than the long term average is not believed to be material for the results prepared using the NERA Method. For the base study, higher than normal export revenues would tend to overestimate RCCs for the General Service Medium and Large classes and to underestimate RCCs of the remaining classes.

This Section outlines the four primary tables of each of these four scenarios: Revenue Cost Coverage (RCC), Customer, Demand and Energy (CDE), and Functional Cost Analysis for each of the following methods:

1. Recommended;
2. Current;
3. NERA; and
4. Generation Vintaging.

Schedules B1 through B3 outline the summary results from PCOSS06 based on Manitoba Hydro's Recommended Method. Subsequent schedules, B4 through B12 outline the same schedules for the Current, NERA and Generation Vintaging Methods respectively.

These include:

1. Revenue Cost Coverage Tables – this ratio compares revenues of each class to its allocated costs. The RCC ratio provides the relative performance of each rate class over a base of 100%. Schedule B1 outlines the customer class RCC;

2. Customer, Demand and Energy Costs (CDE) – in this table the components are converted to unit costs using billing determinants, i.e. number of customers, billable demand and kW.h sales. The information in Schedule B2 is intended to provide a comparison of allocated unit costs with the corresponding price in the appropriate rate schedule; and

3. Functional Breakdown – this table identifies the cost of providing each level of service to each customer class. This information could be beneficial when evaluating service extension policies or construction allowance guidelines. Schedule B3 outlines the functional breakdown.

SCHEDULE B1

Manitoba Hydro
Prospective Cost Of Service Study
March 31, 2006
Revenue Cost Coverage Analysis
Current Method
S U M M A R Y

Customer Class	Total Cost ($000)	Class Revenue ($000)	RCC % Pre Export Allocation	Net Export Revenue ($000)	Total Revenue ($000)	RCC % Current Rates
Residential	605,678.7	413,604.1	68.3%	144,859.5	558,463.6	92.2%
General Service - Small Non-Demand	138,476.4	107,251.5	77.5%	35,526.3	142,777.8	103.1%
General Service - Small Demand	120,301.3	90,861.6	75.5%	36,634.5	127,496.1	106.0%
General Service - Medium	196,833.3	139,754.4	71.0%	62,740.5	202,494.8	102.9%
General Service - Large 0 - 30 kV	95,617.0	59,105.6	61.8%	30,789.1	89,894.6	94.0%
General Service - Large 30-100 kV*	38,100.5	26,974.2	70.8%	14,716.6	41,690.8	109.4%
General Service - Large >100 kV*	222,693.5	158,828.7	71.3%	96,575.5	255,404.2	114.7%
*Includes Curtailment Customers						
SEP	2,534.7	2,495.6	98.5%	-	2,495.6	98.5%
Area & Roadway Lighting	19,987.9	19,297.0	96.5%	1,739.1	21,036.1	105.2%
Total General Consumers	1,440,223.4	1,018,172.6	70.7%	423,581.2	1,441,753.8	100.1%
Diesel	10,839.8	9,309.4	85.9%	-	9,309.4	85.9%
Export	-	423,581.2	0.0%	(423,581.2)	-	0.0%
Total System	1,451,063.2	1,451,063.2	100.0%	-	1,451,063.2	100.0%

Manitoba Hydro
Prospective Cost Of Service Study - March 31, 2006
Customer, Demand, Energy Cost Analysis
Current Method
SUMMARY

Class	CUSTOMER Cost ($000)	CUSTOMER Number of Customers	CUSTOMER Unit Cost $/Month	DEMAND Cost ($000)	DEMAND % Recovery	DEMAND Billable Demand MVA	DEMAND Unit Cost $/KVA	ENERGY Cost ($000)	ENERGY Metered Energy MWh	ENERGY Unit Cost ¢/kWh
Residential	112,911	452,273	20.80	228,963	0%	n/a	n/a	118,945	6,290,431.0	5.53 *
GS Small - Non-Demand	23,154	54,660	35.30	49,667	0%	n/a	n/a	30,130	1,557,598	5.12 *
GS Small - Demand	4,640	6,120	63.18	46,889	39%	2,013	9.14	32,138	1,669,620	3.63
General Service - Medium	5,583	1,777	261.83	74,166	100%	7,965	9.31	54,343	2,879,317	1.89
General Service - Large <30 kV	3,037	248	n/a	34,086	100%	3,511	10.57 *	27,705	1,449,913	1.91
General Service - Large 30-100 kV	1,574	29	n/a	8,138	100%	1,597	6.08 *	13,672	767,993	1.78
General Service - Large >100 kV	1,810	14	n/a	34,331	100%	8,340	4.33 *	89,976	5,123,753	1.76
SEP	330	33	834.11	752	0%	n/a	n/a	1,453	30,000	7.35 *
Area & Roadway Lighting	13,822	147,290	7.82	2,649	0%	n/a	n/a	1,777	95,793	4.62 *
Total	166,861	662,444		479,641		23,426		370,140	19,864,418	

* - includes recovery of demand costs

Manitoba Hydro
Prospective Cost Of Service Study - March 31, 2006
Functional Breakdown
Current Method

S U M M A R Y

Class	Total Cost ($000)	Generation Cost ($000)	%	Transmission Cost ($000)	%	Subtransmission Cost ($000)	%	Distribution Cust Service Cost ($000)	%	Distribution Plant Cost ($000)	%
Residential	460,819	147,749	32.1%	45,910	10.0%	38,076	8.3%	49,857	10.8%	179,228	38.9%
General Service - Small Non Demand	102,950	37,657	36.6%	11,173	10.9%	7,879	7.7%	12,758	12.4%	33,484	32.5%
General Service - Small Demand	83,667	39,933	47.7%	10,374	12.4%	7,413	8.9%	1,663	2.0%	24,284	29.0%
General Service - Medium	134,093	67,331	50.2%	17,774	13.3%	11,085	8.3%	4,318	3.2%	33,585	25.0%
General Service - Large < 30kV	64,828	34,382	53.0%	8,202	12.7%	5,522	8.5%	2,723	4.2%	13,999	21.6%
General Service - Large 30-100 kV	23,384	16,435	70.3%	2,921	12.5%	2,453	10.5%	1,511	6.5%	62	0.3%
General Service - Large >100 kV	126,118	105,695	83.8%	18,613	14.8%	0	0.0%	1,779	1.4%	31	0.0%
SEP	2,535	1,756	69.3%	448	17.7%	0	0.0%	299	11.8%	32	1.3%
Area & Roadway Lighting	18,249	2,127	11.7%	162	0.9%	559	3.1%	586	3.2%	14,815	81.2%
Total General Consumers	1,016,642	453,066	44.6%	115,577	11.4%	72,986	7.2%	75,493	7.4%	299,520	29.5%

Manitoba Hydro
Prospective Cost Of Service Study
March 31, 2006
Revenue Cost Coverage Analysis
Recommended Method
S U M M A R Y

Customer Class	Total Cost ($000)	Class Revenue ($000)	RCC % Pre Export Allocation	Net Export Revenue ($000)	Total Revenue ($000)	RCC % Current Rates
Residential	551,983.6	413,604.1	74.9%	121,795.9	535,399.9	97.0%
General Service - Small Non-Demand	125,288.8	107,251.5	85.6%	27,336.1	134,587.6	107.4%
General Service - Small Demand	108,663.5	90,861.6	83.6%	23,633.4	114,494.9	105.4%
General Service - Medium	177,563.4	139,754.4	78.7%	38,814.6	178,569.0	100.6%
General Service - Large 0 - 30 kV	86,311.0	59,105.6	68.5%	18,678.1	77,783.6	90.1%
General Service - Large 30 - 100 kV*	33,976.0	26,974.2	79.4%	7,525.3	34,499.5	101.5%
General Service - Large >100 kV*	196,760.6	158,828.7	80.7%	44,168.8	202,997.6	103.2%
*Includes Curtailment Customers						
SEP	2,534.7	2,495.6	98.5%	-	2,495.6	98.5%
Area & Roadway Lighting	19,449.5	19,297.0	99.2%	1,531.9	20,829.0	107.1%
Total General Consumers	1,302,531.1	1,018,172.6	78.2%	283,484.0	1,301,656.7	99.9%
Diesel**	10,839.8	9,309.4	85.9%	2,404.7	11,714.2	108.1%
Export	196,334.1	482,222.8	245.6%	(285,888.8)	196,334.1	100.0%
Total System	1,509,704.9	1,509,704.9	100.0%	-	1,509,704.9	100.0%

**Diesel RCC of 108.1% is based on forecast information from IFF04 which does not reflect the large increases in world oil prices and refined diesel fuel oil prices since then. A preliminary review of fuel prices since that time has revealed a price increase of 46% more than that forecast previously. It is estimated as a result that the full cost rate would increase to 46 cents/kW.h versus 36.1 imbedded in the Diesel RCC shown above.

Manitoba Hydro
Prospective Cost Of Service Study - March 31, 2006
Customer, Demand, Energy Cost Analysis
Recommended Method
SUMMARY

Class	CUSTOMER Cost ($000)	CUSTOMER Number of Customers	CUSTOMER Unit Cost $/Month	DEMAND Cost ($000)	DEMAND % Recovery	DEMAND Billable Demand MVA	DEMAND Unit Cost $/KVA	ENERGY Cost ($000)	ENERGY Metered Energy MWh	ENERGY Unit Cost ¢/kWh
Residential	87,862	452,273	16.19	162,085	0%	n/a	n/a	180,241	6,290,431	5.44 *
GS Small - Non-Demand	18,017	54,660	27.47	34,160	0%	n/a	n/a	45,775	1,557,598	5.13 *
GS Small - Demand	3,610	6,120	49.16	32,802	39%	2,013	6.39	48,618	1,669,620	4.11
General Service - Medium	4,345	1,777	203.74	51,780	100%	7,965	6.50	82,624	2,879,317	2.87
General Service - Large <30 kV	2,363	248	n/a	23,496	100%	3,511	7.36 *	41,774	1,449,913	2.88
General Service - Large 30-100 kV	1,225	29	n/a	5,142	100%	1,597	3.99 *	20,085	767,993	2.62
General Service - Large >100 kV	1,409	14	n/a	18,689	100%	8,340	2.41 *	132,494	5,123,753	2.59
SEP	330	33	834.11	350	0.0	n/a	n/a	1,854	30,000	7.35 *
Area & Roadway Lighting	13,535	147,290	7.66	1,968	0.0	n/a	n/a	2,414	95,793	4.57 *
Total	132,696	662,444		330,471		23,426		555,879	19,864,418	

* - includes recovery of demand costs

SCHEDULE B6

Manitoba Hydro
Prospective Cost Of Service Study - March 31, 2006
Functional Breakdown
Recommended Method
S U M M A R Y

Class	Total Cost ($000)	Generation Cost ($000)	%	Transmission Cost ($000)	%	Subtransmission Cost ($000)	%	Distribution Cust Service Cost ($000)	%	Distribution Plant Cost ($000)	%
Residential	430,188	176,000	40.9%	46,295	10.8%	29,629	6.9%	38,796	9.0%	139,467	32.4%
General Service - Small Non Demand	97,953	45,158	46.1%	10,681	10.9%	6,131	6.3%	9,928	10.1%	26,056	26.6%
General Service - Small Demand	85,030	47,920	56.4%	11,152	13.1%	5,768	6.8%	1,294	1.5%	18,897	22.2%
General Service - Medium	138,749	81,089	58.4%	19,540	14.1%	8,626	6.2%	3,360	2.4%	26,134	18.8%
General Service - Large <30 kV	67,633	41,253	61.0%	9,071	13.4%	4,297	6.4%	2,119	3.1%	10,894	16.1%
General Service - Large 30-100 kV	26,451	19,303	73.0%	4,014	15.2%	1,909	7.2%	1,176	4.4%	49	0.2%
General Service - Large >100 kV	152,592	124,898	81.9%	26,285	17.2%	-	0.0%	1,385	0.9%	24	0.0%
SEP	2,535	1,781	70.3%	424	16.7%	-	0.0%	299	11.8%	32	1.3%
Area & Roadway Lighting	17,918	2,750	15.3%	466	2.6%	515	2.9%	540	3.0%	13,647	76.2%
Total General Consumers	1,019,047	540,151	53.0%	127,927	12.6%	56,874	5.6%	58,896	5.8%	235,199	23.1%

SCHEDULE B7

Manitoba Hydro
Prospective Cost Of Service Study
March 31, 2006
Revenue Cost Coverage Analysis
NERA Method
S U M M A R Y

Customer Class	Total Cost ($000)	Class Revenue ($000)	RCC % Pre Export Allocation	Net Export Revenue ($000)	Total Revenue ($000)	RCC % Current Rates
Residential	525,056.4	413,604.1	78.8%	89,034.5	502,638.5	95.7%
General Service - Small Non-Demand	118,735.3	107,251.5	90.3%	19,896.1	127,147.6	107.1%
General Service - Small Demand	101,735.5	90,861.6	89.3%	16,985.9	107,847.5	106.0%
General Service - Medium	165,611.1	139,754.4	84.4%	27,799.1	167,553.5	101.2%
General Service - Large 0 - 30 kV	80,472.1	59,105.6	73.4%	13,362.4	72,468.0	90.1%
General Service - Large 30-100 kV*	31,184.8	26,974.2	86.5%	5,308.8	32,283.0	103.5%
General Service - Large >100 kV*	178,354.9	158,828.7	89.1%	30,814.5	189,643.2	106.3%
*Includes Curtailment Customers						
SEP	2,534.7	2,495.6	98.5%	-	2,495.6	98.5%
Area & Roadway Lighting	19,130.4	19,297.0	100.9%	1,123.2	20,420.2	106.7%
Total General Consumers	1,222,815.3	1,018,172.6	83.3%	204,324.4	1,222,497.1	100.0%
Diesel	10,839.8	9,309.4	85.9%	1,848.6	11,158.0	102.9%
Export	324,477.1	530,650.1	163.5%	(206,173.0)	324,477.1	100.0%
Total System	1,558,132.2	1,558,132.2	100.0%	-	1,558,132.2	100.0%

Manitoba Hydro
Prospective Cost Of Service Study - March 31, 2006
Customer, Demand, Energy Cost Analysis
NERA Method
SUMMARY

Class	CUSTOMER Cost ($000)	CUSTOMER Number of Customers	CUSTOMER Unit Cost $/Month	DEMAND Cost ($000)	DEMAND % Recovery	DEMAND Billable Demand MVA	DEMAND Unit Cost $/KVA	ENERGY Cost ($000)	ENERGY Metered Energy MWh	ENERGY Unit Cost ¢/kWh
Residential	93,655	452,273	17.26	166,704	0%	n/a	n/a	175,663	6,290,431	5.44 *
GS Small - Non-Demand	19,205	54,660	29.28	34,998	0%	n/a	n/a	44,636	1,557,598	5.11 *
GS Small - Demand	3,848	6,120	52.40	33,495	39%	2,013	6.52	47,406	1,669,620	4.06
General Service - Medium	4,631	1,777	217.17	52,633	100%	7,965	6.61	80,548	2,879,317	2.80
General Service - Large <30 kV	2,519	248	n/a	23,853	100%	3,511	7.51 *	40,737	1,449,913	2.81
General Service - Large 30-100 kV	1,305	29	n/a	4,999	100%	1,597	3.95 *	19,572	767,993	2.55
General Service - Large >100 kV	1,502	14	n/a	16,936	100%	8,340	2.21 *	129,103	5,123,753	2.52
SEP	330	33	834.11	335	0%	n/a	n/a	1,869	30,000	7.35 *
Area & Roadway Lighting	13,601	147,290	7.70	2,054	0%	n/a	n/a	2,352	95,793	4.60 *
Total	140,598	662,444		336,006		23,426		541,887	19,864,418	

* - includes recovery of demand costs

Manitoba Hydro
Prospective Cost Of Service Study - March 31, 2006
Functional Breakdown
NERA Method
S U M M A R Y

Class	Total Cost ($000)	Generation Cost ($000)	%	Transmission Cost ($000)	%	Subtransmission Cost ($000)	%	Distribution Cust Service Cost ($000)	%	Distribution Plant Cost ($000)	%
Residential	436,022	171,833	39.4%	42,589	9.8%	31,582	7.2%	41,354	9.5%	148,663	34.1%
General Service - Small Non Demand	98,839	44,122	44.6%	9,826	9.9%	6,535	6.6%	10,582	10.7%	27,774	28.1%
General Service - Small Demand	84,750	46,820	55.2%	10,259	12.1%	6,149	7.3%	1,379	1.6%	20,143	23.8%
General Service - Medium	137,812	79,202	57.5%	17,976	13.0%	9,195	6.7%	3,581	2.6%	27,857	20.2%
General Service - Large <30 kV	67,110	40,314	60.1%	8,345	12.4%	4,580	6.8%	2,259	3.4%	11,612	17.3%
General Service - Large 30-100 kV	25,876	18,843	72.8%	3,693	14.3%	2,035	7.9%	1,253	4.8%	52	0.2%
General Service - Large >100 kV	147,540	121,856	82.6%	24,183	16.4%	0	0.0%	1,476	1.0%	26	0.0%
SEP	2,535	1,799	71.0%	405	16.0%	0	0.0%	299	11.8%	32	1.3%
Area & Roadway Lighting	18,007	2,574	14.3%	411	2.3%	526	2.9%	551	3.1%	13,945	77.4%
Total General Consumers	1,018,491	527,363	51.8%	117,688	11.6%	60,602	6.0%	62,736	6.2%	250,102	24.6%

Manitoba Hydro
Prospective Cost Of Service Study
March 31, 2006
Revenue Cost Coverage Analysis
Generation Vintaging Method
S U M M A R Y

Customer Class	Total Cost ($000)	Class Revenue ($000)	RCC % Pre Export Allocation	Net Export Revenue ($000)	Total Revenue ($000)	RCC % Current Rates
Residential	520,712.2	413,604.1	79.4%	83,523.2	497,127.2	95.5%
General Service - Small Non-Demand	117,652.4	107,251.5	91.2%	18,646.4	125,897.9	107.0%
General Service - Small Demand	100,584.5	90,861.6	90.3%	15,882.5	106,744.0	106.1%
General Service - Medium	163,638.7	139,754.4	85.4%	25,979.0	165,733.4	101.3%
General Service - Large 0 - 30 kV	79,487.8	59,105.6	74.4%	12,481.6	71,587.2	90.1%
General Service - Large 30-100 kV*	30,700.1	26,974.2	87.9%	4,943.8	31,918.0	104.0%
General Service - Large >100 kV*	175,150.6	158,828.7	90.7%	28,632.7	187,461.4	107.0%
*Includes Curtailment Customers						
SEP	2,534.7	2,495.6	98.5%	-	2,495.6	98.5%
Area & Roadway Lighting	19,072.1	19,297.0	101.2%	1,053.1	20,350.1	106.7%
Total General Consumers	1,209,533.2	1,018,172.6	84.2%	191,142.2	1,209,314.9	100.0%
Diesel	10,839.8	9,309.4	85.9%	1,748.7	11,058.1	102.0%
Export	337,759.2	530,650.1	157.1%	(192,890.9)	337,759.2	100.0%
Total System	1,558,132.2	1,558,132.2	100.0%	-	1,558,132.2	100.0%

Manitoba Hydro
Prospective Cost Of Service Study - March 31, 2006
Customer, Demand, Energy Cost Analysis
Generation Vintaging Method
SUMMARY

	CUSTOMER			DEMAND				ENERGY		
Class	Cost ($000)	Number of Customers	Unit Cost $/Month	Cost ($000)	% Recovery	Billable Demand MVA	Unit Cost $/KVA	Cost ($000)	Metered Energy MWh	Unit Cost ¢/kWh
Residential	94,696	452,273	17.45	168,544	0%	n/a	n/a	173,949	6,290,431	5.44 *
GS Small - Non-Demand	19,418	54,660	29.60	35,379	0%	n/a	n/a	44,209	1,557,598	5.11 *
GS Small - Demand	3,891	6,120	52.98	33,859	39%	2,013	6.59	46,952	1,669,620	4.05
General Service - Medium	4,682	1,777	219.59	53,208	100%	7,965	6.68	79,770	2,879,317	2.77
General Service - Large <30 kV	2,547	248	n/a	24,110	100%	3,511	7.59 *	40,349	1,449,913	2.78
General Service - Large 30-100 kV	1,320	29	n/a	5,056	100%	1,597	3.99 *	19,381	767,993	2.52
General Service - Large >100 kV	1,518	14	n/a	17,159	100%	8,340	2.24 *	127,841	5,123,753	2.50
SEP	330	33	834.11	335	0%	n/a	n/a	1,869	30,000	7.35 *
Area & Roadway Lighting	13,613	147,290	7.70	2,077	0%	n/a	n/a	2,329	95,793	4.60 *
Total	142,017	662,444		339,725		23,426		536,649	19,864,418	

* - includes recovery of demand costs

Manitoba Hydro
Prospective Cost Of Service Study - March 31, 2006
Functional Breakdown
Generation Vintaging Method

S U M M A R Y

Class	Total Cost ($000)	Generation Cost ($000)	%	Transmission Cost ($000)	%	Subtransmission Cost ($000)	%	Distribution Cust Service Cost ($000)	%	Distribution Plant Cost ($000)	%
Residential	437,189	170,065	38.9%	43,062	9.8%	31,933	7.3%	41,814	9.6%	150,314	34.4%
General Service - Small Non Demand	99,006	43,681	44.1%	9,935	10.0%	6,608	6.7%	10,700	10.8%	28,082	28.4%
General Service - Small Demand	84,702	46,351	54.7%	10,373	12.2%	6,217	7.3%	1,395	1.6%	20,367	24.0%
General Service - Medium	137,660	78,399	57.0%	18,176	13.2%	9,297	6.8%	3,621	2.6%	28,167	20.5%
General Service - Large <30 kV	67,006	39,913	59.6%	8,438	12.6%	4,631	6.9%	2,284	3.4%	11,741	17.5%
General Service - Large 30-100 kV	25,756	18,645	72.4%	3,734	14.5%	2,058	8.0%	1,267	4.9%	52	0.2%
General Service - Large >100 kV	146,518	120,548	82.3%	24,452	16.7%	0	0.0%	1,492	1.0%	26	0.0%
SEP	2,535	1,799	71.0%	405	16.0%	0	0.0%	299	11.8%	32	1.3%
Area & Roadway Lighting	18,019	2,529	14.0%	413	2.3%	528	2.9%	553	3.1%	13,996	77.7%
Total General Consumers	1,018,391	521,930	51.3%	118,988	11.7%	61,271	6.0%	63,425	6.2%	252,777	24.8%

SECTION C - FUNCTIONALIZATION AND CLASSIFICATION METHODS AND DETAILS

Winnipeg Hydro Integration in the Study

As reported in the PCOSS04 the complete integration of the Winnipeg Hydro acquisition into that year's study was not complete. The deficiencies recognized in the PCOSS04 that have since been overcome with the PCOSS06 include:

1) Asset recognition: the PCOSS04 started with the actual assets as of March 31, 2002 which did not include any assets from Winnipeg Hydro (WH), while a preliminary listing of WH assets were incorporated into the PCOSS04 the values and functions of some of those assets were at some variance to what was actually loaded into Manitoba Hydro's financial system;

2) Matching of revenue data and operating costs, while both were recognized in the PCOSS04, the functionalization of these costs in SAP was not fully integrated which did not match directly to the customer revenue received;

3) Load Research (LR) data – the PCOSS04 was based on LR data from 2001/02 and did not contain any sample from former Winnipeg Hydro customers, as a result load factors from a sample of only Manitoba Hydro customers was applied to integrated energy forecast that did include WH energy forecasts.

Organization and Preparation of PCOSS06 Forecast Data

This section provides a basic review of the approaches taken to organize Manitoba Hydro's 2005/06 forecast data for use in the PCOSS and the functionalization and classification of costs in preparation for allocation to customer classes. Allocation methods are explained in Section D. The remainder of this section is organized as follows:

- Definitions
- Functionalization and Classification Process
- Functionalization and Classification of Capital Related Costs
- Functionalization and Classification of Operating and Administrative Costs
- Adjusted Revenue

Definitions

Functionalization - Functionalization is the preliminary arrangement of cost according to functions performed by the electric system. Manitoba Hydro has defined its functional levels as follows:

1) Generation Function - This function includes all generating facilities, HVDC facilities (excluding Dorsey Converter Station), communication facilities associated with the Generation function and a share of the administration buildings and general equipment.

2) Transmission Function - Historically Transmission facilities have included the high voltage (100 kV and higher) grid transmission lines. With the methodology changes introduced in the PCOSS02, this has been further refined to include only transmission lines which would be recognized for inclusion in Manitoba Hydro's Transmission Tariff. Radial Transmission facilities, including those with voltage greater than 100 kV, are included in the Subtransmission function. In addition to the transmission lines above, this function also includes: Dorsey Converter Station, the high voltage portion of substations, the communications facilities associated with the Transmission function and a share of the administration buildings, general equipment and substation transformers in stock.

3) Ancillary Services Function - This function includes specific items[1] previously bundled in the Generation or Transmission function. Ancillary Services are services necessary to support the Transmission of capacity and energy from resources (Transmission provider) to load while maintaining reliable operation of the Transmission providers electrical system. A complete description of the ancillary services offered can be found in the "Functionalization and Classification of Capital Related Costs" section that follows.

4) Subtransmission Function - This function includes non grid/radial transmission lines (greater than 100 kV), lower voltage (66 kV and 33 kV) subtransmission lines, the low voltage portion of the substations and a share of communication equipment, administration buildings, general equipment and substation transformers in stock. These facilities are required to bring the power from the common bus network to the districts and local towns.

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[1] As based on Business Process Synchronization Unit (BPSU) breakdown in SAP.

5) Distribution Plant Function - This function includes the low voltage (less than 33 kV) distribution lines, the low voltage portion of the substations, meters, metering transformers, distribution transformers and a share of communication equipment, administration buildings, general equipment and substation transformers in stock.

6) Distribution (or Customer) Services Function - This function captures all costs associated with serving the customer after delivery of the energy. This includes such costs as billing and collections, as well as other departmental costs such as Power Smart Energy Services and Rates & Policies. In addition, it includes a share of administration buildings and general equipment associated with these activities.

Classification - All functionalized costs are classified into one or more of the following: Demand, Energy and Customer-related cost components for allocation to the classes of service. This process also enables the determination of unit demand, energy and customer costs for each customer class.

1) Class of Service - A group of customers having reasonably similar service characteristics, plant facilities requirements, ultimate energy use and load patterns.

2) Cost Component - The term used to describe the classification of an electric utility's total operating expenses and capital investment in electric plant as Demand, Energy or Customer-related costs.

3) Customer Costs - Customer costs are costs associated with the carrying of customers on the power system, or the addition of customers to the power system.

4) Energy Costs - Energy costs are costs associated with the consumption of electricity over a period of time by customers of the power system.

5) Demand Costs - Demand costs are costs associated with the rate of flow of electricity demanded at one point in time and the maximum size (capacity) of facilities required to serve the demands of electric customers.

6) Load Factor - Load Factor is an expression of the proportion of time that a utility, a class of service or an individual customer is utilizing the facilities installed to provide service. It is expressed as a ratio or percentage relating energy kilowatt-hours (kW.h) to the maximum demand requirements (kW) during a specified time period.

Functionalization and Classification Process

Manitoba Hydro's COSS has been developed with reference to industry standards as well as the design and operating characteristics of its electric system. Manitoba Hydro functionalizes gross and net plant in-service for the purpose of functionalizing depreciation expense, interest expense, certain operating and maintenance costs as well as the contributions to or appropriations from reserves. Manitoba Hydro does not perform a traditional allocation of rate base as a rate of return is not measured, but reserve additions required to achieve reasonable financial targets are included as a cost of service. Revenue to cost ratios are used to aid in the evaluation of rate levels.

Functionalization and Classification of Capital Related Costs

In the preparation of the PCOSS the base year gross investment, that being actual plant in-service as of March 31, 2004 is first functionalized.

Functionalized gross plant investment for 2004 is set forth in Schedule C1. Plant investment is functionalized into the following areas:

- Generation
- Transmission (Domestic, Export)
- Ancillary Service
- Subtransmission
- Distribution Plant
- Distribution Services

Substations are functionalized recognizing Alternating Current (AC) and Direct Current (DC) facilities. All DC substations (with the exception of Dorsey Station which is functionalized as Transmission) are functionalized as Generation. AC substations are analyzed and functionalized as Transmission, Subtransmission and Distribution. This analysis includes a review of voltage levels, functions, current use and related books and records of the company. Transmission lines and related facilities are functionalized on a comparable basis including analysis of voltage level, current use and function. The Transmission function is separated into facilities used solely by domestic consumers and into facilities used to interconnect Manitoba Hydro's central transmission grid with neighbouring utilities.

There are six types of Ancillary Services, all of which must be offered by the Transmission provider. Of these six services, the purchaser of this service must purchase two (1 and 2 below) from the Transmission provider. The remaining four other Ancillary Services can be procured from the service provider, self supplied, or purchased from a third party.

A brief description of each of the six Ancillary Services is outlined below:

1) Scheduling, System Control and Dispatch Service – required to schedule the movement of power from, to or within a control area.

2) Reactive Supply and Voltage Control from Generation Source Service – required to maintain Transmission voltages within acceptable limits.

3) Regulation and Frequency Response Service – required to provide for the continuous balance of resources (Generation and Transmission) with load and maintaining scheduled interconnections at sixty cycles per second.

4) Energy Imbalance Service – provided when differences occur between scheduled and actual delivery of energy to a load over a single hour.

5) Operating Reserve – Spinning Service – needed to serve load immediately in the event of a system contingency.

6) Operating Reserve – Supplemental Reserve Service – same as spinning reserve, but able to serve load within a short period of time.

As noted previously Ancillary Services are items previously bundled within the Generation and Transmission function. Separation of these components is done through analysis of individual Generation and Transmission asset components. Classification of Ancillary Services is the same as Transmission costs: 100% Demand (PCOSS06, 2 CP)

All Distribution facilities, farm lines, meters and metering transformers are functionalized as Distribution. Subtransmission facilities are analyzed by voltage level and functionalized accordingly.

Communication equipment is functionalized to Generation, Transmission, Subtransmission and Distribution plant. The communication equipment associated with the above functions is based upon the investment in these facilities.

Buildings and other administrative facilities are treated as administration cost centres in the Financial Reporting System (SAP). These non-facility cost centres, as they are called in SAP, are allocated back to facility cost centres based on specific assessment cycles within the system. These assessments bring facility cost centres to full cost which can then be appropriately functionalized.

The forecast of capital additions consists of major item additions and domestic item additions. The domestic items consist of non-blanket items (facilities identified) and blanket items (facilities broadly identified). Capital items consist of gross additions, salvage material and capital contributions. The functionalization of the entries that result from the forecast for salvage material and capital contributions is treated consistently with the functionalization of gross additions with one exception - the assignment of capital contributions for the Diesel Rate Zone. These contributions are deducted from those functionalized to distribution lines, as contributions in the Diesel Zone are received primarily through work undertaken on district work orders.

Major item additions are functionalized as they have been in the past, but functionalization of domestic items is based on a three year rolling average of previous domestic item expenditures.

Included in the forecast of capital additions is salvage labour and expense which must be backed out of the forecast additions to arrive at gross investment. The financial forecast assumes salvage labour and expense at 51% of the salvage material value and the historic cost of facilities being retired at 153% of the salvage material value. The COSS replicates this process. Salvage labour and expense affects the forecast of accumulated depreciation and historic retirement values reduce both gross investment and accumulated depreciation. Schedule C2 details the functionalized gross investment forecast for the fiscal year ending March 31, 2006.

Schedule C3 shows the functionalization of accumulated depreciation forecast for fiscal year end to March 31, 2006. Accumulated depreciation for diesel generation, street lighting (asset class distribution lines and farm lines), HVDC (asset class substation and transmission lines) and export (asset class substation and transmission lines) are assigned. For the remaining functional costs, accumulated depreciation by asset class is prorated based upon functionalized gross investment (opening balance).

The customer contributions are shown in Schedules C4 and C5. Unamortized customer contributions can be found in Schedule C4; whereas Schedule C5 details the functionalization of customer contribution amortization. Schedule C6 outlines the functionalized net depreciation expense. Schedule C7 shows the net investment for fiscal year end 2006.

Depreciation expense, both direct facility depreciation and allocated administrative depreciation, is separated from operating costs. Starting in the 2003/04 fiscal year, depreciation rates changed on all corporate assets following a depreciation review – these revised rates are reflected in the PCOSS06. Functionalized depreciation expense is also adjusted to reflect amortization of customer contributions.

Schedule C8 outlines Rate Base Investment which is used to functionalize net interest expense as well as the forecasted contribution to reserves. The rate base is the average of the net plant in-service forecast for fiscal years 2004/05 and 2005/06 with adjustments for net deferred assets (calculation of the average investment can be found in Schedule C15). Schedule C9 follows with the functionalized net interest and reserve contribution.

Schedule C10 shows the functionalization of rate base for capital tax at March 31, 2006 (gross investment less accumulated depreciation) adjusted to include net deferred expenses which is used to functionalize forecast capital tax assessment. The functionalization of the forecasted capital tax assessment for 2005/06 is shown on Schedule C11.

Functionalization and Classification of Operating and Administrative Costs

The PCOSS is based on revenue and cost data contained in the Corporation's Integrated Financial Forecast (IFF), supplemented with the use of Manitoba Hydro's financial reporting system, SAP.

Schedule C12 outlines operating costs by function and sub-functions.

Reconciliation of operating and administrative cost to the IFF is detailed in Schedule C14. As with net depreciation expense, these values are determined from the Financial Reporting System (SAP) and include allocations for administrative costs. SAP, via settlement cost centres, provides the initial functionalization of all functional operating and maintenance costs as well as depreciation expense. Final functionalization is done off-line and includes functionalization of items such as communication system costs to all functions except customer service. Other off-line changes made include classification of distribution costs into customer and demand components. This approach used to classify distribution facilities are common to regulatory practices elsewhere. The demand/customer split by component is summarized below:

	Cost Classification	
Distribution Facilities	Demand	Customer
Substation	100%	
Line Transformers	100%	
Pole, Wire and Related Facilities	60%	40%
Meters and Metering Transformers		100%
Services		100%

Adjusted Revenue

Schedule C13 details class revenue and the allocation of adjustments to arrive at class/subclass revenue contained in the PCOSS. Unadjusted revenue by rate class/subclass is taken from the Proof of Revenue calculation. The revenue reduction associated with DSM Programs is also assigned to the customer rate classes in the general consumers revenue forecast process. The cost of service has further allocated both the load reduction and the revenue reduction to the rate zones based upon actual 2003/04 sales. Within Residential and General Service Small Non-Demand - Zone 3 subclasses revenues associated with customers served by diesel generation are also included.

DSM revenue reduction by class is shown below:

	Total
Residential	$ 1,830,813
General Service Small-Non-Demand	$ 1,812,189
General Service Small-Demand	$ 1,514,168
General Service Medium	$ 1,716,642
General Service Large:	
0 - 30 kV	$ 1,684,472
30 - 100 kV	$ 123,850
> 100 kV	$ 1,433,011
Total DSM	$10,115,145

The accrual adjustment represents any forecasted increase in either sales or rates over the previous accrual amounts. This adjustment is allocated to the rate classes/subclasses excluding seasonal, large power customers and street lighting. No seasonal accrual is forecast and street lights and large power customers are billed at month end and therefore no accrual is required.

The general consumer's adjustment which is comprised primarily of late payment charges and some customer adjustments which are not identified to a specific rate class, is also allocated based upon unadjusted revenue excluding large power customers. Although some of this revenue would apply to the large power customer it would be minimal and clearly disproportional to sales.

Reconciliation of revenue in the IFF to that in the Cost of Service is shown on Schedule C14.

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2006 Prospective Cost Of Service Study
Functionalization Of Gross Investment
March 31, 2004

Asset Class	Total Gross Investment	Generation	Transmission		Sub Trans	Distribution		Ancillary Services	Direct Allocation	
			Domestic	Export		Plant	Services		Lighting	Diesel
Generation	4,648,682,112	4,613,201,072	35,481,040							
Diesel	38,250,614	37,459								38,213,155
Substation	854,587,186		257,251,327	32,166,823	138,971,425	414,496,889		11,700,722		
- HVDC	1,054,911,951	526,446,311	528,465,640							
Transmission	544,634,043		257,392,568	113,137,507	174,103,968					
- HVDC	181,893,475	181,893,475								
Distribution	933,084,943					818,501,664			110,639,669	3,943,610
Farmlines	569,288,234					565,212,142			4,076,092	
Subtransmission	212,625,183				203,092,540	9,532,643				
Transformers										
- Substation	16,403,803		5,006,487	626,013	2,704,587	8,066,716				
- Distribution	4,730,959					4,730,959				
Meters	37,827,590					37,827,590				
Metering Transformers	5,609,488					5,609,488				
Buildings	148,865,859	60,237,850	16,445,178	7,227,165	10,628,662	38,397,638	12,441,488	-	2,865,401	622,477
Communication	309,057,200	77,043,228	24,956,174	8,635,997	62,801,272	62,521,233		73,099,296		
General Equipment	287,266,096	96,223,221	37,031,066	16,274,048	23,482,505	76,583,188	31,911,956		5,716,116	43,996
Subtotal	9,847,718,736	5,555,082,616	1,162,029,480	178,067,553	615,784,959	2,041,480,150	44,353,444	84,800,018	123,297,278	42,823,238
Motor Vehicles	112,405,249									
Total Fixed Assets	9,960,123,985	5,555,082,616	1,162,029,480	178,067,553	615,784,959	2,041,480,150	44,353,444	84,800,018	123,297,278	42,823,238

2006 Prospective Cost Of Service Study
Functionalization Of Gross Investment
Forecast Year Ending March 31, 2006

Asset Class	Total	Generation	Transmission Domestic	Transmission Export	Sub-Transmission	Distribution Plant	Distribution Services	Ancillary Services	Direct Allocations Lighting	Direct Allocations Diesel
Generation	4,757,175,042	4,721,694,002	35,481,040	-	-	-	-	-	-	-
Diesel	39,349,532	37,459	-	-	-	-	-	-	-	39,312,073
Substation	966,422,304	-	285,259,384	51,868,506	146,998,637	470,595,055	-	11,700,722	-	-
- HVDC	1,207,942,059	590,844,608	617,097,451	-	-	-	-	-	-	-
Transmission	571,948,101	-	284,861,088	113,276,260	173,810,752	-	-	-	-	-
- HVDC	182,389,523	181,893,475	496,048	-	-	-	-	-	-	-
Distribution	1,032,877,138	-	-	-	-	915,582,212	-	-	113,351,316	3,943,610
Farmlines	638,095,481	-	-	-	-	634,019,389	-	-	4,076,092	-
Subtransmission	249,134,161	-	-	-	238,249,047	10,885,114	-	-	-	-
Transformers										
- Substation	16,403,803	-	5,006,487	626,013	2,704,587	8,066,716	-	-	-	-
- Distribution	4,730,959	-	-	-	-	4,730,959	-	-	-	-
Meters	39,886,845	-	-	-	-	39,886,845	-	-	-	-
Metering Transformers	5,609,488	-	-	-	-	5,609,488	-	-	-	-
Buildings	197,214,704	79,884,127	21,808,691	9,584,269	14,095,148	50,920,838	16,499,218		3,799,937	622,477
Communication	362,080,340	103,739,966	46,483,645	9,477,219	64,086,677	65,193,537	-	73,099,296	-	-
General Equipment	361,296,547	121,024,406	46,575,689	20,468,625	29,535,035	96,322,226	40,137,147		7,189,424	43,996
Subtotal	10,632,556,027	5,799,118,043	1,343,069,523	205,300,893	669,479,883	2,301,812,377	56,636,364	84,800,018	128,416,770	43,922,156
Motor Vehicles	130,901,245									
Total Fixed Assets	10,763,457,272	5,799,118,043	1,343,069,523	205,300,893	669,479,883	2,301,812,377	56,636,364	84,800,018	128,416,770	43,922,156

2006 Prospective Cost Of Service Study
Functionalization Of Accumulated Depreciation
Forecast Year Ending March 31, 2006

Asset Class	Accum Depn by Asset Class	Generation	Transmission Domestic	Transmission Export	Sub Trans	Distribution Plant	Distribution Services	Ancillary Services	Direct Allocations Lighting	Direct Allocations Diesel
Generation	1,472,462,235	1,458,311,706	14,150,529	-	-	-	-	-	-	-
Diesel	18,905,289	4,418	-	-	-	-	-	-	-	18,900,871
Substation	362,525,488	-	100,432,772	16,824,710	76,303,678	159,940,597	-	9,023,731	-	-
- HVDC	507,540,170	282,035,542	225,504,627	-	-	-	-	-	-	-
Transmission	167,225,026	-	89,306,167	39,912,625	38,006,235	-	-	-	-	-
- HVDC	58,322,119	58,322,119	-	-	-	-	-	-	-	-
Distribution	408,953,360	-	-	-	-	344,900,644	-	-	62,314,023	1,738,693
Farmlines	238,156,309	-	-	-	-	236,905,126	-	-	1,251,183	-
Subtransmission	70,782,630	-	-	-	68,009,895	2,772,735	-	-	-	-
Transformers										
- Substation	10,298,292	-	3,002,006	453,967	2,037,009	4,805,310	-	-	-	-
- Distribution	1,285,086	-	-	-	-	1,285,086	-	-	-	-
Meters	14,137,754	-	-	-	-	14,137,754	-	-	-	-
Metering Transformers	2,626,804	-	-	-	-	2,626,804	-	-	-	-
Buildings	32,814,290	13,008,738	3,763,716	1,654,040	2,387,369	8,598,624	2,634,683		641,772	125,347
Communication	121,228,418	33,500,285	8,213,752	2,235,565	20,601,405	16,184,617	-	40,492,793	-	-
General Equipment	179,469,881	60,013,303	23,919,712	10,511,999	15,136,814	48,647,186	17,569,025		3,630,992	40,850
Subtotal	3,666,733,150	1,905,196,111	468,293,282	71,592,906	222,482,405	840,804,483	20,203,709	49,516,524	67,837,970	20,805,760
Motor Vehicles	55,213,356									
Total Accum Depreciation	3,721,946,507	1,905,196,111	468,293,282	71,592,906	222,482,405	840,804,483	20,203,709	49,516,524	67,837,970	20,805,760

SCHEDULE C4

2006 Prospective Cost Of Service Study
Functionalization Of Capital Contributions
Unamoritized Balance
Forecast Year Ending March 31, 2006

Asset Class	Unamortized Capital Contribution	Generation	Transmission		Sub-Transmission	Distribution		Ancillary Services	Direct Allocations	
			Domestic	Export		Plant	Services		Lighting	Diesel
Generation	12,103	12,103	-	-	-	-	-	-	-	-
Diesel	457	457	-	-	-	-	-	-	-	-
Substation	36,094,517	-	1,350,137	5,668,074	29,012,812	63,494	-	-	-	-
- HVDC	-	-	-	-	-	-	-	-	-	-
Transmission	70,784,976	-	5,288,251	-	65,496,725	-	-	-	-	-
- HVDC	-	-	-	-	-	-	-	-	-	-
Distribution	120,927,667	-	-	-	-	92,357,393	-	-	28,160,356	409,919
Farmlines	17,619,743	-	-	-	-	17,619,743	-	-	-	-
Subtransmission	14,585,618	-	-	-	14,378,880	206,738	-	-	-	-
Transformers										
- Substation	-	-	-	-	-	-	-	-	-	-
- Distribution	-	-	-	-	-	-	-	-	-	-
Meters	434,727	-	-	-	-	434,727	-	-	-	-
Metering Transformers	18,469	-	-	-	-	18,469	-	-	-	-
Buildings	-	-	-	-	-	-	-	-	-	-
Communication	240,882	-	-	91,461	125,555	23,866	-	-	-	-
General Equipment	27,725	27,725	-	-	-	-	-	-	-	-
Subtotal	260,746,887	40,286	6,638,388	5,759,535	109,013,972	110,724,431	-	-	28,160,356	409,919
Motor Vehicles	-									
Total Unamortized Contribs	260,746,887	40,286	6,638,388	5,759,535	109,013,972	110,724,431	-	-	28,160,356	409,919

2006 Prospective Cost Of Service Study
Functionalization Of Capital Contributions
Annual Amoritization
Forecast Year Ending March 31, 2006

Asset Class	Annual Amortization Contribution	Generation	Transmission		Sub - Transmission	Distribution		Ancillary Services	Direct Allocations	
			Domestic	Export		Plant	Services		Lighting	Diesel
Generation	781	781								
Diesel	473	-								473
Substation	1,402,910		46,217	318,042	1,034,594	4,057				
- HVDC	-									
Transmission	2,251,724		491,697		1,760,027					
- HVDC	-									
Distribution	6,375,981					4,659,950			1,681,799	34,232
Farmlines	665,847					665,847				
Subtransmission	693,696				693,696					
Transformers										
- Substation	-									
- Distribution	-									
Meters	27,376					27,376				
Metering Transformers	1,180					1,180				
BUILDINGS	-									
Communication	35,513				7,756	27,757				
General Equipment	1,519	1,519								
Subtotal	11,457,000	2,300	537,914	318,042	3,496,073	5,386,167	-	-	1,681,799	34,705
Motor Vehicles	-									
Total Annual Amort.	11,457,000	2,300	537,914	318,042	3,496,073	5,386,167	-	-	1,681,799	34,705

2006 Prospective Cost Of Service
Fiscal Year Ending March 31, 2006
Functionalization Of Depreciation Costs

SCC Description	Depreciation	Generation	Transmission	Subtransmission	Distribution Plant	Customer Service	Ancillary Services	Diesel	Street Lighting
Common Generation Costs	15,767,619	15,767,619					-		
Generating Station Costs	7,252,746	7,252,746					-		
Other Generation Related Costs	168,336	168,336							
Dedicated Gen. Facilities	7,421,082	7,421,082					-	-	-
Hydraulic Generating Stations	44,089,703	44,089,703					-		
Other Hydraulic Generation Related Costs	13,266,897	13,266,897					-		
Hydraulic Generation Costs	57,356,600	57,356,600					-		
Thermal Generating Station	17,546,913	17,546,913					-		
Non-Dedicated Gen. Facilities	74,903,513	74,903,513					-		
Generation Facilities Costs	82,324,595	82,324,595					-		
Purchased Power/Export Costs	-	-							
Generation Facilities & Costs	***98,092,214***	***98,092,214***					-		
Common Trans. Costs/Revenues	3,534,845	25,553	2,487,889	428,503			592,900		
Generation Switching Stations	2,030,773	-	2,030,773						
HVDC & Collector Facilities	49,502,573	25,202,575	24,299,998						
Networked AC Facilities	7,378,537	-	7,378,537						
Generation Access Transmission	58,911,883	25,202,575	33,709,309						
Regional Networked Trans.	7,303,487	-	7,215,019				88,468		
Future Transmission Line ROW	11,615	-	11,615						
Transmission Common	1,085,942	-	1,090,872	(16,064)	-	-	11,134		
Transmission Facilities/Costs	***70,847,772***	***25,228,127***	***44,514,705***	***412,439***			***692,502***		
Common Subtransmission Costs	2,148,681	-	-	2,148,681					
Subtrans. Facilities & Costs	***16,507,933***	-	-	***14,407,360***	***2,100,573***	-	-	-	-
Dist. Facilities & Costs	***83,305,292***	-	-	-	***80,670,920***	***236,611***		-	***2,397,761***
Customer Service Costs	***6,967,461***	-	-	-	-	***6,967,461***		-	-
Isolated Diesel Facilities	***6,733,714***	***1,144,980***	-	-	***1,671,021***	-	-	***3,917,713***	
Communication & Control System	***8,228,422***	***1,894,627***	***1,907,647***	***357,222***	***3,576,338***	-	***492,588***	-	-
	290,682,808	**126,359,948**	**46,422,352**	**15,177,021**	**88,018,851**	**7,204,072**	**1,185,090**	**3,917,713**	**2,397,761**

SCHEDULE C7

2006 Prospective Cost Of Service Study
Functionalization Of Net Investment
Forecast Year Ending March 31, 2006

Asset Class	Net Investment	Generation	Transmission		Sub-	Distribution		Ancillary	Direct Allocations	
			Domestic	Export	Transmission	Plant	Services	Services	Lighting	Diesel
Generation	3,284,700,704	3,263,370,192	21,330,511	-	-	-	-	-	-	-
Diesel	20,443,787	32,584	-	-	-	-	-	-	-	20,411,202
Substation	567,802,299	-	183,476,475	29,375,722	41,682,147	310,590,963	-	2,676,991	-	-
- HVDC	700,401,889	308,809,066	391,592,824	-	-	-	-	-	-	-
Transmission	333,938,099	-	190,266,670	73,363,636	70,307,793	-	-	-	-	-
- HVDC	124,067,403	123,571,356	496,048	-						
Distribution	502,996,111	-	-	-	-	478,324,175	-	-	22,876,938	1,794,998
Farmlines	382,319,429	-	-	-	-	379,494,520	-	-	2,824,909	-
Subtransmission	163,765,912	-	-	-	155,860,271	7,905,641	-	-	-	-
Transformers										
- Substation	6,105,511	-	2,004,481	172,046	667,578	3,261,406	-	-	-	-
- Distribution	3,445,873	-	-	-	-	3,445,873	-	-	-	-
Meters	25,314,363	-	-	-	-	25,314,363	-	-	-	-
Metering Transformers	2,964,214	-	-	-	-	2,964,214	-	-	-	-
Buildings	164,400,415	66,875,389	18,044,976	7,930,229	11,707,778	42,322,214	13,864,534	-	3,158,165	497,130
Communication	240,611,040	70,239,681	38,269,893	7,150,193	43,359,717	48,985,053	-	32,606,503	-	-
General Equipment	181,798,941	60,983,378	22,655,976	9,956,625	14,398,221	47,675,041	22,568,121	-	3,558,432	3,146
Subtotal	6,705,075,990	3,893,881,646	868,137,853	127,948,451	337,983,506	1,350,283,463	36,432,656	35,283,494	32,418,444	22,706,477
Motor Vehicles	75,687,889									
Total Net Investment	6,780,763,879	3,893,881,646	868,137,853	127,948,451	337,983,506	1,350,283,463	36,432,656	35,283,494	32,418,444	22,706,477

2006 Prospective Cost Of Service Study
Functionalization of Rate Base Investment
Forecast Year Ending March 31, 2006

Asset Class	Rate Base Investment	Generation	Transmission Domestic	Transmission Export	Sub-Transmission	Distribution Plant	Distribution Services	Ancillary Services	Direct Allocations Lighting	Direct Allocations Diesel
Generation	3,433,872,120	3,412,247,793	21,624,327	-	-	-	-	-	-	-
Diesel	43,785,719	21,839,777	-	-	-	-	-	-	-	21,945,943
Substation	551,650,679	-	177,036,260	29,641,379	41,232,580	300,868,301	-	2,872,160	-	-
- HVDC	689,361,609	301,707,823	387,653,785	-	-	-	-	-	-	-
Transmission	330,304,406	-	182,636,493	74,463,609	73,204,304	-	-	-	-	-
- HVDC	125,529,800	125,159,510	370,290	-	-	-	-	-	-	-
Distribution	498,655,053	-	-	-	-	473,751,861	-	-	23,033,225	1,869,967
Farmlines	379,165,650	-	-	-	-	376,282,248	-	-	2,883,401	-
Subtransmission	158,506,647	-	-	-	150,746,347	7,760,299	-	-	-	-
Transformers										
- Substation	11,753,297	-	3,728,201	387,581	1,598,760	6,038,754	-	-	-	-
- Distribution	4,848,588	-	-	-	-	4,848,588	-	-	-	-
Meters	25,209,280	-	-	-	-	25,209,280	-	-	-	-
Metering Transformers	3,039,935	-	-	-	-	3,039,935	-	-	-	-
Buildings	157,636,153	64,213,784	17,271,169	7,590,164	11,206,884	40,486,229	13,339,713	-	3,025,938	502,272
Communication	237,128,123	69,846,982	31,413,879	7,343,188	44,563,049	49,720,915	-	34,240,109	-	-
General Equipment	207,159,935	75,421,560	24,410,659	10,727,756	15,506,380	50,682,618	26,419,921	-	3,986,993	4,047
Subtotal	6,857,606,991	4,070,437,229	846,145,064	130,153,677	338,058,305	1,338,689,028	39,759,634	37,112,268	32,929,557	24,322,228
Motor Vehicles	74,567,191									
Total Rate Base Investment	6,932,174,182	4,070,437,229	846,145,064	130,153,677	338,058,305	1,338,689,028	39,759,634	37,112,268	32,929,557	24,322,228

2006 Prospective Cost Of Service Study
Functionalization Of Interest Expense & Reserve Contribution
Forecast Year Ending March 31, 2006

Asset Class	Interest & Reserve Expense	Generation	Transmission Domestic	Transmission Export	Sub-Transmission	Distribution Plant	Distribution Services	Ancillary Services	DIRECT ALLOCATIONS Lighting	DIRECT ALLOCATIONS Diesel
Generation	359,751,863	357,486,376	2,265,487	-	-	-	-	-	-	-
Diesel	4,587,240	2,288,059	-	-	-	-	-	-	-	2,299,181
Substation	57,794,045	-	18,547,320	3,105,398	4,319,758	31,520,665	-	300,904	-	-
- HVDC	72,221,421	31,608,618	40,612,803	-	-	-	-	-	-	-
Transmission	34,604,558	-	19,134,032	7,801,229	7,669,297	-	-	-	-	-
- HVDC	13,151,212	13,112,418	38,794	-	-	-	-	-	-	-
Distribution	52,241,923	-	-	-	-	49,632,924	-	-	2,413,091	195,908
Farmlines	39,723,538	-	-	-	-	39,421,456	-	-	302,081	-
Subtransmission	16,606,053	-	-	-	15,793,040	813,013	-	-	-	-
Transformers										
- Substation	1,231,342	-	390,587	40,605	167,495	632,654	-	-	-	-
- Distribution	507,965	-	-	-	-	507,965	-	-	-	-
Meters	2,641,067	-	-	-	-	2,641,067	-	-	-	-
Metering Transformers	318,481	-	-	-	-	318,481	-	-	-	-
Buildings	4,757,814	1,938,116	521,283	229,088	338,249	1,221,965	402,623	-	91,330	15,160
Communication	24,842,883	7,317,565	3,291,096	769,314	4,668,677	5,209,044	-	3,587,187	-	-
General Equipment	6,252,553	2,276,392	736,769	323,788	468,017	1,529,715	797,413	-	120,336	122
Subtotal	691,233,955	416,027,544	85,538,169	12,269,422	33,424,534	133,448,950	1,200,035	3,888,091	2,926,838	2,510,371
Motor Vehicles	-									
Total Interest Exp Allocated	691,233,955	416,027,544	85,538,169	12,269,422	33,424,534	133,448,950	1,200,035	3,888,091	2,926,838	2,510,371

2006 Prospective Cost Of Service Study
Functionalization Of Rate Base For Capital Tax
Forecast Year Ending March 31, 2006

Asset Class	Rate Based for Capital Tax	Generation	Transmission Domestic	Transmission Export	Sub-Transmission	Distribution Plant	Distribution Services	Ancillary Services	DIRECT ALLOCATIONS Lighting	DIRECT ALLOCATIONS Diesel
Generation	3,444,221,236	3,422,890,725	21,330,511	-	-	-	-	-	-	-
Diesel	43,546,787	23,135,584	-	-	-	-	-	-	-	20,411,202
Substation	567,802,299	-	183,476,475	29,375,722	41,682,147	310,590,963	-	2,676,991	-	-
- HVDC	700,401,889	308,809,066	391,592,824	-	-	-	-	-	-	-
Transmission	337,985,471	-	191,615,967	73,599,203	72,770,301	-	-	-	-	-
- HVDC	124,179,984	123,683,937	496,048	-	-	-	-	-	-	-
Distribution	502,996,111	-	-	-	-	478,324,175	-	-	22,876,938	1,794,998
Farmlines	382,319,429	-	-	-	-	379,494,520	-	-	2,824,909	-
Subtransmission	163,765,912	-	-	-	155,860,271	7,905,641	-	-	-	-
Transformers										
- Substation	11,228,895	-	3,568,152	367,569	1,512,299	5,780,875	-	-	-	-
- Distribution	4,923,489	-	-	-	-	4,923,489	-	-	-	-
Meters	25,314,363	-	-	-	-	25,314,363	-	-	-	-
Metering Transformers	2,964,214	-	-	-	-	2,964,214	-	-	-	-
Buildings	164,654,415	67,067,704	18,050,301	7,932,569	11,710,443	42,305,414	13,929,159	-	3,161,693	497,130
Communication	240,611,040	70,239,681	38,269,893	7,150,193	43,359,717	48,985,053	-	32,606,503	-	-
General Equipment	211,374,941	76,833,172	24,954,359	10,966,696	15,851,157	51,807,032	26,888,461	-	4,070,919	3,146
Subtotal	6,928,290,474	4,092,659,869	873,354,529	129,391,951	342,746,335	1,358,395,740	40,817,620	35,283,494	32,934,459	22,706,477
Motor Vehicles	-									
Rate Base For Capital Tax	6,928,290,474	4,092,659,869	873,354,529	129,391,951	342,746,335	1,358,395,740	40,817,620	35,283,494	32,934,459	22,706,477

2006 Prospective Cost Of Service Study
Functionalization Of Capital Tax
Forecast Year Ending March 31, 2006

			Transmission		Sub-	Distribution		Ancillary	DIRECT ALLOCATIONS	
Asset Class	Capital Tax	Generation	Domestic	Export	Transmission	Plant	Services	Services	Lighting	Diesel
Generation	17,776,666	17,666,573	110,093	-	-	-	-	-	-	-
Diesel	224,758	119,410	-	-	-	-	-	-	-	105,348
Substation	2,930,599	-	946,978	151,617	215,134	1,603,054	-	13,817	-	-
- HVDC	3,614,986	1,593,857	2,021,129	-	-	-	-	-	-	-
Transmission	1,744,445	-	988,988	379,868	375,590	-	-	-	-	-
- HVDC	640,930	638,370	2,560	-	-	-	-	-	-	-
Distribution	2,596,115	-	-	-	-	2,468,776	-	-	118,075	9,265
Farmlines	1,973,266	-	-	-	-	1,958,686	-	-	14,580	-
Subtransmission	845,245	-	-	-	804,442	40,803	-	-	-	-
Transformers										
- Substation	57,956	-	18,416	1,897	7,805	29,837	-	-	-	-
- Distribution	25,412	-	-	-	-	25,412	-	-	-	-
Meters	130,655	-	-	-	-	130,655	-	-	-	-
Metering Transformers	15,299	-	-	-	-	15,299	-	-	-	-
Buildings	849,831	346,157	93,163	40,942	60,441	218,351	71,893	-	16,318	2,566
Communication	1,241,866	362,528	197,522	36,904	223,793	252,827	-	168,292	-	-
General Equipment	1,090,970	396,559	128,797	56,602	81,813	267,392	138,779	-	21,011	16
Subtotal	35,759,000	21,123,454	4,507,647	667,831	1,769,017	7,011,091	210,672	182,109	169,985	117,195
Motor Vehicles	-									
Capital Tax Allocation	35,759,000	21,123,454	4,507,647	667,831	1,769,017	7,011,091	210,672	182,109	169,985	117,195

2006 Prospective Cost Of Service
Fiscal Year Ending March 31, 2006
Functionalization Of Operating Costs

SCC Description	Operating	Generation	Transmission	Subtransmission	Distribution Plant	Customer Service	Ancillary Services	Diesel	Street Lighting
Common Generation Costs	24,734,506	24,734,506					-		
Generating Station Costs	33,060,165	33,060,165					-		
Other Generation Related Costs	361,215	361,215	-	-	-	-	-	-	-
Dedicated Gen. Facilities	33,421,380	33,421,380					-	-	-
Hydraulic Generating Stations	103,324,786	103,324,786					-		
Other Hydraulic Generation Related Costs	17,262,975	17,262,975							
Hydraulic Generation Costs	120,587,761	120,587,761					-		
Thermal Generating Station	31,312,832	31,312,832					-		
Non-Dedicated Gen. Facilities	151,900,593	151,900,593					-		
Generation Facilities Costs	185,321,973	185,321,973					-	-	-
Purchased Power/Export Costs	157,379	157,379							
Generation Facilities & Costs	***210,213,858***	***210,213,858***					-	-	-
Common Trans. Costs/Revenues	17,465,665	834,741	14,176,213	2,186,649			268,063		
Generation Switching Stations	6,951,823	-	6,951,823						
HVDC & Collector Facilities	26,950,528	16,213,988	10,736,539						
Networked AC Facilities	2,684,849	-	2,684,849						
Generation Access Transmission	36,587,200	16,213,988	20,373,212						
Regional Networked Trans.	944,529	-	944,529						
Future Transmission Line ROW	-	-	-						
Transmission Common	10,824,466	-	10,329,890	410,905			83,671		
Transmission Facilities/Costs	***65,821,860***	***17,048,729***	***45,823,844***	***2,597,553***			***351,734***		
Common Subtransmission Costs	7,384,030	-	-	7,384,030					
Subtrans. Facilities & Costs	***24,984,537***	-	-	***19,172,083***	***5,812,454***	-	-	-	-
Dist. Facilities & Costs	***56,784,578***	-	-	-	***49,750,549***	-	-	-	***7,034,029***
Customer Service Costs	***67,115,334***					***67,115,334***	-	-	-
Isolated Diesel Facilities	***4,311,993***	***17,478***	-	-	-	-	-	***4,294,516***	
Communication & Control System	***3,720,249***	***2,407,691***	***404,421***	***189,306***	***607,090***		***111,741***	-	-
	439,775,209	**231,943,513**	**48,032,877**	**22,615,581**	**58,275,884**	**67,115,334**	**463,475**	**4,294,516**	**7,034,029**

2006 Prospective Cost Of Service Study
Adjusted Revenue Including DSM Reduction @ Approved Rates
For Year Ended March 31, 2006

Revenue Class	Unadjusted Revenue	Diesel	To Misc Revenue	Other Accrual	General Consumer Adjustment	Total Adjusted Revenue	Export Adj to Offset Uniform Rates	Total Revenue After Uniform Rates Adjustment
Residential								
Zone 1	143,712,755			163,053	1,028,935	144,904,743		144,904,743
Zone 2	127,328,698			144,464	911,631	128,384,792	4,167,370	132,552,163
Zone 3	119,036,651	(929,411)		134,001	845,608	119,086,850	9,576,964	128,663,814
Seasonal	5,034,828				36,048	5,070,876	993,385	6,064,260
Water Heating	1,407,412			1,597	10,077	1,419,085		1,419,085
	396,520,344	(929,411)		443,115	2,832,298	398,866,346	14,737,719	413,604,065
General Service - Small								
Non Demand								
Zone 1	45,213,378			51,298	323,713	45,588,389		45,588,389
Zone 2	36,340,003			41,230	260,182	36,641,416	502,354	37,143,769
Zone 3	22,363,654	-		25,373	160,116	22,549,143	926,319	23,475,462
Seasonal	452,808				3,242	456,050	32,603	488,653
Water Heating	550,657			625	3,943	555,224		555,224
	104,920,500	-		118,526	751,196	105,790,222	1,461,276	107,251,497
Demand								
Zone 1	37,230,847			42,241	266,560	37,539,649		37,539,649
Zone 2	33,350,676			37,839	238,780	33,627,294	122,740	33,750,034
Zone 3	19,273,269			21,867	137,990	19,433,126	138,753	19,571,879
	89,854,792	-	-	101,947	643,330	90,600,069	261,492	90,861,561
					Total GSS -	*196,390,291*		
SEP								
GSM	2,054,617			2331	14,710	2,071,658		2,071,658
GSL	423,953					423,953		423,953
	2,478,570			2,331	14,710	2,495,611	0	2,495,611
General Service - Medium								
Zone 1	90,541,114			102,726	648,244	91,292,084		91,292,084
Zone 2	28,821,905			32,701	206,355	29,060,961	13,659	29,074,619
Zone 3	19,212,061			21,797	137,552	19,371,410	16,272	19,387,682
	138,575,080	-		157,224	992,151	139,724,455	29,931	139,754,385
General Service - Large								
0 - 30 kV	58,619,355			66,508	419,695	59,105,558		59,105,558
30 - 100 kV	26,974,205					26,974,205		26,974,205
Over - 100 kV	158,828,735					158,828,735		158,828,735
	244,422,295	-		66,508	419,695	244,908,498	0	244,908,498
Area & Roadway Lighting								
Street Lighting	16,466,914					16,466,914	217,884	16,684,798
Sentinel Lighting	2,607,476	(16,744)		2,939	18,549	2,612,220		2,612,220
	19,074,390	(16,744)	-	2,939	18,549	19,079,134	217,884	19,297,018
Diesel								
Residential		929,411				929,411		929,411
General Service		-				-		-
Street Lighting		16,744				16,744		16,744
Full Cost	8,363,257					8,363,257		8,363,257
	8,363,257	946,155		-	-	9,309,412	0	9,309,412
Gen. Consumers Before Adj	1,004,209,228	-	-	892,590	5,671,929	1,010,773,747	16,708,302	1,027,482,049
Accrual - Other	892,590			(892,590)				
Miscellaneous - Non-Energy	620,250		(620,250)		-	-		-
Late Pmt Charges & Cust Adjustments	5,671,929				(5,671,929)	-		-
Total General Consumers	1,011,393,997	-	(620,250)	-	-	1,010,773,747	16,708,302	1,027,482,049
Extra-Provincial	546,967,932		390,503			547,358,435	(16,708,302)	530,650,134
Other (Non Energy Net of Subsidiaries)	6,158,000		(6,158,000)			-		
Total Revenue	1,564,519,929	-	(6,387,747)	-	-	1,558,132,182	0	1,558,132,182

MANITOBA HYDRO
PROSPECTIVE COST OF SERVICE STUDY
FOR FISCAL YEAR ENDING
MARCH 31, 2006

RECONCILIATION TO FINANCIAL FORECAST
(In Millions of Dollars)

Reconciliation of Revenue

As per Financial Forecast:		
General Consumers		1,011.4
Extra Provincial		547.0
Other (non-energy)		18.4
Total Revenue Per Financial Forecast		1,576.8
Cost of Service Adjustments		
a. transfer of Other Revenue (non-energy) to Miscellaneous Revenue		(6.2)
b. transfer from General Consumers Revenue (non-energy) to Misc Revenue		(0.2)
c. transfer Operating Costs associated with Export Sales		(107.1)
d. remove Subsidiaries' Revenue from COSS		(12.3)
Total Revenue Per Cost of Service Study	$	1,451.1

Reconciliation of Operating Expenses

As per the Financial Forecast		
- Operating and Administration		317.9
- Tax Expense		53.3
- Fuel and Power		89.7
- Water Rental		108.4
Total Operating Expenses Per Financial Forecast		569.2
Less Share of Fuel, Power and Water Rentals Transferred to Exports		(107.1)
Remove Subsidiaries' O&A and Capital Tax (Not Included in PCOSS)		(11.1)
Remove Capital Tax (Included w/Interest in PCOSS)		(35.8)
Add Motor Vehicle Depreciation (Included in Operations in PCOSS)		7.4
Add Interest Expense on Admin Facilities included in SAP		17.1
Operating Costs Allocated Per Cost of Service Study	$	439.8

MANITOBA HYDRO
PROSPECTIVE COST OF SERVICE STUDY
FOR FISCAL YEAR ENDING
MARCH 31, 2006

Rate Base Calculation and Deferred Items

Allocation of net interest expense and reserve contribution is based upon average net plant in-service forecast for fiscal years 2005 and 2006 adjusted for net deferred items and net major capital additions forecast to come into service during fiscal year 2005/06 which are included on an in-service date basis. This calculation is summarized below:

	2005	2006
Net Investment (Excluding Motor Vehicles)	$ 6,632.1	$ 6,705.1
Add: Total Net Deferred Items	170.6	223.2
Less: Major Capital Item Additions 2006		(185.7)
	$ 6,802.7	$ 6,742.6
Average Investment (2005 + 2006) ÷ 2		$ 6,772.6
Add: Major Capital Item Additions 2006 on an in-service date basis		85.0
		$ 6,857.6

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SECTION D - LOAD INFORMATION

Load data used in the preparation of the PCOSS for 2005/06 has been estimated using forecast energy and peak demand from the System Load Forecast and available class load information. Load research data are used to estimate the average top 50 hourly peaks during both the summer and winter. Also included is a forecast of energy and capacity savings to be achieved through DSM Programs. For 2005/06 the DSM savings are forecast to be 228.2 GW.h and 66.8 MW at Generation, or 201.8 GW.h and 59.5 MW measured at the meter. For the purposes of the COSS, MW savings due to the Curtailable Rate Program are not included in DSM - instead the affected class of service, General Service Large >100 kV, curtailable, is credited with a cost reduction equal to the value of curtailable load.

Schedule D1 outlines Manitoba Hydro's forecast energy and calculation of forecast demand for 2005/06 fiscal year. Forecasted consumption by rate class is shown seasonally and classified by energy and demand. Annual energy is used to allocate Generation energy costs, while seasonal energies are displayed to demonstrate the calculation of the demand allocator. The average of winter and summer demands (2 CP) is used to allocate both Generation and Transmission demand related costs. For the Recommended, NERA and Generation Vintaging scenarios Generation costs are allocated based on energies weighted on marginal cost between the four peak periods: winter on and off peak, summer on and off peak. The development of these allocators is outlined in Schedule D2. Transmission costs are allocated on both energy and demand based on the split between those lines serving the export market (allocated on energy) and all other transmission lines allocated on demand (2 CP).

Schedule D3 shows the computation of expected Transmission and Distribution losses on Manitoba Hydro's Integrated System. Common bus energy and coincident peak losses of 2,172,852 MW.h and 343.5 MW respectively have been taken from the 2004 System Load Forecast and adjusted to reflect forecast DSM savings. These losses apply to forecast Manitoba Hydro firm energy and peak. Distribution energy losses are simply the difference between sales at meters and energy at common bus. Distribution losses at time of system peak are calculated in Schedule D3 based on the approach used by Mr. M. W. Gustafson in his article, "Approximating the System Loss Equation". The adjustment factor of -13% for temperature reflects the reduction in the resistivity of conductors between 0°C and -30°C, 0°C being the average Winnipeg temperature and the ambient temperature on the peak load day usually being around -30°C.

Schedule D3 also shows the difference between total coincident peak calculated by applying class load factors in the PCOSS06 from the system peak forecasted in the 2004 System Load Forecast for the 2006 fiscal year. This difference of 11 MW is applied as an adjustment to all classes' estimated coincident peak based upon Load Research results.

Schedule D5 summarizes the load data and computations for all customer classes. The sources of data and derivation of estimates are elaborated upon below.

Assignment of Losses

In order to properly reflect cost causation in allocating energy and capacity costs, energy sales and demand must be measured at Generation as opposed to the meter. This is accomplished by assigning Distribution and Transmission losses to each of the rate classes based upon the voltage level in which they receive service.

In this process, Distribution energy losses are assigned first. Customers receiving service at greater than 30 kV have been assigned losses based upon a uniform percentage of metered sales. Customers receiving service at supply voltage less than 30 kV share in the residual losses. A differential percentage has been assigned depending upon the rate zone and if service is taken at primary or secondary voltage level. General Service Small - Three Phase, General Service Medium and General Service Large are assumed to receive service at a primary service level, while Residential, Area and Roadway Lighting and General Service Small - Single Phase are assumed to receive service at the secondary level. Capacity losses on the Distribution system are assigned in a similar manner.

The table below summarizes the assignment of Distribution energy losses and Schedule D6 shows the results of this assignment based upon sales at the meter for both energy and capacity.

		Service Supply Voltage	
Losses Assigned Based on Sales at Meter		30 – 100 kV	100 kV
Customer-owned transformation		1.95%	N/A
Utility owned transformation		3.26%	1.30%
Residual Losses Assigned on a Differential % Basis	Zone 1	Zone 2	Zone 3
Secondary	0.0%	+1.5%	+3.5%
Primary – Utility owned transformation	-1.0%	+0.5%	+2.5%
Primary – Customer owned transformation	-2.0%	+0.5%	+1.5%

Transmission losses are shared equally by all rate classes based upon deliveries from common bus, i.e. sales at the meter plus assigned distribution losses.

Load Research Project

Manitoba Hydro has made a commitment to an active program of electric load research. One of the reasons for undertaking this program is to support Cost of Service Studies with particular emphasis on cost causation to aid in rate design. In addition, the program is to support an aggressive DSM Program through improved end-use load and energy data and to support the Load Forecast function as it adopts forecasting methods which rely on end-use based procedures to forecast sales and loads by customer class. The scope of Load Research has also been expanded in order to integrate the load shapes of those customers in the former Winnipeg Hydro service area.

For Cost of Service/Rate Design, there are twenty-four groups overall for which the project is to provide demand and energy estimates with known precision, i.e. 90% confidence with an accuracy of ±10%. To obtain this objective, a sample size of 1,168 customers was selected from Manitoba Hydro's various customer classes. All General Service Large customers are sampled. Class data for 2003/04, is used in the PCOSS to estimate class demands for use in allocating demand related costs.

Development of Class Loads

1) Residential Class

The 2005/06 forecast kW.h sales to the Residential class and the forecast number of customers are taken from the 2004 System Load Forecast. Load Forecasting further processes these estimates to allocate a share of farm customers and consumption into Residential class/subclasses and to provide separate information for Flat Rate Water Heating and Seasonal customers.

In Schedule D5, energy sales have been reduced by the forecast savings of 32 GW.h applicable to the residential DSM Programs before energy at the customer meter is grossed up by Distribution losses and Transmission losses to yield estimated energy generated to serve the various subclasses of the Residential class.

The coincident peak demand at the customer meters has been estimated by applying coincident peak load factors to the kW.h sales. Coincident peak load factors have been developed from load research data based on the average top 50 hourly peaks during the year.

The Flat Rate Water Heating class coincident demand is estimated on the basis of 4.6 kW customer peak and 80% coincident factor of individual customers with the system peak.

The Seasonal class coincident peak load factor is taken from previous Peak Load Responsibility studies as new information from load research is limited. The coincident peak load factor was previously determined to be 157.8% in both Zones 2 and 3.

The estimated coincident peaks at the meter have been adjusted by 9 MW to incorporate Residential's share of the total calibration factor of 11 MW derived in Schedule D3. The applicable share of each class's contribution to the calibration factor is provided by the error margin in the LR sample.

These loads have been reduced by the forecast capacity savings of 10.4 MW to be achieved through the residential DSM Programs.

Estimated Distribution losses and Transmission losses are applied to provide the estimate of class coincident peak at Generation. Load research results available for 2004 are then applied to yield class non-coincident peaks at meter and at Generation.

2) General Service Small Class

The General Service Small class consists of two major subgroups; customers who are demand metered (General Service Small Demand, load over 50 kV.A billing demand, but not exceeding 200 kV.A) and those with no demand meters (General Service Small Non-Demand, load less than 50 kV.A billing demand). In addition, loads shown in Schedule D5 have been separated into single phase and three phase based upon 2004 data. Also shown are loads for small subgroups: Water Heating, Seasonals and Flat Rate Services which include end uses such as telephone booths and traffic control signals.

As with the Residential class, General Service Small kW.h sales and customer counts are taken from the 2004 System Load Forecast and further processed to yield the rate subgroup forecasts shown in Schedule D5. Also similarly, the sales have been reduced by the forecast DSM energy and capacity savings of 71.8 GW.h and 14.2 MW before being grossed up to include Distribution and Transmission losses.

The General Service Small Demand subgroup's coincident peak has been estimated by applying coincidence factors to the sum of class demands in the average of the top 50 hourly system peaks for the year. The average top 50 hourly system peaks in both summer and winter were used.

For the General Service Small Non-Demand subgroup, the coincident peak load factors were determined using load research information for 2004. The same load factors have been applied to both single and three phase customers.

Coincident peak load factors for the small subgroups have been estimated using approaches similar to those employed for past studies as new information from load research is limited. The Seasonal coincident peak load factor of 162.5% is the same as used in previous studies.

The estimated coincident peaks at the meter have been adjusted by 1.3 MW to reflect General Service Small share of the adjustment required to reconcile coincident peak at meter.

The coincident peak load factors are used to derive class coincident peak's at the meter. Distribution and Transmission peak MW losses are added to give coincident peak at Generation. Finally, class coincidence factors, based on the load research information available for 2004 have been applied to derive class non-coincident peaks.

3) <u>General Service Medium</u>

General Service Medium includes 1,777 customers with demands between 200 and 2,000 kV.A, who are served through utility-owned transformation. All these customers are demand metered. A few, mainly those served above distribution voltages, have historically been metered with recording pulse meters which provide a permanent record of 15-minute interval demands. Currently 186 customers are pulse metered.

Customer and kW.h sales data are derived from the load forecast and apportioned among service voltages and zones on the basis of recent past experience. DSM savings of 42.2 GW.h and 8.1 MW have been assigned to this class.

Application of average top 50 hourly system peaks yield the load data outlined in Schedule D5.

General Service Medium estimated coincident peaks at the meter have been adjusted by 0.6 MW to reflect their share of the adjustment required to reconcile coincident peak at the meter.

Most General Service Medium customers are served at distribution voltages and therefore are assigned responsibility for the same percentage losses as General Service Small three phase customers. As with the other classes General Service Medium customers are assigned Distribution energy losses and Transmission energy losses as measured at common bus.

4) General Service Large

For customers in this class, the coincident peak load factors and coincident factors have been based upon data from 2004. Load information for this class has been historically available. Seventy-seven percent of the customers in the 0 - 30 kV subclass, 96% of the customers in the 30 - 100 kV subclass and 100% of the customers in the over 100 kV subclass are pulse metered.

The estimated coincident peaks at the meter have been adjusted by 0.03 MW to reflect General Service Large’s share of the adjustment required to reconcile coincident peak at meter.

DSM savings assigned to this class total 55.9 GW.h and 26.8 MW. Note that these figures do not include savings from curtailable customers within this class of service. Instead these customers are credited with a cost reduction equal to the value of curtailable load.

Customers over 100 kV in this class are not assigned distribution losses. For customers served at 30 - 100 kV distribution energy losses are equal to 1.5% of sales and below 30 kV energy losses are assigned losses at 4.5% of sales.

5) Interruptible

Surplus Energy Program (SEP) energy sales are taken from the 2004 System Load Forecast. Customers and forecast energy have been separated into service voltage levels and into utility or customer owned transformation. Load and coincident factors used to estimate class loads have been based upon data from load research information available for fiscal year 2004.

Distribution and Transmission losses are assigned consistent with the other rate classifications, service voltage levels and transformation ownership.

6) Area and Roadway Lighting

Sentinel Lights

Sentinel light energy consumption and customer count are taken from the 2004 System Load Forecast. The customer count has been derated by 90% for purposes of allocating Customer-related costs. The class non-coincident peak results from the total wattage of luminaires served. Load research indicates that these luminaires are lighted, on average 38.2% of the peak 50 hours, with a class coincident peak of 119.7%. These factors are applied to forecast energy to yield forecast peaks for the class.

No DSM savings have been assigned to Sentinel Lighting class as past DSM is now fully reflected in load forecast estimates.

Sentinel lights are served from the distribution system and are therefore assigned the same energy and peak loss percentage as the Residential class.

Street Lights

Street light energy consumption forecast for 2005/06 is based on the inventory wattage multiplied by 4,252 hours of use per year, a figure based on the most recent load research results. The customer count is based on March 2004 actual billing data plus forecast additions to the system of 1,507 lights to year end 2006. The customer count represents the number of forecast street lights derated by 90%. Street lights also show a class coincident peak load factor of 119.7% and coincidence factor of 38.2%. No DSM savings have been assigned to these customers as past DSM is already fully reflected in inventory wattage data.

2005/2006 Prospective Cost Of Service Study
Prospective Peak Load Responsibility Report
Seasonal Coincident Peaks (2 CP)

			Winter				SUMMER			D14
	Forcast Total Energy @ Generation (E10)	Avg % of Yearly Energy	Estimated Seasonal Energy	Seasonal CP LF	Estimated Seasonal Demand	Avg % of Yearly Energy	Estimated Seasonal Energy	Seasonal CP LF	Estimated Seasonal Demand	2CP Estimated Demand
Residential - Zone 1										
Residential	2,542,066,057	57%	1,446,422,638	66.4%	501,461	43%	1,095,643,419	56.8%	436,886	469,174
Total Zone 1	2,542,066,057		1,446,422,638		501,461		1,095,643,419		436,886	469,174
Zone 2										
Residential	2,431,636,249	65%	1,585,759,144	64.6%	565,437	35%	845,877,105	80.0%	239,495	402,466
Total Zone 2	2,431,636,249		1,585,759,144		565,437		845,877,105		239,495	402,466
Zone 3										
Residential *	2,362,859,664	68%	1,600,872,836	64.1%	574,922	32%	761,986,828	88.5%	194,929	384,926
Seasonal	71,222,805	30%	21,059,438	162.5%	2,983	70%	50,163,367	162.5%	6,990	4,987
Water Heating	20,347,517	50%	10,092,368	126.0%	1,844	50%	8,809,416	126.0%	1,583	1,714
Total Zone 3	2,454,429,986		1,632,024,642		579,749		820,959,611		203,503	391,626
Total										
Residential	7,336,561,970	63%	4,633,054,619		1,641,820	37%	2,703,507,351		871,311	1,256,565
Seasonal	71,222,805	30%	21,059,438		2,983	70%	50,163,367		6,990	4,987
Water Heating	20,347,517	50%	10,092,368		1,844	50%	8,809,416		1,583	1,714
Total Residential	7,428,132,292		4,664,206,425		1,646,647		2,762,480,135		879,884	1,263,266
* Zn 3 residential less diesel										
GS Small										
Zone 1										
Non-Demand	776,802,607	57%	445,107,894	74.0%	138,391	43%	331,694,713	60.2%	124,729	131,560
Demand	791,702,310	57%	450,478,614	72.3%	143,472	43%	341,223,696	68.0%	113,699	128,585
Total Zone 1	1,568,504,917		895,586,508		281,863		672,918,409		238,428	260,146
Zone 2										
Non-Demand	641,177,995	57%	367,394,991	69.9%	120,977	43%	273,783,004	59.3%	104,514	112,746
Demand	709,171,639	57%	403,518,663	72.9%	127,458	43%	305,652,976	79.3%	87,282	107,370
Total Zone 2	1,350,349,634		770,913,654		248,435		579,435,980		191,797	220,116
Zone 3										
Non-Demand	395,890,631	57%	226,845,332	69.1%	75,594	43%	169,045,299	76.2%	50,269	62,932
Demand	450,770,715	57%	256,488,537	80.7%	73,174	43%	194,282,178	83.5%	52,689	62,931
Subtotal Zone 3	846,661,346		483,333,868		148,768		363,327,478		102,958	125,863
Seasonal	5,647,152	20%	1,152,019	162.5%	163	80%	3,781,000	162.5%	527	345
Water Heating	7,321,407	50%	3,631,418	106.0%	789	50%	3,689,989	106.0%	788	788
Total Zone 3	859,629,905		488,117,305		149,720		370,798,467		104,273	126,997

2005/2006 Prospective Cost Of Service Study
Prospective Peak Load Responsibility Report
Seasonal Coincident Peaks (2 CP)

			Winter				*SUMMER*			D14
	Forcast Total Energy @ Generation (E10)	Avg % of Yearly Energy	Estimated Seasonal Energy	Seasonal CP LF	Estimated Seasonal Demand	Avg % of Yearly Energy	Estimated Seasonal Energy	Seasonal CP LF	Estimated Seasonal Demand	2CP Estimated Demand
Total										
Non-Demand	1,813,871,233	57%	1,039,348,217		334,963	43%	774,523,016		279,513	307,238
Demand	1,951,644,664	57%	1,110,485,814		344,103	43%	841,158,850		253,670	298,887
Subtotal Zones 1, 2 & 3	3,765,515,897		2,149,834,030		679,066		1,615,681,867		533,183	606,125
Seasonal	5,647,152	20%	1,152,019		163	80%	3,781,000		527	345
Water Heating	7,321,407	50%	3,631,418		789	50%	3,689,989		788	788
Total GSS	3,778,484,456		2,154,617,467		680,018		1,623,152,856		534,499	607,258
General Service - Medium										
Zone 1	2,210,309,498	53%	1,172,495,199	77.3%	349,400	47%	1,037,814,299	71.2%	329,981	339,690
Zone 2	657,589,798	53%	348,829,375	76.2%	105,355	47%	308,760,423	69.9%	100,055	102,705
Zone 3	474,040,039	53%	251,462,372	77.3%	74,906	47%	222,577,667	78.4%	64,305	69,606
Total GS- Medium	3,341,939,335		1,772,786,947		529,661		1,569,152,388		494,341	512,001
General Service - Large										
0 - 30 kV										
Zone 1	952,570,880	51%	486,175,492	80.8%	138,462	49%	466,395,388	73.8%	143,110	140,786
Zone 2	387,138,012	51%	197,588,460	78.5%	57,943	49%	189,549,552	75.0%	57,254	57,599
Zone 3	331,089,685	51%	168,982,376	85.5%	45,481	49%	162,107,309	85.5%	42,920	44,200
Total 0 - 30	1,670,798,577		852,746,328		241,886		818,052,249		243,283	242,585
30 - 100 kV	613,006,266	51%	312,716,586	95.1%	75,681	49%	300,289,680	96.3%	70,598	73,140
30 - 100 kV - Curtailed Cust	244,651,158	51%	125,016,742	115.5%	24,926	49%	119,634,416	98.8%	27,431	26,178
Over 100 kV	2,870,344,020	53%	1,535,170,736	97.7%	361,794	47%	1,335,173,284	101.6%	297,676	329,735
Over 100 kV - Curtailed Cust	2,790,918,667	51%	1,418,327,216	106.4%	306,748	49%	1,372,591,451	97.5%	318,694	312,721
Total GS - Large	8,189,718,688		4,243,977,608		1,011,035		3,945,741,080		957,682	984,359
Street Lighting	112,203,906	58%	65,347,333	86.7%	17,361	42%	46,856,573	0.0%	-	8,680
Total - Street Lighting	112,203,906		65,347,333		17,361		46,856,573		-	8,680
Total - General Consumers	22,850,478,677		12,900,935,781		3,884,722		9,947,383,031		2,866,407	3,375,564
Extra Provincial	-	0%	-	0.0%	-	0%	-	0.0%	-	-
Integrated System	22,850,478,677		12,900,935,781		3,884,722		9,947,383,031		2,866,407	3,375,564

2005/2006 Prospective Cost of Service Study
Prospective Peak Load Responsibility Report
Energy Weighted by Marginal Cost

	Winter		*Summer*		**Forecast**
Customer Class	**Off Peak**	**On Peak**	**Off Peak**	**On Peak**	**Total Energy**
Streetlights	45,925,837	19,032,914	33,402,325	13,842,831	112,203,907
Res FRWH	4,391,440	5,703,825	4,418,720	5,833,531	20,347,517
GSS FRWH	1,572,194	2,042,045	1,597,789	2,109,378	7,321,407
Res Seasonal	12,632,710	10,631,949	22,348,496	25,609,650	71,222,805
GSS Seasonal	1,001,629	842,992	1,771,980	2,030,552	5,647,152
Residential Zone 1	709,991,224	668,596,081	559,133,772	604,344,980	2,542,066,057
Residential Zone 2	853,336,944	758,993,942	403,742,226	415,563,137	2,431,636,249
Residential Zone 3	855,630,541	751,417,511	374,066,080	381,745,532	2,362,859,664
GS Small Non-Demand Z1	193,214,906	206,824,028	168,483,562	208,280,110	776,802,607
GS Small Non-Demand Z2	184,710,660	197,502,027	111,730,750	147,234,558	641,177,995
GS Small Non-Demand Z3	123,024,115	120,506,700	71,560,328	80,799,489	395,890,631
GS Small Demand Z1	198,514,794	222,645,619	165,691,382	204,850,515	791,702,310
GS Small Demand Z2	210,177,582	214,393,762	134,532,266	150,068,029	709,171,639
GS Small Demand Z3	127,198,268	123,640,082	97,613,677	102,318,689	450,770,715
GS Medium Zone 1	543,784,441	585,898,901	494,074,726	586,551,431	2,210,309,498
GS Medium Zone 2	174,104,624	198,595,073	123,855,447	161,034,654	657,589,798
GS Medium Zone 3	131,613,396	133,930,310	97,051,158	111,445,176	474,040,039
GS Large <30 kV Zone 1	222,627,873	249,992,801	220,059,717	259,890,489	952,570,880
GS Large <30 kV Zone 2	92,971,017	113,974,397	79,986,835	100,205,762	387,138,012
GS Large <30 kV Zone 3	82,891,381	86,084,366	78,752,384	83,361,554	331,089,685
GS Large 30 kV-100 kV	174,593,953	148,309,903	157,781,929	132,320,481	613,006,266
GS Large 30-100 kV Curtail	65,503,326	53,763,136	67,819,584	57,565,113	244,651,158
GS Large kKV> 100 kV	835,942,459	722,663,482	702,965,780	608,772,300	2,870,344,020
GS Curtailable	763,101,745	638,995,072	767,548,152	621,273,697	2,790,918,667
Net Exports	1,125,390,000	2,074,632,000	3,366,384,000	3,219,594,000	9,786,000,000
Total System	7,733,847,056	8,309,612,920	8,306,373,066	8,286,645,636	32,636,478,678
Times: Marginal Weighting	**1.295**	**2.101**	**1.000**	**1.923**	

	Winter		*Summer*		**Forecast Weighted**
Customer Class	**Off Peak**	**On Peak**	**Off Peak**	**On Peak**	**Total Energy**
Streetlights	59,473,959	39,988,152	33,402,325	26,625,301	159,489,737
Res FRWH	5,686,915	11,983,736	4,418,720	11,220,214	33,309,586
GSS FRWH	2,035,991	4,290,337	1,597,789	4,057,179	11,981,296
Res Seasonal	16,359,359	22,337,726	22,348,496	49,257,600	110,303,181
GSS Seasonal	1,297,110	1,771,126	1,771,980	3,905,563	8,745,778
Residential Zone 1	919,438,636	1,404,720,367	559,133,772	1,162,397,134	4,045,689,908
Residential Zone 2	1,105,071,343	1,594,646,273	403,742,226	799,294,137	3,902,753,979
Residential Zone 3	1,108,041,551	1,578,728,191	374,066,080	734,249,356	3,795,085,177
GS Small Non-Demand Z1	250,213,303	434,537,284	168,483,562	400,605,964	1,253,840,113
GS Small Non-Demand Z2	239,200,305	414,951,758	111,730,750	283,190,948	1,049,073,762
GS Small Non-Demand Z3	159,316,228	253,184,577	71,560,328	155,409,737	639,470,870
GS Small Demand Z1	257,076,658	467,778,446	165,691,382	394,009,480	1,284,555,966
GS Small Demand Z2	272,179,968	450,441,295	134,532,266	288,640,847	1,145,794,376
GS Small Demand Z3	164,721,757	259,767,812	97,613,677	196,799,766	718,903,011
GS Medium Zone 1	704,200,850	1,230,973,591	494,074,726	1,128,173,022	3,557,422,189
GS Medium Zone 2	225,465,488	417,248,248	123,855,447	309,734,054	1,076,303,237
GS Medium Zone 3	170,439,347	281,387,581	97,051,158	214,353,651	763,231,737
GS Large <30 kV Zone 1	288,303,095	525,234,875	220,059,717	499,873,367	1,533,471,054
GS Large <30 kV Zone 2	120,397,467	239,460,209	79,986,835	192,735,763	632,580,274
GS Large <30 kV Zone 3	107,344,338	180,863,253	78,752,384	160,337,613	527,297,588
GS Large 30-100 kV	226,099,169	311,599,107	157,781,929	254,505,213	949,985,417
GS Large 30-100 kV Curtail	84,826,807	112,956,348	67,819,584	110,720,738	376,323,477
GS Large > 100 kV	1,082,545,484	1,518,315,975	702,965,780	1,170,912,642	4,474,739,880
GS Large > 100 kV Curtail	988,216,759	1,342,528,647	767,548,152	1,194,957,830	4,293,251,389
Exports	1,457,380,050	4,358,801,832	3,366,384,000	6,192,567,100	15,375,132,982
Total Weighted Energy	10,015,331,938	17,458,496,745	8,306,373,066	15,938,534,216	51,718,735,964

Manitoba Hydro
Prospective Cost Of Service Study
March 31, 2006

Calculation Of Losses

ENERGY (in MWh)	*MANITOBA HYDRO*
Firm Energy at Generation (After DSM)	22,935,234,078
Common Bus Losses (After DSM)	2,177,590,260
Deliveries From Common Bus	20,757,643,818
Sales at Meter	19,907,417,809
Distribution Losses	850,226,009

DEMAND (in MW)	*MANITOBA HYDRO*
Firm Peak Capacity At Generation (After DSM)	3,897.65
Common Bus Losses (After DSM)	344.25
Deliveries From Common Bus	3,553.40
Calculated Distribution Losses	233.26
Calculated Demand at Meter (CP Load Factors)	3,309.19
Adjustment To Reconcile	10.95

Manitoba Hydro
2006 Prospective Cost Of Service Study
March 31, 2006
Determination Of Coincident Peak Distribution Losses

1) ENERGY SALES AND TOTAL LOSSES ON DISTRIBUTION SYSTEM

	Sales	Losses	Energy @ Common Bus
RESIDENTIAL	6,290,430,999	432,435,828	6,722,866,827
GSS SINGLE PHASE	1,258,796,492	88,976,582	1,347,773,073
GSS THREE PHASE	1,968,421,210	103,541,230	2,071,962,440
* GSM	2,904,317,401	146,520,402	3,050,837,803
* GSL O - 30	1,454,912,716	62,590,066	1,517,502,782
* GSL 30 - 100	548,919,209	8,233,788	557,152,997
LIGHTING	95,792,806	5,757,879	101,550,685
MAN. HYDRO BLDGS	43,000,000	2,170,235	45,170,235
	14,564,590,833	850,226,009	15,414,816,842

* (includes interruptible sales)

2) COINCIDENT PEAK AT COMMON BUS

CP AT GENERATION	3,897.7
LESS SALES AT CB LEVEL :	
- EXPORTS	-
- * GSL >100	(332.0)
CB LOSSES	(344.2)
EXPORT LOSSES	-
COINCIDENT PEAK AT COMMON BUS	3,221.4

3) LOAD FACTOR AT COMMON BUS 54.5%
(HOUR PER YR = 8760)

4) EQUIVALENT HOURS LOSS FACTOR

EQF = $(0.08 \times 54.48\%) + (0.92 \times (54.48\%)^2)$
= 0.316600

5) NO LOAD LOSS FACTOR AS A PERCENTAGE OF DISTRIBUTION ENERGY LOSSES 18.0%

a) $850{,}226 \times 0.180 = 153{,}041$ MW.H

b) $\dfrac{850{,}226 \times 0.180}{8{,}760} = 17.4$ MW @ PEAK

6) CO-EFFICIENT OF SYSTEM LOSSES

$$= \frac{850{,}226. - 153{,}041}{8{,}760 \times (3{,}221.38)^2 \times 0.3166}$$

$= 0.000024$

7) SYSTEM DISTRIBUTION LOSSES AT PEAK

$= 17.42 + 0.000024 \text{ X } (3{,}221.38)^2$
$= 268.1$

8) ADJUSTMENT FACTOR FOR TEMPERATURE -13.0%

9) SYSTEM DISTRIBUTION LOSSES AT PEAK ASSIGNED IN COSS 233.3 MW

10) RELATIONSHIP PEAK TO AVERAGE LOSSES (based on sales @ meter).

AVERAGE (KW.h)	850,226	/ 14,564,591	= 5.84%
PEAK (MW)	233.26	/ 2,988.116	= 7.81%

2006 Prospective Cost of Service Study
Prospective Peak Load Report
Using Top 50 Peak Hours

Energy Data

	Forecast # Cust. **C90**	Forecast Total kW.h Sales Before DSM	DSM kW.h Savings	Total kW.h Sales After DSM **E20**	Distribution Losses	Common Bus Losses	kW.h Generated Adjusted **E10**
Residential - Zone 1							
Residential	234,798	2,196,878,967	(11,347,519)	2,185,531,448	115,177,653	241,356,956	2,542,066,057
Seasonal	-	-	-	-	-	-	-
Water Heating	5,960	16,516,943	-	16,516,943	870,444	1,824,032	19,211,419
Total Zone 1	240,758	2,213,395,910	(11,347,519)	2,202,048,391	116,048,097	243,180,988	2,561,277,476
Zone 2							
Residential	118,834	2,071,787,937	(10,568,554)	2,061,219,383	139,544,689	230,872,177	2,431,636,249
Seasonal	15,656	46,055,454	-	46,055,454	3,117,957	5,158,560	54,331,971
Water Heating	116	909,937	-	909,937	61,603	101,920	1,073,460
Total Zone 2	134,606	2,118,753,328	(10,568,554)	2,108,184,774	142,724,249	236,132,656	2,487,041,680
Zone 3							
Residential *	72,676	1,976,133,095	(10,041,927)	1,966,091,168	172,426,326	224,342,170	2,362,859,664
Seasonal	4,223	14,054,546	-	14,054,546	1,232,585	1,603,704	16,890,834
Water Heating	10	52,120	-	52,120	4,571	5,947	62,638
Total Zone 3	76,909	1,990,239,761	(10,041,927)	1,980,197,834	173,663,482	225,951,821	2,379,813,136
Total							
Residential	426,308	6,244,799,999	(31,958,000)	6,212,841,999	427,148,668	696,571,303	7,336,561,970
Seasonal	19,879	60,110,000	-	60,110,000	4,350,542	6,762,263	71,222,805
Water Heating	6,086	17,479,000	-	17,479,000	936,618	1,931,899	20,347,517
Total Residential	452,273	6,322,388,999	(31,958,000)	6,290,430,999	432,435,828	705,265,465	7,428,132,292
* Zn 3 residential less diesel							
GS Small - Single Phase							
Zone 1							
Non-Demand	14,213	287,554,484	(6,308,659)	281,245,825	14,821,674	31,059,098	327,126,597
Demand	181	41,577,876	(911,086)	40,666,790	2,143,143	4,490,996	47,300,928
Subtotal Zone 1	14,394	329,132,360	(7,219,745)	321,912,615	16,964,816	35,550,094	374,427,525
Seasonal	-	-	-	-	-	-	-
Water Heating	533	5,716,787	-	5,716,787	301,275	631,328	6,649,390
Total Zone 1	14,927	334,849,147	(7,219,745)	327,629,402	17,266,091	36,181,422	381,076,915
Zone 2							
Non-Demand	14,246	396,143,098	(8,699,209)	387,443,889	26,229,977	43,396,649	457,070,515
Demand	570	109,254,863	(2,378,196)	106,876,667	7,235,557	11,970,996	126,083,220
Subtotal Zone 2	14,816	505,397,961	(11,077,405)	494,320,556	33,465,535	55,367,645	583,153,735
Seasonal	380	2,779,691	-	2,779,691	188,185	311,346	3,279,223
Water Heating	40	546,026	-	546,026	36,966	61,159	644,151
Total Zone 2	15,236	508,723,678	(11,077,405)	497,646,273	33,690,686	55,740,150	587,077,109
Zone 3							
Non-Demand	12,226	269,940,604	(5,898,266)	264,042,338	23,156,531	30,128,731	317,327,599
Demand	793	171,191,302	(3,706,319)	167,484,983	14,688,444	19,110,988	201,284,415
Subtotal Zone 3	13,019	441,131,906	(9,604,585)	431,527,321	37,844,975	49,239,719	518,612,014
Seasonal	398	1,970,309	-	1,970,309	172,796	224,823	2,367,929
Water Heating	2	23,187	-	23,187	2,034	2,646	27,866
Total Zone 3	13,419	443,125,402	(9,604,585)	433,520,817	38,019,804	49,467,188	521,007,809
Total							
Non-Demand	40,685	953,638,186	(20,906,135)	932,732,051	64,208,181	104,584,478	1,101,524,710
Demand	1,544	322,024,041	(6,995,601)	315,028,440	24,067,144	35,572,980	374,668,564
Subtotal Zones 1, 2 & 3	42,229	1,275,662,227	(27,901,735)	1,247,760,492	88,275,325	140,157,458	1,476,193,275
Seasonal	778	4,750,000	-	4,750,000	360,981	536,170	5,647,151
Water Heating	575	6,286,000	-	6,286,000	340,275	695,132	7,321,407
Total GSS-Single Phase	43,582	1,286,698,227	(27,901,735)	1,258,796,492	88,976,582	141,388,760	1,489,161,833

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Energy Data

	Forecast # Cust. **C90**	Forecast Total kW.h Sales Before DSM	DSM kW.h Savings	Total kW.h Sales After DSM **E20**	Distribution Losses	Common Bus Losses	kW.h Generated Adjusted **E10**
GS Small - Three Phase							
Zone 1							
Non-Demand	8,134	399,019,248	(8,704,289)	390,314,959	16,666,475	42,694,576	449,676,010
Demand	1,923	660,609,863	(14,475,784)	646,134,079	27,589,968	70,677,334	744,401,382
Total Zone 1	10,057	1,059,629,111	(23,180,072)	1,036,449,039	44,256,443	113,371,910	1,194,077,392
Zone 2							
Non-Demand	3,090	161,071,392	(3,533,953)	157,537,439	9,089,921	17,480,120	184,107,480
Demand	1,806	510,040,470	(11,102,262)	498,938,208	28,788,768	55,361,443	583,088,419
Total Zone 2	4,896	671,111,862	(14,636,216)	656,475,646	37,878,688	72,841,564	767,195,898
Zone 3							
Non-Demand	1,398	67,451,174	(1,473,773)	65,977,401	5,126,448	7,459,182	78,563,032
Demand	847	214,155,628	(4,636,503)	209,519,125	16,279,650	23,687,525	249,486,300
Total Zone 3	2,245	281,606,802	(6,110,276)	275,496,526	21,406,098	31,146,708	328,049,332
Total							
Non-Demand	12,622	627,541,814	(13,712,015)	613,829,799	30,882,844	67,633,879	712,346,522
Demand	4,576	1,384,805,961	(30,214,549)	1,354,591,412	72,658,386	149,726,302	1,576,976,100
Total GSS-Three Phase	17,198	2,012,347,775	(43,926,565)	1,968,421,210	103,541,230	217,360,182	2,289,322,622
Total GS Small							
Non-Demand	53,307	1,581,180,000	(34,618,150)	1,546,561,850	95,091,025	172,218,357	1,813,871,232
Demand	6,120	1,706,830,002	(37,210,150)	1,669,619,852	96,725,530	185,299,282	1,951,644,664
Sub-Total G.S. Small	59,427	3,288,010,002	(71,828,300)	3,216,181,702	191,816,555	357,517,639	3,765,515,896
Seasonal	778	4,750,000	-	4,750,000	360,981	536,170	5,647,151
Water Heating	575	6,286,000	-	6,286,000	340,275	695,132	7,321,407
Total GS Small	60,780	3,299,046,002	(71,828,300)	3,227,217,702	192,517,811	358,748,941	3,778,484,455
General Service - Medium							
Zone 1	1,032	1,946,670,892	(28,141,013)	1,918,529,879	81,921,353	209,858,265	2,210,309,498
Zone 2	450	570,828,307	(8,140,617)	562,687,690	32,467,117	62,434,991	657,589,798
Zone 3	295	403,970,802	(5,870,970)	398,099,832	30,932,383	45,007,824	474,040,039
Total GS - Medium	1,777	2,921,470,001	(42,152,600)	2,879,317,401	145,320,854	317,301,080	3,341,939,335
General Service - Large							
0 - 30 kV							
Zone 1	162	860,381,683	(25,551,823)	834,829,860	27,298,992	90,442,027	952,570,880
Zone 2	43	344,664,778	(10,235,938)	334,428,840	15,952,278	36,756,894	387,138,012
Zone 3	43	289,244,055	(8,590,040)	280,654,015	19,000,296	31,435,375	331,089,685
Total 0 - 30	248	1,494,290,516	(44,377,800)	1,449,912,716	62,251,565	158,634,296	1,670,798,577
30 - 100 kV	28	551,239,485	(2,320,276)	548,919,209	5,885,058	58,201,999	613,006,266
30 - 100 kV - Curtailment Cust's	1	220,000,000	(926,024)	219,073,976	2,348,730	23,228,452	244,651,158
Over 100 kV	11	2,602,000,000	(4,181,351)	2,597,818,649	-	272,525,371	2,870,344,020
Over 100 kV - Curtailment Cust's	3	2,530,000,000	(4,065,649)	2,525,934,351	-	264,984,316	2,790,918,667
Total GS - Large	291	7,397,530,001	(55,871,100)	7,341,658,901	70,485,354	777,574,433	8,189,718,688

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Energy Data

	Forecast # Cust. **C90**	Forecast Total kW.h Sales Before DSM	DSM kW.h Savings	Total kW.h Sales After DSM **E20**	Distribution Losses	Common Bus Losses	kW.h Generated Adjusted **E10**
SEP							
GSM							
Medium Zone 2 (SEP)	10	16,196,903		16,196,903	691,609	1,771,697	18,660,209
Medium Zone 3 (SEP)	17	8,803,097		8,803,097	507,939	976,779	10,287,815
Total Medium SEP	27	25,000,000	-	25,000,000	1,199,548	2,748,476	28,948,024
GSL							
0 - 30 kV							
Zone 3 (SEP)	6	5,000,000		5,000,000	338,500	560,038	5,898,538
Total GSL SEP	6	5,000,000	-	5,000,000	338,500	560,038	5,898,538
Total SEP	33	30,000,000	-	30,000,000	1,538,048	3,308,514	34,846,562
Street Lighting							
Zone 1	7,903	60,562,699	-	60,562,699	3,640,280	6,735,243	70,938,223
Zone 2	3,755	22,078,831	-	22,078,831	1,327,106	2,455,411	25,861,348
Zone 3	540	2,931,276	-	2,931,276	176,192	325,990	3,433,458
Total - Street Lighting	12,198	85,572,806	-	85,572,806	5,143,579	9,516,644	100,233,029
Sentinel Lighting							
Zone 1	97	726,694	-	726,694	43,680	80,816	851,190
Zone 2	539	2,822,573	-	2,822,573	169,658	313,901	3,306,133
Zone 3	1,895	6,670,733	-	6,670,733	400,962	741,859	7,813,554
Total - Sentinel Lighting	2,530	10,220,000	-	10,220,000	614,300	1,136,577	11,970,877
Total Lighting							
Zone 1	8,000	61,289,393	-	61,289,393	3,683,960	6,816,060	71,789,413
Zone 2	4,294	24,901,404	-	24,901,404	1,496,764	2,769,312	29,167,481
Zone 3	2,435	9,602,009	-	9,602,009	577,154	1,067,850	11,247,013
Total - Lighting	14,729	95,792,806	-	95,792,806	5,757,879	10,653,222	112,203,906
Total - General Consumers	529,883	20,066,227,809	(201,810,000)	19,864,417,809	848,055,774	2,172,851,655	22,885,325,238
Extra Provincial		8,947,000,000	-	8,947,000,000	-	839,000,000	9,786,000,000
Man Hydro - Buildings		43,000,000		43,000,000	2,170,235	4,738,605	49,908,840
Integrated System	529,883	29,056,227,809	(201,810,000)	28,854,417,809	850,226,009	3,016,590,260	32,721,234,078

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Demand Data

	CP Load Factor	CP @ Meter Before DSM Non-Recon MW	DSM MW Savings	CP @ Meter After DSM Non-Recon. MW	Adjust %'age	Adjust To Recon.	CP @ Meter Reconciled MW	Distrib Losses MW	Common Bus Losses MW	Class Coinc. Factor	Class Demand NCP MW @ Meter **D50**	Class Demand NCP MW @ Gen. **D20**
Residential - Zone 1												
Residential	61%	411.9	(3.7)	408.2	37%	4.1	412.3	30.8	42.9	78%	526.1	620.2
Seasonal	158%	-		-		-	-	-	-	8%	-	-
Water Heating	53%	3.6		3.6		-	3.6	0.3	0.4	80%	4.5	5.3
Total Zone 1	61%	415.5	(3.7)	411.8	37%	4.1	415.9	31.1	43.3	78%	530.6	625.4
Zone 2												
Residential	48%	488.4	(3.4)	485.0	13%	1.4	486.5	46.1	51.6	90%	543.3	652.4
Seasonal	158%	3.3		3.3		-	3.3	0.3	0.4	8%	41.7	50.0
Water Heating	149%	0.1		0.1		-	0.1	0.0	0.0	80%	0.1	0.1
Total Zone 2	49%	491.8	(3.4)	488.4	13%	1.4	489.9	46.4	51.9	84%	585.1	702.6
Zone 3												
Residential *	47%	481.3	(3.3)	478.0	32%	3.5	481.5	58.5	52.3	87%	550.6	677.4
Seasonal	158%	1.0		1.0		-	1.0	0.1	0.1	8%	12.7	15.6
Water Heating	93%	0.0		0.0		-	0.0	0.0	0.0	80%	0.0	0.0
Total Zone 3	47%	482.3	(3.3)	479.1	32%	3.5	482.5	58.6	52.4	86%	563.4	693.0
Total												
Residential	52%	1,381.7	(10.4)	1,371.3	82%	9.0	1,380.2	135.4	146.8	85%	1,620.1	1,950.0
Seasonal	158%	4.3	-	4.3	0%	-	4.3	0.4	0.5	8%	54.4	65.7
Water Heating	55%	3.7	-	3.7	0%	-	3.7	0.3	0.4	80%	4.6	5.4
Total Residential	52%	1,389.7	(10.4)	1,379.3	82%	9.0	1,388.2	136.1	147.7	83%	1,679.0	2,021.0
* Zn 3 residential less diesel												
GS Small - Single Phase												
Zone 1												
Non-Demand	71%	45.9	(1.3)	44.6	2%	0.2	44.9	3.4	4.7	79%	56.6	66.8
Demand	68%	7.0	(0.2)	6.8	0%	0.0	6.9	0.5	0.7	89%	7.7	9.0
Subtotal Zone 1	71%	52.9	(1.5)	51.5	2%	0.3	51.7	3.9	5.4	80%	64.3	75.8
Seasonal	163%	-		-			-	-	-	8%	-	-
Water Heating	62%	1.1		1.1			1.1	0.1	0.1	75%	1.4	1.7
Total Zone 1	71%	54.0	(1.5)	52.5	2%	0.3	52.8	3.9	5.5	80%	65.7	77.5
Zone 2												
Non-Demand	58%	77.5	(1.8)	75.8	2%	0.2	76.0	7.2	8.1	85%	89.0	106.8
Demand	61%	20.6	(0.5)	20.1	0%	0.0	20.2	1.9	2.1	88%	23.0	27.7
Subtotal Zone 2	59%	98.1	(2.2)	95.9	2%	0.2	96.1	9.1	10.2	86%	112.0	134.5
Seasonal	163%	0.2		0.2			0.2	0.0	0.0	8%	2.4	2.9
Water Heating	78%	0.1		0.1			0.1	0.0	0.0	75%	0.1	0.1
Total Zone 2	59%	98.4	(2.2)	96.2	2%	0.2	96.4	9.1	10.2	84%	114.6	137.6
Zone 3												
Non-Demand	56%	55.2	(1.2)	54.0	1%	0.1	54.1	6.6	5.9	80%	67.3	82.8
Demand	72%	27.1	(0.7)	26.4	1%	0.1	26.4	3.2	2.9	83%	31.8	39.1
Subtotal Zone 3	61%	82.3	(1.9)	80.4	2%	0.2	80.5	9.8	8.7	81%	99.1	121.9
Seasonal	163%	0.1		0.1			0.1	0.0	0.0	8%	1.7	2.1
Water Heating	71%	0.0		0.0			0.0	0.0	0.0	75%	0.0	0.0
Total Zone 3	61%	82.4	(1.9)	80.5	2%	0.2	80.7	9.8	8.8	80%	100.9	124.1
Total												
Non-Demand	60%	178.6	(4.2)	174.4	5%	0.5	175.0	17.1	18.6	82%	213.0	256.5
Demand	66%	54.7	(1.4)	53.4	1%	0.1	53.5	5.6	5.7	86%	62.5	75.8
Subtotal Zones 1, 2 & 3	62%	233.4	(5.6)	227.8	6%	0.6	228.4	22.8	24.3	83%	275.4	332.2
Seasonal	163%	0.3	-	0.3	0%	-	0.3	0.0	0.0	8%	4.2	5.0
Water Heating	63%	1.1	-	1.1	0%	-	1.1	0.1	0.1	75%	1.5	1.8
Total GSS - Single Phase	63%	234.8	(5.6)	229.3	6%	0.6	229.9	22.9	24.5	82%	281.1	339.1

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Demand Data

	CP Load Factor	CP @ Meter Before DSM Non-Recon MW	DSM MW Savings	CP @ Meter After DSM Non-Recon. MW	Adjust %'age	Adjust To Recon.	CP @ Meter Reconciled MW	Distrib Losses MW	Common Bus Losses MW	Class Coinc. Factor	Class Demand NCP MW @ Meter **D50**	Class Demand NCP MW @ Gen. **D20**
GS Small - Three Phase												
Zone 1												
Non-Demand	71%	63.7	(1.8)	62.0	3%	0.3	62.3	3.8	6.4	79%	78.6	91.5
Demand	68%	111.6	(2.8)	108.8	1%	0.1	108.9	6.7	11.2	89%	121.8	141.8
Total Zone 1	69%	175.3	(4.6)	170.8	4%	0.4	171.2	10.5	17.6	85%	200.4	233.3
Zone 2												
Non-Demand	58%	31.5	(0.7)	30.8	1%	0.1	30.9	2.5	3.2	85%	36.2	42.9
Demand	61%	96.2	(2.2)	94.0	1%	0.1	94.1	7.7	9.9	88%	107.5	127.5
Total Zone 2	60%	127.7	(2.9)	124.8	2%	0.2	125.0	10.2	13.1	87%	143.7	170.4
Zone 3												
Non-Demand	56%	13.8	(0.3)	13.5	0%	0.0	13.5	1.5	1.5	80%	16.8	20.5
Demand	72%	33.9	(0.9)	33.0	1%	0.1	33.1	3.6	3.6	83%	39.8	48.3
Total Zone 3	67%	47.7	(1.2)	46.5	1%	0.1	46.6	5.0	5.0	82%	56.6	68.8
Total												
Non-Demand	64%	109.0	(2.8)	106.3	4%	0.4	106.7	7.8	11.1	81%	131.6	154.9
Demand	64%	241.7	(5.9)	235.8	2%	0.3	236.1	17.9	24.6	88%	269.1	317.6
Total GSS - Three Phase	65%	350.7	(8.6)	342.1	7%	0.7	342.8	25.7	35.7	86%	400.7	472.5
Total GS Small												
Non-Demand	61%	287.7	(7.0)	280.7	9%	1.0	281.7	24.9	29.7	82%	344.6	411.3
Demand	64%	296.4	(7.2)	289.2	3%	0.4	289.6	23.5	30.3	87%	331.6	393.4
Subtotal GS Small	64%	584.1	(14.2)	569.9	12%	1.3	571.2	48.5	60.0	84%	676.2	804.8
Seasonal	163%	0.3	-	0.3	0%	-	0.3	0.0	0.0	8%	4.2	5.0
Water Heating	63%	1.1	-	1.1	0%	-	1.1	0.1	0.1	75%	1.5	1.8
Total GS Small	64%	585.6	(14.2)	571.3	12%	1.3	572.7	48.6	60.2	84%	681.8	811.6
General Service - Medium												
Zone 1	75%	295.7	(5.4)	290.3	5%	0.5	290.8	17.8	29.9	92%	315.5	367.3
Zone 2	67%	97.4	(1.6)	95.9	0%	0.0	95.9	7.8	10.0	87%	110.3	130.8
Zone 3	69%	67.2	(1.1)	66.1	0%	0.1	66.2	7.2	7.1	89%	74.3	90.3
Total G.S.- Medium	72%	460.3	(8.1)	452.3	6%	0.6	452.9	32.8	47.0	91%	500.1	588.4
General Service - Large												
0 - 30 kV												
Zone 1	81%	121.2	(4.2)	117.0	0%	0.0	117.1	5.6	11.9	81%	145.4	167.1
Zone 2	73%	53.9	(1.7)	52.2	0%	0.0	52.2	3.5	5.4	84%	61.8	72.4
Zone 3	83%	39.6	(1.4)	38.2	0%	0.0	38.2	3.6	4.1	86%	44.6	53.6
Total 0 - 30	79%	214.7	(7.3)	207.4	0%	0.0	207.5	12.8	21.3	82%	251.8	293.1
30 - 100 kV	90%	70.1	(0.5)	69.6		-	69.6	1.1	6.8	77%	90.3	100.5
30 - 100 kV - Curtailment Cust's	118%	21.3	(0.2)	21.2		-	21.2	0.3	2.1	79%	26.7	29.7
Over 100 kV	89%	332.0	(10.3)	321.7		-	321.7	-	31.2	89%	363.2	398.4
Over 100 kV - Curtailment Cust's	105%	274.1	(8.5)	265.6		-	265.6	-	25.7	85%	314.3	344.8
Total GS - Large	93%	912.3	(26.8)	885.5	0%	0.0	885.6	14.2	87.2	85%	1,046.3	1,166.5

2006 Prospective Cost of Service Study
Prospective Peak Load Report
Using Top 50 Peak Hours

Demand Data

	CP Load Factor	CP @ Meter Before DSM Non-Recon MW	DSM MW Savings	CP @ Meter After DSM Non-Recon. MW	Adjust %'age	Adjust To Recon.	CP @ Meter Reconciled MW	Distrib Losses MW	Common Bus Losses MW	Class Coinc. Factor	Class Demand NCP MW @ Meter **D50**	Class Demand NCP MW @ Gen. **D20**
SEP												
GSM												
Medium Zone 2 (SEP)	90%	2.1		2.1		-	2.1	0.1	0.2	34%	6.0	7.0
Medium Zone 3 (SEP)	43%	2.4		2.4		-	2.4	0.2	0.2	54%	4.4	5.2
Total Medium SEP	65%	4.4	-	4.4	0%	-	4.4	0.3	0.5	43%	10.3	12.1
GSL												
0 - 30 kV												
Zone 3 (SEP)	129%	0.4		0.4		-	0.4	0.0	0.0	12%	3.6	4.3
Total GSL SEP	129%	0.4	-	0.4	0%	-	0.4	0.0	0.0	12%	3.6	4.3
Total SEP	70%	4.9	-	4.9		-	4.9	0.4	0.5	35%	14.0	16.5
Street Lighting												
Zone 1	120%	5.8	-	5.8		-	5.8	0.8	0.6	38%	15.1	18.8
Zone 2	120%	2.1	-	2.1		-	2.1	0.3	0.2	38%	5.5	6.8
Zone 3	120%	0.3	-	0.3		-	0.3	0.0	0.0	38%	0.7	0.9
Total - Street Lighting	120%	8.2	-	8.2	0%	-	8.2	1.1	0.9	38%	21.4	26.5
Sentinel Lighting												
Zone 1	120%	0.1	-	0.1		-	0.1	0.0	0.0	38%	0.2	0.2
Zone 2	120%	0.3	-	0.3		-	0.3	0.0	0.0	38%	0.7	0.9
Zone 3	120%	0.6	-	0.6		-	0.6	0.1	0.1	38%	1.7	2.0
Total - Sentinel Lighting	120%	1.0	-	1.0	0%	-	1.0	0.1	0.1	38%	2.6	3.1
Total Lighting												
Zone 1	120%	5.8	-	5.8		-	5.8	0.8	0.6	0%	15.3	19.0
Zone 2	120%	2.4	-	2.4		-	2.4	0.3	0.3	0%	6.2	7.7
Zone 3	120%	0.9	-	0.9		-	0.9	0.1	0.1	38%	2.4	2.9
Total - Lighting	120%	9.1	-	9.1	0%	-	9.1	1.2	1.0	38%	23.9	29.7
Total - General Consumers	68%	3,361.9	(59.5)	3,302.4	100%	11.0	3,313.4	233.2	343.5	84.0%	3,945.1	4,633.6
Extra Provincial	0%	-		-		-	-		-			
Man Hydro - Buildings	72%	6.8		6.8		-	6.8	0.5	0.7			
Integrated System	68%	3,368.6	(59.5)	3,309.2	100%	11.0	3,320.2	233.7	344.2			

Prospective Cost Of Service Study
March 31, 2006

Distribution Energy Losses Expressed as a %'age of kW.h @ meter

	Zone 1	**Zone 2**	**Zone 3**	**Class Avg**
Export Sales				n/a
GS Large				
< 30	3.3%	4.8%	6.8%	4.3%
30-100				1.1%
> 100				n/a
GS Medium	4.3%	5.8%	7.8%	5.1%
GS Small				
3 Phase	4.3%	5.8%	7.8%	5.3%
1 Phase	5.3%	6.8%	8.8%	7.1%
Residential	5.3%	6.8%	8.8%	6.9%
Area & Roadway Lighting	6.0%	6.0%	6.0%	6.0%

Prospective Cost of Service Study
March 31, 2006

Distribution Capacity Losses Expressed as a %'age of MW @ meter

	Zone 1	**Zone 2**	**Zone 3**	**Class Avg**
Export Sales				n/a
GS Large				
< 30	4.8%	6.8%	9.5%	6.2%
30-100				1.5%
> 100				n/a
GS Medium	6.1%	8.1%	10.8%	7.2%
GS Small				
3 Phase	6.1%	8.1%	10.8%	7.5%
1 Phase	7.5%	9.5%	12.2%	10.0%
Residential	7.5%	9.5%	12.2%	9.8%
Area & Roadway Lighting	13.2%	13.2%	12.2%	13.1%

SECTION E – ALLOCATION METHODS

Costs that have been functionalized and classified by cost component in Section C are allocated to the customer rate classes. Allocation methods are based upon:

- direct identification;
- the class's share of load (kW demand and kW.h consumption) to the system load; or
- the number of customers within the class to the total number of customers.

The allocation process uses class characteristics that comport with the classification of the cost: customer costs are allocated based on a weighted or un-weighted count of the number customers in each class; energy costs are allocated based on consumption by each class weighted for losses to reflect energy at Generation; and demand costs are allocated based on demand of each class also weighted for losses to reflect the load at Generation.

Customer counts and class loads developed in Section D are used in the allocation tables to assign classified costs to customer rate classes. In this allocation process, recognition is given to:

- Use of the facilities by the rate class (i.e. the loads of large industrial customers who receive service at the Transmission level are excluded from the allocation tables used to allocate Subtransmission and Distribution facilities).

- Cost distinction between rate classes in providing for Customer-related facilities or services through the use of weighting factors (i.e. a three phase non-demand meter is approximately five times as costly as a single phase non-demand meter and this cost distinction is reflected in the customer weights used to allocate the capital cost of metering equipment).

The balance of this section is intended to provide an insight into the cost allocation process. This section contains the following schedules:

- Schedules E1-E2 summarizes the classified costs by allocation table.
- Schedules E3 – E8 represent some of the main tables used to allocate classified costs.
- Schedules E9 details all other tables used in PCOSS.

For comparison purposes the classified costs by allocation table has been shown in four versions:

- Manitoba Hydro Recommended*
- Current Method
- NERA Method *
- Generation Vintaging *

* Only Generation and Transmission classified costs are shown – other tables remain the same.

A more complete description of the differences between the scenarios can be found in Section C.

Prospective Cost Of Service Study
March 31, 2006
Classified Costs by Allocation Table - Current Method

System Load Factor	65.6%

Allocation Table	Function			Interest	Depreciation	Operating	Misc. Rev	Total
E10	Generation			349,619	108,784	183,562	(4,190)	637,775
D14	Generation - 2CP			76,520	9,543	47,869	5,983	139,914
				426,138	118,327	231,432	1,792	777,689
D14	Transmission - 2CP			106,817	47,502	48,389		202,709
				106,817	47,502	48,389	-	202,709
D21	Subtrans			5,841	15,177	22,616		43,634
D22	Subtrans		Stations	4,710	-			4,710
D23	Subtrans		Line	24,642	-			24,642
				35,194	15,177	22,616	-	72,986
D31	Dist. Plant			-				-
D32	Dist. Plant	Stn		33,786	16,772	28,111		78,669
D34	Dist. Plant	Z1	Lines	16,835	12,744	6,918		36,497
D35	Dist. Plant	Z2	Lines	9,768	5,101	4,351		19,220
D36	Dist. Plant	Z3	Lines	23,711	18,624	1,862		44,197
D38	Dist. Plant	Z1	S/E	5,341	4,276	2,244		11,861
D39	Dist. Plant	Z2	S/E	3,056	998	887		4,942
D40	Dist. Plant	Z3	S/E	7,302	3,903	1,563		12,767
				99,799	62,418	45,935	-	208,153
C20	Dist. Plant			-				-
C21	Dist. Plant	Z1	Lines	10,650	8,496	4,612		23,758
C22	Dist. Plant	Z2	Lines	6,181	3,401	2,901		12,483
C23	Dist. Plant	Z3	Lines	15,109	12,416	1,242		28,767
C25	Dist. Plant	Z1	Services	2,260				2,260
C26	Dist. Plant	Z2	Services	1,293				1,293
C27	Dist. Plant	Z3	Services	2,062				2,062
C40	Dist. Plant		Meter Investment	3,106	1,525			4,631
C41	Dist. Plant		Meter Mtce.	-		3,586		3,586
				40,661	25,838	12,340	-	78,839
C10	Dist Serv		Cust Service - General	467	3,052	23,680	-	27,198
C11	Dist Serv		Cust Acct - Billings	449	1,766	20,544		22,760
C12	Dist Serv		Cust Acct - Collections	219	826	10,007		11,053
C13	Dist Serv		Marketing - R & D	45	115	1,395		1,555
C14	Dist Serv		Inspection	42	158	1,918		2,118
C15	Dist Serv		Meter Read	189	790	9,571		10,550
C30	Dist Serv		Hot Water Tank Program	-	260	-		260
				1,411	6,968	67,115	-	75,494
			Total Allocated Costs	710,019	276,230	427,828	1,792	1,415,869

Prospective Cost Of Service Study
March 31, 2006
Classified Costs by Allocation Table - Current Method

System Load Factor	65.6%

DIRECTS

C02	Generation	Diesel	2,405	3,721	3,911		10,037
E01	Generation	SEP - GSM					
E01	Generation	Zone 2	427	123	226		776
E01	Generation	Zone 3	232	67	123		422
E01	Generation	SEP - GSL					
E01	Generation	Zone 3 (GSL 0 - 30kV)	140	40	74		255
E01	Generation	DSM Direct Assignment - Energy					
E01	Generation	Residential	1,094	854			1,949
E01	Generation	GSS ND	779	577			1,356
E02	Generation	GSS Demand	804	595			1,399
E01	Generation	GSM	947	759			1,706
E01	Generation	GSL 0-30kV	766	622			1,389
E02	Generation	GSL 30-100kV excl Curt.	62	56			118
E01	Generation	GSL >100kV excl Curt.	202	210			412
E01	Generation	Street Lights	3	7			10
E00	Generation	Curtailment (GSL 30-100)	24	22			46
E01	Generation	Curtailment (GSL > 100)	195	202			397
			5,675	4,135	424	-	10,234
D01	Generation	SEP - GSM					
D01	Generation	Zone 2	89	26	47		162
D01	Generation	Zone 3	48	14	26		88
D01	Generation	SEP - GSL					
D01	Generation	Zone 3 (GSL 0 - 30kV)	29	8	16		53
D01	Generation	DSM Direct Assignment - Demand					
D01	Generation	Residential	574	448			1,022
D01	Generation	GSS ND	409	303			711
D02	Generation	GSS Demand	421	312			734
D01	Generation	GSM	497	398			895
D00	Generation	GSL 0-30kV	402	326			728
D01	Generation	GSL 30-100kV excl Curt.	33	29			62
D01	Generation	GSL >100kV excl Curt.	106	110			216
D01	Generation	Street Lights	2	3			5
D00	Generation	Curtailment (GSL 30-100)	148	105		(423)	(171)
D01	Generation	Curtailment (GSL > 100)	2,581	1,814		(7,757)	(3,362)
			5,338	3,897	88	(8,180)	1,143

Prospective Cost Of Service Study
March 31, 2006
Classified Costs by Allocation Table - Current Method

		System Load Factor		**65.6%**			
D04	Transmission	SEP - GSM					
D04	Transmission	Zone 2	126	56	57		240
D04	Transmission	Zone 3	69	31	31		130
D04	Transmission	SEP - GSL					
D04	Transmission	Zone 3 (GSL 0 - 30kV)	41	18	19		79
			236	105	107	-	448
C01	Distribution	Lighting	3,097	2,398	7,034		12,529
C01	Distribution	Diesel	223	196	383		803
			3,320	2,594	7,417	-	13,331
		Total Directs	16,973	14,453	11,947	(8,180)	35,194
	Total		726,993	290,683	439,775	(6,388)	1,451,063
	Generation		439,556	130,081	235,855	(6,388)	799,104
	Transmission		107,053	47,608	48,496	-	203,157
	Subtransmission		35,194	15,177	22,616	-	72,986
	Distribution Plant		143,780	90,850	65,693	-	300,322
	Distribution Services		1,411	6,968	67,115	-	75,494
			726,993	290,683	439,775	(6,388)	1,451,063
	Energy		355,294	112,920	183,986	(4,190)	648,009
	Demand		323,903	138,642	165,005	(2,197)	625,353
	Customer		47,796	39,121	90,784	-	177,701
			726,993	290,683	439,775	(6,388)	1,451,063

Prospective Cost Of Service Study
March 31, 2006
Classified Costs by Allocation Table - Recommended Method

System Load Factor	**65.6%**

Allocation Table	Function	Interest	Depreciation	Operating	Misc. Rev	Total
E12	Generation	426,192	118,343	289,979	(6,388)	828,126
D14	Generation - 2CP	-	-	-	8,180	8,180
		426,192	118,343	289,979	1,792	836,306
E10	Transmission	17,288	5,893	11,814		34,995
D14	Transmission - 2CP	89,542	41,615	36,581		167,738
		106,830	47,508	48,395	-	202,733

Prospective Cost Of Service Study
March 31, 2006
Classified Costs by Allocation Table - NERA Method

System Load Factor	**65.6%**

Allocation Table	Function	Interest	Depreciation	Operating	Misc. Rev	Total
E12	Generation	426,232	118,354	338,337	(6,388)	876,535
D14	Generation - 2CP	-	-	-	8,180	8,180
		426,232	118,354	338,337	1,792	884,715
E10	Transmission	17,288	5,893	11,814		34,995
D14	Transmission - 2CP	89,552	41,619	36,585		167,757
		106,840	47,513	48,400	-	202,752

Prospective Cost Of Service Study
March 31, 2006
Classified Costs by Allocation Table - Generation Vintaging Method

System Load Factor	**65.6%**

Allocation Table	Function	Interest	Depreciation	Operating	Misc. Rev	Total
E10	Generation Wpg River	31,086	10,301	41,481	(878)	81,989
E12	Generation High Cost Plant	395,146	108,054	296,856	(5,509)	794,546
D14	Transmission - 2CP				8,180	8,180
		426,232	118,354	338,337	1,792	884,715
E10	Transmission	17,288	5,893	11,814		34,995
D14	Transmission - 2CP	89,552	41,619	36,585		167,757
		106,840	47,513	48,400	-	202,752

ANNUAL ENERGY TABLE (kW.h)

(E10)

PURPOSE

This table is used to allocate costs associated with the Energy component within the Generation function.

METHOD

This table represents the kW.h sales as measured at Generation. Distribution and Transmission losses are assigned to each rate class based upon the voltage level in which they receive service.

JUSTIFICATION

Costs that are identified as Generation are allocated to each customer class in proportion to the energy (kW.h) used by each class to the total energy generated during the period.

(E12)

PURPOSE

This table is used to allocate costs associated with the Energy component within the Generation function.

METHOD

Table represents kW.h sales as measured at Generation multiplied by seasonal marginal costs (winter on/off plus summer on/off).

JUSTIFICATION

Generation costs are weighted by marginal cost factors to recognize the differential price of energy at various diurnal and seasonal periods.

AVERAGE WINTER AND SUMMER COINCIDENT PEAK DEMAND TABLE (MW)

(D 14)

PURPOSE

This table is used to allocate costs associated with the Demand component of the Generation and Transmission function.

METHOD

Class contributions to the seasonal system peaks in both summer and winter have been averaged to develop the allocators (2CP) using load research data for 2003/04.

JUSTIFICATION

This allocation recognizes the integrated effects of export activity in both summer and winter seasons. These costs are allocated to each customer class in proportion to the contribution of each class to the maximum system peak demand. The contribution of each class to system peak includes the assignment of Distribution and Transmission losses.

CLASS NON-COINCIDENT PEAK DEMAND TABLE (MW)

(D 21 - Subtransmission)

PURPOSE

This table is used to allocate costs associated with the demand component within the Subtransmission function. There are adjustments within this allocation table to recognize the use of the facilities by the different rate classes. For example, customers who receive service at the Transmission level (>100 kV) do not share in any of the Subtransmission function costs.

METHOD

This table is based on the non-coincident peak demand of each class including losses. Class non-coincident demands have been developed using historical data derived from load research data available from fiscal year ending March 31, 2004.

JUSTIFICATION

Subtransmission costs are incurred in order that the necessary facilities are available to meet the non-coincident peak demand at the secondary level (66 kV and 33 kV). These costs are allocated to each customer class in proportion to the maximum demand requirements of each class.

CLASS NON-COINCIDENT PEAK DEMAND TABLE (MW)

(D 31 - Distribution Plant)

PURPOSE

This table is used to allocate costs associated with the demand component within the Distribution plant function. There are adjustments within this allocation table to recognize the use of the facilities by the different rate classes. For example, customers who receive service at the Transmission or Subtransmission level (33 kV or greater) do not share in any of the Distribution costs.

METHOD

This table is based on the non-coincident peak demand of each class including losses.

JUSTIFICATION

The demand component costs within the Distribution plant function are incurred in order that the necessary facilities are available to meet the non-coincident peak demand at the distribution level (25 kV and below). These costs are allocated to each customer class in proportion to the maximum demand requirements of each class.

WEIGHTED RATIO CUSTOMER SERVICE GENERAL TABLE

(C10)

PURPOSE

This table is used to allocate the general customer service costs within the Distribution services function.

METHOD

Customer classes are weighted according to total time spent by line departments on serving each customer class. For example, Key Accounts Department spend all their time providing customer service to General Service Large customers and no time on Residential customer service and are weighted accordingly. Each class is allocated a portion of the non-specific customer costs based on their share of the total weighted table.

JUSTIFICATION

General costs associated with customer service and business activities are incurred relative to the customer service efforts devoted to each customer class, rather than the number of customers actually within each class.

CUSTOMER WEIGHTING FACTORS

Table No. - C11/12 Cost Component - Customer Accounting - Billing/Collections

- The allocation table represents the percentage of billing/collection costs assignable to each rate class.

Table No. - C13 Cost Component - Marketing - Research and Development

- These costs are incurred relative to the number of customers that are being served. These costs are allocated to each customer class in proportion to the number of customers in each class.

Table No. - C14 Cost Component - Electrical Inspection

- The table represents the percentage of costs assigned to each rate class/subclass based upon an analysis of electrical inspections for the most recent five-year period. Statistics are maintained by Domestic vs. Commercial inspections within each operating area. The percentages contained within the table reflect the cost distinction between residential and commercial inspections and between Zone 1 vs. Zones 2 and 3.

Table No. - C15 Cost Component - Meter Reading

- The allocation table represents customers weighted by the relative frequency in which a meter is read by the utility. The relative frequency of meter readings by rate class is shown in the following table.

RATE CLASS	ZONE 1	ZONE 2	ZONE 3
Residential			
Standard	6.0	6.0	1.0
Seasonal	-	1.0	1.0
General Service - Small			
Demand	12.0	12.0	12.0
Non-Demand - Single Phase	6.0	6.0	2.0
Non-Demand - Three Phase	7.0	7.0	4.0
Seasonal	-	1.0	1.0
General Service Medium	12.0	12.0	12.0
General Service Large			
<30 kV	12.0	12.0	12.0
30 - 100 kV	12.0	12.0	12.0
>100 kV	12.0	12.0	12.0

Table No. - C21-23 Cost Component - Distribution Pole and Wire

- The allocation table represents unweighted customers except for street lights, sentinel lights and flat rate water heating. No costs are allocated to sentinel lighting or flat rate water heating as this service has been provided by the primary rate class (i.e. Residential or General Service). Street Lighting count reflects the number of taps into the distribution system that would be required if the lights were connected in a series through a relay.

Table No. - C25-27 Cost Component - Services

- The allocation table represents weighted customers where three phase services have a 5x weight compared to a single phase service.

Table No. - C30 Cost Component - Hot Water Tank Program "No Worry Plan"

- The allocation table represents forecasted number of customers (Residential only) enrolled in the program at March 31, 2006.

Table No. - C40 Cost Component - Meter Investment
Table No. - C41 Cost Component - Meter Maintenance

- These two tables represent number of customers weighted by the relative cost of metering equipment and the related cost of maintaining the metering equipment. No costs are allocated to non-metered services such as Street Lighting and Flat Rate Water Heating. The weighting factors for cost allocation are shown in the table below.

	WEIGHTING FACTOR	
	METER INVESTMENT	**METER MAINTENANCE**
Residential	1.0	1.0
General Service Small		
Single Phase - Non-Demand	1.0	1.0
- Demand	14.0	155.0
Three Phase - Non-Demand	5.0	50.0
- Demand	23.0	105.0
General Service Medium	36.0	215.0
General Service Large		
0 - 30 kV	49.0	530.0
30 - 100 kV	224.0	530.0
>100 kV	233.0	530.0

ALLOCATION TABLES

Function/ Table No.	Table Description	Purpose	Justification
Power Supply			
D14	Average Winter and Summer Coincident Peak	Used to allocate demand costs associated with Generation and Transmission	Generation costs are incurred so that the necessary facilities are in place in order to meet the system requirements at the time of peak usage. These costs are allocated to each customer class in proportion to the contribution of each class to maximum system peak demand in the winter and summer periods. Class demands include assigned losses.
E12	Marginal Cost Energy	This table is used to allocate costs associated with the Energy component within the Generation function.	Generation costs are weighted by marginal cost factors to recognize the differential price of energy at various diurnal and seasonal periods.
Subtransmission			
D20	Class Non-Coincident Peak adjusted for losses (NCP)	Used as a base for the class non-coincident peak demand tables, D21 - D23	Costs are incurred in order that the necessary facilities are available to meet the non-coincident peak demand at the secondary level. These costs are allocated to each customer class in proportion to the maximum demand requirements of each class including line losses.
D21	Class Non-Coincident Peak adjusted for losses excluding: - Services >100 kV	Used to allocate the demand portion for: Interest, Depreciation and Operating - associated with buildings, communication and general equipment	Loads for customers that are served at Transmission voltage levels are excluded from the Subtransmission allocation tables.
D22	Class Non-Coincident Peak adjusted for losses excluding: - Services >100 kV	Used to allocate the demand portion for: Interest, Depreciation and Operating - associated with substations and transformers	
D23	Class Non-Coincident Peak adjusted for losses excluding: - Services >100 kV	Used to allocate the demand portion for: Interest, Depreciation and Operating - associated with radial Transmission and Subtransmission lines	

Function/ Table No.	Table Description	Purpose	Justification
Distribution Plant			
D32	Class Non-Coincident Peak adjusted for losses excluding: - Services >30 kV	Used to allocate the demand portion for: Interest, Depreciation and Operating - Distribution stations and station transformers	Demand component costs are incurred in Distribution plant in order that the necessary costs are allocated to each customer class, in proportion to the maximum demand requirements for facilities in place to meet the non-coincident peak demand. Class non-coincident peak has been used to allocate all demand Distribution related costs as cost data associated with primary and secondary voltage is not available. Loads for customers that are served at the Transmission and Subtransmission voltage levels are excluded from the Distribution allocation tables.
D33	Class Non-Coincident Peak adjusted for losses excluding: - Services >30 kV	Used as a base for tables D34 - D36	
D34	Zone 1 - Class Non-Coincident Peak adjusted for losses excluding: - Services >30 kV	Used to allocated the demand portion for Zone 1: Interest, Depreciation and Operating - associated with Distribution lines and associated infrastructure	As outlined in Section B of main report. Distribution facilities are classified further into demand and customer classification on the basis of common regulatory practice of 60% demand and 40% customer.
D35	Zone 2 - Class Non-Coincident Peak adjusted for losses excluding: - Services >30 kV	Used to allocate the demand portion for Zone 2: Interest, Depreciation and Operating - associated with Distribution lines, farm lines and associated Distribution infrastructure	
D36	Zone 3 - Class Non-Coincident Peak adjusted for losses excluding: - Services >30 kV	Used to allocate the demand portion for Zone 3 : Interest, Depreciation and Operating - associated with Distribution lines, farm lines and associated Distribution infrastructure	

Function/ Table No.	Table Description	Purpose	Justification
D38	Zone 1 - Class Non-Coincident Peak adjusted for losses excluding: - Services >30 kV - Customer owned transformation	Used to allocate the demand portion for Zone 1: Interest, Depreciation and Operating - associated with Distribution transformation	
D39	Zone 2 - Class Non-Coincident Peak adjusted for losses excluding: - Services >30 kV - Customer owned transformation	Used to allocate the demand portion for Zone 2: Interest, Depreciation and Operating - associated with Distribution transformation	
D40	Zone 3 - Class Non-Coincident Peak adjusted for losses excluding: - Services >30 kV - Customer owned transformation	Used to allocate the demand portion for Zone 3: Interest, Depreciation and Operating - associated with Distribution transformation	
C20	Number of customers excluding: - Services >30 kV - Water Heating and Sentinel Lights	Used as basis for tables C21 - C23	Customer component costs are incurred in Distribution plant dependent upon the number of customers and the type of customer being served (i.e. plant installed to serve a General Service customer is more expensive than plant installed to serve a Residential customer). Weighted number of customers are used to allocate costs where there is a cost distinction between customer rate classes.
C21	Zone 1 - Number of customers excluding: - Services >30 kV - Water Heating and Sentinel Lights	Used to allocate customer portion for Zone 1: Interest, Depreciation and Operating - associated with Distribution lines, Regional buildings and general equipment	As noted in table D34, these tables represent the 40% of Distribution facilities allocated on a customer rather than demand basis.

Function/ Table No.	Table Description	Purpose	Justification
C22	Zone 2 - Number of customers excluding: - Services >30 kV - Water Heating and Sentinel Lights	Used to allocate customer portion for Zone 2: Interest, Depreciation and Operating - associated with Distribution lines, Regional buildings and general equipment	
C23	Zone 3 - Number of Customers excluding: - Services >30 kV - Water Heating and Sentinel Lights	Used to allocate the customer portion for Zone 3: Interest, Depreciation and Operating - associated with Distribution lines, farm lines, Regional buildings and general equipment	
C25	Zone 1 - Number of Customers - weighted excluding: - Services >30 kV - Water Heating and Street/Sentinel Lights	Used to allocate the customer portion for Zone 1: Interest, Depreciation and Operating - associated with service drops	Number of customers are weighted 5 x for GS Small - 3 Phase and 5 x for GS Medium and GS Large customers. Weighted customer recognizes cost differential to serve different customer classes.
C26	Zone 2 - Number of Customers - weighted excluding: - Services >30 kV - Water Heating and Street/Sentinel Lights	Used to allocate the customer portion for Zone 2: Interest, Depreciation and Operating - associated with service drops	
C27	Zone 3 - Number of Customers - weighted excluding: - Services >30 kV - Water Heating and Street/Sentinel Lights	Used to allocate the customer portion for Zone 3: Interest, Depreciation and Operating - associated with service drops	
C40	Weighted Customers	Used to allocate the customer portion for: Interest and Depreciation - associated with meters and metering transformers	An analysis of meter costs was undertaken to determine the relative costs for metering equipment by customer class and voltage level. The results of this analysis are used to weight the forecasted number of customers.

Function/ Table No.	Table Description	Purpose	Justification
Distribution Services			
C41	Weighted Customers	Used to allocate the customer portion for: Operating Costs - relating to meter maintenance costs	An analysis of meter maintenance costs was undertaken to determine the relative costs for meter maintenance by customer class. Weighted number of customers recognizes cost differential to serve different customer classes.
C10	Weighted ratio of Customer Service efforts	Used to allocate general customer service costs	Customer service costs are incurred relative to the attention demanded by the customer class, and may not be proportional to the number of customers in each class. An analysis was undertaken to estimate the efforts various departments devote to each customer class, which was weighted by the budget for each department. This table represents the weighted percentage of costs assignable to each rate class.
C11	Percentage of billing costs assignable to the rate classes	Used to allocate the customer portion for billing costs	An analysis was undertaken to determine the percentage of customer related costs assignable to each class based upon a detailed billing study which was updated with PCOSS 2006 customer numbers. This table represents the weighted percentage of costs assignable to each rate class.
C12	Percentage of collection costs assignable to the rate classes	Used to allocate the customer portion for collection costs	An analysis was undertaken to determine the percentage of customer related costs assignable to each class based upon a detailed collection study which was updated with PCOSS 2006 customer numbers. This table represents the weighted percentage of costs assignable to each rate class.
C13	Number of customers adjusted for water heating and street/sentinel lighting	Research and development	Costs are incurred relative to the number of customers that are being served. These costs are allocated to each customer class in proportion to the number of customers in each class.

Function/ Table No.	Table Description	Purpose	Justification
C14	Percentage of electrical inspection costs assignable to the rate classes	Used to allocate the customer portion of electrical inspection costs	An analysis was undertaken to determine the percentage of customer related costs assignable to each rate class based upon electrical inspection permit statistics. The results of this analysis are used to weight the forecasted number of customers.
C15	Weighted Customers	Used to allocate the customer portion for meter reading costs	An analysis was undertaken to determine the relative costs for meter reading by customer class based on relative reading frequency. The results of this analysis are used to weight the forecasted number of customers.
C30	Number of customers (Residential only)	Used to allocate costs relating to the Hot Water Tank Program (No Worry Plan)	Costs are incurred relative to the number of customers that are being served. These costs are allocated to each customer class in proportion to the number of customers in each class.